DETAILED FEASIBILITY REPORT
FOR
ADDITIONAL COGENERATION UNIT GT-IV
AT URAN PLANT

OIL AND NATURAL GAS CORPORATION

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1.0 EXECUTIVE SUMMARY

Oil and Natural Gas Corporation Ltd (ONGC), Uran Plant is an On-shore installation located at sea shore with an average distance of approximately 205 Km from the Off-shore platform. It is well connected by road off the Mumbai - Panvel road at Uran. It is about 65 Km from the city of Mumbai. It is also connected by sea opposite to the Mumbai port. Location wise, it is approximately seven Km away from JNPT (Jawaharlal Nehru Port at Nhava Sheva).

Crude Oil and Associated Gas produced at Mumbai High and other satellite fields are being transported to Uran via 203 Km long subsea pipeline viz. 30" and 26" pipeline respectively. Crude received at Uran is finally stabilized at the CSU plant and water is separated out by de-hydrator before sending to storage tanks. Besides, oil processing huge quantity of gas is processed at Uran to produce value added products like LPG, LAN, and C2-C3 etc. Following are process units of Uran plant.

Crude Stabilization Unit	: 05 Trains
LPG Plants	: 02 Units
Gas Sweetening Units	: 02 Units
Ethane Propane recovery Units	: 01 Unit
Condensate Fractionating Units	: 02 Units
Offsite and Storage	: 02 Units
Co- Generation Plant with HRSG	: 03 Units
Effluent Treatment Plant	: 01 Unit
Utilities and Flare	: 02 No

The processing complex at ONGC, Uran is of strategic importance as it handles 60% of hydrocarbons India Produces. ONGC, Uran plant has won many safety awards from Ministry of P&NG for its safe working & safe planning. In view of its importance, everybody inside the plant has to ensure that care for the safety of the plant is given top most priority. Every job inside the plant has to be thoroughly planned and executed, without any safety violation. No relaxation is permitted in safety aspects.

1.1 PURPOSE

The purpose of present study is to prepare a techno-economic Detailed Feasibility study of Gas Turbine based Co- generation power plant of approximate capacity of 20 MW Gas Turbine and 90 TPH (60 TPH + 30 TPH Supplementary Fired) HRSG at ONGC Uran Plant, district Raigad in Maharashtra.

This project report highlights the features of the existing cogeneration plant, fuel gas and process water requirements, technical features of the main plant equipments, plant mechanical, electrical, Instrumentation and Control Systems, civil and infrastructure works involved, effluent and utilities system, evacuation of power, hook-up with existing system, environmental aspects, estimates of project cost, project implementation schedule etc. of the proposed power project.

1.2 SCOPE

The scope of feasibility is to be carried out considering, but not limited to, the GT and HRSG with various details including existing cogeneration plant data, location, technical features of major equipments and equipment layout for different configurations, electrical system study, environmental aspects, project capital cost and financial analysis, project implementation plan etc. of project.

1.3 BACKGROUND

Uran plant has three Gas Turbines GE Frame V of 19.6 MW (at 40 deg Celsius ambient) each. The first two Gas Turbines were commissioned in the year 1984. Subsequently with the increase in plant power & steam loads, third Gas Turbine was commissioned during the year 2000. These machines, apart from generating power, also fulfil steam requirement of the process plant.

1.3.1 Existing Power & Steam Scenario

The Cogeneration plant Uran is run in synchronism with M.S.E.D.C.L grid. The power is either exported or imported from/ to M.S.E.D.C.L as per plant power requirements.
The installed capacity of the Plant is 58.8 MW of Power & 300 Tons of Steam per hour

- Present plant load is 48.80 MW (app) with installation & commissioning new motor driven propane compressor (3.35 MW) of LPG-1 & taking in to consideration of oil pumping as well as GT (1,2,3) internal consumptions.
- Existing steam requirement of plant is 143 TPH

1.3.2 Requirement of Power & Steam for upcoming Units

In order to process additional C-series gas from offshore, commissioning of additional LPG-III, GSU-III, CFU-III& CHU-IV are under installation.

- Additional process plant is expected to be in operation in FY 13-14.
- Requirement of Power for other coming up projects viz. Firewater Network, Air Compressor, etc. other than APUs.

Power requirement is approximately 20 MW (Continuous) and 60 TPH Steam from HRSG (with provision of another 30 TPH steam augmentation from HRSG with supplementary firing).

1.4 PROJECT HIGHLIGHTS

Table 1-1 Highlights of the project

S. NO.		DESCRIPTION/ DETAILS
1.	Project	Detailed Feasibility Report for Additional Cogeneration Unit- GT-IV at Uran Plant
2.	Location	The Proposed Cogeneration Unit shall be located at Uran Plant
3.	Accessibility to Site	
	Nearest Highway	Mumbai JNPT Highway
	Nearest Airport	Domestic airport : Mumbai – 58 km International airport : Mumbai– 58 km
	Nearest sea port	Jawaharlal Nehru Port at Nhava Sheva – 7 km
	Nearest Railway	Panvel Railway station
4.	Site Features	Site : ONGC Uran District : Raigad State : Maharashtra Latitude - Longitude : 18.86525^{o} - 72.92784^{o} Elevation above MSL : 3 to 5 m
5.	Fuel, Water and Electricity	
	Main Fuel	Natural Gas
	Gas cost with Royalty (NCV-8350 Kcal/SM3)	Rs 7.72/SM3
	Gas Consumption in GT	385 SM^3/MWh
	Gas Consumption in APU Boiler	75 SM^3/MT/hr
	Nearest Raw water source	MIDC Supply

<table>
<tr><td></td><td>Raw Water</td><td colspan="2">Rs. 25 /kL</td></tr>
<tr><td></td><td>DA/DM Water</td><td colspan="2">Rs 40 /kL (Inclusive of Raw water cost)</td></tr>
<tr><td></td><td>Imported Power with taxes</td><td colspan="2">Rs 9 /kWh</td></tr>
<tr><td></td><td>Fixed Demand Charges</td><td colspan="2">Rs 190/kVA</td></tr>
<tr><td></td><td>Electricity Duty</td><td colspan="2">Rs 0.3/kWh</td></tr>
<tr><td rowspan="4">6.</td><td>Main plant & Auxiliary systems</td><td colspan="2">Gas Turbine Generator
Heat Recovery and Steam Generator System
Auxiliary systems for Gas Turbine and HRSG
Water systems
Balance of plant systems
Electrical systems
Power evacuation arrangement
Instrumentation and control systems
Civil and structural works</td></tr>
<tr><td>Unit size</td><td colspan="2">Approx. 20 MW GT + 90 TPH HRSG</td></tr>
<tr><td>Unit type</td><td colspan="2">Cogeneration cycle</td></tr>
<tr><td>Cooling water system</td><td colspan="2">Closed Circuit Cooling Water System</td></tr>
<tr><td>7.</td><td>Overall Project Schedule</td><td colspan="2">37 Months</td></tr>
<tr><td rowspan="2">8.</td><td rowspan="2">Project capital Cost & Tariff</td><td>Capital cost</td><td>Rs 249.69 Cr</td></tr>
<tr><td>Tariff (deemed import)</td><td>Rs 9.00/ kWh</td></tr>
</table>

1.5 PROJECT COST & FINANCIAL HIGHLIGHTS

Capital cost estimate & financial analysis for DFR has been worked out and summarized below:

Table 1-2 Project Cost

DESCRIPTION	COST IN ₹ CRORES
Power Plant	
Major Items	102.03
Bulks, Spares & Chemicals	20.82
Construction Cost	42.48
Plant Buildings	8.40
Indirect Cost	34.90
Contingency	10.42
PMC Charges &TPI	8.00
Dismantling/Scrap Materials Sales	-1.00
DM Water Plant	23.62
TOTAL	**249.69**

1.5.1 Financial Highlights for the Project

Operating cost & financial analysis has been worked out based on following:

Table 1-3 Operating Cost

S.NO.	DESCRIPTION	ASSUMPTIONS MADE
1	Natural Gas price	Rs 7.72 / SCM
2	Raw Water	Rs 40.00 /SCM
3	Electricity Duty	Rs. 0.30 /kWh
4	Annual O & M charges	Rs 17.50 lakhs/MW
5	Deemed Import of Power	Rs. 9 /kWh
6	Fixed Demand Charges	Rs. 190 / kVA
7	Construction Period	28 months
8	Project Life in Years	15
9	Debt/ Equity Ratio	100% Equity
10	Working capital	Excluded

11	Depreciation	P&M-@ 5.28% SLM; @ 15% WDV ; @ 5% Salvage Value
12	Capital Phasing (half yearly)	1st 6 months - 10% 2nd 6 months - 20% 3rd 6 months - 25% 4th 6 months - 35% Last 3 months 10%
13	Capacity Build-up	1st year onwards - 100%
14	Operating hours (Annual)	330 days
15	Deemed import of Power	19.5 MW
16	Corporate Tax Rate	Basic 30% + 5% + 3% = **32.45%**
17	MAT (%)	Basic 18.5% + 5% + 3% = **20.01%**

Yearly variable operating cost comprising of cost for Natural Gas, Raw Water and Electricity duty has been escalated @ 8% pa as per ONGC input. Yearly fixed operating cost has been considered to take care of Salary & wages, Repair and maintenance, General administrative expenses and Insurance @ Rs 17.50 lakh / MWH in 1st year of operation. Yearly fixed operating cost has been escalated @ 5.72% pa (CERC guide lines) 2nd year onward over the life of the plant.

Annual Sales revenue has been calculated considering saving in energy import, saving in demand charges and saving in gas consumption by HRSG-4. No escalation has been considered in the yearly revenue over the life of the plant as suggested by ONGC as per their norms.

Capital cost has been escalated by 6% as per ONGC norms for financial analysis. Based on above assumptions, Operating cost, sales revenue, Cash flow, NPV, Internal rate of return and Payback period has been worked out for the project and are summarized in Table 1-4.

Table 1-4 Financial Analysis

SL.NO	DESCRIPTION	VALUES
1	Capital Cost (Rs. lakh) for IRR payback period calculations using 6% escalation as per ONGC norms	26466
2	Total operating Cost (Rs. lakh)	5771
3	Annual revenue (Rs. lakh)	16878

4	IRR (%) on total capital	
	Before Tax	19.66%
	After Tax	15.07%
5	Payback period (years) on Total Capital	
	Before Tax	2.9
	After Tax	3.7

1.6 CONCLUSIONS

The project, in view of above, has been considered economically viable and has been recommended for implementation.

SECTION 2.0
EXISTING COGENERATION PLANT

2.0 EXISTING COGENERATION PLANT

2.1 EXISTING CAPTIVE POWER PLANT DESCRIPTION

The existing Captive Power Plant (CPP) of Uran Complex comprises of three Gas Turbine Generators (henceforth shall be mentioned as GTG) of Frame-V model and one Heat Recovery Steam Generator (henceforth shall be mentioned as HRSG) associated with each GTG. The HRSGs are of supplementary fired type and also have Forced Draft fan (FD fan) for Forced Draft mode of operation. Each GTG produce 19.6 MW at site at ambient condition and each HRSG produce 60 TPH saturated steam at medium pressure (design pressure of 13.5 Kg/cm2) without any supplementary firing. The HRSG-1 & 2 can achieve up to 75 TPH of steam generation with supplementary firing where as the HRSG-3 can achieve up to 90 TPH with supplementary firing.

In the existing CPP, there is one package Boiler from Thermax which is installed in 1990 and is old and has reliability/ maintainability issue for sustained operation.

The IAEC boiler house in the CPP premises is currently not in use and the same is being used as store room.

The existing DA/DM (De-alkaline/ De-mineralised) plant with capacity of 57.5 DA & 2.5 DM caters to the DA/DM water requirement of the entire Uran complex including CPP.

There is one returned Condensate Stabilization System (vessel V-306, V-308 & T-303) which receives the returned condensate coming from CSU along other process units. It separates the steam from the condensate and the recovered condensate is further used in deaerator for HRSGs.

One new gas fired boiler (APU boiler of 90 TPH), as a part of ongoing APU project is being installed.

The Uran complex also has provision of Power import/ export from M.S.E.D.C.L. The Cogeneration plant Uran is run in synchronism with M.S.E.D.C.L grid. The power is either exported or imported from/ to M.S.E.D.C.L as per plant power requirements.

Following are the power Supply- Demand scenario of the ONGC Uran Complex (all data below table are in MW unit):

Table 2-1 Power supply- demand scenario (Existing)

DESCRIPTION	INSTALLED CAPACITY (MW)	EXISTING DEMAND (MW)
GAS TURBINE GENERATOR-1	19.6	48.8 – (with new propane compressor (3.35 MW) & GT-1, 2, 3 internal consumptions.)
GAS TURBINE GENERATOR-2	19.6	
GAS TURBINE GENERATOR-3	19.6	
TOTAL INSTALLED GENERATION CAPACITY	58.8	
REMARKS	Existing: CPP is capable of meeting the demand however for approximate 3 months power is imported from grid considering one month shutdown per gas turbine & during unplanned shut down of GT/s	

Following are the steam Supply- Demand scenario of the ONGC Uran Complex (in TPH unit);

2.2 Steam Supply demand scenario (Existing)

	YEAR OF INSTAL-LATION	INSTALLED/ CAPACITY (TPH)		NET USABLE CAPACITY (TPH)		EXISTING DEMAND (TPH)
		UNFIRED	WITH SF	UNFIRED	WITH SF	
HRSG-1	1984	60	75	54	67.5	143
HRSG-2	1984	60	75	54	67.5	
HRSG-3	2000	60	90	57.5	85	
Thermax Boiler	1990	60		54		
TOTAL	NA	240	300	220	275	
REMARKS	Normal operation philosophy- Plant steam demand is met through three HRSGs during 9 months of the year. During shutdown, due to annual statutory inspection, for 30 days/year of each HRSG, Thermax boiler is used to meet steam demand deficiency. Also, Thermax boiler is required during plant start-up due to power failure/ unplanned shutdown of any turbine & part load operation of turbine (due to technical/ grid isolation condition)					

2.2 REQUIREMENT OF CPP CAPACITY ENHANCEMENT

The Uran complex is undergoing revamp and capacity addition. In order to process additional C-series gas from offshore, commissioning of additional LPG-III, GSU-III, CFU-III, CHU-IV and firewater network are under installation There is also planning for new facilities in near future like air compressor system and desalination unit. To cater to the increased power and steam demand, an additional Gas Turbine of approximate 20 MW and HRSG of 90 TPH (60 TPH in HRSG mode and another 30 TPH steam augmentation provision with supplementary firing) needs to be installed.

Table 2.3 Power Scenario of the existing and Proposed Plant

	INSTALLED CAPACITY (MW)	DEMAND (MW) [UPDATED WITH NEW FACILITIES]
GAS TURBINE GENERATOR-1	19.6	48.8 - Existing with new propane compressor (3.35 MW) & GT-1, 2, 3 internal consumptions. 22- APU 2.5- Air Comp & Fire water network 05- Desalination approximate Total = 78.3 approximate With all internal consumption of GT-HRSG-4, demand will become 78.8 MW.
GAS TURBINE GENERATOR-2	19.6	
GAS TURBINE GENERATOR-3	19.6	
GAS TURBINE GENERATOR-4	20 Approximate.	
TOTAL INSTALLED GENERATION CAPACITY	78.8 Approximate	
REMARKS	As shown in the table above,GT-4 of 20 MW (app) capacity shall meet power shortfall meeting its internal consumption also otherwise this shortfall needs to be imported from MSEDCL	

Table 2.4 Steam scenario of the existing and proposed plant

UNIT	YEAR OF INSTALL ATION	INSTALLED/ CAPACITY (TPH)		NET USABLE CAPACITY		EXISTING DEMAND (TPH)
		UNFIRED	WITH SF	UNFIRED	WITH SF	
HRSG-1	1984	60	75	54	67.5	143 + 77= 220
HRSG-2	1984	60	75	54	67.5	
HRSG-3	2000	60	90	57.5	85	

Thermax	1990	0		0		
APU Boiler	2012	90		90		
HRSG-4	--------	60	90	60	90	
TOTAL	NA	330	390	316	370(app)	

Table 2.5 Steam scenario in HRSG (unfired) mode of operation

UNIT	USABLE CAPACITY (TPH)	SETAM DEMAND WITH APU (TPH)
HRSG 1	54	
HRSG 2	54	
HRSG 3	57	220
HRSG 4	60	
TOTAL	225	
REMARKS	Operation Philosophy: Total availability of steam from HRSG is matching the steam demand without any supplementary firing. Thermax boiler is considered for de-commissioning because of reliability and maintenance issue and for creation of space for installation of new GT and HRSG. In order to retain existing operation philosophy, plant steam demand shall be met through four HRSGs during 8 months of the year. This will also enable to achieve high efficiency of cogeneration cycle over simple cycle. During shutdown, due to annual statutory inspection, for 1 month/year of each HRSG, APU boiler (gas fired) shall be in operation for 4 months/year to meet steam demand deficiency. Also APU boiler will be required during plant start up after power failure with MSEDCL power, unplanned shutdown of any turbine & part load operation of turbine/ turbines (due to technical/grid isolation condition) Replacing gas fired THERMAX boiler by HRSG-4 will save fuel gas of the tune of 32 MMSCM/year amounting to savings of 25 Cr/year Surplus steam (in gas fired mode) shall be utilized in upcoming projects such as desalination, etc. (estimated demand = 60 TPH)	

Based on the above one steam generator in HRSG mode is justified for energy efficient mode of operation of the CPP.

Heat Recovery Steam Generator at downstream of gas Turbine Generator will generate steam from the hot exhaust of Gas Turbine and maximise the fuel efficiency. Typically HRSG downstream of a GT of 20 MW (at site condition) will produce 60 TPH of steam without supplementary firing. Supplementary firing provision of 30 TPH steam output augmentation will be useful to maintain steam output even at GT part load condition without much bearing of additional space and cost.

Thus with new proposed gas turbine of approximately 20 MW to meet the additional power requirement of the complex, one 90 TPH HRSG downstream of it will meet the steam demand of the complex. Additionally, the overall installed steam generation capacity will also supplement the steam requirement of the future units.

SECTION 3.0
CONFIGURATION COMPARISON

3.0 CONFIGURATION COMPARISON

3.1 PROPOSED SYSTEM

The following are the power and steam scenario in the complex with new and future process units.

Power	:	Capacity 20 MW to meet plant power demand with new facilities
Steam	:	90 TPH (60 TPH unfired + 30 TPH with supplementary firing) HRSG
Fuel	:	Fuel gas

Considering the fuel type the most efficient way of power and steam generation shall be co-generation mode by using one Gas Turbine to generate power and to generate steam Heat Recovery Steam Generator with the hot exhaust gas from the Gas turbine. Typical HRSG downstream of one standard Gas Turbine of approximately 20 MW will give 60 tonnes of steam per hour without supplementary firing. Thus one gas turbine + one HRSG shall be required to meet to the generate steam and power demands of the complex.

The power and steam scenario will be as follows;

Considering the above, Gas turbine shall be rated for approximately 20 MW in site rated design condition and HRSG shall be optimally sized for 90 TPH with supplementary firing mode and this will give power and steam reliability to the complex and even allow to maintained steam output with GT part load also.

This also gives a distinct advantage of most reliable operation as sudden failure of one HRSG will have no significant effect on complex's steam scenario as the remaining three HRSG will ramp up to meet the demand. However the power to be imported in case of tripping of any gas turbine or load shedding is resorted to non critical facilities. It may be however noted that both GTG and HRSG s are very reliable equipment.

Non-availability of space in the current plot of Uran complex is a constraint for installing this new unit. To accommodate the new units the old Thermax boiler, IAEC boiler shed (store) is considered for dismantling. This area is adjacent to the existing GT- HRSG area. Hence the new unit once installed will seamlessly integrate with the existing GT-HRSG plot. For this the following existing facility need to be dismantled.

Table 3-1 Facilities which need to be dismantled for installation of additional GT-IV

FACILITY	STATUS	REMARKS
IAEC Boiler House	Not In Service. Currently used as store.	No impact as these storage requirement shall be taken care by other existing storage facility in the complex
Thermax Boiler	Old and Have reliability/ maintainability problem.	Total availability of steam from HRSG is matching the steam demand without any supplementary firing. Thermax boiler is considered for decommissioning because of reliability and maintenance issue and for creation of space for new GT with HRSG. In order to retain existing operation philosophy Plant steam demand shall be met through four HRSGs during 8 months of the year. This will also enable to achieve high efficiency of cogeneration cycle over simple cycle. During s/d due to annual statutory inspection for 1 month/year of each HRSG, APU (gas fired) shall be in operation during 4 months/year to meet steam demand deficiency. Also APU boiler will be required during plant start up after power failure with MSEDCL power, unplanned s/d of any turbine & part load operation of turbine/ turbines (due to technical/grid isolation condition) Even for non availability of two steam generator, the complex's demand including upcoming APU can be met. Hence the Thermax boiler becomes redundant. But for non availability of two steam generator, the steam demand of the complex with upcoming APU and future Desalination plant cannot be met, for this steam shedding shall be done in non critical utilities such as desalination plant.
Existing DA/DM plant	In service. However it is highly corroded and need replacement.	As per present industrial practices a new DM water plant is installed as a part of ongoing APU project. This will give uniformity &improved quality of water and hence longer life of equipments. **For this one new DM plant is to be installed at new location (i.e. NGL unloading area) to replace the existing DA plant which is highly corroded.**
Existing returned condensate stabilization system (vessel V-306 &V-308& T-303)	In service. However is very old and highly eroded, needs frequent maintenance.	This unit is old and under frequent maintenance. **Thus new facility shall come first before replacing this existing unit**. For this, new facility need be created in respective units, i.e. in CSU where un-stabilized condensate is generated. All other unit are currently producing stabilized condensate. In CSU, there is probability of condensate

		contamination also. SO along with condenser stabilizer Vessel, Condensate Polishing Unit (CPU) is also to be installed in CSU
Existing DA tank	Not in service	This existing facility need to be dismantled to accommodate the new DM water tank.
Gas Metering Station For GT-1&2	In active service.	This need to be dismantled to accommodate the extension of control room. New facility of gas conditioning and metering facility for GT-4 shall be designed to cater GT-1 & 2 also. During the execution of the GT-HRSG-4, the installation of gas metering system for GT-1 & 2 shall be installed first before dismantling otherwise the GT-1&2 need to be run on emergency gas.
Pipe rack around Thermax boiler	Some pipes in service some not.	A new pipe rack will be erected to accommodate the pipes of Steam, returned condensate and utilities lines required for the new facility as well as the pipes need rerouting due to this new GT-HRSG unit first and then lines for HRSG-1+2 and 3 shall be hooked up one by one.
Road at the south of the CPP and culvert	In service	The Road at the south side of CPP shall be widened and the culvert on this road need to be strengthened as required for the dismantling and erecting/construction of the new GT-HRSG system.

The proposed system shall be based on standard Gas turbine model from Gas turbine manufacturer. Gas turbine model of site rated output of 20 MW will meet the requirement of complex for 8 month and approx 19 to 20 MW of power to be imported from grid for the balance 4 months from grid considering one month shutdown per gas turbine.
The available gas turbine model in this class is as follows.

Table 3-2 Gas Turbine Models

MODEL	MANUFACTURER	ISO OUT PUT	APPROX SITE RATED OUT PUT
Frame-V	BHEL/GE	26.3	20.7
H25	Hitachi	32.0	25.8
SGT 700	Siemens	31.2	24.3
Frame-VI B	BHEL/GE	42.0	33.0

Some gas turbine model are in marginal zone for the requirement such as SGT-600 model of Gas Turbine from Siemens with ISO rating 24.77 MW is expected to produce approximately 19.4 MW at site design condition.

Current engineering practice followed by Gas turbine vendors is to enhance the power output of gas turbine by providing inlet air chiller. With chiller the turbine inlet air temp is reduced and as the gas turbine output is largely affected by inlet air temperature, the output of the gas turbine is increased.

Some of the other Gas turbine models such as SGT 500 (from Siemens), Titan-250 (from Solar Turbines) are having lesser output in site rated condition (approx14 to 15MW without chiller and 18 to 19.5 MW with chiller) than the required approximately 20MW.

The chiller with its necessary refrigeration system will require some more space.

The comparative advantages and disadvantages of chiller system are as follows.

Table 3-3 Comparative advantages and disadvantages of chiller system

ADVANTAGE OF CHILLER	DISADVANTAGE OF CHILLER
○ Improve gas turbine performance. ○ Gas turbine output can be maintained irrespective of ambient dry bulb and wet bulb temperature. ○ This gives an option to utilizing the chiller capacity in certain ambient condition to generate surplus power if export option is available. ○ Considering the typical ambient condition of this site, the chiller may be required for approx 190 days (for approximately 26 MW ISO Gas Turbine model. This data shall vary with different GT model) in a year with different loading factor.	○ Requires additional chiller and refrigeration system ○ Requires more area, approximately 20 X 5 m^2 footprint per 1000 TR of VAM chiller and approx6 meter more GT inlet duct length. ○ Requires more aux power/ steam consumption. ○ High installation cost ○ Additional maintenance involved.

However considering the scarcity of space in the complex and concern of effectiveness in high humid atmosphere at Uran, gas turbine with chiller is not preferable.

Similarly sometimes supplementary fired HRSGs are designed for operating in FD (forced draft) fan also, to enable the HRSG to operate when Gas Turbine is not available. The advantage and disadvantages of this FD mode system are as follows.

Table 3-4 Comparative advantage and disadvantages of this FD mode system

ADVANTAGE OF FD MODE	DISADVANTAGE OF FD MODE
It gives operational flexibility to generate steam independent of associated gas turbine is running or not.	○ Requires more maintenance. ○ Requires more electrical, instrumentation. ○ Space requirement is more. ○ Operationally and control wise comparatively complex. ○ Initial cost is more.

The proposed HRSG of 90 TPH is similar to that of existing HRSG-3. However considering the reliability of gas turbine and all the other HRSGs already having FD fan mode, the FD fan mode for the proposed HRSG will be redundant. Hence, FD fan mode in HRSG is not considered.

3.2 COMPARISONS WITH EXISTING SYSTEM

3.2.1 Main Plant

The current gas turbines are of Frame –V model and 2 no's of HRSGs (1&2) are of 75 TPH capacity each and the HRSG-3 is of 90 TPH capacity. All the HRSGs are supplementary fired and have FD fan operation mode available. Proposed GT is similar to the existing GT capacity

Some of the higher rating gas turbine models like Frame-VIB will be able to generate much higher power than the requirement and will, thus, require running on part load as per the demand. This will result in inefficient performance of gas turbine. Hence too large size of gas turbine model will not be suitable for this project unless the excess capacity is exported to grid. Other different model of gas turbine can also meet the requirement with or without inlet chiller as mentioned earlier.

Options of different competitive established Gas Turbine models from various manufacturers are available in the required range. The final GT model will be selected during tendering stage.

The proposed HRSG of 90 TPH is similar to that of existing HRSG-3. Only difference will be that, there will be no FD fan mode in the proposed HRSG-4.

3.2.2 Balance of plant

Deaerator

One dedicated deaerator of 20 minutes holdup between normal and low level will meet the feed water requirement of proposed HRSG-4.

Boiler Feed water pump

Three no's of Boiler feed water pumps (2 running +1 standby) will meet the boiler feed water topping requirement of the proposed HRSG-4.

De Mineralized (DM) Water plant

The current DA/DM plant is very old and highly corroded. The lines, acid & alkali tanks & other associated equipments have got deteriorated in corrosive atmosphere. This DA/DM plant needs replacement. One DM plant is already coming up with APU. This new DM plant as replacement of existing DA/DM plant will provide uniformity in terms of water quality also eliminate DA and DM water mixing possibility in water and steam cycle of this entire complex.

ONGC process units are also intended to shift to entirely DM water system as per current industry practice instead of present DA & DM combined system for better performance with respect to erosion/ deposition in piping and equipment system.

Table 3-5 Capacity of Existing DA/DM plant

UNIT DESCRIPTION	CAPACITY/HR	CAPACITY / DAY	REMARKS
Existing DA plant	57.5M3–Double Streams	1380 M3	24 Hrs basis
APU DM plant	75 M3 –Single stream	1500 M3	20 Hrs basis
Total Capacity		2800 M3	

Table 3-6 DM Water Consumption

CONSUMPTION	UNIT/HR	UNIT/DAY	REMARKS
Existing plant	143 X 0.4 = 57.2	1373	Return Condensate @ 60 % considered
APU	77 X 0.3 = 23.1	555	Return Condensate @ 70 % considered
Acid Scrubber	16	384	New requirement
Process	1.5	36	Jacket cooling & others
Total consumption		2348	

However in monsoon conditions, due to municipality water quality issues, regeneration is required to be carried out much before 20 hours & thus usable capacity is effectively reduced for 4 months during the year.

Also as APU DM plant configuration is 1X 75 M3/Hr, during planned/unplanned maintenance of the unit, net availability will be reduced to nil.

In view of the above mentioned factors & to have 2 running & one standby philosophy for more reliability, new DM plant of the size 2 X 75 M3/Hr is required selected. This will offer self sufficiency with reliability of DM water.

One DM water storage tank for 1000 to 1200 m3/hr may be considered in place of existing DA tank (1000 m3 capacity) which is not in use or the same DA tank may be upgraded to store DM water. This DM water storage tank is in addition to the DM water storage tanks in APU DM plant. The feed of treated water to proposed DM plant shall be sourced from existing facility.

SECTION 4.0
PROJECT DESCRIPTION (MAIN PLANT)

4.0 PROJECT DESCRIPTION (MAIN PLANT)

4.1 DESIGN BASIS

4.1.1 Site Condition

The site is situated near Mumbai, Maharashtra. The plant is located near sea. The site ambient condition is as follows;

Table 4-1 Site Conditions

S. NO.	PARAMETER	MINIMUM	NORMAL/ AVERAGE	MAXIMUM/DESIGN
1.	Metrological data			
2.	Elevation above mean sea level (meter)		3 to 5	
3.	Barometric pressure , mbar	999	1005	1015
4.	Ambient temperature, °C	10	27	40
5.	Relative humidity, %	65	75	85
6.	Rain fall in mm (a) for 1 hr period (b) for 24 hr period	62.5	83.3	125 350
7.	Wind data wind velocity, km/hr Prevailing wind direction		South-west	160 @ is 875 South-west
8.	Earth quake design criteria			ZONE-III (as per IS 1873)
9.	Data for equipment design			
10.	Dry bulb temperature ,°C			40
11.	Wet bulb temperature , °C			29
12.	Low ambient temperature for MDMT , °C			10
13.	Designed ambient condition for gas turbine without inlet chiller			
14.	Barometric pressure , mbar			999
15.	Ambient temperature, °C			40
16.	Relative humidity, %			65

4.1.2 Fuels & Fuel Specification

4.1.2.1 Fuel Type

Table 4-2 Fuel used in GT and HRSG

GAS TURBINE	
Normal Fuel	Fuel Gas
Alternate Fuel	Emergency Fuel Gas
Starting Diesel Engine Fuel	Diesel
HRSG	
Normal Fuel	Fuel Gas
Alternate fuel	Emergency Fuel Gas

4.1.2.2 Fuel Specifications

Table 4-3 Fuel specifications for Fuel Gas

FUEL GAS COMPOSITION (%)	DESIGNED FUEL GAS (NORMAL)	ALTERNATE FOR EMERGENCY GAS	
C1	96.29	97.22	55.75
C2	2.42	1.28	30.10
C3	0.78		13.87
i-C4	0.07		0.01
n-C4	0.09		
CO2	0.05	0.01	
N2		1.49	
H2O		Saturated	Saturated
H2S			20 ppm
MOL WT	16.72		
NET CV (KCAL/SM3)	8381		
GROSS CV (KCAL/SM3)	9298		

Gas turbine and HRSG shall be designed for firing emergency gas also. Dew point of Emergency fuel gas is 40^{o}C @ 26 kg/cm^{2}a.

Battery Limit parameter for Fuel Gas:

Table 4-4 Battery Limit parameter for Fuel Gas

	NORMAL	MINIMUM	MAXIMUM	DESIGNED
PRESSURE (kg/cm^2a)	38	32	44.5	53
TEMPERATURE	30 to 35	18	35	65

Battery Limit parameter for Emergency Fuel Gas:

Table 4-5 Battery Limit parameter for Emergency Fuel Gas

	NORMAL	MINIMUM	MAXIMUM	DESIGNED
PRESSURE (kg/cm^2a)	17.5	14	18.5	20
TEMPERATURE	30 to 35	18	45	65

4.1.3 Pollution Control

The stack pollutions level shall not exceed the following limits

Table 4-6 Stack pollutions level

S.N	PARAMETER	TYPE OF FUEL	MG/NM3
1	Oxides of Nitrogen (NOX)	Gas Firing	100
2	Particulate Matter(PM)	Gas Firing	5
3	Carbon Monoxide (CO)	Gas Firing	100

Latest Pollution control measures to be applied such as DLN burner for Gas turbine and Low NOx burner for HRSG.

Continuous on-line stack monitoring system consisting of sampling probes, piping, analysers, etc. for analysis of SOx, NOx, UHC, CO & SPM shall be provided on the main stack of HRSG. The analysers and recorder shall be located in a suitable air conditioned enclosure near the stack.

The stack height shall be as per Statutory Pollution control Board regulation.

4.1.3.1 Noise Level

The noise level shall not exceed than 85 dB at a distance of 1 meter from source of Individual Equipment. Acoustic enclosure is to be used for Gas turbine for minimising the sound exposure to surrounding.

4.1.4 Steam

The steam shall be generated in the Heat Recovery Steam Generators (HRSGs) to be located in CPP. The HRSG shall deliver the required quantities of steam to the Process units.

LP Steam required for Deaerator shall be met internally.

4.1.4.1 Steam Parameters at Power Block Header

Process requirement of MP steam at Battery limit of CPP for proposed HRSG-4 are defined as below.

Table 4-7Steam parameters of MP steam at Battery limit

SERVICE	PRESSURE (kg/cm²a)				TEMP (°C)		REQUIRED QTY
	NORMAL	MAX	MIN	DESIGN	NORMAL	DESIGN	
MP steam	8.5	13.5	7.5	15	193 (sat)	<200	– 60 TPH without supplementary firing at GT base load – 90 TPH with supplementary firing at GT base load – 35 TPH with/ without supplementary firing at GT turndown

4.1.4.2 Steam Quality

Table 4-8 Steam Quality at Battery limit

S. NO.	PARAMETER	VALUE
1	Steam dryness	99.9 % (minimum)
2	Conductivity	1µS/cm (Max)
3	Silica	0.02 ppm (Max)
4	Sodium	5 ppb (Max)
5	pH	8.3 (Minimum)

4.1.5 Boiler Feed Water Quality

Table 4-9 Boiler feed water quality

S. NO.	PARAMETER	VALUE
1	Turbidity	NIL
2	Conductivity	< 5µS/cm
3	Silica	0.02 ppm (Max)
4	Dissolve Oxygen	0.005 mg/l (max)
5	Dissolve CO2	NIL
6	pH	8.5 to 9

4.1.6 DM Water Quality

Table 4-10 DM water quality

S. NO.	PARAMETER	VALUE
1	Turbidity	**NIL**
2	Conductivity	**< 5µS/cm**
3	Silica	**0.02 ppm (Max)**
4	pH	**6.5 to 7.5**

4.1.7 Miscellaneous

The Broad design consideration for the additional unit is;

- The HRSG shall be designed as per IBR
- The Gas turbine shall be designed as per API.
- The fuel firing system shall be designed as per NFPA-85.
- All relevant statutory code, standards and regulation shall be complied.

The GTG and HRSG shall be designed for minimum turndown.

4.2 MAIN PLANT DESCRIPTION

4.2.1 Gas Turbine

In order to ensure reliability in the gas turbine, its design philosophy is based upon simplicity, robustness and the use of proven technology. The gas turbines are of heavy duty industrial type which are already proven with numerous power producing installation and this class of gas turbine in the capacity range of approx 20 to 35 MW range are still the most commonly installed gas turbine in the country and abroad. One of such heavy duty gas turbine in this range is itself operating in the Uran complex for decades.

The gas turbine in this class are having a frame design with a minimum number of parts in a single-shaft arrangement operating at approximately 5000 rpm rotor speed. The compressor rotor and the turbine module form a single shaft, which rests in standard hydrodynamic bearings of the tilting pad type.

- Modularization, few parts, long component life and easy inspection ensure long time between overhauls and low maintenance costs.

- Borescope ports are available for inspection of each compressor stage.

- Manholes are standard feature in this class of turbine for easy inspection of the compressor inlet bell mouth during standstill and operation.

- The compressor casing is in general vertically split in the longitudinal direction, which allows half of it to be removed for easy access to the rotor and stator parts.

- The rotor centre line is approx 1.5m /5ft above the grating, making inspections very convenient.

An overhead crane is in general installed inside the gas turbine enclosure to facilitate maintenance and enough space is available to allow operating personnel to walk around the machine.

4.2.1.1 Compressor Section

The compressor is of a transonic type with the latest compressor aerodynamic design. It is typically a 17 stages compressor with ISO pressure ratio of10. To minimise leakage over the blade tips, generally abradable seals are applied. The vane carrier of the high-pressure section, stages where the blades are the shortest, is made from a low expansion material that helps keep clearances to a minimum.

Cooling air for the hot section of the turbine is extracted from the compressor at different stages is extracted external or internal.

4.2.1.2 Turbine section

The typical two-stage turbine is built as one module with tie-bolts for ease of maintenance and bolted to the stub shaft of the compressor. It has an advanced aerodynamic design with a fully 3D-analyzed flow path with cylindrical sections over the first, second stage blades. The airfoils of first and second stage vanes and blades are cooled. The exhaust is either radial or axial.

4.2.1.3 Combustors

Multiple numbers typically 10 no's of combustors are standard feature in this range of gas turbine. Dual fuel combustors are also available as standard feature of different gas turbine model. Some manufacturer offer dry low NOx combustor option also where as some offer water / steam injection for NOx control. DLN combustor with less than 25 ppm NOx is also available for this class of gas turbine.

DLN system of combustor shall be preferable for this project.

4.2.1.4 Generator

The driven electric generator is connected to the gas turbine shaft with gear box arrangement.

4.2.1.5 Heat and Noise Attenuation

The "core engine" has external insulation for personnel protection to reduce temperature on exposed surfaces and to minimise noise levels within the enclosure. Often acoustic enclosures are also provided.

Acoustic enclosure shall be used for the proposed gas turbine generator.

4.2.1.6 Control and Automation

The control system is built up standard control system as applicable to different manufacturer. These control system are designed for integration to different DCS system.

4.2.1.7 Measuring Equipment

Signals from the GT process are connected to I/O modules located in electrical/control room cabinets or in skid mounted junction boxes. In the process stations the signals are scaled and checked to be within the nominal signal range. When alarm or shutdown is derived from a measurement, this is performed in the process stations, with annunciation in the operator's station.

4.2.1.8 Flame Condition Measurements

Thermocouples or flame scanners are used for monitoring the temperature/ flame condition inside the gas turbine and thermocouples for the gas turbine exhaust. The exhaust temperature is measured in multiple points. The detectors together with the difference spread signal between the average and the minimum exhaust temperatures constitute the flameout protection.

4.2.1.9 Vibration

The gas turbine, gearbox and generator bearings are monitored by vibration sensors. The vibration sensors are connected to the vibration measuring rack, where signal conditioning and protection is performed. The information in the measuring rack is transferred to the control system via bus.

4.2.1.10 Gas Detection System

The gas detection system detects gas in the ventilation outlet duct to the gas turbine enclosure, other area like AIFH, GCV, SRV, GCS and metering skid, etc. The gas detectors sense the gas concentration of the air. The central unit receives and analyses the signals from the two detectors, carries out any signal treatment required and gives necessary alarm.

The central unit located in the control panel has light diodes and buzzers for alarms. Detection of a high gas concentration releases an alarm. A high-high detected gas concentration shuts down the gas turbine, by closing the fuel shut off valve and the fire valves of the external fuel system.

The system detects gas fuel leakage during all operation modes and standstill. It can only be shut down from the control room.

Smoke detections system as required at suitable places shall be provided.

4.2.1.11 CO_2 Fire Extinguishing System

Automatic fire extinguishing system based on Carbon Dioxide purging is a standard feature for fire protection purpose.

4.2.1.12 Starting System

Typical starting system for this type of machine is either Diesel generator based or static frequency based or starting motor based. Since for the Uran complex no additional margin on power in existing DG set is available for black start of proposed gas turbine, the gas turbine generator shall have on board Diesel Generator based start up system like the existing gas turbine generator.

4.2.1.13 NOx Control

DLN combustor with typically as low as 9 to 25 ppm NOx is also available for many this class of gas turbine. However some gas turbine model is having only conventional combustor with wet NOx control system (steam/ DM water injection).Gas turbines with both the types of NOx control system are in operation in several installations.
DLN system of combustor shall be preferable for this project.

4.2.1.14 Mist Eliminator

The mist eliminator is standard feature of this class of gas turbine and the same shall be provided.

4.2.1.15 Inlet Air Filter

Pulse jet (self cleaning filters) is commonly installed. In line with existing gas turbine inlet filter system, high-efficiency pulse jet filters to be installed and material of constructions of all metallic components shall be stainless steel.

4.2.1.16 Online oil cleaning system

Centrifuge based portable oil purification system are optionally provided as per the requirement of Gas turbine oil purification.

4.2.1.17 Online & Off Line Gas Turbine Compressor Cleaning System

The online water wash reduces the compressor fouling. For online water wash DM water is used and gas turbine continues to produce power during water wash. However this is not very effective in removing the compressor fouling. For this offline water wash is resorted. During off line water wash the gas turbine is desynchronized and used to rotate in slow speed and specific chemical solution is injected to gas turbine compressor for cleaning. This restores compressor performance and hence GT output.

4.2.2 Heat Recovery Steam Generator (HRSG)

The Heat Recovery Steam Generators shall be of natural circulation, single drum and single pressure type. It shall have supplementary firing. Economisers shall be non-steaming at all loads and turndown. MP steam will be generated in HRSG. The burner shall be ultra Low-NOx type.

Make up water heater (MUH) to be provided in each HRSG. It is to be ensure that

- The metal temperatures of the MUH shall be maintained minimum 5 deg C above acid dew point under all conditions.
- There shall be no steaming inside the make-up water preheater section even at low flow and lowest turndown condition.

Only seamless tubes shall be used. First few rows of the tubes shall be plain tubes and rest of the tubes shall be finned.

The design of HRSG shall ensure minimum pressure drop through the HRSG and the flow through the stack.

Steam drum shall be designed with minimum 2 minutes of capacity of storage between normal water level and drum dry level.

Necessary dosing System including unloading, storage etc. of chemicals at various points to maintain BFW and boiler water quality, which is required, finally to ensure the desired steam purity shall be provided.

Continuous on-line stack monitoring system consisting of sampling probes, piping, analysers, etc. for analysis of SOx, NOx, UHC, CO & SPM shall be provided on the main stack of HRSG. The analysers and recorder shall be located in a suitable air conditioned enclosure near the stack.

Blow down from HRSGs shall be collected in pit after being quenched with service water to 60 Deg C.

The diverter damper shall be electrically operated. For complete isolation there shall be one electrical Guillotine damper downstream of diverter damper.

Separate HP chemical dosing systems shall be provided for each HRSG.
Following on-line analyzer shall be provided in SWAS system;

- pH, Conductivity, silica analyser at BFW header.
- pH, Conductivity at condensate inlet to MUH

- pH, Silica & Conductivity for superheated steam and drum water for HRSG.

4.2.3 Process Water system

The existing water shall be used to generate DM water. Currently Reverse Osmosis (RO) based and ion exchange based DM water generation technology is used to produce DM water. Before the water is passed through the DM chain, it is generally pre-treated in Sand bed or duel bed filer. The DM water chains generally run for approximately 20 hours a day and regeneration shall be carried out in the rest of the time.

The ion exchanged based technology uses chemical for regeneration and the same is neutralised in DM plant neutralisation pit and then sent to Effluent treatment plant. On the other hand with RO technology the RO membranes are regenerated by back wash and the RO reject is also sent to ETP. In both the technology, this DM plant effluent is mixed to other incoming effluent in effluent treatment plant. The boiler blowdown water is also sent to ETP. In line with industrial practice of using ion exchanged based DM water technology in general, Ion exchange based DM technology shall be used for the proposed DM plant. The same technology is already in use in APU DM plant. This will give added advantage in terms of commonality in O&M and inventory. The DM water is stored in one storage tank in addition to the tanks in APU DM plant and this DM water is supplied to process units or to CPP steam water system as per demand. The DM water in CPP is first deaerated in Deaerator and sent to HRSG. Necessary chemical dosing as per requirement is dosed in process water.

4.2.4 Cooling water system

The Gas Turbine Generator and HRSG with their associated system generally need some cooling water. Currently there is no significant margin available in the existing cooling water system. Thus the cooling water consumption shall be tried to be minimum by adopting good engineering practice. The cooling water requirement for the system shall be met with new FRP cooling tower/ fin fan cooler.

4.2.5 Condensate Stabilizing Unit

As the old and eroded Condensate Stabilisation Unit (vessel V-306, V308) situated in CPP complex will be dismantled, the same shall need to be installed in respective unit (i.e. CSU) producing unstable condensate. As there is a possibility of contamination of condensate in CSU, condensate polishing unit shall also be installed along with condensate stabilization system.

4.2.6 Fuel Gas Conditioning Skid

One fuel gas conditioning skid with the capacity to treat the combined fuel gas quantity of GT-4 and GT-1 & 2 shall be installed. This will subsequently enable to spare the existing old and eroded gas conditioning skid for GT-1&2. This fuel gas conditioning skid comprises of 2 x 50% knock out drum, 2 X 100 % coalescer filter and 2 x 100% heater (one steam +one electric type). Metering of Fuel gas flow to individual gas turbine shall be installed adjacent to this skid.

4.2.7 Emissions

Clean gaseous fuel shall be used in the complex hence emission will be inherently low. To further reduce the emission, Dry low NOx burner shall be used in gas turbine and Low NOx burner shall be used in HRSG. Latest emission measuring instruments shall be installed in stack as per statutory pollution control board regulation.

No significant liquid and solid effluent is generated in gas based CPP. Only some transformer oil, etc. are generated during schedule replacement of oil which is taken care as per OEM recommendation. The DM plant liquid effluent and Boiler blowdown shall be treated in the existing effluent treatment plant.

4.2.8 Utilities

This new GT HRSG unit requires Instrument Air (IA), Plant Air (PA), Service Water (SW), N_2 and Cooling water. The Existing IA, PA, SW and N_2 (only intermittent requirement) system in the complex shall take care of the requirement of IA, PA, SW and this quantity are also very small quantity. The proposed GT shall be capable of Black start and for this one FRP cooling tower with one spare shell is to be installed. However the requirement of CW shall be restricted to minimum usage by adopting good engineering practice. Rest of the cooling water requirement shall be met through cooling tower or fin fan cooler. Service Water shall be used for HRSG blowdown water cooling.

4.3 ELECTRICALPOWERSYSTEM

In the existing plant, the electrical power is generated at 11kV, three phase, 50Hz by the 3 nos. existing GTG (Gas Turbine Generators) (GTG-1&2 rated at 23.8635MVA and GTG-3 rated at 21.83MW). The details included are for the addition of suitable rated GTG 4 and its other electrical equipments as required.

The existing GTGs generate power at 11kV at 22kV Co-gen bus which is stepped up through 11kV/ 22kV generator transformers (TR-751 rated at 28MVA for GTG-1, TR-752 rated at 40MVA for GTG-2, TR-753 rated at 28MVA for GTG-3) and connected to 22kV COGEN bus. The rating of the existing 22kV switchboard is 22kV, 2000A, 26.2kA for 1 sec. The 22kV COGEN bus is further connected to 22kV HBB bus via two 22kV, 40/48MVA series reactors. The rating of the 22kV switchboard at HBB is 22kV, 3000A, 26.2kA for 1 sec. Power from 220kV grid of MSEB is imported and stepped down to 22kV using 2 Nos. 60/75MVA 220/22kV grid transformers. These are hooked up at 22kV HBB bus. Auxiliary power for GT auxiliaries at 415V is obtained through 11/0.433kV Unit Auxiliary Transformer (UAT) by tapping from the main run of the cable between Generator circuit breaker and Generator transformer of Gas Turbine Generator (GTG) unit. The electrical power distribution system for the existing plant is shown in the enclosed as Annexure-2 **“Main Single Line Diagram & Emergency Power Distribution System at LPG/ CSU Plant, Uran”- (ONG-URN-ELE-04-B-001)**

The new GTG-4 shall also generate power at 11kV which shall be stepped up to 22kV using generator transformer. It is intended to hook up the new generator at 22kV HBB bus instead of hook-up to the 22kV COGEN as is the case with the existing generators. Since bulk of the power including the new APU is being utilized from HBB and the series reactor rating is limited to 40/48MVA due to constraints of the short circuit level, in order to get maximum advantage and reliability for power evacuation, GT-4 shall be connected to the 22kV HBB bus. The auxiliary power (415V) for unit auxiliaries shall be obtained through UAT as followed in the existing electrical system.

Electrical Auxiliary power distribution arrangement & Power Evacuation Arrangement is shown in the enclosed as Annexure-3 “**Electrical Key Single Line diagram”-** (**A333-000-16-50-00001 Rev. A)**

During normal operation, all four generators would be running and grid shall be connected at the 22kV HBB bus with **HBB bus coupler NO**. Preliminary power system studies were carried out on E-TAP software and following were the broad observations for the same:

- The short circuit rating of existing 22kV switchboards at COGEN as well HBB is not found adequate. With addition of new generator the short circuit rating of 22kV switchboard both at COGEN as well HBB shall exceed the existing rating.

Based on the report outputs, **both switchboards are to be replaced by 22kV, 2500A, 40kArms/ 100kA (peak) for 1sec GIS.**

- The existing series reactors with new generator connected to HBB bus are found to be of adequate and the same shall be retained with new GIS.

For complete details of the power system studies, refer the report enclosed Annexure-4 Preliminary Power System Studies- (A333-000-16-50-CAL-4001)

- The following major electrical equipment is envisaged for the project:
- Electrics for GT-4, generator transformer, Unit Auxiliary Transformer, Cabling, lighting etc.
- Synchronising panel, relay & protection panel for GT-4 and generator transformer
- 22kV, 40kA GIS switchgears at COGEN and HBB. 22kV, 40kA GIS isolator breaker panel.
- Adequately rated 22kV cable shall be laid between generator circuit breaker (GCB) at CO-GEN substation and 22kV HBB bus.
- New 22kV busduct/ cable shall be provided between grid transformers and the 22kV HBB bus.
- Cable joints shall be provided in existing power & control feeder cables in existing 22kV panels at COGEN & HBB to facilitate their termination at new 22kV GIS at both the substations.

The electrical equipment for the project shall be installed in the following substations:

- 22kV GIS at CO-GEN shall be installed in the switchgear room for the existing main substation at CO-GEN after dismantling the existing 22kV switchboard.
- Generator Circuit breaker and UAT Circuit breaker shall be installed in the switchgear room in the existing CO-GEN substation.
- All electrical control, synchronizing and annunciation equipment shall be installed in the existing control room building in CO-GEN. It is proposed to extend this building to accommodate the control system equipment for new GTG.
- All GT aux 415V, MCCs, PCCs, LDB, ASB and UAT shall be accommodated in the new GTG switchgear hall.
- Generator transformer shall be accommodated in the transformer bay near the new GT switchgear hall.

- 22kV GIS at HBB shall be installed in the existing switchgear room in HBB by dismantling the existing 22kV switchboard.

For emergency power requirement of the entire project & during blackout condition, emergency 415V power supply from existing EPMC shall be provided for black start of the GTG and to feed all the essential loads and for safe shutdown of the Units.

Motors rated upto160kW shall be connected to 415V bus and motors of rating above 160kW shall be connected to 6.6kV bus. MV motors up to55 kW will be fed from Motor Control Centres (MCCs) whereas; motors rated above 55kW and up to 160 kW shall be fed from Power Control Centres (PCCs)

415V PCCs shall be provided with Auto/manual transfer arrangement between the two incomers and bus coupler.

Normal, emergency and DC critical lighting has been envisaged for the plant.

The lighting loads of the newly added buildings, equipments and areas shall be fed through lighting Distribution Boards (LDBs) connected to 415/415V lighting transformers which draw power from 415V switchboard. 20% to 25% of plant lighting shall be on AC emergency. Emergency lighting load shall be fed through suitable nos. and rated emergency lighting feeders (to be provided by Client) which in turn shall get feed from Emergency Lighting Distribution Boards (ELDBs) having supply through 415V/415V Emergency lighting transformers.

Auxiliary Service Boards (ASBs) shall be provided to feed new power panels, welding receptacles, miscellaneous loads etc, as required.

To provide uninterrupted power supply to DCS and other Control Panels, a dedicated 110V AC UPS system shall be provided. To feed GTG essential loads, such as the emergency oil pumps 125V DC system shall be provided. For the control Supply to Switchgears / Panels, Emergency DC lighting etc, 110 V DC supply backed by DC Batteries shall be provided.

4.3.1 System Design Philosophy

4.3.1.1 Voltage Levels in the power plant shall be as follows:

- Power evacuation : 22kV (+10%,-10%), 3 phase, 3 wire, 50Hz
- Generation Voltage : 11kV,3phase,50 Hz
- Plant LT Auxiliary Supply : 415V (±10%), 3 phase, 4 wire, 50Hz
- Plant DC Supply : 110V (±10%), DC 2 wire.
- DC system for GTG-4 : As Required

- Plant UPS Supply : 110 (±10%), 1 phase, 2 wires 50 Hz, A.C.
- Voltage level for AC Motors Below 0.2kW : 240 V, Single phase, 50 Hz, with DOL start.
- Voltage level for AC Motors From 0.2kW to 160kW : 415 V, Three phase, 50 Hz, with DOL start.

4.3.1.2 Design short circuit levels shall be at least the following and has to be supported by calculation:

- Three phase symmetrical short circuit ratings of 22kV System: 40 kA for 1 sec.
- Three phase symmetrical short circuit ratings of 415V System: 50kA for 1 sec

4.3.1.3 The Electrical system shall be designed to provide:

- Safety to personnel and equipment both during operation and maintenance
- Reliability of service.
- Minimal fire risk.
- Ease of maintenance and convenience of operation.
- Automatic protection of all electrical equipment through selective relaying system.
- Electrical supply to equipment and machinery within the design operating limits.
- Adequate provision for future extension and modification.
- Suitability for applicable environmental factors.
- Maximum inter-changeability of equipment.

4.3.2 Electrical Equipment

Electrical equipment and components shall be designed in accordance with applicable Indian Standards and shall conform to statutory regulations.

4.3.2.1 Generator Circuit Breaker (GCB-4)

The generator circuit breaker (GCB-4) shall be installed inside the switchgear room (first floor of the control room).The circuit breakers shall be designed for natural air cooling. The GCB shall be of VCB, metal enclosed, indoor and free standing type with an operating duty of CO-30 min-CO for short circuit current and O-3min-CO-3 min-CO for load current.

The voltage rating of generator transformer primary shall preferably be 11kV same as that of the existing system and the same will be matched with the generator voltage after finalization of generator particulars. The ratings of Generator Circuit Breaker (GCB) shall be matched with the generator particulars. The preferred voltage rating of GCB shall also be 11kV same as that of the existing system.

The short circuit rating of the GCB shall be arrived at by the following criteria:
Fault contribution from the generator.

OR

Fault contribution from the 22kV system and from the motors through Unit Auxiliary Transformer. For this purpose the 22kV system fault contribution shall be considered as limited only by the impedance of the Generator Transformer.
The higher of the two values shall govern the selection of the short circuit rating of the GCB.

4.3.2.2 Generator (GTG-4) Relay Panel

All protective relays, auxiliary relays, timers, etc., to protect the complete generator, its Subsystems, generator transformer (GT) shall be housed in Generator relay panel (GRP). All protective relays shall be numerical communicable type with serial interface facility. All protective relays and meters shall be provided with test terminal blocks for secondary injection testing.

The relay panel shall be of free standing, floor mounting, sheet steel enclosed, with a degree of protection of not less than IP 42. The panel shall be located in the control room. The panel shall be fabricated out of CRCA sheet steel of not less than 2 mm thickness.GRP shall also accommodate a digital tri-vector meter (TVM) and energy accounting /auditmeters. The accuracy class of TVM/energy accounting/audit meters shall be Cl.0.2S. Tri-vectormeters shall have pulse output for interfacing with DCS.

HMI consisting of operator and engineering workstations, data concentrator panels etc. shall be provided for the generator relay control panel.

4.3.2.3 Transformers

Following transformers are envisaged in the project:

- Generator Transformer for GTG-4.
- 1 No. of Unit Auxiliary Transformer (UAT)

Generator transformers shall be three phase, oil immersed double wound type, suitable for outdoor use. Unit Auxiliary Transformer shall be dry type transformer suitable for indoor use. The percentage impedance of each transformer shall generally be as per Indian Standards.

Generator Transformer

Generator Transformer shall be used to connect Generator to 22 kV network to evacuate power. The rating of the generator transformers shall be selected such that there will not be any limitation on the generator transformer for evacuating the full Gas Turbine output under all operating conditions at site. The generator transformer for GTG shall be suitable for bidirectional power flow.

Unit Auxiliary Transformer

1 x100% UAT shall be provided for supplying plant auxiliaries as per the Single line diagram. The rating of Unit Auxiliary Transformers shall be chosen such that each transformer can take the entire loads of complete plant. It shall be of dry-type and shall be installed inside the GT-4 rack room. Starting requirements of higher size motors shall be duly considered while sizing the transformer.

4.3.2.4 Gas Insulated Switchgears (GIS)

22kV Switchboards at COGEN and HBB shall be gas insulated switchboards. The GIS shall have double busbar arrangement. The minimum degree of enclosure protection shall be IP-4X.

The switchgear gas enclosures shall be sectionalized with gas tight barriers between sections. The power connections from one compartment to the other shall be done using gas tight high voltage bushings. Suitable busbar disconnectors and earthing switch shall be provided for each circuit breaker/ isolator to permit safe isolation and earthing of any feeder circuit. Suitable gas release mechanism shall be provided for different enclosures.SF_6 / VCB circuit breakers shall be used in the switchboard. **The existing numerical relays in the existing relay and control panels shall be utilized for the GIS switchboards. However, the protection relays for GT-4 incomer shall be mounted on the existing relay & control panel.**

The connection between the 220kV grid transformers and 22kV GIS incomers at HBB shall be through busduct/ cables.

4.3.2.5 MV Switchgear

All the switchgears shall have rating at least equal to the maximum demand plus a provision for 10% future load growth. Incomers of switchgear shall be designed to cater to the complete load including 10% margin for future load growth. Spare outgoing feeders shall be provided in all switchgears. At least one number of each rating & type or 10%, whichever is more, shall be provided as spares. Service breaking capacities for all breakers shall be equal to or higher than the maximum value of the short-circuit at the point of installation. Numerical relays are envisaged for PCCs along with data concentrator & HMI.

Switchboards (e.g. PCC, MCC, ASB and LDB etc.) shall be with two fully rated incomers and one buscoupler with interlock. Normal operation shall be with both incomers ON and buscoupler OFF. Upon failure of any one of the incomer due to loss of power supply, the buscoupler will be closed.415VMCC/ASB incomers shall be heavy-duty switch having mechanical interlock &415VLDBincomersshall be MCCB having mechanical interlock.

4.3.2.6 DC System (Battery charger, battery bank and DCDB)

Battery Charger and Distribution board shall be floor mounted, free standing, metal enclosed and vermin proof type having hinged door for front access and shall be suitable for indoor use.

The battery charger/rectifier shall feed the load and keep the batteries under fully charged condition.

Provision shall also be made for necessary boost charging/initial charging of battery. Batteries shall be of adequate capacity to meet the back-up requirements as envisaged on the duty cycle.

While sizing the battery, temperature correction factor and ageing factor shall be considered in addition to the maintenance factor.

4.3.2.7 Uninterrupted Power Supply System

UPS system shall include a set of storage batteries, rectifier transformer, rectifier- cum-charger, inverter, set of filter circuit, static switches, bypass transformer, facility for manual transfer between inverter supply and bypass line, facility for bypassing inverter & static switch for maintenance, AC Distribution board and other associated accessories.

4.3.2.8 Motors

In general, three phase squirrel cage induction motors designed for direction line starting shall be used. Motors shall be totally enclosed, fan cooled type and suitable for continuous outdoor use.

Motors rated up to 160KWshall be fed from 415V and 6.6KV above 160KW.

Motors above 22KW shall be provided with space heaters.

4.3.2.9 Cables and Wires

HV power cables shall be XLPE insulated, PVC sheathed, armoured type with aluminium/ copper conductors and MV power and control cables shall be PVC insulated, PVC sheathed, armoured type with aluminium/copper conductors.

The sizing of high voltage cables shall be based on short-circuit withstand capacity for a minimum period in addition to the maximum anticipated load current.

4.3.2.10 Lighting system

The lighting system of the complete area shall be designed as per good engineering practices to achieve the specified illumination levels.

The lighting system shall include

- Normal lighting
- Emergency Lighting
- DC critical lighting

Lighting distribution system shall consist of normal & emergency lighting transformers, normal & emergency lighting distribution board, lighting panels etc. Lighting transformers shall receive power from PCC in substation and distribute to LDB. Lighting transformers shall be dry type, 415/415Vand provided with ±2.5% & ±5% taps.

For indoor lighting in the buildings, HPMV/ fluorescent lighting fixtures shall be used.

For general outdoor lighting, 30m tubular telescopic type flood lighting high mast shall be provided.

For street lighting, HPSV lamps on bent arm street lighting pole of9m/11m height shall be provided.

DC lighting shall be provided in the critical areas/building for safety of plant operations.

Aviation warning lights shall be provided for all tall structures, stacks chimneys etc. as per statutory regulations.

4.3.2.11 Earthing and lightning protection

Earthing and lightning protection shall be provided for plant safety and shall be designed in accordance with IS-3043.

The earthing system shall be provided with adequate numbers of GI earth electrodes in test pit and interconnected network of GI earth strips to achieve designed value of earth resistance.

4.3.3 Salient Features of Electrical System/Facilities

The following are some of the important features of electrical system/facilities envisaged:

- All protection relays for HV switchboards, PCCs and Generators shall be numerical microprocessor based communicable type and provided with data concentrator and HMI system.
- Fire alarm devices have been considered for the new facilities which shall be hooked up to the existing fire alarm system.
- Field call stations etc. have been considered for the new faculties and the same shall be hooked up to the existing plant communication system.

4.4 PIPING SYSTEM AND FUTURE HOOK UP

Suitable tap off connection shall be provided in all applicable headers such as steam header tapping for future Desalination unit. This will enable future unit hook up without shut down.

4.4.1 Codes and Standards

All piping shall be designed as per ASME B31.3, Boiler external piping which required to conform to ASME B31.1 as per also be complied. Steam, boiler feed water and condensate lines falling under the purview of the IBR shall be meeting the requirement of Indian Boiler Regulation (IBR).

4.4.2 Equipment/Piping Layout Criteria

- Equipment Layout shall meet all the aspects of erection, maintenance, operation, safety etc.

- In general foundation height of pumps and equipment shall be minimum 300mm above HPP (Highest Point of Paving).

- Piping passing through structure (RCC floors) or passing near the concrete column etc. should have adequate annular space to avoid restriction of line movement during thermal expansion. The gap should be taken care for hot lines along with insulation thickness. The gap should be sufficient to take care of any fouling with fireproofing etc.

- All branches from headers shall be taken from top (utilities) unless restrained by P&ID requirement.

4.4.3 Pump Piping

Monorail shall be provided along with chain pulley blocks for pumps as per the requirement for maintenance of pumps, exchangers, etc.

Operation and maintenance access shall be clearly marked around the pumps. All auxiliary piping shall be routed in such a way so as to ensure that there is no hindrance in the access areas.

Cone type temporary strainers shall not be used in pump suction piping.

4.4.4 Pipe Rack

To design the pipe rack/sleeper with a minimum of **25%** extra future space of the total width of the pipe rack(all tiers combined together)/sleeper up to widths of 16 metres and

10% extra future space for widths above 16 meters, shall be earmarked for future expansion on the pipe rack/ sleeper. The future space on each tier of the rack/ sleeper throughout the length of pipe rack/sleeper shall be maintained and shall be 1500mm minimum on each tier of the pipe rack.

Maximum width of the T-post shall be restricted to 2.5M. The width of main pipe rack shall be 6M/ 8M/ 10M/ 12M/ 16M/ 20M as per requirement having 4 tiers maximum. The span of the pipe rack shall be 6M/ 8M.

No cantilever shall be provided in the pipe rack for meeting present as well as future extra space requirement.

Requirement of intermediate beams for width/span of pipe rack shall be established during detailed engineering on the basis of support requirement of small bore piping.

Piping shall run at different elevations for North-South & East-West directions and change elevation at change in direction.

Total rack shall be designed for densest/ heaviest section. Rack shall be designed to meet specific requirements of P&ID, like, free draining, no pocket etc.

Weld seam of pipe shall be kept such that it is always in the upper quadrant.

Cable tray-laying shall take care of necessary clearance for fire proofing of structure.

Instruments on piping to be planned in such a way, meeting P&ID requirements, that access for all instruments on piping & vessel is provided. Flow instruments in pipe-rack also to be located in such a way that these are approachable by platforms/ladder.

4.4.5 Pipe Spacing / Pipe Span

Actual line spacing shall take care of thermal expansion of adjoining lines during operation as well as pre-commissioning/start up conditions. The spacing of pipelines in the transverse direction across the pipe rack should take into consideration the longitudinal expansion of the pipe along the pipe rack.

4.4.6 Nozzle Loading

Piping shall be so routed and supported, to limit nozzle loadings and moments on equipment and machinery within allowable limits when furnished by respective vendors.

In the absence of vendor data relevant codes like API 610, API 621, NEMA SM23, API560, API661 etc. or any other approved proven international code/ practices may be followed in case of equipments conforming to these standards.

4.4.7 Utility Hose Station

Utility hose stations shall be provided for steam, Air, Water, etc. as indicated in the P&IDs. Number of Hose Stations, if shown in P&IDs, have indicative importance only and adequate number of hose stations shall be provided so that every area at Grade, in structure, buildings etc. can be reached from at least one hose station.

Each hose station shall be furnished with 1" dia., 15 meter long hose, and one for steam, one for Air and one for Water. All piping connections at the hose stations shall be flanged for steam and shall have quick coupling for Air and Water. Free end of hoses shall be provided with nozzle, with insulated holder for steam hose.

Hose Stations for Nitrogen and any other service shall be provided as per the requirements of P&IDs. Hose station for nitrogen shall be provided with inbuilt non return valve in the quick coupling at pipe side connection.

The sequence of lines in hose station shall be steam, air and water from left to right when looking from front.

Care shall be taken, while installing utility stations under Pipe-rack, to ensure that they do not foul with electrical /instrument junction box. If necessary, these may be staggered.

Hose stations, with numbers, are to be marked on the Equipment Layout during detailed engineering.

4.4.8 Steam Piping

Steam piping under the purview of IBR shall meet the requirement of Indian Boiler Regulation (IBR). Latest IBR shall be followed for execution.

4.4.9 Flare Piping

Flare header shall be sloped towards flare knock-out drum. Expansion loop shall be provided in horizontal plane as per requirement to accommodate thermal expansion. The desired slope shall be ensured throughout including flat loop. Flare header shall be supported on shoe of height ranging from 100mm to 300mm.

Proper thermal analysis temperature shall be established including the possibility of temperature gradient along the line before providing expansion loops. Efforts shall be made to minimise the number of loops.

Flare line between knock out drum and water seal drum shall be designed for pressure fluctuations and adequately supported to avoid vibrations.

4.4.10 Heat Traced Piping

A condensate collection system shall be designed to collect condensate from traps and steam supply/return manifolds.

Steam supply manifolds for steam tracing shall not be located at grade. These shall be located above on the pipe rack and shall be accessible by continuous platform. This continuous platform shall be approachable from grade by monkey ladder at every 50 meters.

4.4.11 Stress Analysis

Piping arrangement shall provide for flexibility of lines to take care of the thermal expansion, contraction and equipment settlement. Large reactions or moments at equipment connections shall be avoided.

Expansion computation and Stress Analysis shall be done on the basis of a base temperature of 21.1ºC (70ºF) and shall cover (+ve or -ve) design temperature(s) as shown in line schedule as well as start-up, shutdown and variable operating conditions. Analysis shall be done considering the actual fluid densities in the line.

i. Flexibility analysis shall meet the requirements of Code ASME B-31.3 (latest edition). Analysis shall consider stress intensification factors as per ASME B-31.3.

ii. Flexibility Analysis of lines shall be carried out using simplified methods or a comprehensive computer program. Comprehensive computer analysis shall be carried out for piping as per sub clause (vii) below for lines connected to equipments like vessels, pumps, turbine, filters, furnaces or other strain-sensitive equipments. The result of the analysis must satisfy the allowable loading on nozzles of such equipments.

iii. Piping shall be adequately supported for weight of piping, water full, attached unsupported components, wind, seismic, dynamic loads, insulation and any other applicable forces. Care should be taken that these supports are adequate to prevent excessive stress, loads or moments in either the piping or terminal nozzles of the equipment to which it is connected. The supports shall be indicated in the piping isometrics.

Adequacy of supporting of lines having heavy valves shall be checked. Adequacy check of the supports for imposed loads shall also be carried out. Adequacy of nozzles shall be checked to bear hydro-test loads, otherwise suitable precaution to be taken at nozzle points.

For design of supports, due consideration shall be given for all load cases including hydro-test. Load generated due to wind and seismic effects shall be considered for design of supports. Pressure thrust shall be considered for all lines.

iv. Safety valve manifolds and piping downstream of control valves shall be adequately supported to avoid vibrations.

v. Flange joints shall be checked for leakage for total equivalent pressure at flange joints due to combined effect of imposed forces and bending moments and internal pressure. **Flange leakage checks shall be performed for the above lines as per ASME Section VIII Div. 1 or Div. 2.**

vi. The following factors/limits shall be considered in the stress analysis:

- Friction factor:
  - STEEL to STEEL = 0.3
  - STEEL to PTFE = 0.1
  - STEEL to GRAPHITE = 0.15
- With and without Corrosion Allowance
- Initial thermal displacement of nozzles
- Transverse deflections due to sustained loading = 25mm (maximum)
- Vertical deflections in piping system between two adjacent supports due to sustained loading =15 mm (max) for all lines except steam and flare lines. For steam lines the above deflection limit shall be 3mm max and for flare line it shall be such that slope is maintained in the flare line.
- Stress Analysis report shall contain corresponding nodes to demonstrate that the above limit of vertical deflection is not exceeded.
- Longitudinal expansion/contraction = 200mm (maximum)
- Special care to be taken to check for expansion loops and shoe support lengths shall be finalized accordingly.

4.4.12 Dynamic Analysis

Dynamic analysis shall be performed during detailed engineering for all two phase lines having slug flow and transfer lines in the plant, in order to ensure that such lines are provided with proper supports and there shall be no vibrations in the line during normal operation as well as during start up or any upset conditions.

Dynamic analysis to be performed at design temperature and operating temperature. Actual densities shall be considered while carrying out static analysis.

The fundamental frequency of the piping system is to be checked to avoid resonance. The minimum acceptable frequency can be considered as 7 Hz for Transfer lines and 6 Hz for other lines. Contractor shall submit mode shape plots up to 15Hz. Model displacement output shall be submitted.

Boundary condition and other parameter used in dynamic analysis shall also be part of dynamic analysis report.

4.4.13 Piping Supports

All piping shall be adequately supported, guided or anchored so as to prevent undue vibration, deflection/expansion or loads on connected equipment and piping and leakage at joints.

Piping at valves and equipments such as heat exchangers and pumps, requiring periodic maintenance, shall be supported in such a way so that the valves and Equipments can be removed with a minimum necessity of installing temporary pipe supports.

The first solid support for pump suction and discharge lines shall be adjustable type to facilitate pump alignment. Pedestal for pipe supports for outdoor installation shall be 150mm above HPP.

Long trunnion type supports are to be avoided. In case long trunnion type supports are unavoidable in straight length of pipe, it is to be provided with reinforcement pad on the pipe.

For insulated lines on pipe rack shoe support shall be provided. Shoe height shall be based on insulation thickness. Minimum shoe length shall be 300mm and shall be suitably increased to suit thermal movement of line.

Shoe shall be sufficient height such that temperature of the contact point on pipe rack/ support location shall not exceed a temperature of 120deg.C on concrete or 350deg.C on structural steel.

All the supports in a piping system shall be checked for their correctness & adequacy after complete installation by the designer.

The pump piping from vessels in technological building/columns may require cantilever supports to be taken from the pipe rack or from the technological building to maintain the basic spans.

T-supports from pavement shall be minimized. Anchor fasteners for T supports shall not be used.

Spring supports shall have Teflon pad on top slide plate of spring for temperature up to 200°C and graphite pad or roller bearing for higher temperatures.

Spring supports should be unlocked and cold set prior to commissioning of the system, by Contractor as per the instructions of the spring manufacturer.

For lines on pipe rack/sleeper, resting support on every grid of pipe rack/sleeper shall be provided.

4.5 CIVIL & INFRASTRUCTURE

The Site is almost flat. Existing facilities is already there. Some of these facilities are required to be dismantled to accommodate the new unit. North side road and the culverts need to be widened and strengthen to enable construction of new GT HRSG unit. The existing control room need to be extended to accommodate new electrical and instrumentation facility.

4.5.1 Plant Layout

The layout of main plant along with all auxiliary systems is shown in, Annexure-1. In laying out the various facilities, consideration has been given to the following general principles:

I. Power and steam Generation facility
II. Fuel gas facilities
III. DM plant facility

Emphasise have been given to minimise the facility/ building footprint on the lay out and multi storied facility is adopted where possible such as in switch gear room.

4.5.2 Site Topography and Graded Level

The proposed power plant area is found to be flat. There are existing facilities which will be dismantled. During detail engineering to finalize the finished grade level of the site existing plant grade level of the adjacent GT HRSGs to be considered.

4.5.3 Foundations

For moderate to heavily loaded columns, for all major and important structures such as GT, HRSG & stack etc. deep foundations in the form of piles will be finalised based on soil load bearing capacity. Pile foundations are also required to support high dynamic loads. Open shallow foundations can be provided for lightly loaded structures such as boundary wall, pipe supporting structures etc.

4.5.4 Main Power House Buildings

The main power block comprises of gas turbine generator building planned to suite functional requirement. After finalisation of Gas turbine model during award of tender, all effort shall be made to accommodate the proposed gas turbine to be accommodated in a shed which will be the extension of the existing GT hall shed.

4.5.5 Design

Dead and live loads will be considered as per relevant IS codes and standard engineering practices. The basic wind speed would be considered for design of buildings/ structures as per IS code. Accordingly to seismic zone seismic forces would be considered for the design of structures / buildings. The buildings / structures are designed for wind or seismic loads whichever governs. All designs would be carried out in SI units and would be as per relevant IS codes.

4.5.6 Materials

All civil construction materials used would confirm to relevant IS standards.

4.6 CONTROL AND INSTRUMENTATION

4.6.1 Totally new Instrumentation and control systems both at field and control room are envisaged for the Additional Co-generation unit, including the following.

- Gas turbine control system
- Distributed Control system
- Programmable Logic Controllers
- Analyzer systems

4.6.2 The new control system will need to be integrated with the existing control systems details of which are as given below

- Existing DCS- Honeywell make
- GT-I control system- Mark V
- GT-II control system- Mark II being upgraded to Mark VI E
- GT-III control system- Mark V

4.6.3 It has been envisaged to engineer control room for Gas turbine generator-IV, HRSG-IV, new DM plant and all related/associated /auxiliary units. The man-machine interface/consoles for all new control systems including those required for new Gas Turbine Controls, new Burner Management Systems (BMS) shall be located in the existing control room building. The existing control room building will need to be modified/ extended to accommodate the above.

4.6.4 Adequacy of the existing UPS and HVAC systems of the control room needs to be assessed during detailed engineering.

4.6.5 The new control system rack/panels along with its new UPS are envisaged to be located in new GT-4 switch gear building.

4.6.6 Existing analyzer room located adjacent to the Thermax boiler needs to be relocated and the new analyzer systems will also be installed in this relocated analyzer room.

SECTION 5.0
PROJECT DESCRIPTION (DM PLANT)

5.0 PROJECT DESCRIPTION (DM PLANT)

ONGC's upcoming process units (APU) are designed to use DM water and for this purpose, one DM water plant is being installed along with APU. As per current industry practices, only DM water is used instead of DA water since it provides benefit of better (lesser) corrosion and deposition characteristics to the equipments and piping. So, ONGC intended to shift to DM water system entirely, instead of present DA & DM combined system for better performance of its existing facilities.

The existing DA/DM plant is very old and highly corroded. Further this existing DA/DM plant need to be dismantled for creation of space for new additional Gas Turbine -IV and HRSG. Thus this DA/DM plant needs replacement and a new DM plant needs to be installed.

For uninterrupted DM water supply the new DM plant will be installed before dismantling of existing DM plant.

The new DM water plant shall be with double chain each with a capacity of 75 m^3/hr. The purpose of the DM Plant will be to demineralise the feed water to the required quality.

DM Plant shall consist of PSF-SAC-SBA-MB and a degasser tower for producing DM water. Degasser Tower will be designed for the gross flow of SAC exchanger.

For regeneration of cation exchange resins (of SAC and MB exchangers) Hydrochloric acid will be used. Two Nos. each (1W+1S) of Acid measuring tanks (which can be interchangeably used) will be provided separately for SAC exchanger and MB exchanger respectively. For regeneration of anion exchange resins (of SBA and MB exchangers) Caustic lye will be used. Two Nos. each (1W+1S) of Alkali Measuring / dilution tanks (which can be interchangeably used) will be provided separately for SBA exchanger and MB exchanger respectively. Each tank will be provided with an agitator. Each tank will be provided with hydraulic ejectors.

One neutralisation pit for collection and neutralisation of effluent from all exchangers will be provided. The pit having acid/alkali proof 'Fibre Reinforced Epoxy Screed' lining inside will be sized to hold the total regeneration effluent of DM Plant and neutralisation of effluent. One acid/alkali dilution tank (10% concentration) along with agitator will be provided for neutralisation purposes.

5.1 PROCESS DESIGN BASIS

Number of Chains	-	Two (2)
Capacity of each Chain	-	75 m^3/ hr
Chain structure	-	PSF-SAC-SBA-MB
Capacity of Degasser Tower	-	Gross flow capacity of SAC

5.1.1 Design Characteristics of Feed Water

Table 5-1 Feed water system design characteristics

SL. NO	PARAMETER	UNIT	VALUE
1.	Ph		7.6
2.	Turbidity	NTU	5.9
3.	Total Suspended Solids	mg/l	5
4.	Total Dissolved Solids	mg/l	150
5.	Electrical Conductivity 20 Deg C	Micro-Siemens/cm	210
6.	Calcium as $CaCO_3$	mg/l	45
7.	Magnesium as $CaCO_3$	mg/l	35
8.	Sodium as Na	mg/l	-
9.	Potassium as K	mg/l	-
10.	Chloride as Cl	mg/l	15
11.	Sulphate as SO_4	mg/l	15
12.	Iron as Fe	mg/l	0.3
13.	Silica (Reactive) as SiO	mg/l	17
14.	M - Alkalinity as $CaCO_3$	mg/l	80
15.	Total Copper as Cu	mg/l	-
16.	Organic Matter as $KMnO_4$ value 100 DegC	mg/l	-

5.1.2 Resins to be used

SAC	-	Indion / Tulsion/ Rohm & Hass make
SBA	-	Type I of Indion / Tulsion/ Rohm & Hass make

5.1.3 Regeneration Mode adopted

For SAC exchanger	-	Counter Current (hold down by water)
For SBA exchanger	-	Counter Current (hold down by water)

5.1.4 Regenerant Chemical to be used

Hydrochloric acid - 30 % w/w as per IS-265 (Technical grade)
Caustic lye (NaOH) 45 % by w/w as per IS-252 (Rayon Grade)

5.2 OPERATION OF THE DM PLANT

Operation of the DM Plant shall be PLC based microprocessor control with a selector switch for manual operation. The operating sequence of regeneration will be controlled by programmable logic controller. The regeneration will initiate from the DM Plant Control Room by a push button, on receipt of conductivity/ silica high alarm from the exchangers and the same will be put back to service by initiation of push button from the DM Plant Control Room. The initiation of PSF backwash shall be on exceeding the specified limit of pressure drop with alarm in DM Plant Control Room or end of cycle time whichever is earlier. DM Plant will have provision to trip in case any one of the parameters pH, Conductivity, silica is off spec.

5.3 ENGINEERING DESIGN DATA

5.3.1 Tanks& Vessels

The Pressure Sand Filter, priming chamber and ion exchanger vessels, shall be designed and constructed of boiler quality plate. Vessel shall be designed to contain filter media, supporting media, ion exchange resins, under drains and distribution system (corrosion resistant construction), all interconnecting piping with pipe supports and valves. All internal support beams shall be bolted or clamped in position. Supports rings may be welded to the shell. The exchanger vessels and priming chamber shall be completely rubber lined on the insides with 4.5 mm thick (minimum) rubber as per IS - 4682 Part-I latest edition, with rubber lining extending up to the full face of all the nozzle flanges on the vessel. Priming chamber shall be designed as pressure vessel for both condition of full vacuum and full liquid. The Pressure Sand Filter shall be epoxy lined on all internal surfaces.

HCl/ NaOH bulk storage tank and Acid/ Alkali measuring tanks shall be of FRP (with UV protection). PSF back wash tank and DM Water storage tank shall be epoxy painted on all internal surfaces.

PSF and Ion exchange vessels shall be furnished with manholes, handholes, sight glasses, inlet, outlet, vent and drain, instrument nozzles, regeneration nozzles, etc, with flanged connections for the piping system and structural steel leg supports.

Wastewater from ion exchangers shall be drained to neutralisation pit. Waste water shall be drained to Fibre Reinforced Epoxy Screed lined regeneration control sump with orifice boards from where it shall be taken through U-PVC pipes housed in acid/alkali proof epoxy lined RCC drains and drain covered with precast RCC slabs.

All tanks with Soda lime breather shall be suitably designed for the maximum positive pressure as well as vacuum condition.

5.3.2 Piping and Valves

Each PSF and ion exchanger unit shall be provided with a group of individual pneumatically operated valves designed as required for semi-automatic control with provision of manual operation. Hand wheel shall be provided for all valves. Also all other pneumatically operated ON-OFF valves shall be provided with hand-wheels to facilitate manual operation in the field. Besides the pneumatically operated valves, on each PSF, ion-exchanger and PSF back wash tank, manually operated isolation valves at inlet and outlet of each PSF, ion-exchanger and PSF back wash tank, shall also be provided.

Isolation valves shall be provided at suction of each pump and on discharge of each pump and blower. Check valve shall be provided on discharge of each pump and lobe type blowers. Dampers shall be provided on discharge of each turbo blower. Valves shall be provided at inlet, outlet and drain on each tank and elsewhere in the total system as required for making it operational and safe.

All pumps shall have permanent strainers on the suction side.

5.3.3 Painting

Primer and finish painting of all piping, vessels, tanks, equipments, structural supports, etc. shall be as per Corrosive Industrial Environment specifications.

5.3.4 Civil and Structural Works

I. Proper slopes should be provided in the DM Plant area for storm water drainage.

II. Acid /Alkali proof brick (75mm thick) flooring inside the dykes/ kerb walls around the HCl bulk storage and measuring tanks, NaOH bulk storage, and dilution tanks, acid /alkali unloading and transfer pumps, brine preparation and dosing tank, degassed water storage tank, degassed water pumps, effluent pumps and wherever required shall be provided. Acid /Alkali storage area shall be dyked to hold total volume of the largest storage tank.

III. All RCC drains inside the battery limit of the DM Plant (lined as well as unlined) along with precast RCC covers (Removable type) top of cover shall be raised above pavement level (provided with champering) to avoid rain ingress.

IV. Acid / alkali proof epoxy lined RCC effluent drains with precast RCC covers.

V. Fibre Reinforced Epoxy Screed lining in neutralisation pits and in regeneration control sumps shall be provided.

VI. Acid / alkali proof bitumastic lining over bitumen primer on RCC foundations in acid/alkali handling areas.

VII. Handrailing shall be provided all round the neutralisation pit.

VIII. 150 mm high kerbs of RCC construction shall be provided around all measuring / dilution tanks, acid/alkali unloading and transfer pumps, effluent transfer pumps, degassed water tanks and pumps, safety shower and eyewash facilities, hose stations, and as required / shown..

IX. RCC Platform, with stairs and handrailing (for degasser platform and acid/ alkali bulk storage tanks), steel platform with handrailing and ladders (for all ion exchangers and PSF), steel stairs with handrailing and platform (for degassed water tank, DM water storage tank, PSF back wash tank, wherever specified/required.

5.4 COST ANALYSIS

The cost details of DM water plant are carried separately and attached as per Annexure-5.

SECTION 6.0
SAFETY AND ENVIRONMENTAL ASPECTS

6.0 SAFETY AND ENVIRONMENTAL ASPECTS

6.1 INTRODUCTION

Industrial development is essential for growth and betterment of the living conditions of the society. Industrial development, however, is endemic with its effect on the environment. It is essential that even while the industrial development is spurred for growth, the environment is conserved and protected.

The proposed Cogeneration Cycle Power Plant is a step in the direction of spurring industrial activity. Notwithstanding this fact, it has been considered essential to adopt environmental protection measures and adhere to legislations such that the ecology and the habitat of the area are not disturbed.

Various pollution control measures required to meet the prevailing environmental standards are planned at the different stages of execution of the project, viz., design, construction and operational phases.

6.2 INDIAN ENVIRONMENTAL LEGISLATION

Government of India has made many legislations/rules for the protection and improvement of environment in India. Various environmental legislations/rules are tabulated in Table 6 -1.

Table 6-1Indian Environmental Legislation

S. NO.	LEGISLATION
1	The Environment (Protection) Rules, 1986
2	Environment (Protection) Third Amendment Rules, 2002
3	Coastal Regulation Zone-Notification dated May 21, 2002
4	The Public Liability Insurance Act, 1991
5	The Public Liability Insurance Rules, 1991
6	The Water (Prevention and Control of Pollution) Act, 1974, and its subsequent notifications.
7	The Water (Prevention and Control of Pollution) Cess Rules 1977 and its subsequent notifications.

8	The Air (Prevention and Control of Pollution) Act 1981 and its subsequent notifications.
9	Hazardous Wastes (Management and Handling) Rules, 1989, and its subsequent notifications.
10	Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 and its subsequent notifications.
11	Noise Pollution (Regulation and Control) Rules, 2000 and its subsequent notifications.

The proposed project shall be designed taking into account the above-referred legislations/rules.

A brief description of the environmental protection measures proposed to be adopted in the project with respect to the various components of the environment like air, water, noise, land, etc., is given in the subsequent sections.

6.3 POLLUTION CONTROL MEASURES

In order to minimize the impact of the project on the environment, due attention is being given for implementing effective pollution control measures. The design stage endeavours to mitigate the problems related to health, safety and environment at the process technology/source level itself.

The design basis for all process units lays special emphasis on measures to minimize the effluent generation at source.

During the operation of the plant, the major areas of concern will be stack emissions from the power generation unit along with disposal of treated effluent.

The specific control measures related to gaseous emissions, liquid effluent treatment/discharges, noise generation, etc., along with relevant stipulated standards are described below;

6.3.1 Air Environment

The gaseous emissions from the proposed project will be controlled to meet all the relevant standards stipulated by the regulatory authorities. Standards applicable to this project are classified into these categories;

- Ambient Air Standards
- Emission Standards

6.3.1.1 Ambient Air Standards

The ambient air quality around the premises will be limited to those limits as per National Ambient Air Quality Standards, which are given below in Table 6 -2.

Table 6-2 National Ambient Air Quality Standards 2009

S. NO.	POLLUTANTS	TIME WEIGHTED AVERAGE	CONCENTRATION IN AMBIENT AIR	
			INDUSTRIAL, RESIDENTIAL, RURAL AND OTHER AREA	ECOLOGICALLY SENSITIVE AREAS (NOTIFIED BY CENTRAL GOVERNMENT)
1.	Sulphur Dioxide (SO2), µg/m3	Annual Average*	50	20
		24 hours**	80	80
2.	Oxides of Nitrogen as NO2, µg/m3	Annual Average*	40	30
		24 hours**	80	80
3.	Particulate Matter (size less than 10 µm) or PM10 µg/m3	Annual Average*	60	60
		24 hours**	100	100
4.	Particulate Matter (size less than 2.5 µm) or PM2.5 µg/m3	Annual Average*	40	40
		24 hours**	60	60
5.	Ozone (O3), µg/m3	8 hours**	100	100
		1 hour**	180	180
6.	Lead (Pb), µg/m3	Annual Average*	0.5	0.5
		24 hours**	1	1
7.	Carbon Monoxide (CO) mg/m3	8 hours**	2.0	2.0
		1 hour**	4.0	4.0
8.	Ammonia (NH3), µg/m3	Annual Average*	100	100
		24 hours**	400	400
9.	Benzene (C6H6), µg/m3	Annual Average*	5	5
10.	Benzo (α) Pyrene (bap), Particulate Phase Only ng/m3	Annual Average*	1	1

11.	Arsenic (As), ng/m3	Annual Average*	6	6
12.	Nickel (Ni), ng/m3	Annual Average*	20	20

* Annual Arithmetic mean of minimum 104 measurements in a year at a particular site taken twice a week 24 hourly at uniform intervals.

** 24 hourly or 8 hourly or 1 hourly monitored values, as applicable shall be complied with 98% of the time in a year. 2% of the time, it may exceed the limits but not on two consecutive days of monitoring.

6.3.1.2 Emission Standards

The Standard in the context of the proposed project, are given below;

Table 6-3 Emission Standards

GENERATION CAPACITY	POLLUTANT	EMISSION LIMIT
Generation capacity 210 MW or more	Particulate matter	150 mg/ Nm3
Generation capacity less than 210 MW	Particulate matter	300 mg/ Nm3

Note:

Depending upon the requirement of local situation, such as protected area, the State Pollution Control Boards and other implementing agencies under the Environment (Protection) Act, 1986, may prescribe a limit of 150 mg/Nm3, irrespective of generation capacity of the plant.

General Notes:

1. Emission monitoring shall be carried out as per the Emission Regulations – Part III, published by Central Pollution Control Board.
2. Following methods may be used for measurement of pollutant concentrations in the emissions:

Table 6-4 Method of Measurement of Emissions

S. NO.	PARAMETER	METHOD OF MEASUREMENT
1	Sulphur Dioxide(SO2)	USEPA CFR – 40 Part 60 Appendix A Method 6
2	Oxides of Nitrogen (NOx)	USEPA CFR – 40 Part 60 Appendix A Method 7
3	Particulate Matter (PM)	USEPA CFR – 40 Part 60 Appendix A Method 5
4	Carbon Monoxide (CO)	USEPA CFR – 40 Part 60 Appendix A Method IOA / Combustion analyser with electro chemical detector / NDIR detector

6.3.2 Noise Environment

Ambient Standards for Noise, specified by CPCB is given below in Table 6-5.

Table 6-5 Ambient Air Quality Standards in respect of Noise

S. NO.	AREA CODE	CATEGORY OF AREA	LIMIT IN dB (A) LEG	
			DAY TIME	NIGHT TIME
1	A	Industrial area	75	70
2	B	Commercial area	65	55
3	C	Residential area	55	45
4	D	Silence zone	50	40

Notes:

- Daytime is reckoned in between 6 am and 9 pm
- Night time is reckoned in between 9 pm and 6 am
- Silence zone is defined as areas up to 100 meters around such premises as hospitals, educational institutions and courts. The Silence zones are to be declared by the competent authority.
- Mixed categories of areas should be as "one of the four above Mentioned categories" by the competent authority and the Corresponding standard shall apply.

Comprehensive measures for noise control will be followed at the design stage in terms of

- Noise level specification of various rotating equipment as per Occupational Safety and Health Association (OSHA) standards.
- Equipment layout considering segregation of high noise generating sources.
- Erecting suitable enclosures, if required, to minimize the impact of high noise generating sources.

6.3.3 Water Environment

Effluents (if any) generated from the proposed project shall be treated conforming the guidelines of CPCB and the treated effluent shall be disposed-off suitably.

Table 6-6 General Standards for discharge of Environmental Pollutants

S. NO.	PARAMETER	INLAND SURFACE WATER	PUBLIC SEWERS	LAND FOR IRRIGATION	MARINE/COASTAL AREAS
.	.	(a)	(b)	(c)	(d)
1.	Suspended solids mg/l, max.	100	600	200	(a) For process waste water (b) For cooling water effluent 10 per cent above total suspended matter of influent.
2.	Particle size of suspended solids	Shall pass 850 micron IS Sieve	-	-	(a) Floatable solids, solids max. 3 mm (b) Settleable solids, max 856 microns
3.	pH value	5.5 to 9.0	5.5 to 9.0	5.5 to 9.0	5.5 to 9.0
4.	Temperature	Shall not exceed 5°C above the receiving water temperature			Shall not exceed 5°C above the receiving water temperature
5.	Oil and grease, mg/l max,	10	20	10	20

6.	Total residual chlorine, mg/l max	1.0	-	-	1.0
7.	Ammonical nitrogen (as N), mg/l, max.	50	50	-	50
8.	Total Kjeldahlnitrogen (as N); mg/l, max.	100	-	-	100
9.	Free ammonia (as NH3), mg/l max.	5.0	-	-	5.0
10.	Biochemical oxygen demand (3 days at 27°C), mg/l, max.	30	350	100	100
11.	Chemical oxygen demand, mg/l, max.	250	-	-	250
12.	Arsenic (as As).	0.2	0.2	0.2	0.2
13.	Mercury (As Hg), mg/l, max.	0.01	0.01	-	0.01
14.	Lead (as Pb) mg/l, max	0.1	1.0	-	2.0
15.	Cadmium (as Cd) mg/l, max	2.0	1.0	-	2.0
16.	Hexavalent chromium (as Cr + 6), mg/l, max.	0.1	2.0	-	1.0
17.	Total chromium (as Cr) mg/l, max.	2.0	2.0	-	2.0
18.	Copper (as Cu) mg/l, max.	3.0	3.0	-	3.0
19.	Zinc (as Zn) mg/l, max.	5.0	15	-	15
20.	Selenium (as Se)	0.05	0.05	-	0.05
21.	Nickel (as Ni) mg/l, max.	3.0	3.0	-	5.0

22.	Cyanide (as CN) mg/l, max.	0.2	2.0	0.2	0.2
23.	Fluoride (as F) mg/l, max.	2.0	15	-	15
24.	Dissolved phosphates (as P), mg/l, max.	5.0	-	-	-
25.	Sulphide (as S) mg/l, max.	2.0	-	-	5.0
26.	Phenolic compounds (as C_6H_5OH) mg/l, max.	1.0	5.0	-	5.0
27.	Radioactive materials: (a) Alpha emitters micro curie mg/l, max. (b)Beta emitters micro curie mg/l	10 -7 10 -6	10 -7 10 -6	10 -8 10 -7	10 -7 10 -6
28.	Bio-assay test	90% survival of fish after 96 hours in 100% effluent	90% survival of fish after 96 hours in 100% effluent	90% survival of fish after 96 hours in 100% effluent	90% survival of fish after 96 hours in 100% effluent
29.	Manganese	2 mg/l	2 mg/l	-	2 mg/l
30.	Iron (as Fe)	3mg/l	3mg/l	-	3mg/l
31.	Vanadium (as V)	0.2mg/l	0.2mg/l	-	0.2mg/l
32.	Nitrate Nitrogen	10 mg/l	-	-	20 mg/l

These standards shall be applicable for industries, operations or processes other than those industries, operations or process for which standards have been specified in Schedule of the Environment Protection Rules, 1989.

6.4 PERMISSIONS AND CLEARANCES

Various Approvals and Clearances required for implementation of Power Projects shall be as below;

Table 6-7 List of Approvals and Clearances required for implementation of Power Projects

S. NO.	RELEVANT APPROVAL & CLEARANCE	RESPONSIBLE GOVERNMENT ENTITY
1	Clearance from Environment / Pollution board	State pollution Board
2	Clearances from the GoI (Civil Aviation Department) and the Director, National Airports Authority in connection with the height of any chimneys.	GoI (Civil Aviation Department) / National Airports Authority
3	Clearance of the Ministry of Environment and Forests following consideration of the Environment Impact Assessment and Environment Management Plan pursuant to Sections 3(1) and 3(2) (v) of the Environment (Projection) Act, 1985 and Rules 5(3)(a) of the Environment (Protection) Rules, 1986	Ministry of Environment and Forests
4	Approval of the Chief Engineer Inspector for the Power Station	Commissioner of Electricity
5	Permission from the Director General of Foreign Trade for the various imports pursuant to the Foreign Trade (Development and Regulation) Act 1992.	Directorate General of Technical Development/ Director General of Foreign Trade
6	Consent under the Factories Act 1948 relating to fire-fighting capability	Government of Maharashtra
7	Consent of the Controller of Explosives to the possession and use of explosives for the purpose of blasting	Controller of Explosive, Government of Maharashtra
8	Permission from the Director General of Foreign Trade for the import of spares pursuant to the Foreign Trade Development	Directorate General of Technical Developments / Director General of the

	and Regulation Act 1992	Foreign Trade
9	Municipal Byelaws of Urban Development Authority of State Government for Buildings in Township.	Municipal Corporation

The selected contractor during detailed engineering and construction shall take into account and comply with various local statutory requirements, standards and codes, as applicable including but not be limited to the following:

- OISD (Oil Industry safety Directorate) Guidelines (for Insurance purposes)
- Requirement of Chief Controller of Explosives (CCE), Nagpur, in case of liquid fuel storage only India.
- On completion of project, intimation about the plant is to be given to CEA also.

6.5 OTHER BENEFITS FROM PROJECT

The proposed power plant uses natural gas as the fuel for power generation at highly efficient power plant. The natural gas is considered as 'cleaner source' of thermal energy, having low carbon intensity as compared to coal due to the following primary reasons;

- Substantial amount of heat is generated from combustion of Hydrogen in natural gas as compared to coal, forming water as combustion product, which is not harmful to environment.

- The atomization of fuel is better during combustion as compared to coal, as the gas molecules get rigorously mixed with air molecules providing oxygen for combustion. This helps in reduction of 'excess air quantity, in combustion and thereby increasing the 'flame temperature' and reducing flue gas losses.

- The incombustibles (e.g. Ash) in natural gas are negligible as compared to coal.

The emission factors of Lignite and Natural Gas as per the International Panel for Climate Change (IPCC) are 0.1012 and 0.0561 (kilo tonnes CO_2/Trillion Joules) respectively. It is evident that coal is 80% higher CO_2 emitting source than natural gas for the generation of equivalent amount of energy. This gap further widens due to better efficiency factor of the proposed plant. The average efficiency of coal-fired conventional power plants is 30%, as against over 65% efficiency of the proposed gas based power plant. This facilitates 35% less usage of input energy of natural gas as compared to input energy in conventional coal based power plant for the power production of equivalent amount.

The plant shall operate at a PLF of 91 %.

No transmission and distribution losses are considered since the project will mainly cater to the additional power requirement of the plant and will export only a small surplus power to the nearby existing grid.

Without the proposed project activity, the same energy load would have been taken up from the GRID to compensate the increased demand due to additional LPG-III, GSU-III CFU-III & CHU-IV which would have resulted in higher GRID connectivity. Thus the proposed project will help in reduction of cost and dependency on the grid.

This power plant operating on cleaner fuel like Natural Gas will lead to lower Carbon Dioxide (GHG) emissions for producing equivalent amount of power as compared to the other power plants operating on other fuels like coal/ oil/ naphtha.

The project will also increase the installed electricity generating capacity of the plant making the plant self sufficient in Normal operation condition.

The project is a clean fuel power project, which will use Natural Gas as a fuel for power generation. Since the Carbon Dioxide (CO_2) emission due to combustion of Natural Gas is substantially less as compared to combustion of coal or Naphtha, the project helps in reducing GHG emission.

Further this project is based on natural gas; it will positively contribute towards the reduction in (demand) use of coal and increasing its availability to other places where natural gas is not available.

ONGC's contribution will be towards providing employment opportunities during construction stage and operation stage, thereby improving the quality of the life of people in surrounding habitations.

SECTION 7.0
STATUTORY APPROVALS AND CLEARANCES

7.0 STATUTORY APPROVALS AND CLEARANCES

In order to control and regulate the development of Power Projects by State / Private Sector, a legal framework has been developed by Government of India. Accordingly, several clearances and approvals shall have to be obtained from different Government and Statutory Agencies at various stages of the project. An Indicative list of approvals / clearances to be obtained from Govt. Authorities for this project is presented below;

Table 7-1 Statutory Approvals and Clearances

S. NO.	RELEVANT APPROVAL & CLEARANCE	RESPONSIBLEGOVERNMENTENTITY
1.	Clearance from Environment / Pollution board	State Pollution Control Board & CPCB
2.	Water availability and use	(State Govt. / Central Water Commission (CWC)
3.	Clearance of the Ministry of Environment and Forests following consideration of the Environment Impact Assessment and Environment Management Plan pursuant to Sections 3(1) and 3(2) (v) of the Environment (Projection) Act, 1985 and Rules 5(3)(a) of the Environment (Protection) Rules, 1986	Ministry of Environment and Forests
4.	Clearances from the GoI (Civil Aviation Department) and the Director, National Airports Authority in connection with the height of any chimneys.	GoI (Civil Aviation Department) / National Airports Authority
5.	Boiler pressure parts	Chief inspector of Boilers
6.	Approval of the Chief Engineer Inspector for the Power Station	Commissioner of Electricity, Govt. of Maharashtra
7.	Permission from the Director General of Foreign Trade for the various imports pursuant to the Foreign Trade (Development and Regulation) Act 1992.	Directorate General of Technical Development/ Director General of Foreign Trade
8.	Consent under the Factories Act 1948 relating to fire-fighting capability	Government of Maharashtra

9.	Consent of the Controller of Explosives to the possession and use of explosives for the purpose of blasting	Controller of Explosive, Government of Maharashtra
10.	Clearance for handling & storage of Fuel	Chief Controller Of Explosives (CCOE)
11.	Permission from the Director General of Foreign Trade for the import of spares pursuant to the Foreign Trade Development and Regulation Act 1992	Directorate General of Technical Developments / Director General of the Foreign Trade

SECTION 8.0
PROJECT COST ESTIMATE

8.0 PROJECT COST ESTIMATE

8.1 CAPITAL COST ESTIMATE & FINANCIAL ANALYSIS

Capital cost estimate & financial analysis for DFR has been worked out and summarized below:

Table 8-1 Cost Estimate of the Project

DESCRIPTION	COST IN ` CRORES
Power Plant	
Major Items	102.03
Bulks, Spares & Chemicals	20.82
Construction Cost	42.48
Plant Buildings	8.40
Indirect Cost	34.90
Contingency	10.42
PMC Charges &TPI	8.00
Dismantling/Scrap Materials Sales	-1.00
DMW	23.62
TOTAL	**249.69**

The basic assumptions made for working out the cost estimate are as under:

- Cost estimate is based on present day price level as of 3rd quarter' 2012. No provision has been made for any future escalation.
- Cost estimate is targeted to have an accuracy of ± 20%.
- It has been assumed that the project would be implemented on "EPC" mode of execution under one package.

The battery limit cost estimate for the identified scope of work is presented as Annexure-5.

8.2 BASIS OF COST ESTIMATE

The basis of cost estimate for power block is as under:

- Cost estimate has been prepared based on configurations supplemented with in-house engineering inputs for cost estimation.
- Cost estimate is based on cost information available from in-house cost database which is a repository for storing cost data from ongoing jobs. In-house cost data has been analyzed and adopted for estimation after incorporating the project conditions. Cost data has been updated to prevailing price level using relevant economic indices.

8.3 PLANT & MACHINERY

8.3.1 Supply Costs

The cost estimates have been prepared based on specifications and in - house cost data for similar type of equipment. Sourcing of equipment and material has been made as per in-house information on previous executed projects.

Cost estimate for Gas Turbine Generator (GTG), and HRSG is based on in-house cost data for similar items, updated for required specifications and time escalation. Cost estimate for Balance of Plant (BOP) such as Gas conditioning skid, Cooling tower with pumps and Stack is based on in-house cost data.

Cost for supply of piping, electrical items and instrumentation items are based on the factor of equipment cost. Cost provision for spares has been made on factor basis as per in-house norms.

Lump-sum cost provision has been made for chemicals.

8.3.2 Construction Costs

Cost provisions towards erection of equipment, piping, electrical and instruments, Civil & structural works, insulation & painting work have been made on factor basis.

8.3.3 Plant Building

Cost provisions towards plant buildings such control room, sub-station, MCC room is based on the sizes of the buildings.

8.4 STATUTORY & INDIRECT COSTS

The cost estimate includes following statutory and indirect costs:

Table 8-2 Statutory and Indirect Costs for the Project

Inland Freight	3% of ex-works cost of indigenously sourced equipment
Excise Duty	12.36% of ex-works cost of indigenously sourced equipment.
Central Sales Tax	2% of ex-works cost of indigenously sourced equipment including excise duty.
Service Tax	12.36% on subcontracted works
Octroi / State Entry Tax	4.5% of landed cost of supply items
Insurance	0.5% of total cost

8.5 CONTINGENCY

Provision for contingency has been made @ 5%.

8.6 PMC CHARGES & TPI

A lump-sum cost provision for PMC charges (Pre-award & post award) and TPI has been made in the capital cost estimate based on in-house information.

8.7 DISMANTLING /SCRAP MATERIALS SALES

The cost estimates for Dismantling & Disposal/Sales of Scrap materials have been prepared based on weight of the scrap.

8.8 EXCLUSIONS

Following costs have been excluded from the cost estimate:-

- Site Development
- HVAC, Ventilation & Pressurization for plant buildings
- Owner's management expenses
- Forward Escalation

SECTION 9.0
FINANCIAL ANALYSIS

9.0 FINANCIAL ANALYSIS

9.1 OPERATING COST & FINANCIAL ANALYSIS

Operating cost & financial analysis has been worked out based on following:

Table 9-1 Operating Cost of the Project

S.NO.	DESCRIPTION	ASSUMPTIONS MADE
1	Natural Gas price	Rs 7.72 / SCM
2	Raw water	Rs 40.00 / SCM
3	Electricity Duty	Rs 0.30 / kWH
4	O & M charges	Rs 17.50 lakhs/MW
5	Sale of Power	Rs 9.00 / KWH
6	Demand charges	Rs 190 / kVA
4	Construction Period	28 months
5	Project Life in Years	15
6	Debt/ Equity Ratio	100% Equity
7	Working capital	Excluded
8	Depreciation	P& M - @ 5.28% SLM , @ 15% WDV ; @ 5% Salvage value
9	Capital Phasing (half yearly)	1st 6 months - 10% 2nd 6 months - 20% 3rd 6 months 25% 4th 6 months 35% Last 4 months 10%
10	Capacity Build-up	1st year onwards - 100%
11	Operating hours (Annual)	330 days
12	Exportable power	19.5 MW
13	Corporate Tax Rate	Basic 30% + 5% + 3% = 32.45%
14	MAT (%)	Basic 18.5% + 5% + 3% = 20.01%

Yearly variable operating cost comprising of cost for Natural Gas, Raw Water and Electricity duty has been escalated @ 8% pa as per ONGC input. Yearly fixed operating cost has been considered to take care of Salary & wages, Repair and maintenance, General administrative expenses and Insurance @ Rs 17.50 lakh / MWH in 1st year of operation. Yearly fixed operating cost has been escalated @ 5.72% pa (CERC guide lines) 2nd year onward over the life of the plant. Annual Sales revenue has been calculated considering saving in energy import, saving in demand charges and saving in gas consumption by HRSG-4. No escalation has been considered in the yearly revenue over the life of the plant as suggested by ONGC as per their norms. Capital cost has been escalated by 6% as per ONGC norms for financial analysis.

Based on above assumptions, Operating cost, sales revenue, Cash flow, NPV, Internal rate of return and Payback period has been worked out for the project and are summarized below:

Table 9-2 Financial Analysis of the Project

SL.NO	DESCRIPTION	VALUES
1	CAPITAL COST (Rs. LAKH) FOR IRR, PAY BACK PERIOD CALCULATIONS USING 6% ESCALATION AS PER ONGC NORMS	26466
2	TOTAL OPERATING COST (Rs. LAKH)	5771
3	ANNUAL REVENUE (Rs. LAKH)	16878
4	IRR (%) ON TOTAL CAPITAL	
	BEFORE TAX	19.66%
	AFTER TAX	15.07%
5	PAY BACK PERIOD (YEARS) ON TOTAL CAPITAL	
	BEFORE TAX	2.9
	AFTER TAX	3.7

SECTION 10.0
PROJECT IMPLEMANTATION AND SCHEDULE

10.0 PROJECT IMPLEMANTATION AND SCHEDULE

10.1 PROJECT IMPLEMENTATION METHODOLOGY

Single Engineering Procurement and Construction (EPC) Contract including the complete Technical Requirements and scope under this Contract for Design, Engineering, procurement, Supply, Fabrication, Construction, Inspection, Testing, Pre-Commissioning, Commissioning and Performance Guarantee Test Run to be carried out by the CONTRACTOR is proposed for the Project in order to execute project on time.

This will cover following major works

- Clearing NGL loading area to accommodate DM plant
- Construction of new DM plant
- Dismantling and disposal of existing DA/DM plant/ Thermax Boiler/ IAEC Boiler House and other facilities
- Re-routing of existing pipelines catering to GT/ HRSG 1,2 & 3
- Construction and Installation of GT/ HRSG and associated facilities

If multiple CONTRACTORS for different jobs are deployed, delay in finalizing any one of the contracts, default of any one contractor or delayed due to any interface issues will lead to abnormal delay in overall completion of the project.

Lump Sum Turnkey Contract (LSTK) / Engineering, Procurement and Construction contract (EPC)

Under this mode of operation, owner awards the implementation of the project to a contractor with turnkey responsibility. The award of the contract is based on a tender comprising of technical requirements (specified in FEED) and commercial conditions. In this case, LSTK / EPC contractor takes full responsibility to complete the project as per the scheduled completion date specified in the contract. The delay in completion invites heavy penalties which range from 5% to 10% of total project cost under LSTK / EPC contractor's scope. Since the liabilities are high, the LSTK / EPC contractor generally loads his liabilities to the quoted price thus owner has to spend high capital cost. Therefore even though LSTK / EPC mode of operation minimizes the risk of delayed completion to some extent however this is at the cost of high capital expenditure.

The mandatory requirement to successful completion of LSTK / EPC contract is;

a) to ensure a perfect FEED document with necessary detailing and minimum contradictions

b) To engage a competent PMC consultant to manage the contract. In most of the cases, FEED is also generated by PMC consultant.

The main advantages of LSTK mode are;

- Minimal project schedule risk
- Micro level Project Monitoring not required
- No interface requirements between various packages
- Performance guarantees of the complete system.

It is envisaged that entire project shall be executed as above on single responsibility under one contract with fixed contract price and time schedule with provision of liquidated damages. The plant is scheduled to be setup within 28 months from date of order to EPC. The Project Implementation Schedule has been detailed in Annexure-7.

However site grading and any area clearance/dismantling/shifting work have to be executed separately and prior to main plant contract, as above.

To ensure timely completion, the Contractor shall establish and maintain an effective Planning, Scheduling, Monitoring and Control system, including mobilization of required number of professionally qualified and experienced Planning Engineers for design office and construction site. The system shall be capable of accurate and timely prediction of trend, evolution of adequate preventive actions for likely slippages, and formulation of suitable catch-up schedule for delays, if any, that have occurred.

Schedules, reports and documents to be prepared and submitted by the contractor for review of Client/ Project Management Consultant (PMC) at various stages and details of meetings to be held are described here.

10.2 AFTER AWARD OF WORK THE CONTRACTOR SHALL COMPLY WITH:

10.2.1 90 Days Front End Schedule

The Contractor shall prepare and submit a detailed 90 days front-end schedule within two weeks of award. Pending finalization of functional schedules, this schedule shall be the basis of monitoring of front-end activities. The schedule shall cover all activities to be carried out during initial 90 days period of the contract. The schedule shall be reviewed in the kick-off meeting.

10.2.2 Kick off Meeting

A Kick off Meeting shall be organized within two weeks of award of contract. The meeting shall be attended by Client's and PMC's representatives. During the meeting the following with respect to Planning, Scheduling, Monitoring and Control system shall be discussed and finalized,

1. Planning deliverables required for Project Monitoring and Control.
2. Work Breakdown Structure for Project Schedules, organization and level of detailing for Overall Project Schedule and Functional Schedules.
3. Procedure for Project Planning, Scheduling, Monitoring and Control including all reporting formats.
4. Progress Measurement Methodology and Unit, Function, Discipline, and Deliverable wise weight age breakdown.
5. List of engineering deliverables with indicative schedule for submission.
6. List of unit wise milestones to be included in the network, in addition to milestones specified in the Contract, if any (the number of milestones shall be at least 2 to 3 per unit per month).
7. List of critical equipment and materials for the fortnightly expediting report to be issued by the Contractor.
8. Procedure for Bulk material control.
9. Cut off dates, distribution list with number of copies and Project calendar indicating submission of various planning documents and revisions.
10. ANY OTHER DOCUMENT AS REQUIRED.

10.3 PROGRESS MEASUREMENT METHODOLOGY

The Contractor shall submit during Kick off Meeting, the detailed methodology of progress measurement of Residual Basic Engineering, Detailed Engineering, Ordering, Manufacturing & Delivery, Sub-contracting, Construction and Commissioning for review by Client/PMC. Contractor shall also furnish the methodology of progress measurement for sub-contracted packages, if any and integration of the same with the overall progress.

During the Kick Off meeting, Client/PMC shall specify weighted values to be used for the following:

- Unit wise within the package, if applicable.
- Function wise within each unit.
- Milestone weight age within each deliverable.

Effort based weighted values for the following, along with the basis of their derivation, shall be submitted by Contractor for review by Client/PMC, and the comments if any shall be incorporated by Contractor before submission of functional schedules that use these weighted values as the basis:

- Discipline wise within each function.
- Deliverable level weight age Percentage.

Progress figures at Unit / Function / Discipline level shall be summarized from deliverable level and indicated in the functional schedules

SECTION 11.0
RISKS AND MITIGATIONS

11.0 RISKS AND MITIGATIONS

As projects are exposed to a wide variety of risks in the various stages of project evolution, risks associated with the development and commissioning of the project were identified, categorized and measures for risk mitigation defined as far as feasible.

Main categories of risks are

- Design risks
- Project related
- Construction related
- Operations related
- Revenue risks
- Financial risks
- Force majeure risks
- Insurance risks
- Environmental risks

The proposed mitigation measures shall be a basis for development of adequate strategies in the contractual framework of the tendering documents and later in the contracts with the construction contractors, subcontractors and in the O&M contractual documents.

The results of the preliminary assessment listed according to the type of risk are shown below;

Table 11-1 Preliminary assessment listed according to the type of risk

RISK TYPE	RISK EVENT	RISK MITIGATION
Design Related	Design risk/ faulty design	Sound supervision at EPC stage with provision for remedy and liquidated damages from EPC contractors for curing the risk along with coverage from insurance
Project Related	Delay/non receipt of environmental and other statutory approvals	Proactive consultation and negotiation with authorities and other stakeholders
Project Related	Project target cost estimate inadequate (PTC)	Open book approach, proactive activity with contractors
Project Related	Delay caused by governmental action or inaction / Force Majeure	Efforts to proactively act to acquire required approvals

Construction Related	Contractor Capability	Sound pre-selection process for the award of the project development contracts to contractors with experience, reputation and track record. Additional contractual safeguards like liquidated damages for non-performance, performance security, defects liability clause etc.
Construction Related	Suitability and availability of land	Field investigation studies to establish suitability. Land to be made available as condition precedent.
Construction Related	Cost overrun	Provide for reasonable cost overrun in fixed lump sum price in the construction contract. Any overrun on account of contractors to be absorbed by EPC contractors
Construction Related	Delay in construction	Safety clauses in EPC contract including liquidated damages from the contractor (sufficient to cover interest due to lenders and fixed operating costs)
Operations Related	Failure to meet performance criteria at completion tests due to quality shortfall and defects in construction	Include planned redundancy in process design
Operations related	Failure of plant to meet performance criteria at completion tests	Require liquidated damages Payable by the construction consortium, supplemented by insurance.
Operations related	Industrial action such as strike, lockouts, work-troubles blockades, go-slow actions	Establish sound industrial relations and also put in place insurance cover for loss or physical damage as well as for business interruption
Operations related	Operator failure.	Sound pre-selection process for the award of the operator contracts to contractors with experience, reputation and track record. Additional contractual safeguards like liquidated damages for non-performance, performance security, defects liability clause etc.
Revenue Risk	Low off-take	Fixed capacity charge on take or pay principle to cover fixed costs like maintenance cost, debt servicing etc.

Revenue Risk	Rising fuel and other input costs	Long term fuel supply agreement / input cost recovery on actual for quantity delivered
Revenue Risk	Exchange rate variation. Devaluation of local currency, fluctuations in foreign currencies.	Judicious mix of Rupee and Forex debts to optimize on interest cost. Protection against adverse currency movement by exchange cover, swapping of rupee debt etc.
Revenue Risk	Fluctuations in interest rates	Same as above (for hedging facilities against exchange rate risks).
Force majeure risk	Flood, earthquake, riot, strike	Insurance cover for loss or physical damage as well as business interruption
Force majeure risk	Changes in tax law, customs practices, environmental standards	Timely approvals/certification by statutory authorities
Insurance risk	Uninsured loss or damage to project facilities	Insure against all the main risks
Environmental risk	Environmental incidents due to Operator's fault	Require indemnity from the operator