

PRE FEASIBILITY REPORT

FOR

“BS-VI FUEL QUALITY UPGRADATION PROJECT”

(Revamp of DHDT Unit, New FCC GDS Unit and SRU Block for MS quality
upgradation & increased BS VI Diesel production)

AT

Village: Manali
Taluk: Ambattur
District: Thirvallur
State: Tamil Nadu

[Project termed under Schedule (4a) Category ‘A’ – Petroleum Refining Industry as per
EIA Notification 2006 and its Amendments]

Submitted By

CHENNAI PETROLEUM CORPORATION LIMITED

MANALI REFINERY

(A Group Company of Indian Oil)



Report Prepared By

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JULY, 2016

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	7
2. INTRODUCTION OF THE PROJECT	8
2.1 ABOUT THE PROJECT PROPONENT.....	8
2.2 MAJOR PRODUCTS OF CPCL.....	8
2.3 ABOUT THE PROJECT.....	9
2.4 PROJECT BENEFITS	11
3. PROJECT DESCRIPTION	12
3.1 TYPE OF PROJECT	12
3.2 PROJECT LOCATION.....	12
3.3 MAJOR PROJECTS OF CPCL.....	13
3.4 DESCRIPTION OF THE PROJECT.....	14
3.5 PROJECT NEED	14
3.6 MANUFACTURING PROCESS DESCRIPTION	15
3.6.1 DIESEL HYDRO-TREATING (DHDT)	15
3.6.2 FCC GDS	24
3.6.3 SRU BLOCK.....	31
3.7 POWER AND FUELS	31
3.8 LAND USE	32
3.9 MANPOWER	32
3.10 WATER REQUIREMENT	33
3.11 UTILITIES.....	33
3.12 LIQUID WASTE MANAGEMENT.....	34
3.12.1 FCC GDS LIQUID EFFLUENT.....	35
3.12.2 DHDT WASTE EFFLUENT SUMMARY.....	35
3.13 HAZARDOUS AND SOLID WASTE MANAGEMENT	36
3.14 GREEN BELT DEVELOPMENT	37
3.15 ENVIRONMENT, SAFETY AND HEALTH MONITORING	37
4. SITE ANALYSIS	39
4.1 CONNECTIVITY	39
4.2 LAND FORM, LAND USE, LAND OWNERSHIP.....	39
4.3 EXISTING LAND USE PATTERN	39
4.4 CLIMATIC CONDITIONS	39
5. CONCLUSION	41

LIST OF TABLES

Table 2.1 -List of products from the refinery	9
Table 2.2- BS V/VI Specifications for Diesel	10
Table 2.3- BS V/VI Specifications for Gasoline	11
Table 3.1- Capacity of major units of CPCL	14
Table 3.2- BS Specifications.....	15
Table 3.3- Power and fuel oil requirement	32
Table 3.4- Manpower Requirement for BS-VI project.....	32
Table 3.5- Water Requirement.....	33
Table 3.6- List of Utilities.....	34
Table 3.7- Sour Water Generation	35
Table 3.8- Municipal Solid Waste details.....	36
Table 3.9- Green belt details	37
Table 4.1- Water bodies in the study area.....	39
Table 4.2- Meteorological Observations.....	40

LIST OF FIGURES

Figure 3-1: Project Site	12
Figure 3-2: 10 km Radius around project site.....	13
Figure 3-3: DHDT – Reaction Section – Process Flow Diagram	20
Figure 3-4: DHDT – Stripping & Drying Section – Process Flow Diagram.....	21
Figure 3-5: DHDT – Amine Section – Process Flow Diagram	22
Figure 3-6: DHDT – Naphtha Stabiliser Section – Process Flow Diagram	23
Figure 3-7: FCC GDS –SHU & Splitter Section – Process Flow Diagram.....	27
Figure 3-8: FCC GDS –1 st stage HDS Reaction Section – Process Flow Diagram	28
Figure 3-9: FCC GDS –2 nd stage HDS Reaction Section – Process Flow Diagram.....	29
Figure 3-10: FCC GDS –Stabiliser Section – Process Flow Diagram.....	30

LIST OF ANNEXURES

- Annexure:1** Land deed Agreement of CPCL
- Annexure:2** CPCL agreement with CMWSSB
- Annexure:3** CPCL Overall Plant Layout
- Annexure:4** Hazardous Waste Management Authorization from TNPCB
- Annexure:5** CMDA Land use Map
- Annexure:6** DHDT Earlier Environment Clearance
- Annexure:7** Hazardous Waste Agreement between CPCL & Tamil Nadu Waste Management Limited
- Annexure:8** Consent to operate letter from TNPCB for DHDT
- Annexure:9** Layout of ETP and TTP

LIST OF ABBREVIATIONS

BS	Bharat Stage
CBR	Cauvery Basin Refinery
CDU	Crude Distillation Unit
CPCL	Chennai Petroleum Corporation Limited
DHDT	Diesel Hydro Treating
EOR	End of Run
LABFS	Linear Alkyl Benzene Feed Stock
LOBS	Lube Oil Base Stock
LPG	Liquefied Petroleum Gas
MDEA	Methyl Di-Ethanol Amine
MMT	Million Metric Tonnes
MMPA	Million Metric Tonnes Per Annum
MP	Medium Pressure
SOR	Start of Run
SRGO	Straight Run Gas Oil
SRU	Sulphur Recovery Unit
GDS	Gasoline De-Sulphurisation
ATU	Amine Treating Unit
SWS	Sour Water Stripping

1. EXECUTIVE SUMMARY

Chennai Petroleum Corporation Limited (CPCL) is the oldest refinery in Southern part of India and the most complex public sector refinery within India in a spread of 800 acres land. Over the last 45 years, Chennai Petroleum Corporation Limited has expanded its capacity from 2.5 MMTPA to 10.5 MMTPA. The CPCL site is located about 4 km away from Thiruvottiyur Town and it is in the express highway connecting Thiruvottiyur and Ponneri.

The existing Diesel Hydrotreating (DHDT) unit in CPCL is designed for treating the feed consisting of straight run gas oil, vacuum diesel oil to produce treated diesel to meet the required specifications. New FCC GDS Unit is designed for treating FCC Gasoline rundown from existing FCC Unit. The DHDT revamp, new SRU block & FCC Unit of CPCL is proposed at survey numbers 266 / 2, 274, 296, 297, 298 and 299 Manali Village, Ambattur Taluk, Tiruvallur District, Tamil Nadu.

The DHDT unit is proposed to be revamped to increase the treating capacity for diesel as outlined in “AUTO FUEL VISION & POLICY 2025” (AFV), submitted in the year 2014. Presently BS-IV specification diesel with sulphur content of 50 ppm wt is being supplied to major cities and BS-III specification diesel with sulphur content of 350 ppm wt is being supplied to rest of the country. As per AFV recommendation, 100% BS-IV specification fuels have to be supplied by 1st April 2017 and 100% BS-VI specification fuels by 1st April 2020. The proposed DHDT revamp is to increase the capacity from 1.80 MMTPA to 2.4 MMTPA and to meet the BS-VI standards by producing treated diesel having sulphur content of less than 10 ppm wt.

The new FCC GDS Unit is proposed to meet the new specifications for gasoline as outlined in “AUTO FUEL VISION & POLICY 2025” (AFV), submitted in the year 2014. Presently BS-IV specification gasoline with sulphur content of 50 ppm wt is being supplied to major cities and BS-III specification gasoline with sulphur content of 150 ppm wt is being supplied to rest of the country. As per AFV recommendation, 100% BS-IV specification fuels have to be supplied by 1st April 2017 and 100% BS-VI specification fuels by 1st April 2020.

The proposed new FCC GDS Unit of 0.6 MMTPA is to meet the BS-VI standards by producing treated gasoline having sulphur content of less than 10 ppm wt. To treat the acid gas generated from these Units a new SRU block with SRU capacity of 200 TPD is proposed. The project cost for the proposed revamp of DHDT and new SRU block is Rs. 456 Crore and for new FCC GDS is Rs. 497 Crore.

2. INTRODUCTION OF THE PROJECT

2.1 ABOUT THE PROJECT PROPONENT

Chennai Petroleum Corporation Limited (CPCL) (formerly known as Madras Refineries Limited) was formed as a joint venture of the Government of India (GOI), Amoco India Inc., U.S.A. and National Iranian Oil Company (NIOC), Iran with the initial equity contribution in the ratio of 74:13:13. The company was incorporated on 30.12.1965 as a Public Limited Company. Amoco Inc. disinvested its equity holding in favour of GOI in 1985. Later, Govt. of India transferred its equity share of 51.89% to Indian Oil Corporation Limited.

The Manali refinery was originally designed for processing 2.5 MMTPA (Million Metric Tonnes Per Annum) of imported Darius crude from Iran. CPCL's Manali refining capacity was increased from 2.5 MMTPA in 1969 to 10.5 MMTPA in 2011 through addition of new units and debottlenecking existing units. Secondary processing units like FCCU and OHCU were implemented to improve the total distillate yield. Facilities like DHDT, CCR and ISOM were also added to meet stringent Euro-IV quality norms for Diesel and Gasoline.

CPCL's Cauvery Basin Refinery (CBR) was commissioned in Nov 1993 initially with a capacity of 0.5 MMTPA to process Narimanam crude. CPCL completed the CBR capacity expansion to 1.0 MMTPA in 2002 and construction of an Oil Jetty facility for crude in 2003.

2.2 MAJOR PRODUCTS OF CPCL

The main products of the company are LPG, Motor Spirit, Superior Kerosene, Aviation Turbine Fuel, High Speed Diesel, Naphtha, Bitumen, Lube Base Stocks, Paraffin Wax, Fuel Oil and Hexane. In addition, CPCL, as a mother industry, supplies Petrochemical feed stocks like Propylene and Butylenes stream for the manufacture of Propylene Oxide, Propylene Glycol, MEK, Polybutylene and Kerosene stream for the manufacture of Linear Alkyl Benzene. List of refinery product is as shown in **Table 2.1**.

All Fuel products, Bitumen and Lubes of the Manali Refinery of CPCL and all the products of CBR of CPCL are marketed through Indian Oil Corporation Limited. CPCL does direct marketing of some of its speciality products from Manali Refinery, like Waxes, Propylene, Hexane, LAB feed stock, Petrochemical Feed stocks and Lube Extracts.

A Propylene Plant with a capacity of 17,000 tonnes per annum was commissioned in 1988 to supply petrochemical feedstock to neighboring downstream industries. The unit was

revamped to enhance the propylene production capacity to 30,000 tonnes per annum in 2004. CPCL also supplies LABFS to a downstream unit for manufacture of Liner Alkyl Benzene.

The crude throughput for the year 2015-16 was 9.644 million metric tonnes (MMT). The company's Profit after tax for the year 2015-16 was Rs. 770.68 Crores.

Table 2.1 -List of products from the refinery

S.No	Product	Quantity (% of Crude Processed)
1	LPG	3.07
2	Naphtha	6.31
3	MS	10.39
4	SK	3.27
5	ATF	7.02
6	HSD	39.91
7	Fuel Oil	10.02
8	Bitumen	6.14
9	Lube Oil Stocks	2.04
10	Petrochemical feed stocks	0.58
11	Hexane	0.07
12	Linear Alkyl Benzene Feed stock	0.52
13	Extracts	0.44
14	Wax	0.23
15	LVFO	0.23
16	Sulphur	0.37

2.3 ABOUT THE PROJECT

As per the Auto Fuel Vision and Policy 2025 of Government of India and the directives from MoP&NG, 100% BS – IV quality fuels have to be supplied by the refineries from April 2017 and 100% BS – V / VI quality fuels from April 2020. To comply with this directive, the existing Diesel HydroTreating (DHDT) is proposed to be revamped from 1.80 MMTPA to 2.4 MMTPA to ensure 100% BS – VI diesel production and new FCC GDS with 0.6 MMTPA capacity to ensure 100% BS-VI gasoline production from the Manali Refinery. After the revamp, the DHDT unit will be able to produce hydro treated diesel with less than 10 ppm Sulphur & new FCC GDS unit will be able to produce hydro treated gasoline with less than 10 ppm Sulphur . To treat the acid gas generated from these Units a new SRU block

with SRU capacity of 200 TPD is proposed. The DHDT revamp / new FCC GDS unit is being proposed to comply with the BS – VI specifications for Diesel and Gasoline is as given in **Table 2.2** and **Table 2.3** respectively.

Table 2.2- BS V/VI Specifications for Diesel

S. No	Attribute	Unit	BS VI
1	Density @ 15 °C	kg/m ³	820 – 845
2	Distillation: 95 % vol. Recovery @ °C, max	°C	360
3	Sulphur	ppm max	10
4	Cetane number	Min	51
5	Cetane Index	Min	46
6	Flash Point, Abel, min	°C	42
7	KV @ 40 °C	cSt	2.0 – 4.5
8	Carbon residue (Rams bottom) on 10% residue, max (without additive)	% wt max	0.3
9	Water content	mg/kg max	200
10	Lubricity corrected Wear Scar Diameter @ 60 °C, max	Microns	460
11	Ash	% wt max	0.01
12	Cold Filter Plugging Point		
	a) Summer	°C	18
	b) Winter	°C	6
13	Total contamination, max	mg/kg	24
14	Oxidation stability	g/m ³ , max	25
15	Polycyclic Aromatic Hydrocarbon (PAH), max	% wt	11
16	Copper strip corrosion for 3 hrs @ 50 °C, max	Rating	Class-1

Table 2.3- BS V/VI Specifications for Gasoline

S. No	Attribute	Unit	BS VI
1	Density @ 15 °C	kg/m ³	720-775
2	FBP	°C max	210
3	Sulphur	ppm max	10
4	RON	min	91
5	RVP@38°C,max	kPa	60
6	VLI(10RVP+7E70)	max	750
7	Benzene	% vol.max	1
8	Aromatics	% vol. max	35
9	Olefins	% vol.max	21
10	Gum	mg/100ml max	5
11	Oxidation stability	Minutes,min	360
12	Lead as Pb	g/litre, max	0.005
13	Oxygen	% wt max	2.7
14	Copper strip corrosion for 3 hrs @ 50 °C, max	Rating	Class-1

The proposed DHDT capacity expansion / new FCC GDS does not require any new process or new raw materials. Since the project is proposed to reduce the sulphur content, there will not be any additional pollutants. The existing effluent treatment plant and other treatment systems have adequate design capabilities to handle the additional pollutant loads from expansion as there are no changes in characteristics.

2.4 PROJECT BENEFITS

The proposed revamp will enhance the quality of the product, to meet the BS VI specifications. This DHDT revamp / new FCC GDS will also help in enhancing the environmental conditions by reducing the emission of Sulphur into the atmosphere.

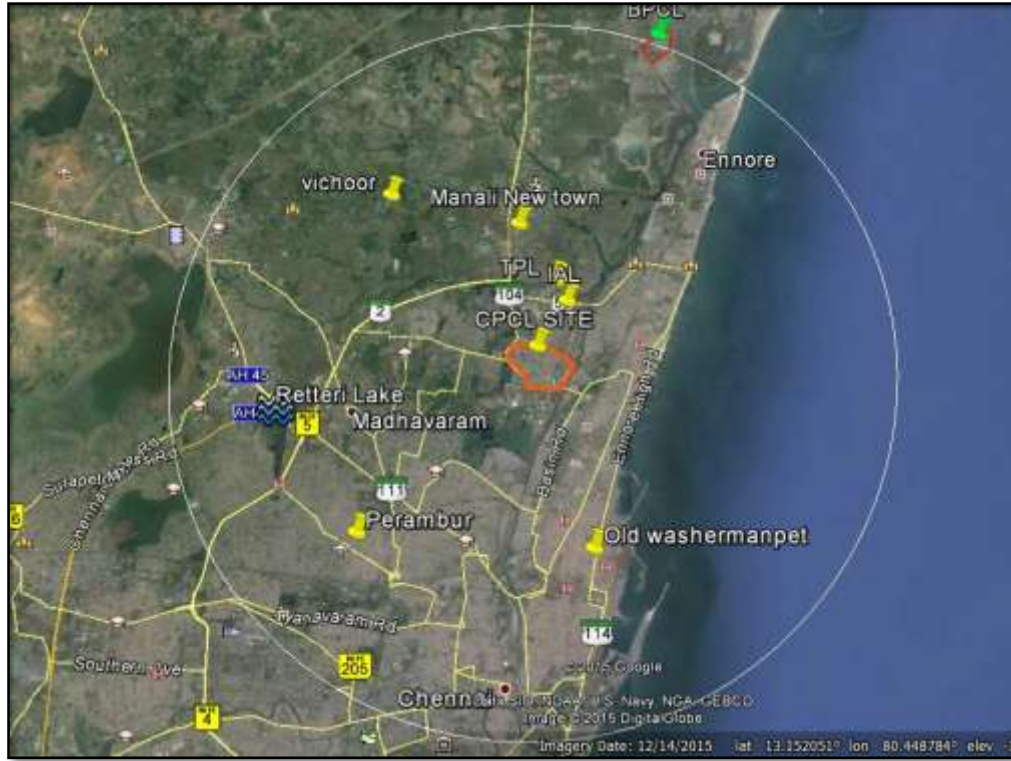


Figure 3-2: 10 km Radius around project site

3.3 MAJOR PROJECTS OF CPCL

The details of current major projects are given below:

3.3.1 RESID UPGRADATION PROJECT

To improve the distillate yield of Manali refinery, a Resid Upgradation Project is under implementation with an estimated cost of Rs 3110.36 Crores. This project involves installation of Delayed Coker Unit and Revamping of existing Hydrocracker Unit along with other associated facilities. The Environment clearance for the Project was given in March 2013. The project is under implementation.

3.3.2 NEW 42" CRUDE OIL PIPELINE

A new 42 " Crude Oil Pipeline Project, from Chennai Port to Manali Refinery, with enhanced safety features is planned to ensure reliable faster crude transfer from Port. The estimated cost of the project is Rs. 257.87crore. The Ministry of Environment, Forests & Climate Change (MoEF&CC), Government of India, accorded CRZ clearance for this Project in January 2014.

As part of Resid Upgradation project enabling job, a new reservoir of 4 MG Reservoir was constructed and commissioned. Installation of 2 Crude Oil storage tanks of 10,500 kL each was implemented at an estimated cost of Rs 25 Crore.

The capacities of the major units is as shown in **Table 3.1**

Table 3.1- Capacity of major units of CPCL

UNIT	DESIGN (Million Metric Tonnes Per Annum)
CDU – I	2.8
CDU – II	3.7
CDU – III	4.0
FCCU	0.83
OHCU	1.85
VBU	1.15
CRU	0.3
ISOM	0.14
DHDT	1.8
DHDS	1.8
LOBS	0.27

3.4 DESCRIPTION OF THE PROJECT

The DHDT unit was commissioned in 2011. The proposed project is the revamp of existing DHDT unit to increase the capacity from 1.80 MMTPA to 2.4 MMTPA.

As per the Auto Fuel Vision and Policy 2025 of Government of India and the directives from MoP&NG, 100% BS – IV quality fuels have to be supplied by the refineries from April 2017 and 100% BS – V / VI quality fuels from April 2020. To comply with this directive, the existing Diesel HydroTreating (DHDT) unit is proposed to be revamped from 1.80 MMTPA to 2.4 MMTPA to ensure 100% BS – VI diesel production and new FCC GDS Unit with 0.6 MMTPA capacity to ensure 100% BS-VI gasoline production from the Manali Refinery. To treat the acid gas generated from these Units a new SRU block with SRU capacity of 200 TPD is proposed. After the revamp, the DHDT unit will be able to produce hydro treated diesel with less than 10 ppm Sulphur & FCC GDS will produce hydro treated gasoline with less than 10 ppm sulphur.

3.5 PROJECT NEED

The Diesel Hydro Treating Unit (DHDT - Unit No.211) was installed and commissioned in 2011 with a capacity of 1.80 MMTPA, to produce treated diesel with sulphur content less than 50 wt ppm. It was installed for treating the feed consisting of Straight Run Gas Oil, Vacuum Diesel Oil. After the above proposed revamp, the sulphur content in treated diesel will meet BS-VI standards. New FCC GDS will be used to meet BS-VI standard for gasoline. The sulphur content for BS standards is shown in **Table 3.2**.

Table 3.2- BS Specifications

BS CODE	SULPHUR CONTENT (PPM)
BS – III	<350
BS – IV	<50
BS – VI	<10

3.6 MANUFACTURING PROCESS DESCRIPTION

3.6.1 DIESEL HYDRO-TREATING (DHDT)

The DHDT Unit (Unit No.211) is proposed to be revamped from the existing 1.80 MMTPA to 2.4 MMTPA. The main objectives of the revamp are as follows:

- To increase the capacity to, additional 33% of existing capacity.

The existing DHDT Unit is designed for treating the feed consisting of Straight Run Gas Oil, Vacuum Diesel oil to produce Diesel complying to BSVI norms.

Feed / Reaction section

The feed to the Hydrotreating unit is a blend of straight run gasoil from atmospheric and vacuum distillations units, light and heavy coker naphthas and heavy gasoil. The blend is filtered in automatic backwash Feed Filter 211-T1. Then the feed is sent to the Feed Surge Drum 211-C1 where it is pumped to the reaction heat exchanger train by a New Feed Pumps 211-G1 A/B under flow control. The drum pressure is maintained by split range control of nitrogen flow and venting to flare. Antifouling agent is injected at the suction of 211-G1 A/B. The feed is mixed with a mix of recycle gas and hydrogen make-up gas. The mixture is heated against the reactor effluent in the following way: In the First Reactor Feed/Effluent Exchangers 211-E1A/B/C/D/E/F and then in The Second Reactor Feed Effluent Exchanger 211-E2. A part of the feed can by-pass the exchangers 211-E1 A/B/C/D/E/F and 211-E2 before mixing with the mix of gas in order to control the temperature at the heater inlet (to ensure a sufficient duty in the heater for control purposes).

The feed is routed to the Reactor Heater 211-F1 where the Feed is heated up until the required inlet temperature of the reactor. The reactor inlet temperature is controlled by acting on fuel gas / fuel oil pressure to the Reactor Heater burners. Inside the Reactor 211-R1, the following reactions take place: olefins saturation, desulfurization, denitrification and aromatics saturation reactions. The reactor contains 3 catalytic beds with an intermediate quench between each bed.

As these reactions are highly exothermic and in order to operate the catalyst beds in an optimized temperature range, an injection of cold quench is foreseen between the first and the second beds and the second and the third bed. These injections are performed under flow control reset respectively by the second and the third catalyst bed inlet temperature controller. Equiflow™ mixing trays in 211-R1 ensures a good mixing between quench gas and bed effluents. Equiflow™ distributor trays ensure a good liquid and gas distribution within the catalyst beds of the reactor.

At the outlet of the reactor, the effluent is used to preheat the reactor feed in the Second Reactor Feed Effluent Exchanger 211-E2 and the First Reactor Feed/Effluent Exchangers 211-E1 A/B/C/D/E/F exchangers. The reactor effluent stream is also preheating the stripper feed in the Reactor Effluent / Stripper Feed Exchangers 211-E3 A/B which is located between 211-E2 and 211-E1 A/B/C/D/E/F.

The effluent is then cooled and partially condensed in the Reactor Effluent Air Cooler 211-E4. To avoid ammonium salt deposits and risk of corrosion in the Reactor Effluent Air Cooler 211-E4, water is injected at the inlet of the air cooler using the New Washing Water Pumps 211-G2 A/B. Wash water is a mixture of water from Stripper Reflux Drum 211-C12, Coalescer 211-C22, Stabilizer Reflux Drum 211-C21 and stripped sour water from a sour water stripper unit. The mixture is collected in the Washing Water Drum 211-C6. The drum pressure is maintained by split range control of Fuel gas flow and venting to flare. BFW can also be injected into the washing water drum in case of shutdown of the sour water stripper unit or if the flow from this unit is not sufficient. From this drum the wash water is pumped by the New Washing Water Pumps 211-G2 A/B under flow control for injection in the reactor effluent.

The effluent after being cooled down in the Reactor Effluent Air Cooler 211-E4 is collected in the New HP Separator 211-C3 where three phases are separated. Pressure of the new HP Separator 211-C3, which dictates hydrogen partial pressure at the outlet of the HDS Reactor 211-R1, is controlled by acting first on the spill back control valve of the H2 Make-

up Compressors 211-K1 A/B and second on the HP purge valve located on the overhead line of the New HP Amine Absorber 211-C8. The gas from the New HP separator 211-C3 is first routed to the HP Amine Absorber KO Drum 211- C7 and then to the New HP Amine Absorber 211-C8 where H₂S is removed by MDEA solution. Rich amine from the New HP Amine Absorber 211-C8 is withdrawn under level control to the LP Amine Absorber 211-C16. The sweetened recycle gas is routed to the Recycle Compressor KO Drum 211-C9 and then is compressed in the centrifugal Recycle Compressor 211-K2. This recycle gas is routed to:

- Quench gas to control the inlet temperature of the second and the third bed (2 different streams).
- Recycle gas first mixed with hydrogen make-up and then with the fresh feed upstream 211-E1A/B/C/D/E/F. The recycle compressor is driven by a steam turbine. The hydrogen make-up comes from H₂ units and is routed to the Make-up Compressors

1st stage KO Drum 211-C4 and then compressed into the first stage of the alternative Make-up Compressors 211-K1 A/B. At the inter-stage, the gas is routed to the Make-up Compressors Inter- stage Cooler 211-E5 A/B and to the Make-up Compressors 2nd Stage KO Drum 211-C5 A/B. Compressed make-up gas from the second stage of 211-K1 A/B is then mixed with the recycle gas. The sour water coming from the New HP Separator 211-C3 is removed under level control, mixed with a part of the water from the Modified Stripper Reflux Drum 211-C12 and routed to the Water Degasser Drum 211-C10. The sour water from 211-C10 is routed to sour water stripper unit under flow control reset by level control and the gas is routed to LP Amine Absorber KO Drum 211-C15 under pressure control.

A part of the hydrocarbon liquid phase from the New HP Separator 211-C3 (about 15 % wt in normal operation) by-passes the Power Recovery Turbine 211-PRT1 and controls the level of the New HP Separator 211-C3. The other part of the liquid (85 % wt) is routed to a power recovery turbine 211- PRT1 under cascade level/flow control. That means that the flow to the turbine has to be constant but if the control of the level in HP separator is no more possible with the by-pass line, the level controller will reset the set point of the flow controller (refer to special loop description). Then the 2 parts are mixed and are routed to the stripping section.

Stripping and Drying section

Stripper feed contains H₂S which has to be removed. The hydrocarbon liquid phase from the New HP Separator 211-C3 is preheated first in the Stripper Feed / Dryer Bottom Exchanger 211-E12, then in the Stripper Feed / Bottom Exchangers 211-E8 A/B/C/D/E and finally in the Reactor Effluent / Stripper Feed Exchanger 211-E3 A/B. The Stripper 211-C11 with New High Performance trays feed inlet temperature is controlled acting on opposite range over the exchanger 211-E3 bypass. Stripping is ensured by injection of medium pressure steam at the bottom of the column. The steam is first superheated in the convection section of the Reactor Heater 211-F1.

An injection of corrosion inhibitor is provided at the Stripper overhead. The overhead vapor is partially condensed in the Stripper Overhead Air Condenser 211-E6 and in the Stripper Overhead Trim Condenser 211-E7 and then collected in the Modified Stripper Reflux Drum 211-C12. For the control of the pressure at the Stripper overhead, refer to special loop description.

A part of the condenser liquid hydrocarbon is used as a reflux to the Stripper 211-C11. Flow control of this stream is reset by overhead temperature. The remaining part is sent under flow control reset by reflux drum level control to naphtha stabilizer section. A part of the sour water from the Stripper Reflux Drum is sent under flow control to the Washing Water Drum 211-C6. The other part is pumped by Stripper Sour Water Pumps 211-G10 A/B to the Water Degasser Drum 211-C10. Sour gas coming out from the Stripper Reflux Drum is routed to the LP Amine Absorber 211-C16 to be washed. The stripper bottom is cooled against the stripper feed in 211-E8 A/B/C/D/E and routed to the Coalescer 211-C22. The decanted water from the Coalescer is routed to Washing Water Drum 211-C6 under level control and the liquid hydrocarbon enters in the Vacuum Dryer 211-C13 under flow control reset by level control. The dryer overhead temperature is controlled acting on opposite range over the bypass line of the Stripper Feed / Bottoms Exchangers 211-E8 A/B/C/D/E.

The overhead vapor is sent to the Vacuum Package 211-H1. Vapor is cooled in the Dryer Overhead Precondenser 211-C14 before entering into the vacuum package. The steam condensed in the vacuum package and the entrained hydrocarbons are collected in the Dryer Overhead Receiver 211-C14 where the two liquid phases are separated. Liquid hydrocarbon phase is pumped by 211-G6 A/B under level control and is recycled back to the Vacuum Dryer 211-C13 inlet. It can also be routed to the inlet of Stripper Feed / Dryer Bottom exchanger 211-E12 (tube side).

The water is pumped by 211-G7 A/B under level control and routed to the Effluent Treatment Plant. It can contain some traces of hydrocarbon. The uncondensables from the Vacuum Package 211-H1 are sent through the Dryer Seal Pot 211-C24 and then to the Reactor Heater 211-F1. In case of shutdown of the heater, the uncondensables are sent to the atmosphere at safe location. The bottom of the Vacuum Dryer (the hydrotreated diesel) is pumped by the New Diesel Product Pumps 211-G5 A/B and is used to preheat the stripper feed in the 211-E12 exchanger. Before being sent to storage under flow control reset by level control, it is cooled down first in the Diesel Product Air Cooler 211-E13 and afterwards in the New Diesel Product Trim Cooler 211-E14.

Naphtha Stabilizer section

The mixing of naphtha from Stripper and condensed liquid from Off-gas Compressors section is heated in Stabilizer Feed/Bottom Exchangers 211-E16 A/B and then feeds the Naphtha Stabilizer 211- C20 where H₂S is removed. An injection of corrosion inhibitor is provided at the Naphtha Stabilizer overhead. The overhead vapor is partially condensed in the Stabilizer Overhead Trim Condenser 211-E18 and then collected in the Stabilizer Reflux Drum 211-C21. The sour gas flow from 211-C21 is sent to LP Amine Absorber KO Drum and controls the stabilizer overhead pressure. The liquid hydrocarbon (total reflux) of 211-C21 is pumped by Stabilizer Reflux Pumps 211-G8 A/B under flow control reset by reflux drum level control to Naphtha Stabilizer 211- C20. The water from 211-C21 is routed under on/off level control to Washing Water Drum 211-C6. A part of the stabilizer bottom liquid is heated by HP steam in Stabilizer Reboiler 211-E17.

The other part of the bottom liquid is pumped by Naphtha Product / Recycle Pumps 211-G9 A/B and routed to Stabilizer Feed / Bottom Exchangers 211-E16 A/B. The stabilized naphtha is then cooled through Stabilized Naphtha Trim Cooler 211-E19 before being sent to storage under flow control reset by stabilizer level control. A stabilized naphtha recycle line under flow control is also provided from 211-G9 A/B to the inlet of Naphtha Stabilizer.

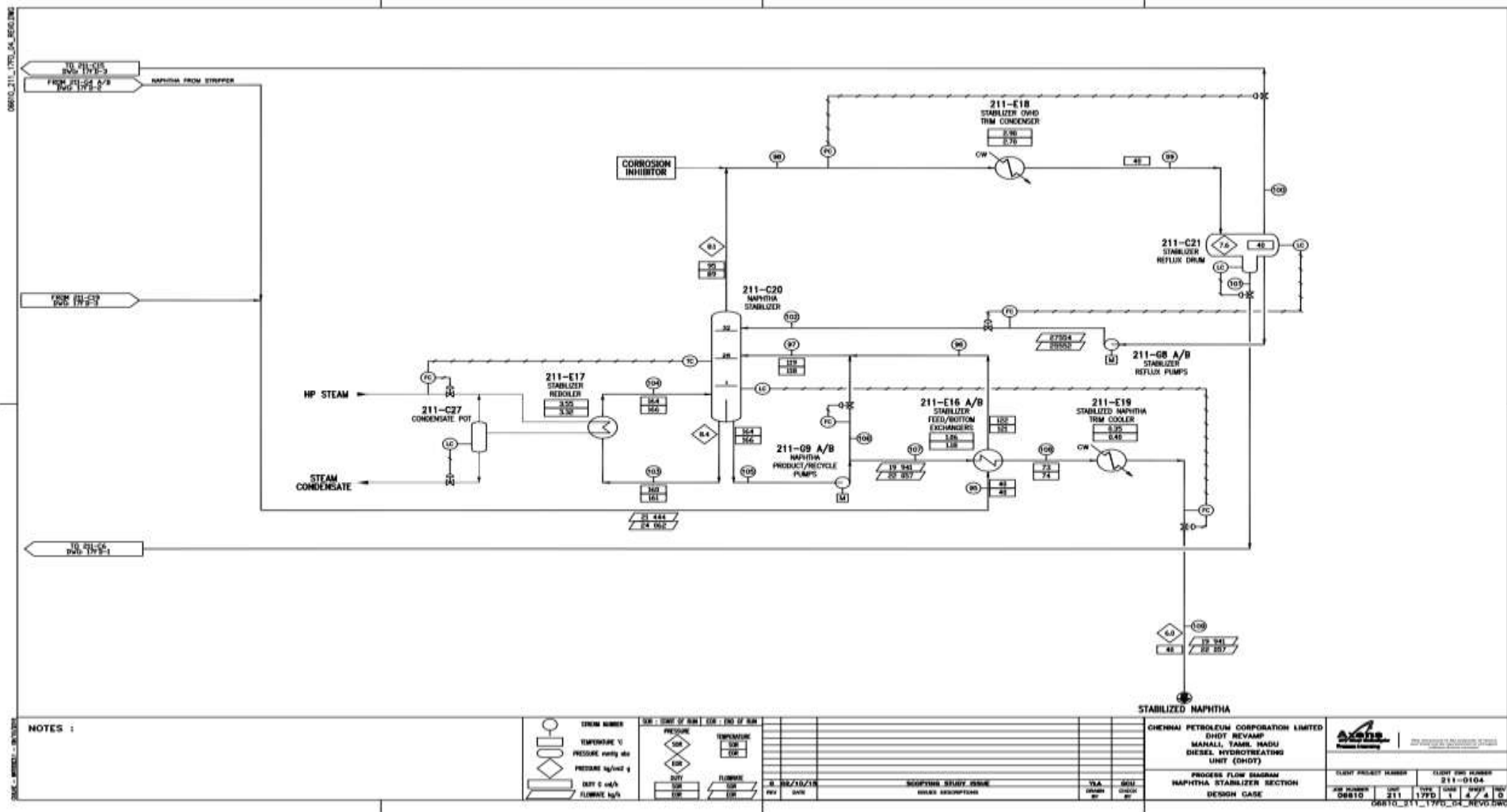


Figure 3-6: DHDY – Naphtha Stabiliser Section – Process Flow Diagram

3.6.2 FCC GDS

Selective hydrogenation section (SHU)

FCC gasoline from debutanizer bottom is sent to feed surge drum. Installation of filters is foreseen upstream surge drum in order to trap possible particles and rust coming from upstream units/storage. The feed is then taken from the drum by a feed pump and sent under flow control to the SHU reaction section. The feed is mixed with hydrogen make-up then heated against first stage HDS section effluent and SHU reactor effluent before entering the SHU reactor. Temperature at SHU reactor inlet is controlled either by adjusting the heat exchange train bypass or by means of a steam preheater. The SHU reactor operates in down-flow mode at moderate temperature, under mainly liquid phase. Diolefins are hydrogenated into olefins with virtually no further hydrogenation into paraffins and/or naphthenes, and light sulphur species are converted into heavier ones. The effluent of the SHU reactor is sent to the Prime-G+TM gasoline splitter

Splitter section

The splitter is reboiled by means of HP steam. A side reboiler is also installed and uses the second stage HDS reactor effluent as hot fluid. It produces as vapor distillate a sweet hydrogen rich gas to be routed to fuel gas network. In the top section, the desulphurized and diolefin-free light cut (LCN) is recovered as a side-draw such as to control RVP. LCN can be sent to gasoline pool without any further sweetening. However, it shall be blended with heavier material such as HCN before being stored. The diolefin-free heavy cut (HCN) is recovered from splitter bottom and sent to selective HDS section. The sulphur concentrates in the heavy cut while most of the olefins concentrate in the light cut. This way, octane loss through the unit is minimized. The cut point between LCN and HCN shall be adjusted depending on the sulphur in the feed and the sulphur target in the recombined (LCN+HCN) FCC gasoline such as to ensure maximum octane retention while meeting stringent sulphur specification.

Selective HDS section – 2 stages HDS scheme

Splitter bottom (HCN) is mixed with hydrogen make-up and part of the recycle gas then heated against first stage HDS reactor effluent before entering the first stage HDS reactor. Reactor inlet temperature is controlled by adjusting the duty of the fired heater located on reactor effluent. Hydrodesulphurization reactions and limited olefins saturation reactions take place in the reactor operating in down-flow mode in fully vapour phase. A gas quench (NNF)

is foreseen between the catalytic beds of the reactor to limit the temperature rise due to the heat of reaction and control olefins saturation. The quench flow is controlled by the temperature at catalytic bed inlet.

The effluent of the first stage HDS reactor is cooled down against first stage HDS reactor feed before entering the first stage hot separator. From the first stage hot separator, two phases are separated:

- The gas phase, which has to be cooled down before feeding to the first stage cold separator.
- The liquid phase, which is pumped and sent to H₂S stripper in order to reduce the H₂S content in the liquid hydrocarbons feeding the second stage HDS.

Before entering the first stage cold separator, the gas phase is cooled down against SHU reactor feed then in an air cooler. Wash water shall be injected in the effluent on an intermittent basis in order to avoid any salt deposits.

From the first stage cold separator:

The gas phase is circulated by the recycle compressor after H₂S removal in amine absorber. The aqueous phase (if any) is sent to the sour water stripper (outside battery limits) The liquid phase is pumped to the H₂S stripper in order to reduce the H₂S content in the liquid hydrocarbons feeding the second stage HDS. There is normally no purge and the reaction section pressure is maintained by resetting the hydrogen make-up flow. Stripping of H₂S from the liquid phase is performed using hydrogen from recycle compressor. Identically to the first stage, the liquid hydrocarbon phase from H₂S stripper bottom is mixed with hydrogen make-up and part of the recycle gas then preheated against second stage HDS reactor effluent before entering the second stage HDS reactor. Reactor inlet temperature is controlled by adjusting the duty of the fired heater located on reactor effluent.

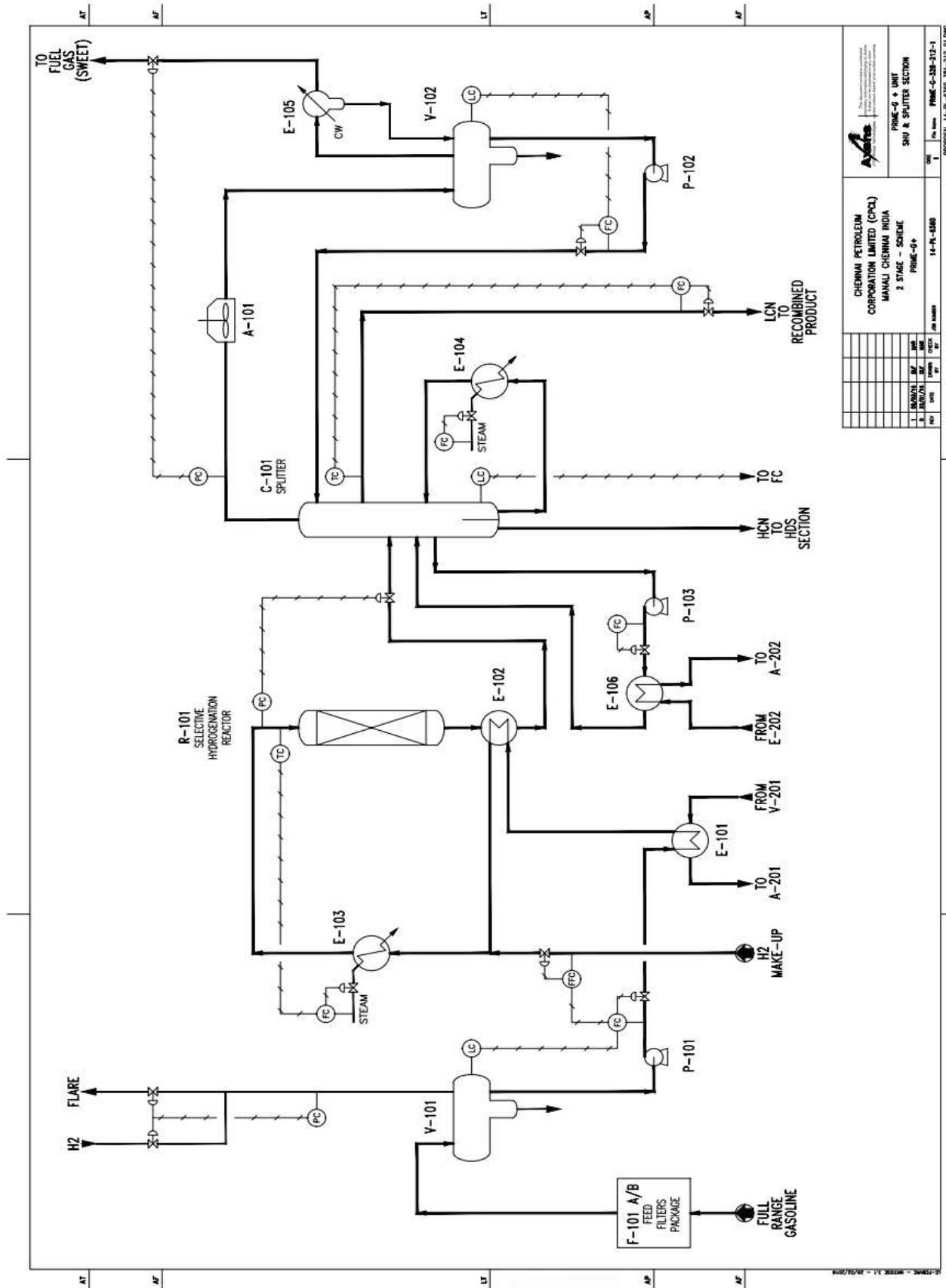
This second reactor still achieves a high desulphurization rate while minimizing olefins saturation. This is of paramount importance to maximize octane retention while ensuring a very low sulphur specification in the effluent (and thus in the recombined FCC gasoline product). The effluent of the second stage HDS reactor is cooled down first against second stage HDS reactor feed, against the side reboiler of the splitter, and then in an air cooler before entering the second stage cold separator. Wash water shall be injected in the effluent on an intermittent basis in order to avoid any salt deposits.

From the second stage separator:

The gas phase is circulated by the recycle compressor after H₂S removal in amine absorber. The aqueous phase (if any) is sent to the sour water stripper (outside battery limits). The liquid phase is sent to the downstream stabilizer, under flow control reset by the level in the separator drum. It shall be highlighted that amine absorber and recycle compressor are common for the two HDS sections.

Stabilizer section

H₂S and light ends removal in the desulphurized heavy naphtha is carried-out in the stabilizer. The tower, reboiled by means of HP steam, produces a sour vapour distillate which can be routed to FCC gas plant. Sweet and desulphurized heavy naphtha is taken from stabilizer bottom, cooled down against stabilizer feed then mixed with treated light naphtha from Prime-G+TM splitter side-draw. After further cooling, recombined desulphurized gasoline is routed to gasoline pool. The sour Stabilizer purge is treated in a dedicated LP Amine Absorber to produce a sweet purge gas effluent before being routed to Fuel Gas system.



CHENNAI PETROLEUM CORPORATION LIMITED (CPL)		PRIME-G + UNIT	
MAHALI CHENNAI INDIA		SHU & SPLITTER SECTION	
2 STAGE - SCHEME		PRIME-G+	
14-PL-1550		14-PL-1550	
NO.	DATE	NO.	DATE
1		2	
3		4	
5		6	
7		8	
9		10	
11		12	
13		14	
15		16	
17		18	
19		20	
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95		96	
97		98	
99		100	

Figure 3-7: FCC GDS -SHU & Splitter Section – Process Flow Diagram

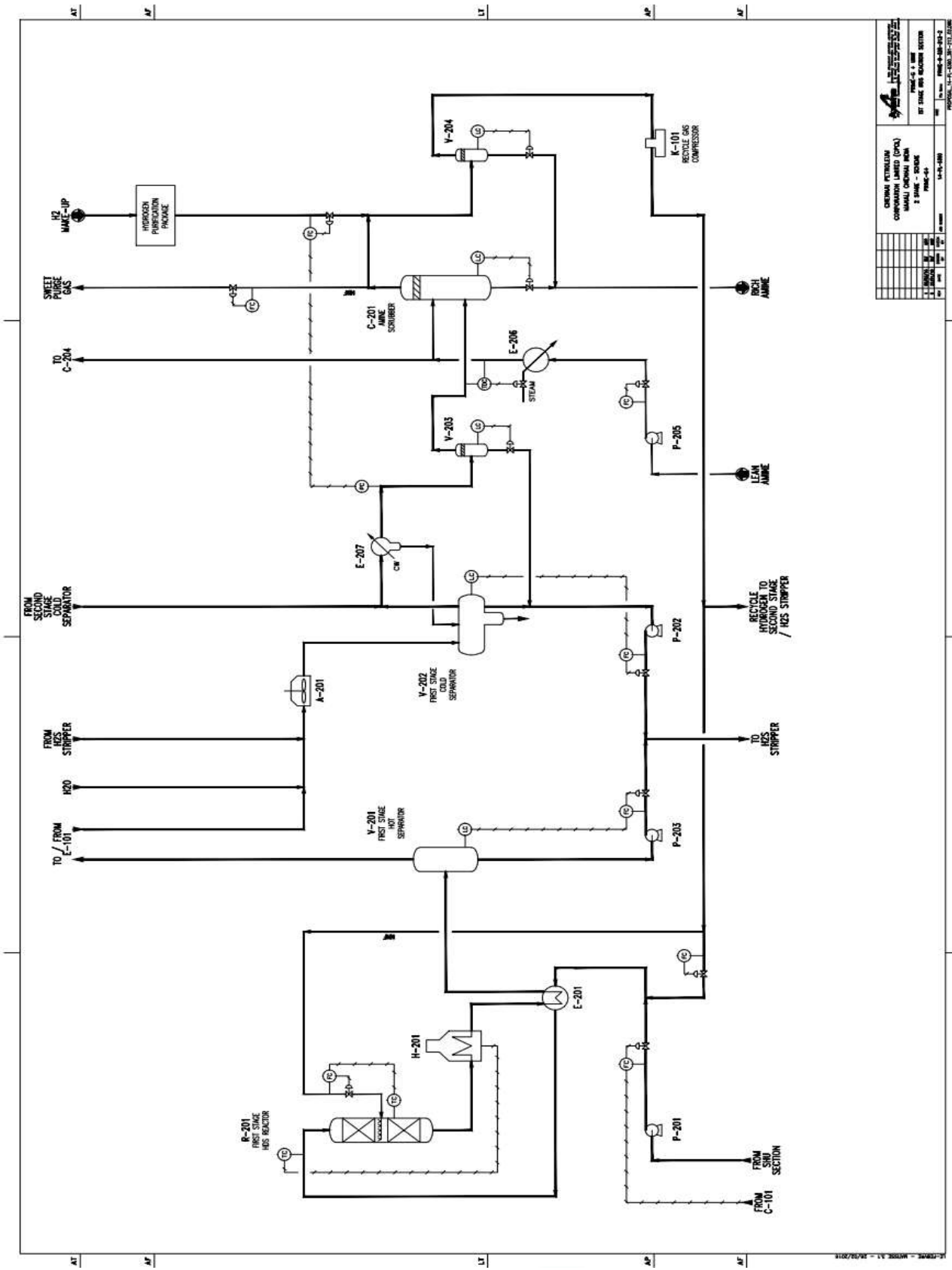


Figure 3-8: FCC GDS –1st stage HDS Reaction Section – Process Flow Diagram

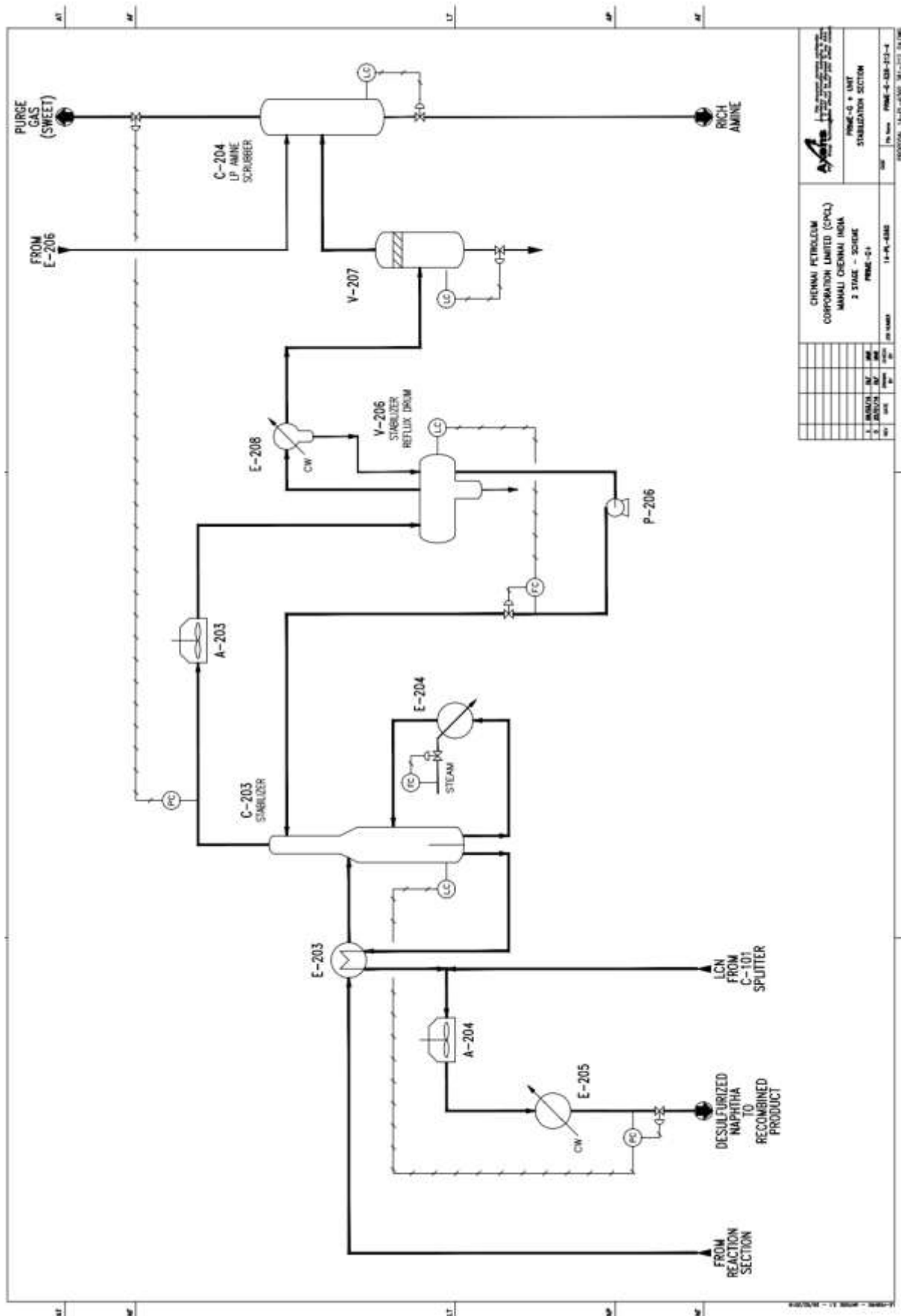


Figure 3-10: FCC GDS –Stabiliser Section – Process Flow Diagram

3.6.3 SRU Block

This involves 3 Units

- 1) Sulphur Recovery Unit
- 2) Amine Treating Unit
- 3) Sour Water Stripping Unit

Acid gas generated in the Amine Regeneration Unit and Sour Water Strippers is received in the surge drum and then fed to the Thermal Reactor. The process gas produced in the Thermal Reactor passes through the Waste Heat Boiler in which saturated steam is produced at 50 barg. The Waste Heat Boiler is of tubes smoke type. The process gas from Waste Heat Boiler at temperature of about 370 deg C enters the first Condenser, where Sulphur is condensed, separated and collected in the sulphur pit via the sulphur seal. The process gas coming from the first condenser at temperature of about 190 deg C is heated to the Temperature of 230 deg C by an HP steam re-heater and the enters into the first catalytic converter.

The catalytic conversion is made on the standard alumina catalyst. The catalytic reaction is exothermic and the gas coming from the first converter enters the second condenser, where Sulphur is condensed, and separated and collected in the sulphur pit via the sulphur seal.

The process gas coming from the second condenser at temperature of about 170 deg C is heated to the Temperature of 205 deg C by an HP steam re-heater and then enters into the second catalytic converter.

The process gas inlet temperature is automatically controlled by a controller. The gas coming from second converter enters the second condenser , where Sulphur is condensed, separated and collected in the sulphur pit via the sulphur seal.

The heat recovered in the final sulphur condenser is used to preheat the boiler feed water to the waste heat boiler. The tail gas coming from the third condenser at temperature of 130 deg C enters the tail gas KOD sulphur coaleser where the sulphur mist is separated and passes to the tail gas treating unit.

3.7 POWER AND FUELS

The existing power requirement of DHDT Unit is 3200 kWh and with the proposed expansion, additional power required is 600 kWh. The power requirement for FCC GDS Unit is 1047 kWh. The power requirement for SRU block (SRU, ARU & SWS) is 1551 kWh. This

is a combination of HT and LT loads. The power required will be sourced from existing internal Captive Power Plants.

The details of power and fuel requirements are given in **Table 3.3**.

Table 3.3- Power and fuel oil requirement

Details	DHDT	FCC GDS	SRU Block	Source
Power Requirement	3800 kWh	1047 kWh	1551 kWh	Internal Captive Power Plants
Fuel oil	1272 kg/hr	300 kg/hr	100 kg/hr	Refinery Fuel Oil (Internal)

3.8 LAND USE

There is no change in land distribution after proposed capacity expansion as all the new equipment will be installed in the spare slots within existing buildings & layouts. The land deed agreement is given in **Annexure 1**.

3.9 MANPOWER

The existing DHDT Unit has a total of 20 employees including 2 contract workers, details of manpower requirement for BS-VI project is as shown in **Table 3.4**. There will be no additional manpower required for revamped DHDT Unit.

Table 3.4- Manpower Requirement for BS-VI project

Designation	Shift	FCC GDS	SRU Block
Manager	General Shift	1	1
Panel Engineers	Rotating Shift	4	4
Shift Engineers	Rotating Shift	5	5
Field Operators	Rotating Shift	8	8
Contract workers (House Keeping)	General Shift	2	2
Total Manpower		20	20

3.10 WATER REQUIREMENT

The total requirement of raw water for the entire refinery is 50234 KLD. The water requirement is met mainly by the treated water from CPCL's sea water desalination plant and effluent recycling units. A small quantity is received from Chennai Metro Water Corporation (CMWSSB). In this regard the correspondence between CPCL and CMWSSB is provided in **Annexure 2** for reference. There is no bore well source inside the Plant premises. Water requirement for the proposed units are shown in **Table 3.5**.

Table 3.5- Water Requirement

Phase	Details	Quantity (KLD)		Source
Construction		30		CPCL Desalination Plant, Sewage water treatment and Metro water .
Operation		Existing	Additional Proposed	
	DHDT	2500	No additional requirement	
	FCC GDS	NIL	500	
	SRU Block	NIL	500	
	Total	2500	1000	

3.11 UTILITIES

The following **Table 3.6** shows the list of utilities in the project:

Table 3.6- List of Utilities

S. No.	Utility	Existing Flow rate	Revised Flow rate
DHDT			
1	HP Steam	24.3 MT / hr	26.3 MT / hr
2	MP Steam	6.8 MT / hr	10.0 MT / hr
3	LP Steam	3.0 MT / hr	4.0 MT / hr
4	Cooling Water	1600 m ³ / hr	1650 m ³ / hr
5	Electrical Power	3200 kW	3800 kW
FCC GDS			
1	HP Steam	18.5 MT/hr	
2	LP Steam	0.1 MT/hr	
3	Cooling water	106 m ³ /hr	
4	Power	1020 kWh	
SRU Block			
1	Cooling water	1500 m ³ /hr	
2	Power	1551	

3.12 LIQUID WASTE MANAGEMENT

The revamp of DHDT unit designed for a nominal capacity of 2,400,000 MTPA, (133% of the 1,800,000 MTPA original design capacity) with on-stream factor of 8000 hours per year. Capacity of FCC GDS Unit is 600,000 MTPA. Capacity of SRU Unit is 200 TPD.

The liquid effluent generated from these units is treated in the existing Effluent Treatment Plant (ETP) and the sewage generated is treated in the existing Tertiary Treatment Plant (TTP). The layouts of Effluent Treatment Plant (ETP) and Tertiary Treatment Plant (TTP) are given in **Annexure 9**.

3.12.1 FCC GDS Liquid Effluent

Wash water and stripping condensates containing H₂S, NH₃ and traces of HC are sent to S.W.S Section. The stripped water is sent before being recycled to the biological treatment. Rich amine is sent to amine regeneration. Please refer to section 3.3.2 “chemicals consumption” for further details about flow rates of wash water and amine.

Oily water

Oily water is collected from:

- Feed Surge Drum: Normally, there is no free water from the FCC gasoline feed. However, water can originate during upset of the upstream units. This water does not contain sulfur or H₂S.
- Splitter Reflux Drum: This stream is normally no flow. However, water can originate during upset of the upstream units. This water does not contain sulfur or H₂S.

Sour water

The PG+ Unit produces streams containing ammonium salts (NH₄HS and NH₄Cl) and dissolved H₂S. This production is intermittent. During wash water phase, sour water is collected from Separator Drum.

3.12.2 DHDT waste Effluent Summary

Sour Water containing ammonium salts is recovered at the HP Separator 211-C3 and the StripperReflux Drum 211-C12 then routed to the Sour Water Stripper Unit via the Water Degasser Drum 211- C10. Sour water generation from DHDT is as shown in **Table 3.7**.

Table 3.7- Sour Water Generation

Origin (tag)	Flowrate (kg/h) SOR/EOR	Frequency / Duration	Nature	Impurities	Destination
211-C3	12 668 / 12 424	Continuous	H ₂ O = 96.76 wt%	Ammonium salts: wt%	Sour water stripper

211-C12	2 884/ 2 910		H ₂ S = 2.16 wt% NH ₃ = 1.08 wt%		
Total	15 552/ 15 334				

3.13 HAZARDOUS AND SOLID WASTE MANAGEMENT

The hazardous wastes generated from CPCL are collected, stored and disposed through authorized disposal cum recycle facilities as per the authorization from PCB and the unit has agreements with all waste disposal facilities for the same. There is no internal disposal facility availability within the site. The Authorization Letter from TNPCB is enclosed as **Annexure 4**.

The hazardous waste generated from the DHDS unit, is Spent Catalyst of and this will be sent to MoEF&CC approved TSDF facility which is located in Gummudipondi in TamilNadu for secured landfill.

The Municipal Solid Waste generated from the site is collected and transported to recyclers, municipal yards and landfills depending on the type of waste. The details are given below in **Table 3.8**

Table 3.8- Municipal Solid Waste details

S. No	Nature of Solid Waste	Quantity T / Year	Method of Handling		
			Collection & Storage	Treatment	Disposal
1	Paper / Card Board	125	Manual collection & storage in Bins	Nil	Sales to Recyclers
2	Dust Bin collections	475	Manual collection	Bio Composting	Manali Municipal Yard
3	Dry leaves Grass	95	Manual collection	Nil	Landfill
4	Metal scrap	805	Manual collection scrap yard	Nil	Sales to Recyclers
5	Wooden scrap	175	Manual collection scrap yard	Nil	Sales to Recyclers

3.14 GREEN BELT DEVELOPMENT

The existing Refinery is having a Greenbelt area which already has been developed and the Green belt area coverage is being progressively increased. The green belt details are as shown in **Table- 3.9**.

Table 3.9- Green belt details

Location	Area in Acres	Remarks
Existing Green belt in Refinery	52	Already existing
CPCL polytechnic (outside)	25	Recently completed
Amullavoyal (outside)	150	Out of a total 360 acres
Total Green Belt	227	

3.15 ENVIRONMENT, SAFETY AND HEALTH MONITORING

CPCL periodically carries out Internal Safety Audit, External Safety audit Comprehensive Risk Analysis and HAZOP study periodically. The fire protection systems and equipments are provided as per Oil Industry Safety Directorate (OISD) Standards and other relevant guidelines. Adequate no. of Fire Fighting Vehicles & Emergency Rescue Vehicle equipped with rescue apparatus / gadgets, fire water storage, fire water pumps, fire fighting chemicals meeting the specified norms are available.

Automatic gas detection and alarm systems are installed in refinery units and tank farm for quick detection of hydrocarbon leaks and emergency mitigation. CCTV is installed at critical locations and linked to the Control Rooms for continuous monitoring. For Communication of emergency scenarios, Fire Call telephones, Manual Call Points (MCP), Plant Communication System, UHF handsets and emergency sirens have been provided. CPCL has entered into Mutual Aid Agreement with two of the neighboring industries. Well documented On-site Emergency Preparedness Plan, offsite Emergency preparedness plan & Disaster Management Plan (ERDMP) are in place.

Following pollution control/ mitigation measures are adopted to minimize the impact of Refinery operation on Environment:

- Continuous Operation of 3 numbers of Effluent Treatment plants and reuse of treated effluent.
- Monitoring of treated effluents from Effluent Treatment Plant for compliance against Minimum National Standard (MINAS), surface water & Ground water
- Use of low sulphur fuel & low NOX burners to maintain emissions from heaters at permissible limits
- Use of Gas turbine in captive power plant with cleaner Naphtha as main fuel.
- Monitoring and inventorisation of Fugitive emissions by using Leak deduction & Repair (LDAR) program in the entire plant area for minimizing emission of Hydrocarbons.
- Continuous improvement in Energy consumption reduction and use of alternate energy like solar & wind power to reduce Carbon-di-Oxide emission.
- Continuous monitoring of Ambient Air Quality & Continuous Emissions Stack Monitoring Green house gas emissions reporting and control measures taken for reducing the GHG.
- Continuous operation of VOC collection & removal system with Activated carbon adsorbent to reduce the VOC emissions.
- Ensuring Hazardous waste management in the refinery as per Hazardous Waste Rules, 2008.
- Safe disposal of Hazardous waste in segregated & dedicated, Hazardous Waste Treatment Storage & Disposal Facility (HAWTSDF)
- Monitoring of ground water quality.

4. SITE ANALYSIS

4.1 CONNECTIVITY

The proposed site on the SH – 56 and it is in the express highway connecting Thiruvottiyur and Ponneri. The nearest railway station is Thiruvottiyur.

4.2 LAND FORM, LAND USE, LAND OWNERSHIP

The Plant is located at survey nos. 266 / 2, 274, 296, 297, 298 and 299, Manali Village, Ambattur Taluk, Tiruvallur District, and Tamil Nadu. Layout of CPCL is enclosed as **Annexure-3**

4.3 EXISTING LAND USE PATTERN

The present land use is in industrial zone. The details of sensitive areas from the site boundary are given in **Table 4.1**. The site does not fall within the CRZ area. The CMDA land use map is enclosed in **Annexure 5**.

Table 4.1- Water bodies in the study area

S.No	Name	Distance & Direction (km)
1.	Surplus canal from Korttalaiyar River	0.13 Km (North)
2.	Buckingham canal	0.63 Km (East)
3.	Retteri	7.56 Km(South-west)
4.	Madhavaram Lake	3.57 Km (West)
5.	Kadapakkam Panchayat Lake	4.56 Km (North West)
6.	Periyathoppu Lake	3.1 Km (North West)
7.	Bay of Bengal	3.13 Km (East)

4.4 CLIMATIC CONDITIONS

The study region receives rainfall predominantly during monsoon season with an average annual rainfall of about 1211 mm per year. The South west monsoon season is from July – September and North east monsoon is from October to December. The relative humidity recorded in the district is about 49-79%. Due to its proximity with the Bay of Bengal, the ambient temperature at project site ranged between 25-40°C. The area has a tropical climate with the highest and lowest temperatures recorded is Maximum of 40.3°C and Minimum of 25°C respectively. The metrological observation is as shown in **Table 4.2**.

Table 4.2- Meteorological Observations

S.No	Parameter	Observation
1	Wind Direction	SW-SE-W-WSW
2	Wind Speed Range	2 to 8.8 m/sec
3	Annual Average Rainfall	1211 mm
4	Average Wind Speed	3 m/sec
5	Temperature Range	Max. Temp: 40°C Min. Temp: 25°C
6	Average Temperature	32°C
7	Humidity Range (24hr)	49 to 79 %
8	Cloud cover	Partly cloudy

5. CONCLUSION

- The proposed project is to increase Diesel treating capacity and also to make Gasoline fuel to meet the BS VI norms which will help in reducing the vehicular emissions to atmosphere.
- As the proposed project is coming up in the existing plant which is located in special and hazardous zone, there will not be any change in land use.
- The existing water infrastructure will be adequate for the proposed expansion also. The treated water is reused for gardening and process requirements.
- The marginal impact of proposed capacity expansion within the existing facility will be fully mitigated with the existing Environment Management Plans (EMP).