Report of the Comptroller and Auditor General of India on

Planning and Implementation of Phase III Expansion Project of Mangalore Refinery and Petrochemicals Limited

Union Government (Commercial)
Ministry of Petroleum and Natural Gas
Report No. 33 of 2017
(Performance Audit)

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Preface

This Performance Audit Report of the Comptroller and Auditor General of India has been prepared in accordance with the Performance Audit Guidelines and the Regulations on Audit and Accounts, 2007 of the Comptroller and Auditor General of India.

In February 2006, Mangalore Refinery and Petrochemicals Limited decided to undertake a refinery upgradation project with an estimated cost of ₹ 7,943 crore. The cost underwent changes from time to time due to change in capacity, addition and deletion of various units. The Project was completed during the period from August 2013 to June 2015. As of March 2016, the total expenditure incurred by the Company on the Project was ₹ 14,832 crore.

The Performance Audit was conducted with a view to examine the economy, efficiency and effectiveness in execution of the Project and to review the refinery operations so as to ensure that the same were carried out economically and efficiently.

Audit observed deficiencies in the planning phase of the Project which resulted in time and cost overrun. Audit also observed that various factors such as deficiencies in planning for crude in consonance with the capacity of processing units, delayed commissioning, synchronisation of the commissioned units with other existing / new secondary processing units, operating below optimal capacity etc. adversely impacted the efficiency of the operation of the refinery units. Further, non-compliance with the directions on environment conservation issued by various statutory authorities was also observed.

Audit has recommended that in future, the Company may draw up a comprehensive plan before finalising the projects in order to avoid time and cost overrun and also ensure sequential completion and proper integration of the processing units to avoid their idling and underutilisation.

Audit acknowledges the co-operation and assistance extended by Mangalore Refinery and Petrochemicals Limited and Ministry of Petroleum and Natural Gas in the conduct of this Performance Audit.

Executive Summary

Executive Summary

Mangalore Refinery and Petrochemicals Limited, in the year 2006, decided to undertake a refinery upgradation project with an estimated cost of ₹ 7,943 crore. The objective of the Project was to increase the refinery capacity from 11.82 MMTPA to 15 MMTPA and to enhance the production of value added products. In June 2010, the estimated cost stood revised to ₹ 15,008 crore due to change in the scope of the Project. The project, which was initially proposed to be completed in June 2010, was actually completed in June 2015.

The planning, execution and commissioning of units under the project and its impact on refinery operations during 2011-16, were reviewed during the course of Performance Audit. Significant audit findings are detailed below:

- Deficiency in planning, due to lack of clarity regarding revamping of existing units and commissioning of additional units, led to time over run of more than two years and cost overrun of ₹ 2,509 crore.

  (Paragraph 2.1.1)

- The Company availed External Commercial Borrowings without hedging the associated currency fluctuation risk. The Company lost approximately ₹ 13.70 crore (net of currency hedging cost) due to exchange rate variation on loan repayments (up to September 2016) and may incur further losses in case of non-strengthening of the rupee against USD.

  (Para 2.2.1)

- The Company drew funds for the project in excess of its requirements due to which ₹ 768.46 crore was lying idling in non-interest bearing current account.

  (Paragraph 2.2.2)

- Out of 87 major contracts reviewed in Audit, there were delays in execution of formal contract in 84 cases after issuance of Letter of Acceptance.

  (Paragraph 2.3.2)

- Delayed commissioning of Captive Power Plant resulted in idling of various processing units for a period ranging from 11 to 26 months, even though the same had been mechanically completed.

  (Paragraph 2.4.1)

- Savings in freight, avoidance of demurrage and improvement in Gross Refinery Margin as envisaged while the decision for setting up of Single Point Mooring facility was taken, were actually not achieved.

(Paragraph 2.5.5)

- Non synchronisation of revamped Hydrocracker units with Petrochemical Fluidized Catalytic Cracking unit led to production of low value products in place of high value products during the period from 2011-12 to 2014-15 which resulted in loss of revenue of ₹ 6328.76 crore.

(Paragraph 3.3)

- Non production of Propylene as per the designed yield and its non conversion to Poly Propylene, a high value product, in the Poly Propylene Unit during the period from August 2014 to May 2015 resulted in a loss of margin of ₹ 382.83 crore.

(Paragraph 3.6.2)

- The processing units consumed Steam in excess of norms and incurred extra expenditure of ₹ 231.94 crore.

(Paragraphs 4.1)

- There were delays in complying with environmental directives.

(Paragraphs 5.1, 5.2 and 5.3)

Chapter 1 Introduction

Mangalore Refinery and Petrochemicals Limited (the Company) is a Miniratna Company under the administrative control of Ministry of Petroleum and Natural Gas (MoPNG), Government of India (GoI). The Company is a subsidiary of Oil and Natural Gas Corporation (ONGC). It produces Liquefied Petroleum Gas, Motor Spirit, Naphtha, Mixed Xylene, Aviation Turbine Fuel, Kerosene, High Speed Diesel, Furnace Oil, Bitumen, Polypropylene, Petroleum Coke and Sulphur.

Till 2011-12, the Company had a refining capacity of 11.82 MMTPA[1] which was expanded to 15 MMTPA under Phase III expansion project.

1.1 Organisation set up

The Company is headed by a Non-Executive Chairman. Managing Director is the executive head of the Company. The Board of Directors (Board) comprise of Chairman, three functional directors including the Managing Director, one nominee director of Hindustan Petroleum Corporation Limited and two government nominee directors. There were no independent directors in the Board since 14 September 2014.

Managing Director, Director (Finance) and Director (Refinery) are the full time functional directors in the Board. Various departments of the Company are headed by Group General Managers who report to Director (Finance) or Director (Refinery) based on the functions performed. The Company has a branch at Bangalore to assist in marketing activities and

[1] ***MMTPA -Million Metric Tonne per Annum.***

another at Delhi to assist in financial activities, including international transactions and to facilitate crude import and product export.

1.2 Financial Performance

The financial position of the Company for the five years ending 31 March 2016 is reflected in the following table:

Table 1.1: Balance Sheet (₹ in crore)

Particulars	2011-12	2012-13	2013-14	2014-15	2015-16
Share Capital	1,757.26	1,752.66[2]	1,752.66	1,752.66	1,752.66
Reserves	5,471.94	4,715.03	5,316.21	3,552.29	4,667.78
Borrowings	6,183.11	7,557.65	9,792.72	9,032.47	8,102.84
Deferred Tax Liability	453.14	734.33	470.27	0.00	80.63
Total Liabilities	**13,865.45**	**14,759.67**	**17,331.86**	**14,337.42**	**14,603.91**
Fixed Assets (Net)	11,149.02	13,335.11	14,542.97	15,486.76	15,104.54
Investments	42.28	15.00	15.00	1,349.67	1,349.67
Net Current Assets	2,674.15	1,409.56	2,773.89	-2,499.01	-1,850.30
Total Assets	**13,865.45**	**14,759.67**	**17,331.86**	**14,337.42**	**14,603.91**

The increase in borrowings during the period from 2011-12 to 2013-14 was to meet the capital expenditure up to 2013-14. The same started decreasing thereafter as the Company started repaying the borrowings. Further, investments also increased in the year 2014-15 on account of subscription (February 2015) to share capital of ONGC Mangalore Petrochemical Limited, which became a subsidiary of the Company.

Operating performance of the Company for the five years ending 31 March 2016 was as given below:

Table 1.2: Statement of Profit and Loss (₹ in crore)

Particulars	2011-12	2012-13	2013-14	2014-15	2015-16
Income					
Sales (Net of Excise Duty)	53,763.34	65,691.52	71,810.50	57,438.15	39,632.04
Other Income	354.31	116.04	324.47	810.16	872.52
Increase/ (Decrease) in Stocks	150.21	1,116.15	674.07	-1,886.13	-683.17
Total – A	**54,267.86**	**66,923.71**	**72,809.04**	**56,362.18**	**39,821.39**
Expenditure					
Raw Materials	51,236.75	65,400.18	70,740.63	55,886.06	34,650.43
Sales Tax & Excise Duty on Stocks (net)	-60.62	21.8	19.96	91.69	158.89
Salaries & Other Expenses	160.64	184.56	215.47	240.74	306.14
Exchange Fluctuation Net Loss	648.22	536.49	1.91	683.5	1,190.27
Other Expenses	322.11	324.56	393.51	710.38	1,051.92
Interest	206.68	328.55	321.44	407.09	577.83

[2] *Reduction in capital due to redemption of 91.86 lakh Preference Shares of ₹ 5.00 each*

Depreciation	433.87	604.41	706.42	498.61	712.41
Total – B	**52,947.65**	**67,400.55**	**72,399.34**	**58,518.07**	**38,647.89**
Profit/Loss Before Tax **C=(A-B)**	1,320.21	-476.84	409.70	-2,155.89	1,173.50
Provision for Taxation - **D**	411.63	280.07	-191.49	-443.66	25.35
Profit/Loss After Tax C-D	**908.58**	**-756.91**	**601.19**	**-1,712.23**	**1,148.15**

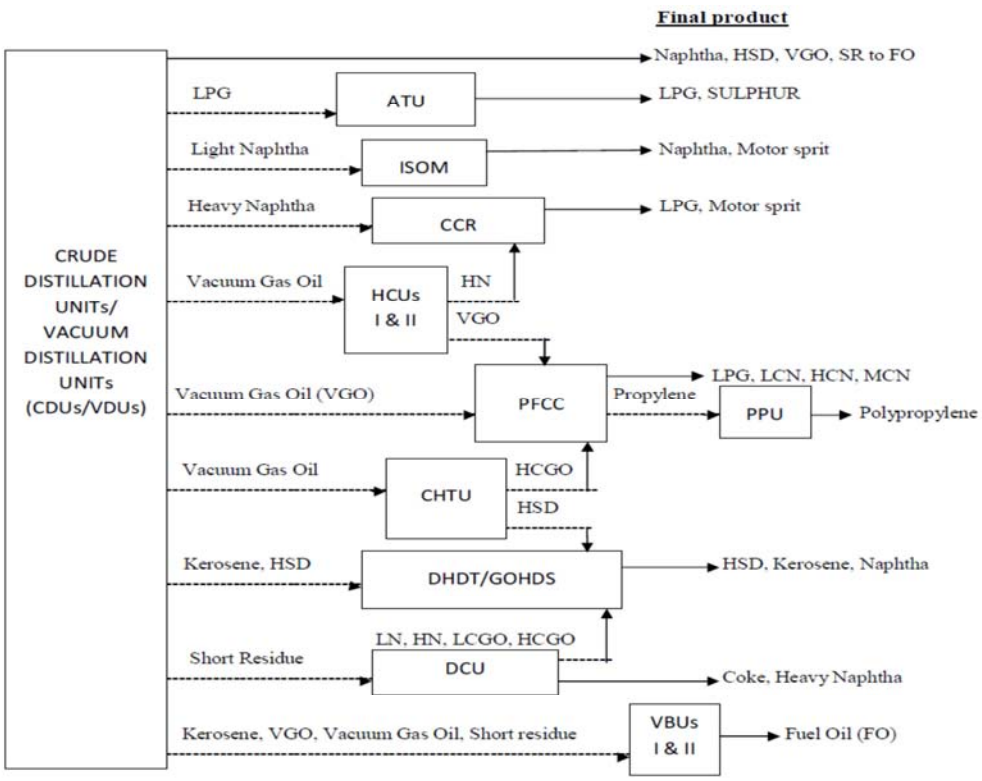
The Company earned profits during 2011-12, 2013-14 and 2015-16 and incurred losses during 2012-13 and 2014-15. One of the reasons for this fluctuating result was delay in stabilisation of the newly commissioned units of Phase III expansion project and their non-synchronisation with Phase I & II units. Further, other factors like currency rate variations and fluctuations in crude oil prices, also contributed to the fluctuations in results.

1.3 Production process

The Company plans refinery operations on the basis of demand for petroleum products, availability of required grade of crude oil as per designed parameters of processing units and refinery configuration. Yield pattern of the refinery depends upon the crude mix, refinery configuration, technology, finished product demand, production process optimisation and operating performance of primary and secondary processing units.

A simplified flow diagram of MRPL refinery is shown below:

Refinery Process Flow



1.4 Production Performance

The production performance of the Company was reviewed keeping in mind the commissioning of various facilities projected under Capital Projects including Phase III Expansion Project, setting up of Poly Propylene Unit[3] (PPU) and Single Point Mooring[4] (SPM) facility and their synchronisation with the existing facilities created under Phase I and II. Following table summarises the production performance of the Company for five years ending March 2016.

Table 1.3: Production performance

Particulars	2011-12	2012-13	2013-14	2014-15	2015-16
Capacity (MMTPA)	11.820	13.620	15.000	15.000	15.000
Crude Oil receipt (MMT)	13.025	14.156	14.971	14.354	15.871
Throughput (MMT)	12.818	14.403	14.547	14.648	15.692
Production (MMT)	11.953	13.394	13.397	13.169	14.166
Capacity utilisation (Throughput/Capacity) (in *per cent*)	108.44	105.75	96.98	97.65	104.61
Gross Refining Margin (USD/BBL[5])	5.60	2.45	2.67	(-)0.64	5.20
Fuel & Loss [6] (*per cent* to throughput)	6.75	7.00	7.90	10.09	10.06

Though the Crude Distillation Unit (CDU)[7] III under Phase III Expansion Project was commissioned in March 2012, the Company considered addition of 60 *per cent* capacity for the year 2012-13 on trial run basis and full capacity thereafter i.e. from 2013-14. Though design capacity was estimated at 15 MMTPA, the Company could not achieve the designed capacity during 2013-14 and 2014-15 due to delay in commissioning of Phase III units which was actually achieved in 2015-16. Delay in commissioning of Phase III units also impacted the Gross Refinery Margin (GRM), which turned negative during 2014-15. Fuel & Loss, which affects efficiency and GRM, showed an increasing trend for four years up to 2014-15 while during 2015-16, it showed a marginal decline compared to previous year. Thus, GRM and Fuel & Loss which affect the operating efficiency showed an adverse trend during the period. These aspects have been discussed in ensuing Chapters.

1.5 Capital Projects

Based on a Detailed Feasibility Report (DFR) prepared by Engineers India Limited (EIL) in December 2005, the Company decided (February 2006) to undertake a refinery upgradation

[3] *Petrochemical unit for production of Poly Propylene from Propylene.*
[4] *An offshore facility for discharge of crude*
[5] *The Gross Refinery Margin (GRM) is the difference between the total value of petroleum products coming out of an oil refinery (output) and the price of the raw material (input) which is crude oil. GRM is typically expressed in US dollars per barrel (USD/bbl).*
[6] *'Fuel & Loss' is the oil used in running the various units of refinery or is lost during processing.*
[7] *Distils and separate valuable distillates and bottom products from crude.*

project (Phase III Expansion Project) with an estimated cost of ₹ 7,943 crore. This cost was revised to ₹ 12,412 crore in August 2008 due to change in capacity/deletion of units and addition of CDU and Heavy Coker Gas Oil Hydrotreating Unit (CHTU)[8]. In May 2009, it was revised to ₹ 13,964 crore due to inclusion of PPU at an estimated cost of ₹1,804 crore and reduction of ₹ 252 crore due to deletion of handling facility of Propylene. Again in June 2010, the cost was revised to ₹ 15,008 crore due to inclusion of SPM at a cost of ₹ 1,044 crore. The detailed reasons for the revisions are included in **Annexure I**. Details of estimated cost in 2006 and its revision in 2008, 2009 and 2010 are given in **Annexure II**.

In October 2015, the Company obtained approval of its Board for adjustment in Project Cost of Phase III expansion to ₹13,475 crore. Thus, the total adjusted cost of the Capital Projects including Phase III Expansion Project, setting up of PPU and SPM worked out to ₹ 16,323 crore. As of March 2016, the Company had incurred an expenditure of ₹14,832 crore.

Initially, the project was scheduled to be commissioned within 48 months from June 2006 i.e. by June 2010 which was later extended (August 2008) to October 2011 due to change in capacity/deletion of units and addition of CDU and CHTU. The project, however, got commissioned in September 2014. PPU and SPM, which were envisaged in 2009 and 2010, had a commissioning target of September 2012 and May 2012, respectively. PPU was commissioned in June 2015 and SPM was commissioned in August 2013.

1.6 Audit Objectives

The Performance Audit was conducted with a view to ascertain whether:

- The Capital Projects were designed, prepared, awarded, implemented and synchronised efficiently within the estimated cost and as per schedule with proper planning for crude oil in order to ensure smooth operation of refinery.
- Refinery operation was carried out economically and efficiently and maintenance was taken up as scheduled.
- Fuel & Loss and consumption of utilities (Power, Steam, Fuel and Water) and consumption of chemicals and catalyst were within norms, and
- Environmental aspects were taken care of and statutory norms relating to the same were complied with.

[8] ***Produces feed stock of low sulfur, low nitrogen feed hydro treated Heavy Coker Gas Oil Feed stock for another downstream unit.***

1.7 Scope of Audit

Audit covered the planning and execution of Capital Projects including Phase III expansion, setting up of PPU and SPM, synchronisation and operational performance of the processing units, auxiliary units and utilities for the period 2011-12 to 2015-16. Compliance with relevant statutory regulations relating to environmental issues were also covered.

1.8 Audit methodology

Performance Audit commenced with an Entry Conference (20 May 2016) with the Management to discuss the Audit objectives, criteria, scope, methodology etc. Audit methodology included examination and analysis of records, discussion with the Management, issue of audit queries and review of Management's reply. Audit examination also included review of Board Minutes, Production Plans, MoUs signed with the Holding Company, Annual Maintenance Programmes, Reports of Management Information System and records relating to refinery operation and technical services. Audit findings were shared with the Management by issue of Draft Performance Audit Report (October 2016) and in an Exit Conference (November 2016). The Draft Report was issued to the Ministry of Petroleum and Natural Gas in February 2017. Despite reminders issued on 15 March 2017, 29 March 2017, 27 April 2017, 22 May 2017 and 1 June 2017, the Ministry did not furnish a written reply. An Exit Conference with Ministry was, thereafter, held on 21 June 2017. Replies furnished by the Management and views of the Management/Ministry in the Exit Conferences have been considered while finalising the Performance Audit Report.

1.9 Audit Criteria

Audit criteria adopted for the Performance Audit included Detailed Project Report/ Detailed Feasibility Report, MoUs, Process Licensors Agreement, Agreement with Consultants, Contractors and other agencies, Auto Fuel Policy of Government of India, agreement with Oil Marketing Companies (OMCs) and foreign customers, prevalent Industrial Standards / Norms and Environmental laws, Government policy and guidelines, Working Group Report - XII Five Year Plan by Ministry of Petroleum and Natural Gas etc.

1.10 Acknowledgement

Audit acknowledges the co-operation and assistance extended by the Management at various stages during the conduct of the Performance audit.

Chapter 2 Planning and Execution of Capital Projects

The objectives of undertaking the capital projects, as envisaged in the year 2006, were to upgrade the refining capacity from the existing 11.82 MMTPA to 15 MMTPA, process cheaper crudes, upgrade low value products to high value products, maximise distillate yields, produce pet coke, upgrade entire diesel into BS III/IV and produce Propylene.

Poly Propylene Unit (PPU), with a capacity of 0.44 MMTPA, was planned (2009) as an additional package to Phase III refinery project with the objective of producing Polypropylene, a value added petrochemical product, by converting the polymer grade Propylene to be produced in Petrochemical Fluidized Catalytic Cracking unit (PFCCU) coming up as a part of Phase III project.

The Company also decided (2010) to set up Single Point Mooring (SPM) facility at an estimated cost of ₹ 1,044 crore, to ensure smooth discharge of imported crude, through larger vessels at the nearby Mangalore Port, with the objective of savings in freight and demurrage.

2.1. Deficiencies in planning

It was observed in audit that the Company planned to undertake capital projects without considering the requirements from a long term perspective, which necessitated revisions at later dates. The inadequacies in the original plan necessitated its revision which resulted in delays in implementation, synchronisation with other units and cost escalation. Further, the sequence of project cycle was disturbed, resulting in inordinate delay in commissioning.

2.1.1 Changes at the time of project conceptualization resulted in time and cost overrun

The Board approved (February 2006) a proposal to expand refining capacity from 11.82 MMTPA to 15 MMTPA at an estimated cost of ₹ 7,943 crore. The project, inter-alia, included revamping of the existing Crude Distillation Unit (CDU) I and II units and setting up of Lube Oil Base Stock[9] (LOBS) unit. However, based on the feedback from Process Licensors, the Company changed the scope of the project in the year 2008 and opted for setting up of new CDU, instead of revamping the existing CDUs. It decided to set up Heavy Coker Gas Oil Hydrotreating Unit (CHTU), as a feed preparation unit for PFCCU, by reducing the scope of revamping of existing Hydro Cracker Units (HCUs). The LOBS was

[9] ***Unit which produces lubricants***

also dropped for the reason that production of desired quality of LOBS from Mumbai High and Arab Heavy crudes was not possible, as also due to marketing constraints.

The requirement of units at the initial stage of conceptualization was firmed up without obtaining the feedback from the process licensors which led to revisions in the year 2008 and consequent time and cost overrun. Apart from increase in the cost by ₹ 1,960 crore due to change in the scope, there was an avoidable increase of ₹ 2,509 crore on account of escalation. The estimated cost, which was approved as ₹ 7,943 crore in the year 2006 increased to ₹ 12,412 crore in the year 2008. The scheduled mechanical completion date was also extended from June 2010 to October 2011.

The Company stated (November 2016) that the revision in schedule and scope was necessitated due to the delay in obtaining additional land, change in capacity of units/introduction of new units based on licensor feedback etc., which resulted in increase in cost also.

During the Exit Conference (June 2017) with Ministry, the Company stated that while taking up of a capital project, to save time and cost, Company relied upon project costing based on data available with Project Management Consultant instead of Detailed Feasibility Report. In such systems, modifications would always be required at a later date. Ministry added that BS-IV was a time bound project and that the Ministry had given its commitment to the Hon'ble Supreme Court for launching it in a time bound manner. Hence, MRPL was supposed to ensure the completion of project considering Ministry's commitment

The reply of the Company/Ministry is to be viewed against the fact that the licensor feedback could have been obtained at the time of conceptualisation of the project in the year 2006 itself. This would have avoided the revisions in the year 2008 and the consequent time overrun as well as significant increase in the cost.

2.1.2 Delay in taking decision to establish PPU

The Financial Feasibility Reports, which were prepared by Axis Bank (earlier UTI Bank) in the year 2006 and 2008 envisaged sale of Propylene produced in PFCCU. In July 2008, EIL, which developed the Detailed Project Feasibility Report for a Standalone Poly Propylene Unit (PPU), estimated a cost of ₹ 3,181 crore for such unit by using Propylene produced by processing Naphtha. However, this was not taken up due to low Internal Rate of Return (IRR). Later in May 2009, realizing the problems in evacuation of Propylene, the Company decided to setup an integrated PPU for processing Propylene into Polypropylene, at an estimated cost of ₹ 1,804 crore and got the approval of its Board. At this juncture, the Company realised that the Propylene produced from Vacuum Gas Oil (VGO) would be a cheaper feed for Poly Propylene as compared to the Propylene produced by using Naphtha.

Though the production of Propylene by processing the VGO in PFCCU was known to the Company at the time of evaluating the viability of the standalone PPU in August 2008, it did not consider the same at that point of time. Instead, it included the integrated PPU in the plant in May 2009 which delayed the whole process of acquisition of land, obtaining clearances etc. Though the PFCCU, the feed unit for PPU got commissioned in August 2014 and the required Captive Power Plant (CPP) was commissioned in September 2014, the production of Polypropylene, a value added product, could not be achieved as the unit was not ready up to May 2015 which impacted the GRM.

The Company stated (November 2016) that due to logistic constraints in sale of Propylene, it decided to switch over to production of Polypropylene, based on the detailed analysis of the viability.

In the Exit Conference (June 2017) with the Ministry, the Company while agreeing with the audit observation stated that initially it was decided to set up Naphtha cracker unit in the SEZ land adjacent to MRPL complex. However, it could not be established due to non-availability of land due to encroachment. Further, due to economic slowdown and logistic constraints, setting up of PPU was dropped initially. Later as export of propylene was not found viable, the Company decided to set up the polypropylene plant in the refinery complex.

The fact, however, remains that even at the time of original proposal in 2006 and revision of proposal in 2008, the situation/parameters which affected the decision making in 2009, existed. Had the Company considered this and planned the Integrated PPU at least, at the time of revision in 2008, the delay and consequent impact on production as brought out in Chapter 3 could have been avoided.

2.2. Project Financing

For execution of the Capital Projects, the Company decided (February 2006) a debt equity ratio of 2:1. The Company utilised ₹ 5,741 crore (up to May 2012) from internal accruals and availed the following domestic loans and external commercial borrowings (ECB):

Table 2.1: Details of Borrowings

Sl. No.	Source	Sanctioned Loan	Drawn	Drawn period	
				From	To
1	ONGC (₹ in crore)	5,000	4,800	October 2011	July 2013
2	Oil Industry Development Board (₹ in crore)	1,125	1,100	August 2011	March 2014
3	ECB – I (2012)	USD 250 Million	₹ 1,362@	March 2012	September 2012
4	ECB – II (2013)	USD 400 Million	₹ 2,365#	March 2013	March 2014
	Total		**₹ 9,627**		

@ I USD= ₹ 54.4680, average rate for ECB I based on actual drawal;
 # 1 USD= ₹ 59.1285, average rate for ECB II based on actual drawal;

The Company obtained the above loans in various tranches from October 2011 to March 2014 based on the projected requirements.

2.2.1 Availing ECB loan without mitigation of risk

After obtaining approval of its Board (October 2011), the Company availed (March 2012) USD 250 million as ECB from different foreign banks with SBI Hong Kong branch as the ECB Facility agent. The Company had the option to hedge the ECB loan against any currency fluctuations. While obtaining the approval of its Board to avail the loan, it had stated that the ECB loan was cheaper as compared to domestic loan even after considering the cost of hedging. However, at the same time it was mentioned to the Board that the Company would have the advantage of natural hedge for foreign currency borrowing because of continuous flow of dollar through export proceeds and its margins were dollar dominated to a large extent. The above ECB loan, was finally availed without hedging the same.

In May 2012, the Board opined that considering the exchange risk involved in foreign currency borrowing and the above borrowing of USD 250 million, further borrowing in foreign currency might not be prudent commercially and the Company may consider further borrowing in rupee to meet the remaining capex requirement.

However, in January 2013, approval for availing ECB of USD 250 million with green shoe option of another USD 250 million was accorded in a Board meeting. During this meeting also it was mentioned that the Company would have advantage of natural hedge for foreign currency borrowing as the Company was having continuous flow of dollars through export proceeds and its margins were also dollar dominated to a large extent. Against this approval, the Company availed USD 400 million as ECB. This ECB was also not hedged, even though it was apprised to the Board that the cost of the ECB including the hedging cost would be lower than the domestic loan.

Audit observed that due to non-hedging of the ECB, the Company had already lost approximately ₹ 13.70 crore due to exchange rate variation (net of currency hedging cost) on loan repayments (up to September 2016) and may incur further losses in case the rupee does not strengthen against USD. Audit was of the view that the justification regarding availability of natural hedge ignored the fact that natural hedging would offset the currency fluctuations relating to import of crude and export of final products.

The Company replied (November 2016) that the issue of currency fluctuation risk was discussed by the Board and it was decided to not to hedge considering the loss suffered on hedging in the past, natural hedge available in the business of the Company and the associated hedging cost. Further, the ECB loan was naturally hedged against its revenue account cash flow. The Consultant had also opined to not to hedge.

In the Exit Conference (June 2017) with the Ministry, the Company reiterated that hedging was available naturally to the Company including repayment of loan. It further stated that cost of hedging was high and by availing of hedging the benefit of gains through cheap ECB loans would have been defeated. The Company affirmed that matter was discussed in Board but no decision was taken on hedging and that the decision was left to the Management.

The reply of the Company/Ministry is to be viewed in the light of the fact that the natural hedging would offset the currency fluctuations relating to import of crude and export of final products. In fact, while evaluating (May 2012) the proposal for capital and working capital financing, the Board noted that considering the exchange risk involved in foreign currency borrowing and existing borrowing of USD 250 million through ECB, further borrowing in foreign currency may not be prudent commercially. However, contrary to this, within a short span of 8 months, the Board approved another ECB in January 2013 which was availed without hedging.

2.2.2 Drawal of funds in excess of requirement

The Company availed ECB-I of USD 250 million in 2012. In January 2013, the Company estimated (January 2013) further requirement of ECB loan at USD 250 million for 2013-15, after considering domestic borrowings from ONGC and Oil Industrial Development Board

(OIDB). The Board, while approving (January 2013) the proposal, in addition to the above amount permitted the Company to avail an additional amount of USD 250 million as may be required for the project. When entering into agreement for ECB II in March 2013, the Company decided to avail of USD 400 million. Thus, the ECB availed during the period from March 2012 to March 2014 amounted to USD 650 million equivalent to ₹ 3727 crore.

The unutilised funds had been parked in an interest bearing designated bank account. However, in September 2015, the unutilised fund amounting to ₹ 1,111.35 crore had to be shifted to non interest bearing current account as per the directions of Reserve Bank of India. ECB balance lying unutilized as on 31 March 2016 and 30 September 2016 was ₹ 807.84 crore and ₹ 768.46 crore, respectively even though all the units under Capital Project had been already commissioned.

The Company stated (November 2016) that the final certified bills from the contractors got delayed due to formalities of project closure, reduced cash outflow due to invocation of Price Reduction Clause, etc. The prepayment of loan was not permissible before the average maturity period of 5 years as per ECB guidelines.

The fact remains that the Company failed to assess the ECB requirement correctly resulting in non utilisation of a significant amount, which had to be parked in a non interest bearing bank account, while interest on the same was being paid. As the Company was aware of the terms and conditions on prepayment, more prudence should have been exercised at the time of planning and drawal of funds for the project requirements.

Ministry did not furnish any reply (June 2017).

2.3. Award of contracts

For execution of Capital Projects, the Company entered into 1998 contracts valuing ₹ 11,279 crore during 2006 to 2015. Audit scrutinised a total of 87 contracts valuing ₹ 10,608 crore, where the value of individual contract exceeded ₹ 10 crore, in addition to various other small value contracts.

Audit observations based on the scrutiny are discussed in the succeeding paragraphs.

2.3.1 Entrustment of execution contract to Project Management Consultant

As per the Central Vigilance Commission (CVC) guidelines of December 2004, a firm providing consultancy services for preparation/implementation of a project would be disqualified from subsequently providing goods/works/ services related to the same project.

The Company appointed (June 2006) Engineers India Limited (EIL) as Project Management Consultant (PMC) at a cost of ₹ 256 crore for Phase III expansion. Later, during the period from November 2008 to July 2009, contrary to the guidelines of CVC, the Company awarded four more contracts to EIL for execution of PFCCU, Sulphur Recovery Unit[10] (SRU), SRU licence and PPU valuing ₹ 3,337.80 crore, on nomination basis on the justification of early/timely completion of the work. The Company had decided (October 2008) to withdraw the consultancy work of the related four contracts and to reduce the PMC fees to that extent which was done in July 2012 i.e. after 45 months (October 2008 to July 2012).

The Company stated (November 2016) that delay in finalising the change order was due to the time taken for arriving at the mutually acceptable value of the services withdrawn and included in the PMC.

In the Exit Conference (June 2017) with the Ministry, the Company accepted the delay in issuing the change order by 45 months. It further stated that due to technical reasons the Company awarded the contract to EIL and on 17 November 2008 the decision was taken to eject EIL out of PMC contract for the contracts for which execution was awarded but the formal contract in this regard was signed in July 2012. The Company also stated that MRPL formed the Project Monitoring Cell with its own officials upon EIL being awarded the four contracts without waiting for issuance of a change order. It further mentioned that Management has now issued clear directions for project teams to sign a contract within a period of 30 days.

The reply may be viewed against the fact that as per the CVC guidelines, the execution contracts should not have been awarded to the Project Management Consultant.

2.3.2 Delay in finalising formal Contract Agreements

In respect of the 87 contracts reviewed in audit, it was observed that the Company issued a Letter of Acceptance (LoA) to the successful bidder pending finalisation of the terms and conditions and formulation of the final contract. A time limit of 10 days was specified in the LoAs for execution of the formal contract except for a few where the time limit was not mentioned. It was noted that in 84 contracts, there was delay in execution of formal contract ranging from 20 to 1002 days. These included contract for SPM which was signed after a lapse of 1002 days by which date the work had already been mechanically completed. Four other contracts having a value of ₹ 1,044 crore were signed after a delay of more than one year. In respect of one work valuing ₹ 18 crore, the contract was not executed at all.

[10] ***Unit recovers Sulphur from the feed***

The Company stated (November 2016) that the delay in execution of the contracts was due to large number of contracts and volume of pages to be handled by EIL. It added that this had no impact on the quality / delivery & project cost.

The reply of the Company is to be seen against the fact that the LoAs do not include specific conditions and stipulations which generally form part of formal contract document and as such, there was an inherent risk in the enforceability of the mutual rights and obligations in the absence of a valid contract.

During the Exit Conference (June 2017) with the Ministry, the Company informed (June 2017) that Management had now issued clear directions for project teams to sign contracts within a period of 30 days.

2.4. Execution of Phase III Expansion Project and PPU Project

The Company had planned various processing units to increase capacity and to produce value added products thereby increasing the Gross Refinery Margin as depicted in the following Table.

Table 2.2: Important processing units

Feed	Unit	Major Products
Crude	Crude/Vacuum Distillation Unit (CDU/VDU)	Naphtha, Kerosene, HSD, VGO, short residue
Vacuum Gas Oil (VGO)	Hydro Cracker Unit[11] (HCU)	VGO, Light Naptha, Kerosene, HSD
Short residue	Delayed Coker Unit[12] (DCU)	Naphtha, LPG, Coke
Heavy Coker Gas Oil (HCGO), VGO	Heavy Coker Hydrotreating Unit (CHTU)	Treated HCGO, Naptha, HSD
VGO, Treated HCGO	Petrochemical Fluidized Catalytic Cracking Unit (PFCCU)	Propylene, Motor Spirit
Propylene	Polypropylene Unit (PPU)	Polypropylene
High Speed Diesel (HSD)	Diesel Hydro Desulphurisation Treating Unit[13] (DHDT)	BS III/IV HSD

[11] ***Unit in heavier fractions of VGO are cracked into lighter and more valuable products***
[12] ***Converts low value residue into valuable products***
[13] ***Removes Sulphur, Nitrogen and Metal impurities from the feed received from different units.***

The output from one unit becomes the feed for other processing units, wherein value addition as proposed in the Phase III Expansion Project is carried out. Delay in commissioning of any of the primary units has a cascading effect on the subsequent secondary processing units and value added products.

In addition to the above units, the Company had proposed (2006) a Captive Power Plant (CPP) III to cater to the need of power and steam of all units in the Phase III.

A review of the plan and actual execution of the units revealed delays in commissioning due to delay in commissioning of CPP. Even the mechanically completed units could not be commissioned and integrated with the related existing/new secondary processing units due to such delay. These have been discussed in subsequent paragraphs.

2.4.1 Delay in commissioning of Captive Power Plant

Captive Power Plant (CPP) is a critical utility for a refinery for supply of steam and power and needs to be commissioned before commissioning of all other process units. The Company had planned a CPP in the year 2006 as a part of Phase III Expansion Project. The work of setting up of CPP was placed (February 2009) on BHEL (the contractor) on single tender basis to save time. The work was bifurcated in ten packages and was to be completed by January 2012.

There was a delay in execution of work by the contractor and various units of CPP III could be commissioned only in August/September 2014. However, in respect of three out of ten packages, the Performance Guarantee test was pending (November 2016) for want of shut down/ repair works. Due to delay in commissioning of CPP, various units (other than CDU/VDU) remained idle even after mechanical completion for a period ranging from 11 to 26 months.

The Company stated (November 2016) that as BHEL was a PSU, the work was awarded to them on single tender basis. The project got delayed due to engineering and supply related issues, poor store management, non-deployment of adequate staff and delayed execution etc. on the part of BHEL. This was reiterated (June 2017) by the Ministry also during the Exit Conference.

The reply is not acceptable considering the fact that in Phase III expansion project which had an outlay of ₹ 13,475 crore, CPP was the most critical utility and hence, various factors which affected the timely implementation of CPP should have been controlled through close monitoring and follow-up.

2.4.2 Impact of delay in commissioning of Captive Power Plant

As CPP III units were not ready by the scheduled date, the Phase III processing units that were mechanically completed could not be commissioned for want of steam and power. The impact of the delayed commissioning of the processing units on account of delay in commissioning of CPP is detailed in the table below:

Table 2.3: Impact of delay in commissioning of CPP on processing units

Unit	Date of Mechanical Completion	Date of Commissioning	Delay in months	Impact of CPP delay
CDU/ VDU	27 October 2011	25 March 2012	5	• Delay in achieving envisaged throughput. • Non upgradation of VGO and short residue, delay in additional production and failure in converting the diesel into BS-III & IV. • Incurred additional expenditure of ₹ 23 crore for arranging steam and power from Phase I & II by laying additional line.
DHDT	10 January 2012	29 November 2012	11	• Idling of unit and resulting in non conversion of HSD into BS III/IV
CHTU	19 March 2012	10 May 2014	26	• Idling of unit, loss of production due to non conversion of VGO.
DCU	22 February 13	4 April 2014	13	• Idling of unit, non production of Light Coker Gas Oil/Heavy Coker Gas Oil and Naphtha resulting in Fuel Oil production which was a low value product.
PFCCU	26 December 2012	27 August 2014	20	• Idling of unit, non production of Propylene as envisaged. • In the absence of PFCCU, VGO which was the feed to the unit was sold instead of getting converted into value added product in PFCCU.

In response, the Company stated (November 2016) the following:

a. CDU/VDU - The high pressure steam pipeline could be used in future in case of any requirement of such transfer of steam from Phase I & II to Phase III and vice versa. DCU/DHDT - In the absence of DCU, short residue was processed into marketable Fuel Oil.

b. PFCCU/CHTU - The Company agreed that non-availability of steam and power did affect the commissioning of PFCC and CHTU. Non availability of CHTU did not have a bearing on VGO exports as it processes only HCGO from DCU for subsequent routing to PFCCU.

Audit, however, noticed that the Company could not achieve the objective of production of value added product till the commissioning of all the processing units. Further, laying of additional line for steam and power from Phase I and II, which was not envisaged/needed for the expansion scheme, resulted in additional cost of ₹ 23 crore. Non-synchronisation of CPP with DCU resulted in production of Fuel Oil, which is a low value product and which was against the objective of Phase III Project. The reply that VGO would not be processed in CHTU was also against the Financial Feasibility Report (FFR) of Phase III Expansion Project which clearly stated HCGO as well as VGO as the feed for CHTU.

During the Exit Conference (June 2017) with the Ministry, impact of delay in commissioning of CPP by BHEL on the commissioning of the processing units was agreed to by the Company/Ministry.

2.5 Execution of Single Point Mooring Project

The Company receives crude oil and despatches products through New Mangalore Port at its two dedicated oil berths which can handle smaller vessels (Aframax). The Company planned (2010) to install a Single Point Mooring (SPM) facility at an estimated cost of ₹ 1043.57 crore, 17 km away from the Port to handle the increased quantity of crude in larger vessels (VLCC).

The Company decided (December 2009) to tie up with Indian Strategic Petroleum Resource Limited (ISPRL), a Special Purpose Vehicle and a wholly owned subsidiary of OIDB for crude storage in cavern (0.3 MMT out of 1.5 MMT available capacity) considering mutual benefit. Construction of cavern and the pipeline from the Company's Booster Pumping Station to cavern at estimated cost of ₹ 1,100 crore was ISPRL's responsibility. Of this, the Company's share was estimated at ₹ 220 crore.

The remaining project cost of SPM facility i.e. ₹ 823.57 crore was towards SPM offshore facility, sub-sea pipeline, Booster Pumping Station on the shore and pipeline from the cavern of ISPRL to the refinery.

The Company estimated a saving of ₹ 254.17 crore per annum in freight (₹ 166.77 crore), demurrage charges (₹ 15.50 crore) and improvement in refinery margin (₹ 71.90 crore) by installation of SPM.

SPM facility was commissioned in August 2013 at a cost of ₹ 806.77 crore (excluding the share towards capital cost of cavern of ISPRL). ISPRL cavern facility was yet to be commissioned (September 2016). The issues relating to execution of the SPM project are discussed below:

2.5.1 Deficiencies in SPM contract with EIL

The Company awarded (July 2010) the contract for execution of SPM to EIL on nomination basis to save time and to complete the project before May 2012 under Open Book Execution[14] (OBE). The Company had anticipated that there would be better co-ordination and synergy during the project execution as EIL was the contractor for ISPRL also. The estimated cost of the work was ₹ 1,043.57 crore which included ₹ 600 crore towards Plant & Machinery. A fee of 8.5 percent of 'as built' Plant and Machinery cost was payable to EIL. As per the letter of award, the work was to be converted into Lump Sum Turn Key (LSTK) contract upon placement of orders for equipment, materials and works for 70 *per cent* of the estimated cost of the Plant & Machinery.

Audit scrutiny revealed that though the Contractor completed 70 *per cent* of ordering position by April 2011, the Company did not initiate steps to analyse cost and benefit of converting the contract into LSTK as per stipulations and EIL completed the work under the OBE method.

The Company stated (November 2016) that Project Approval and Execution Committee (PAEC), while awarding the contract, had decided to adopt the OBE terms and conditions similar to that of other contracts (PFCCU/PPU). Regarding conversion of OBE to LSTK, the proposal on conversion was acted upon immediately on receipt of the same from EIL.

During the Exit Conference (June 2017) with the Ministry, the Company stated that it did not push for LSTK as actual cost of LSTK was more than OBE. Ministry agreed with the reply of the Company.

The basis for the reply given by the Company that LSTK prices exceeded the OBE prices was the proposal from EIL received in April 2014 after the contract had been executed. Comparison of LSTK prices with OBE prices was therefore inappropriate.

2.5.2 Non finalisation of arrangement with ISPRL for crude storage

Even though the decision to share the cavern to be constructed by ISPRL was taken in December 2009, no agreement in this regard was entered. In October 2012, when the SPM was mechanically completed, the Company got a study conducted which indicated that

[14] ***A contract which involves reimbursement of all the related costs to the contractor along-with a pre-decided margin/fee.***

VLCC vessels could not be unloaded prior to commissioning of cavern due to logistical reasons and multiple crude grades. However, it was only in June 2014 that the Company entered into an MoU with ISPRL for sharing SPM and cavern facility on mutually agreed terms and conditions. Infrastructure Sharing Agreement (ISA) referred in the MoU which would have addressed the operation, commercial, financial and legal issues, was however, not yet finalised (November 2016).

Audit observed that though SPM facility was commissioned in August 2013, the Company was yet to reap the envisaged benefits as the linked cavern facility was not ready (November 2016). The Company took 48 months (Jul 2010 to June 2014) for signing the MoU with ISPRL and the related ISA was pending for more than two years.

The Company stated (November 2016) that the SPM was tied up with ISPRL cavern at the instance of Ministry of Environment & Forest (MoEF) while seeking the permission for construction of shore tanks and it was actively pursuing with ISPRL to conclude the agreement.

In the Exit Conference (June 2017) with the Ministry, the Company agreed with the audit observation. It was informed that ISPRL had decided not to share the storage facility with the Company even though efforts were being made by the Company in this regard. Ministry stated that the cavern of ISPRL was constructed for strategic purpose and MRPL may not be allowed to use the cavern. Further, the Company clarified that only the 1.5 KM pipeline which had been laid from the Cavern to the refinery would be idle in case MRPL was not allowed to draw crude from the storage and that this pipeline had also been used in the interim for supply of water.

The reply of the Company/Ministry was not acceptable as MoEF had advised the Company to reexamine the location of Crude Oil Storage Tanks by suggesting to locate these at a higher level to avoid construction of Storage Tanks on the sandy Beach Soil. It had suggested that the Company explore the possibility of sharing the Mangalore Crude Oil Cavern being built by ISPRL. However, the final decision in this regard was to be taken by the Company. It remains a fact that the expenditure of ₹ 806.77 crore on SPM was incurred without having specific terms and conditions for sharing the cavern for crude receipts. Hence, the main objective of SPM i.e. receiving crude in VLCC could not be met even after three years of commissioning.

2.5.3 Idling of Booster Pumping Station and pipeline

The Company commissioned (December 2013) Booster Pumping Station (BPS) at a cost of ₹ 188.69 crore and pipeline from cavern to refinery (August 2014) at a cost of ₹ 14.73 crore. Audit observed that on account of delay in commissioning cavern facility by ISPRL, the BPS and pipeline from cavern to refinery were lying idle (September 2016) since December 2013.

The Company stated (November 2016) that the BPS was necessary for operation of SPM, irrespective of whether ISPRL exists or not, as the station include various controlling units. Further the facilities were created to synchronise with the cavern facility scheduled for commissioning by December 2013.

The fact remains that the facilities constructed in December 2013 at a cost of ₹ 203.42 crore were not put to use as of September 2016.

Ministry did not furnish any reply (June 2017).

2.5.4 Scheduling and diversion of vessels

Expecting the defect-free commissioning of SPM, the Company ordered (from October 2012 to January 2013) four medium vessels (Suezmax) carrying crude to take berth in the SPM facility. However, these vessels could not discharge crude at SPM as the facility was not commissioned due to flange leakage in the facility. Audit observed that though leakage was noticed during test run in October 2012, corrective action could be completed only after three months (December 2012). Similar defects were noticed again during commissioning (January 2013). As leakages were being encountered, planning and ordering of crude in larger vessels instead of smaller vessel at the first instance, resulted in diversion of all the four vessels to Mumbai for lighterage[15] and returning along with four daughter vessels to Mangalore Port for discharge. Consequently, extra expenditure of ₹ 12.34 crore towards diversion and lighterage and ₹ 6.39 crore towards demurrage had to be incurred. The facility was finally commissioned in August 2013

In reply (November 2016), the Company explained the reasons for failure of test run and the reasons for delay in rectification. It stated that the crude procurement was to be planned 2 to 3 months in advance and hence bigger shipments were planned expecting the defect-free commissioning in January 2013 and in fact the overall transportation cost incurred for these

[15] ***Transfering of cargo to smaller vessels for discharging the same at port with lesser draft.***

four vessels was less on comparison with that of transport of crude by deploying smaller vessels.

The reply is to be viewed against the fact that the Company has not made any analysis on the cost and benefit of small vessels against larger vessels. If the proposition was economical, the Company could have continued this system till the commissioning of SPM i.e. upto August 2013. Instead the Company continued to get crude in smaller vessels till the time of commissioning of SPM.

Ministry did not furnish any reply (June 2017).

2.5.5 Non-fulfilment of objective of the SPM

The Company estimated (2010) that post commissioning of SPM, the landed cost of crude would be cheaper by ₹ 166.77 crore per annum due to reduction in freight on transportation of crude in bigger vessels and savings in demurrage charges by ₹ 15.50 crore per annum. The Company also expected to increase its refinery margin by ₹ 71.90 crore per annum. Thus, the total benefit expected from SPM worked out to ₹ 254.17 crore per annum.

Audit observed that even after commissioning of SPM (August 2013) at a cost of ₹ 806.77 crore, the Company could not bring crude in VLCC as envisaged, due to the non readiness of connected storage facility and the objective of reduction in freight could not be achieved. As against the initially projected 54 shipments in a year through VLCC, the Company engaged 273 smaller ships in 2014-15; and five VLCC and 289 other ships in 2015-16. The demurrage, increased from ₹ 12.21 crore (2010-11) to ₹ 54.97 crore (2013-14) and to ₹ 81.70 crore (2015-16) as both the jetties and SPM are connected to same crude discharge line resulting in the ships waiting for discharge. The GRM of the Company declined from USD 5.60 per bbl in 2011-12 to USD (-) 0.64 per bbl in 2014-15 though it again moved up to USD 5.20 per bbl in 2015-16.

The Company replied (November 2016) that the throughput was increased to 15.69 MMT during 2015-16, number of ships handled at port was reduced resulting in reduction in congestion and the demurrage was controlled to actual level by having SPM.

The reply is to be viewed in view of the fact that the increase in the throughput was not reflected in GRM. Further, the reduction of congestion in port did not result in reduction of demurrage which increased by 6.7 times in 2015-16 as compared to 2010-11.

Ministry did not furnish any reply (June 2017)

Chapter 3 Operation of Processing Units

The Company plans refinery operations on the basis of demand for petroleum products, availability of required grade of crude oil as per designed parameters of processing units and refinery configuration. Yield pattern of the refinery depends upon the crude mix, refinery configuration, technology, finished product demand, production process optimisation and operating performance of various processing units.

Various factors such as deficiencies in planning for crude in consonance with the capacity of processing units, delayed commissioning, synchronisation of the commissioned units with other existing / new secondary processing units, operating below optimal capacity etc. adversely impacted the efficiency of the operation of the refinery units. Impact of such deficiencies in refining operations and Gross Refinery Margin (GRM) are discussed in succeeding paragraphs.

3.1 Crude planning and procurement

Crude is the main input that determines the yields and consequently the refinery configuration. Sulphur content in the crude determines the processing scheme and market value of the product. The planning and scheduling of crude oil is a critical task and accurate planning can result in substantial savings. A key issue for a refinery is, therefore, to identify and process optimal crude mix that maximizes profit margins. To find the right crude mix, the refinery has to take into account both processing and economic considerations. Main criterion for selection of crude by the Company is maximization of GRM. After selection of crude oils, the crude procurement and logistics departments have to secure the crudes and schedule them for delivery.

The Company imports nearly 85 *per cent* of crude through term contracts on annual basis from the foreign National Oil Companies at their Official Selling Price. The remaining quantity is sourced from indigenous suppliers and on spot basis.

The Company designed the Crude Distillation Units (CDUs) with a capacity of 15 MMTPA with the objective of processing 9.5 MMTPA (67 *per cent*) Arab Heavy Crude (High Sulphur Crude) and 5.5 MMTPA (33 *per cent*) Mumbai High Crude (Low Sulphur Crude). CDU-III was designed to process 'High TAN' crudes and the secondary processing units were accordingly designed to process feed from CDUs.

Audit observed that during the years 2011-12 and 2013-14 to 2015-16, the Company procured more high sulphur crude when the secondary processing units were not ready. Consequently, the Company could not produce high value products and maximise its revenue which is highlighted in the ensuing paragraphs.

The Company replied (November 2016) that Units were designed to process variety of crudes and processed crudes matching the availability of secondary processing facilities due to which the Company achieved highest distillate yield of 76 *per cent* in 2015-16. GRM was affected due to foreign exchange fluctuations and inventory losses.

In the Exit Conference (June 2017) with the Ministry, the Company agreed (June 2017) that secondary processing units were not ready; however it processed crude as the GRM was positive. The Ministry endorsed the reply of the Company.

The reply of the Company/Ministry may be seen in light of the fact that crude mix is very important factor for determining the product mix, distillate yield, Fuel & Loss and GRM. The Company though achieved the highest distillate yield of 76 *per cent* in 2015-16, it was less than the achievable yield of 83 *per cent* despite having a world class refinery. Further, the Company's GRM was 2.45, 2.67, -0.64 and 5.20 USD/BBL during the period 2012-13 to 2015-16 which was much below the targeted GRM of USD 10.82 per BBL as envisaged in the Phase III project. The Company did not restrict the crude procurement when secondary units of Phase III were not commissioned and operated. Thus, processing of excess crude saturated the existing secondary processing units resulting in non production of desired distillate yield.

3.2 Ineffective planning in operation of Crude Distillation Unit

Distillation is the start of the crude refining process, where the crude is separated into various fractions based on relative volatility and boiling point. Typical products of Crude Distillation Unit (CDU) are Off Gases, Naphtha, Kerosene, Light Gas Oil (LGO), Heavy Gas Oil (HGO) and Residue.

Audit found that the Company commissioned CDU III in March 2012. Various other secondary units under Phase III were commissioned from November 2012 to September 2014. However, the Company without taking into account the non-commissioning of the secondary processing units, procured crude commensurate with the processing capacity of all the units. This resulted in production of more High Speed Diesel (HSD), Vacuum Gas Oil (VGO), Naphtha, Aviations Turbine Fuel (ATF) and Fuel Oil (FO) during 2011-12 to

2014-15. Even after commissioning of all the secondary units, the Company continued production of low value products like FO and Naphtha in the year 2015-16. Audit noticed that during the period from 2011-12 to 2015-16, some of these products had to be exported at a price less than the domestic price. Even though cost in some of these cases was recovered, there was short revenue realisation to the tune ₹ 2,774.52 crore. It was also noticed that for some of these products which were exported, the realisation was even below the cost of production which resulted in non recovery of cost to the tune of ₹ 1,666.86 crore (**Annexure III**). This affected the overall GRM.

The Company replied (November 2016) that loss of revenue on account of export be treated as a notional difference between export and domestic prices. It recorded positive operating margins and the sequential lag in commissioning of Phase III units was on account of non availability of stable power and steam.

In the Exit Conference (June 2017) with the Ministry, the Company again reiterated that it processed crude as the GRM was positive. The Ministry endorsed the reply of the Company.

The reply of the Company/Ministry has to be viewed in the light of the fact that the Company procured and processed crude without considering availability of secondary processing units and produced low value products. Further, though the Company had exported Vacuum Gas Oil (VGO) and earned revenue, it could not utilise the same in secondary processing units to convert it into value added product. The Company could not supply BS III and IV grade MS (2011-12 to 2014-15) and High Speed Diesel (HSD) (2011-12 to 2014-15) to the Oil Marketing Companies (OMCs) to meet domestic demand adequately. All these factors led to decrease in GRM from USD 5.60/BBL (2011-12) to USD (-) 0.64/BBL (2014-15).

3.3 Non synchronisation of revamped Hydrocracker units with PFCCU

Prior to Phase III expansion, the Company had two Hydrocracker Units (HCUs) which were designed for recycle mode of operation with 100 *per cent* conversion. HCUs are mainly used to produce middle distillates of low sulphur contents such as kerosene and diesel. Operation of HCU is affected by the factors like feed quality and quantity, mode of operation, catalyst type, maximization of certain product, catalyst cycle and hydrogen pressure. HCU produces VGO, Naphtha, kerosene and High Speed Diesel. The streams which are not cracked are called Unconverted Oil (UCO).

Under Phase III Expansion, both HCUs were revamped (HCU-1 in September 2011 and HCU-2 in May 2012) to convert the mode of operation from Recycle[16] to Once Through[17] Mode (54 *per cent* conversion rate) with design capacity of 1.6 and 1.7 MMTPA respectively, with the objective of processing Unconverted Oil (UCO) in Petrochemical Fluidized Catalytic Cracking Unit (PFCCU) which was also planned in Phase III. The process licensor, M/s UOP, had guaranteed that the revamped units performance would be at 54 *per cent* conversion rate with HC115 LT cracking catalyst and KF 848 hydro treating catalyst. Although, HCU-1 was revamped in September 2011, its catalyst was not changed from the existing HC215 to HC115 on the ground that HC215 had remaining life of one year and that the PFCCU was not ready. HCU-2 was revamped in May 2012 and its catalyst was changed from HC215 to HC115 on the assumption that PFCCU would be commissioned in second half of 2012. However, both the HCUs had to be operated under recycle mode for four years (2011-15) and it was only in 2015-16, the units operated under once-through mode.

A review of functioning of HCU-1 & 2 for the period 2011-12 to 2014-15 when the units continued to operate on recycle mode, revealed that there was under recovery of high value products and over recovery of low value products as compared to the standard yield under recycle mode which resulted in loss of revenue of ₹ 6,328.76 crore **(Annexure IV)**. Further, operation of the units under recycle mode during the above period resulted in non-achievement of objective of the revamping.

The Company replied (November 2016) that actual yields are directionally in line with the design yields and agreed that conversion rates of both Hydrocrackers were high during the period. The catalyst change was delayed due to delay in commissioning of PFCCU that resulted in higher production of naphtha in 2012-13.

The reply of the Company may be seen in the light of fact that the purpose of revamp of HCUs was not achieved upto 2014-15 on account of non-conversion of VGO/UCO into value added product in PFCCU. Even with the same mode of operation, the standard yield could not be achieved which resulted in loss of revenue.

In the Exit Conference (June 2017) with the Ministry, it was stated by the Company that PFCCU did not come up due to delay in commissioning of CPP by BHEL which was agreed to by Ministry.

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[16] ***Under Recycle mode the feed will be reprocessed to ensure 100 per cent conversion of feed.***

[17] ***Under Once Through Mode, feed will be processed once and the remaining unconverted feed will be sent to PFFCU which produces Propylene and then to PPU which produced Poly Propylene, a high value product***

3.4 Underutilization of Diesel Hydro Desulphurisation Treating Unit

Hydro treating is the process of removal of Sulphur, Nitrogen and metal impurities of the feed received from different units by treating with Hydrogen in the presence of catalyst. Diesel Hydro Treating Desulphurisation Unit (DHDT), with a capacity of 3700 TMTPA was commissioned (November 2012) under Phase III expansion project. The unit produces BS III/IV grade HSD and low sulphur Naphtha and Kerosene. This unit was planned in addition to the Gas Oil Hydro Desulphurisation Unit[18] (GOHDS) with a capacity of 1750.76 TMTPA which was an existing unit.

The capacity utilisation of the DHDT and GOHDS for the three years ending 31 March 2016 was as follows:

Table 3.1: Capacity utilisation of DHDT and GOHDS

Year	DHDT		GOHDS	
	Feed processed (TMT)	Capacity Utilisation (%)	Feed processed (TMT)	Capacity Utilisation (%)
2013-14	1947.87	53	1213.56	69
2014-15	3149.15	85	623.41	36
2015-16	3379.04	91	1528.73	87

From the above, it could be seen that the capacity utilisation of DHDT was only 53 *per cent* during the year 2013-14. The utilisation though improved during 2014-15 and 2015-16, the same was below the installed capacity of the unit. In case of the GOHDS, the utilisation of the unit was below its installed capacity during the period from 2013-14 to 2015-2016.

Though, DHDT was commissioned with an intention of converting the entire HSD into BS III/IV, there were exports of lower grade HSD on spot tender basis even after commissioning of DHDT. Audit further observed that the export was made even when the demand of 653 TMT of BS III/IV HSD from domestic Oil Marketing Companies (OMCs) during 2013-14 and 2014-15 remained unfulfilled, as reflected in the following table:

[18] ***Removes Sulphur from Light Gas Oil, Heavy Gas Oil and Vacuum Gas Oil.***

Table 3.2: OMC demand of HSD and supply by MRPL

(Qty in TMT)

Year	OMC Demand	Actual supply	Shortfall	Quantity exported
2013-14	4,750	4,338	412	710
2014-15	4,902	4,661	241	630
2015-16	5,543	5,547	-	-

The Company (November 2016) accepted that the unit was operated at lower capacity due to non-commissioning of units such as Delayed Coker Unit (DCU), Heavy Coker Gas Oil Hydrotreating Unit (CHTU) and PFCCU. The Company further stated that only desulphurised HSD was exported since July 2014.

In the Exit Conference (June 2017) with the Ministry, the Company informed that due to non-commissioning of CPP by BHEL, units which were to provide feed to DHDT could not be commissioned which resulted in underutilization of DHDT.

The reply may be seen in the light of the fact that the Company produced 17639 TMT of HSD during the period 2013-14 to 2015-16, which was more than the total HSD processed i.e. 10003.22 TMT through DHDT and GOHDS. Further, when the processing capacity and adequate domestic demand were available, the Company did not process and sell BS III/IV diesel. Thus, the Company did not achieve the main objective of converting entire diesel into BS III/IV as envisaged.

3.5 Non production of value added product from CHTU

Heavy Coker Gas Oil Hydro Treating Unit (CHTU) is a feed preparation unit for the PFCCU. The purpose of this unit was to produce low sulphur, low nitrogen hydro treated Heavy Coker Gas Oil (HCGO) for PFCCU. Fuel gas, Naphtha and Diesel were also to be produced from the CHTU. CHTU was commissioned in May 2014.

Against the input of 506 TMT in 2014-15, as per the design yield, the total output should have been 521 TMT. Similarly, in 2015-16, against the input of 741 TMT, the design yield should have been 762 TMT. However, the actual yield in 2014-15 and 2015-16 was 505 TMT and 741 TMT, respectively.

The Company's reply (November 2016) was silent about the reasons for short recovery of products during 2014-15 and 2015-16.

Ministry did not furnish any reply.

3.6 Commissioning and Operation of PFCCU

PFCCU was commissioned (August 2014) under Phase III expansion project to produce polymer grade Propylene, which was intended for processing into Polypropylene, a high value product, in the PPU. In case of non conversion, the Propylene from the plant would be diverted to LPG pool. PPU was commissioned on 17 June 2015.

3.6.1 Audit noticed that during commissioning of PFCCU, there was less flow in the unit due to which plant load could not be increased and the unit was commissioned bypassing the control valve. However, within a few days i.e. on 2 September 2014, the plant had to be shut down due to no flow through the bypass. The Company took 20 days (02 September 2014 to 21 September 2014) to repair the above defects which resulted in loss of production and consequent loss of revenue to the tune of ₹ 198.53 crore.

The Company replied (November 2016) that teething troubles were expected in commissioning a large process unit and the incident in PFCCU was a teething trouble which could occur to any complex system.

In the Exit Conference (June 2017) with the Ministry, Company stated that the repair work was completed in five days but it took another 15 days to restart the unit due to power failure which was attributable to the BHEL. Ministry's representative seconded the reply of the Company.

Audit observed that the problem was known to the Company before commissioning and therefore, it should have assessed the time required for rectifying the defects to ensure the effectiveness of the repair. In the absence of estimation of time, it could not be ensured that the Company took reasonable time to rectify the defect.

3.6.2 The designed yield of Propylene in PFCCU was 20.60 per cent of the feed. Audit observed that the total feed in PFCCU during the period from August 2014 to May 2015 was 6,96,922 MT which should have produced 1,43,566 MT of Propylene for conversion into Polypropylene in Poly Propylene Unit (PPU) against which only 3,951 MT of Propylene was produced in PFCCU. However, as the PPU was not ready, even this quantity had to be diverted to Liquefied Petroleum Gas (LPG) pool. Non production of Propylene as per the designed yield and its non conversion to Poly Propylene, a high value product, in the PPU resulted in loss of margin of ₹ 382.83 crore (**Annexure V A**).

The Company stated (November 2016) that as the PPU was commissioned in 2015, the entire propylene was sold as LPG.

Ministry did not furnish any reply.

3.6.3 Audit also noticed that post commissioning of PPU, propylene produced by PFCCU during June 2015 to March 2016 was 1,54,611 MT (10.93 *per cent* of 14,14,595 MT of feed) which was short by 1,36,791 MT compared to the design yield. The short recovery of Propylene during this period resulted in short production of Poly Propylene, a high value product to the tune of 136,244 MT and consequent loss of margin of ₹ 364.77 crore (**Annexure V B**). The Company replied (November 2016) that during 2015-16, PPU was in stabilisation mode and the entire feed to unit was limited to 156000 MT and due to continuous efforts, the propylene yield reached 19 *per cent* as against the design yield of 20.60 *per cent.* Further tuning for improving the yield was under progress.

However, the fact remains that as against the installed capacity of 4,40,000 MT per annum, only 1,56,149 MT was processed in PPU during the period from June 2015 to March 2016. This indicated that there was ample scope for production of Propylene in PFCCU which could have been further processed in PPU.

Ministry did not furnish any reply.

3.7 Commissioning and operation of PPU

PPU, which was to covert Propylene into Polypropylene, was commissioned in June 2015. The design yield of Polypropylene was estimated at 99.60 *per cent* of the feed.

3.7.1 After commissioning in June 2015, the unit had to be shut down for 16 days (11 July 2015 to 27 July 2015) on account of bagging issues. This resulted in loss of production of Polypropylene for 16 days and consequent loss of ₹ 28.57 crore[19].

The Company replied (November 2016) that bagging unit broke down frequently during commissioning and various technical issues had caused down time of these machines.

Ministry did not furnish any reply.

3.7.2 Audit observed that out of 156,149 MT of feed that was processed by PPU during June 2015 to March 2016, the Company could recover 140,544 MT which was 90 *per cent* of the

[19] ***140,544 MT/244 days x 16 days x ₹ 31,005 (margin as per cost accounts)***

feed as against 155,524 MT of design yield. Under-recovery of 14,980 MT of Polypropylene resulted in loss of ₹ 46.45 crore[20].

In reply, the Company stated (November 2016) that the lower yield could be attributed to operating at lower loads and lower sized carrier gas filter.

The reply is to be viewed against the fact that the reasons for lower yield were controllable in nature.

Ministry did not furnish any reply.

3.8 Commissioning and operation of DCU

Under Phase I and II, short residue (SR) produced in Crude Distillation Unit (CDU)/ Vacuum Distillation Unit (VDU) was processed in two Visbreaker Units[21] (VBU) into Fuel Oil (FO) which was a low value product. Under Phase – III expansion project, the Company planned minimization of production of FO by processing the SR in the DCU. DCU was mechanically completed in December 2012 and commissioned in April 2014 at a cost of ₹ 1,057.57 crore as against the scheduled completion date of September 2011.

3.8.1 Due to the delay in commissioning (April 2014) of DCU, the SR was processed in the VBU and FO was produced during 2012-13 to 2013-14. Details of the FO produced and sold during these two years are given below:

Table 3.3: FO production and Sales

(Qty in TMT)

Year	Total Production	Sales		
		Domestic	Export	Total sales
2012-13	2113	128	1955	2083
2013-14	2281	89	2216	2305

It may be seen that the Company exported more FO which by itself reduced the sales realization by ₹1,459.89 crore during 2012-13 and 2013-14 as compared to the domestic realisation.

3.8.2 After commissioning, DCU was operated at 39 and 87 *per cent* of its capacity in 2014-15 and 2015-16, respectively. Further, change in operating parameters like temperature, pressure etc affected the yield of various products. Audit noticed that the actual yield of

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[20] *14980 MT x ₹31,005 (margin as per cost accounts)*
[21] *Upgrades short residue into lighter value added products.*

Coke which is a low value product was 32.47 and 33 *per cent* during 2014-15 and 2015-16, respectively against the design yield of 29.66 *per cent*.

It was also observed that the Company continued to produce and sell FO during 2014-15 and 2015-16 as per details given below:

Table 3.4: FO production and Sales

(Qty in TMT)

Year	Total Production	Sales		
		Domestic	Export	Total sales
2014-15	1873	66	1731	1797
2015-16	604	90	630	720

The Company replied (November 2016) that, it processed more crude, produced and exported FO as the topping margin remained positive. As regards increase in Coke yield, the Company accepted the audit observation and stated that the Company is making continuous modifications to the operating conditions for reduction of coke and improving the yield of distillates.

The Company's reply is to be seen against the fact that, the Company could not achieve one the objectives of Phase III i.e. minimisation of FO production to increase the margin.

3.8.3 The DCU had faced problems with Wet Gas Compressor (WGC) while commissioning. The unit had to be shut down again for a period of 21 days (from 06 June 2014 to 24 June 2014 and from 12 January 2015 to 15 January 2015) after commissioning for carrying out maintenance work relating to WGC.

The Company stated (November 2016) that utilization of a new process unit was normally expected at 60 to 75 *per cent* and the availability of the unit was 71.20 percent in terms of number of days.

The Company's reply was not acceptable as the capacity utilisation of the unit in the year 2014-15 was only 39 percent.

In the Exit Conference (June 2017) with the Ministry, the Company stated that they were trying to improve the distillation yield by reducing coke formation. It was also stated that the yield of coke had improved to 30 *per cent* (2016-17) as against the norms of 29.66 percent. This was confirmed by the representative of Ministry also.

3.9 Non operation of the processing units for want of feed

The process units are interlinked based on the requirement of products. Non receipt of feed from one unit affects operation of another unit. Audit observed that, some of the units commissioned under Phase III expansion were to be shut down for want of feed.

Details of shutdown of units due to non- availability of feed were as follows:

Table 3.5: Units shut down due to non availability of feed

Sl. No.	Unit	Commissioned on	Year	Duration days	Brief reasons
1.	CHTU	May 2014	2014-15	11	No feed & Unit was shut down due to CDU-III shutdown
2.	DCU	April 2014	2014-15	12	Non availability of Vacuum Residue
3.	DHDT	November 2012	2015-16	10	Due to low stock Crude, CDU-I shutdown and non-availability of Hydrogen due to tripping of Hydrogen General Unit - 3

New units were shut down due to non availability of feed though the Company processed crude in excess of installed capacity of the refinery.

The Company replied (November 2016) that the above units were not available on account of non availability of feed from the concerned units due to operational constraints. Further, the DCU was shut down for 12 days due to excess production and evacuation of coke.

The fact remains that the above instances of shut down of units due to non-availability of feed points towards inadequate planning.

Ministry did not furnish any reply.

Chapter 4 Operation of Support Facilities

Refineries encompass various additional process units of varying complexity and purpose. Some produce special products (waxes, lubricants, asphalt, etc.), others control emissions of air and water and some others provide support to the mainline processes. The primary support facilities include electricity and steam generation, hydrogen production and recovery and light gas handling separation, waste water treatment and oil movement and storage etc.

4.1 Excess consumption of Steam

Steam is used in various process/utility units mainly for chemical reaction and for power generation by Captive Power Plants. Steam is generated with the help of Boilers. The Company is using a Linear Program (LP) software viz., Process Industry Modelling System (PIMS), for planning its production. The software is also used for ascertaining the optimum product pattern as well as the utility consumption.

Data relating to consumption of utilities as per PIMS for the period from 2011-12 to 2015-16 was called for from the Company. Based on the PIMS monthly solution report for the year 2015-16, it was observed that the actual consumption (17.40 MMT) of steam during the year which was 17.40 MMT, was more than the ideal consumption being 15.51 MMT which resulted in an extra expenditure of ₹ 231.94 crore. Data relating to years from 2011-12 to 2014-15 was not furnished by the Company.

The Company stated (November 2016) that the LP model is primarily used for modelling the hydrocarbon side and LP results are not used by refineries to predict and evaluate utility performances. It was further stated that consumption of utilities could be indirectly mapped to energy consumption for which norms have been developed by Ministry of Petroleum and Natural Gas (MoPNG).

In the Exit Conference (June 2017) with the Ministry, the Company stated that the steam consumption was configured in Linear Programming (LP) model which was a mathematical model and not a thermodynamic model. The system of LP had been developed by the Company for its own Management to compare the consumption of steam and possibility of deviation was always there. It also stated that MBN was a better reflection of consumption of steam and the MBN of the Company was in the range of 65 to 85 as compared to Panipat refinery which had the best MBN of 63 to 65 in the public sector. It was informed that

MRPL was getting energy study conducted and was striving to achieve the better target. Ministry informed that the Company had been instructed to lower the MBN as per the MoU.

The reply of the Company/Ministry was not supported by results of any analysis with reference to the norms as mentioned in the reply and actual achievement there-against.

4.2 Low yield of Hydrogen from Hydrogen Generation Unit resulting in excess consumption of Naphtha

Hydrogen is needed for treating products like Petrol (Motor Spirit), High Speed Diesel (HSD), Fuel Oil (FO) and feeds for Petrochemical Fludized Catalytic Cracking Unit (PFCCU) and other plants for bringing down the sulphur content. The feed for Hydrogen plant is Light Naphtha. The Company had three Hydrogen Generation Units[22] (HGUs) with a total annual installed capacity of 138,000 MT[23] to cater to the requirement of the refinery. Hydrogen was also produced from the Continuous Catalytic Reformer Unit[24] (CCR).

Audit observed that none of the HGUs could achieve the designed yield of hydrogen (33 *per cent*) production during the period from 2011-12 to 2015-16. The same was in the range of 22.25 to 27 *per cent.* Due to low yield, 3,35,990 MT of additional naphtha had to be processed for obtaining the required quantity of hydrogen. The value of excess quantity of Naphtha processed was ₹ 1,363.98 crore and considering the value of extra FO produced in the process which was ₹ 339.20 crore, the extra cost worked out to ₹ 1024.78 crore. It was noted that the excess consumption of Naphtha was on account of the operation of HGUs at lower loads, shut down and start-up of the unit due to interruptions in the power supply from Captive Power Plant (CPP) and technical problems in the Hydrogen Generating Unit (HGU) 3.

In the Exit Conference (June 2017) with the Ministry, the Company stated that the audit observation was made on the basis of cost audit report which shows the cost aspect only whereas the actual consumption of hydrogen as per meter reading was equal to the design yield of 33 percent. The Ministry endorsed the reply of the Company.

The reply was not supported by any documentary evidence. However, Audit had computed the loss on the basis of the information available in the year-wise Plant Ledger of the Company which reflects the actual input of feed and actual production of Hydrogen.

[22] ***Produces hydrogen by steam reforming of Naphtha.***
[23] ***HGU 1 and 2 – 34,000 TPA each and HGU 3 – 70,000 TPA.***
[24] ***It convert lower octane value naphtha into higher octane products***

4.3 Arrangement of power from economic and reliable sources

The Company had established 115.50 MW of Captive Power Plant (CPP) under Phase I and Phase II. In Phase III, another CPP of 114 MW was commissioned in August/September 2014. In addition, the Company maintained a contract demand of 12.5 KVA with Mangalore Electricity Supply Company Limited (MESCOM), Karnataka for meeting non-critical load.

4.3.1 It was noted that one of the thrust areas in oil and gas sector as per XII five year plan period (2012-17) was optimization of energy and evolving a viable plan for the future. The Working Group of the MoPNG had advised (January 2015) the refineries to study the feasibility of shifting to grid supply preferably at 132/220 KV. The Company, in order to overcome the problem of power supply from captive power plants and also to save the energy cost had engaged (January 2015) Power Trading Corporation India Limited (PTC) to conduct feasibility study for assessing and evaluating various alternatives available to the Company for obtaining reliable power from the dedicated Grid connectivity. PTC observed that during the year 2014-15, the cost of procurement of power from State/Open Access was ₹ 7 per kwh as against the average cost of captive power generation of ₹ 13.65 kwh. PTC had recommended (February 2016) to have a direct 220 KV connection with 1200 MW plant of Udupi Power Corporation Ltd. (UPCL) at an estimated cost of ₹ 560 crore so as to reduce MRPL's cost of operation by ₹ 450 crore annually.

Considering the fact that the captive power was costing more than the power from the Grid, action in line with the directions of MoPNG and recommendations of PTC, needed to be expedited.

The Company stated (November 2016) that it had evaluated external power from an economic point of view and not on the view that own power is unreliable and intends to proceed with import of power from the grid based on the economics.

4.3.2 It was also observed that the Company had problems in obtaining uninterrupted power supply to the processing units. Due to non-availability of uninterrupted power to the processing units, the Company lost sizeable production hours. Unit-wise production hours lost during the period 2012-13 to 2015-16 are given in **Annexure VI**. The shut-down of Processing Units due to power failure showed an increasing trend over the years.

As regards erratic power supply from CPP, the Company informed (November 2016) that CPP III units were getting stabilised.

In the Exit Conference (June 2017) with the Ministry, the Company stated that it has initiated necessary steps as per the direction of the Ministry for considering grid supply as a source of power. It further informed that it has done a route survey alongside the railway line of Konkan Railways, who had agreed to allow the Company to use their corridor for power supply from Udupi Power Corporation Limited. Ministry informed that for new refineries, it was not advocating Captive Power Plant.

4.4 Fuel and Loss

Refineries use fuel oil, natural gas and waste gas as fuel in various operation processes and generation of utilities including power and steam. In addition, the processing losses add to the normal operating cost. Fuel and Loss is a very important variable operating cost in the operation of refinery as Gross Refinery Margin (GRM) of the Company could be improved by reducing/controlling this cost.

It was observed that the Company did not prescribe any norms for Fuel and Loss. Audit reviewed the fuel and loss for the period 2011-12 to 2015-16 in respect of various units of the refinery and found that the Company's Fuel and Loss had increased from year 2013-14 onwards as reflected in the following table:

Table 4.1:Fuel and Loss for last five years ending 31 March 2016

(Percentage of throughput)

Year	Fuel	Loss	Total Fuel and Loss [B]+[C]
[A]	[B]	[C]	[D]
2011-12	6.42	0.33	6.75
2012-13	6.48	0.52	7.00
2013-14	7.51	0.39	7.90
2014-15	9.74	0.35	10.09
2015-16	9.88	0.18	10.06

The Company stated (November 2016) that various parameters being followed in industry for fuel consumption and the energy consumption was being monitored based on set targets.

The reply is not supported by results of any analysis with reference to the parameters stated in the reply in the absence of which Audit was unable to derive an assurance that the Fuel and Loss was within norms.

In the Exit Conference (June 2017) with the Ministry, the Company informed that it was in the process of setting the targets. Ministry representative agreed with the reply of the Company.

4.5 Management of Catalyst

Refinery uses catalysts to improve the quality of products to meet the desired specification as well as to improve the distillate yield. Management of catalysts is essential as they play a major role in the overall economics of the refinery.

4.5.1 Audit observed that the Company had drawn (January 2009) policy for utilisation of catalysts for Phase I and II only, but was yet to draw policy for Phase III units (November 2016).

The Company stated (November 2016) that the catalyst policy for Phase III was yet to be framed.

Ministry did not furnish any reply.

4.5.2 Audit observed that CCR unit was generating spent catalyst. This spent catalyst generally contains a small percentage of precious metals including Platinum. It was observed that the Company did not make any evaluation to determine the quantity of precious metals including Platinum in the spent catalyst.

The Company stated (November 2016) that it would evaluate the quantity of platinum present in the spent catalyst and would get in touch with catalyst supplier and other Refineries for disposal.

Ministry did not furnish any reply.

Chapter 5 Environmental Aspects

Petroleum refinery, during the conversion process of crude, impacts the environment and the eco system. Potential environmental issues associated with petroleum refining include air pollution, water pollution, noise pollution, land pollution, waste water and other hazardous materials.

The Company incorporated environmental-friendly technologies in its process systems to ensure fuel reduction, manage air emission, conserve water and manage waste water. Audit observed that the Company generally complied with the norms of emission prescribed by the Pollution Control Board. However, there was scope for further improvement as discussed in the following paragraphs:

5.1 Non-installation of Flare Gas Recovery System

The Company generates and releases various obnoxious gases during the process of refining. While according Environmental Clearance for Phase III Expansion, MoEF had directed (April 2008) the Company to install Flare Gas Recovery System (FGRS) for the reduction of Hydrocarbon loss and emission of obnoxious gases to the environment. The Company, however, deferred the installation of FGRS at design stage stating non-availability of flaring data from Phase III process units complex, though budgetary allocation of ₹ 20 crore was made for FGRS.

It was observed in audit that the Company commissioned various units under Phase III expansion (March 2012 to June 2015) without installing the FGRS which was not in compliance to the Environmental Clearance accorded by MoEF. It was further seen that the Company, after a delay of 7 years, commenced (September 2015) the process to install FGRS at an estimated cost of ₹ 30 crore for which it selected (May 2016) MECON as Engineering consultant. However, it is yet to place order for the installation of FGRS (November 2016).

Thus, the Company not only failed to comply with the provisions of Environmental Clearance accorded by MoEF but also lost the opportunity of recovering flare gas which could have been utilized as fuel gas monetary impact of which worked out to ₹ 67 crore for the five year period ending March 2016.

The Company stated (November 2016) that it could not design the flare recovery system due to non availability actual flare operating data.

The reply is not acceptable as non-compliance with the provision of the Environmental Clearance on the grounds of non-availability of data cannot be a proper justification.

In the Exit Conference (June 2017) with the Ministry, the Company informed (June 2017) that installation of FGRS is in process and was expected to be installed in December 2017.

5.2 Non-development of green belt

While according the Environmental Clearance to the Phase III Expansion Project, MoEF directed (April 2008) the Company to dedicate 33 *per cent* of the project area for green belt development by associating the local Forest department. The Company earmarked (September 2010) 120 acres for establishing green belt to mitigate the possible fugitive emissions, control noise pollutions, soil conservation and creation of an aesthetic atmosphere in the refinery premises for which Company estimated an expenditure of ₹ 2.10 crore in a period of 4-5 years. A work order in this regard was issued (March 2011) for ₹ 1.91 crore to the State Forest Department (SFD) for taking up the project during the years 2011-2016. The plantation work was to be completed by September 2013 and maintenance work was to be completed by March 2016.

Audit observed that SFD had planted 1,759 seedlings covering an area of 5.30 acres only during the years 2011-13 and there was no progress afterwards.

The Company replied (November 2016) that there was shortfall of land for green belt due to utilization of land for Phase III project. The Company further stated that it is acquiring additional land of 27 acres for augmenting green belt

Ministry did not furnish any reply.

5.3 Delay in complying with the directions of Pollution Control Board

The Delayed Coker Unit (DCU) produces valuable distillates and Petroleum Coke (Pet Coke). The pet coke is transported by a closed conveyer system to open coke lay down area and to truck loading facility through Silos (3x1000 MT). Similarly, sulphur produced in Sulphur Recovery Unit is (SRU) stored in open yard and in 6 Silos.

The Karnataka State Pollution Control Board (KSPCB), during the year 2014 and 2015, issued various show cause notices to the Company with regard to dust emissions and surface water contamination from the Phase III coke yard and sulphur yard. KSPCB suggested

(March 2015) covering the coke yard and the sulphur yard completely to avoid dust pollution. KSPCB also recommended providing permanent arrangement for collection and recycling of the wash water in the coke yard, so that the wash water containing suspended particulate matter is not allowed to overflow to the nearby natural drains that pass through the neighbouring villages.

The Company, therefore, proposed (September 2015) to install three additional Silos of 3,000 MT each or five new Silos of 1,000 MT each with suitable conveyor connectivity and unloading facility for pet coke, suitable wash water management facility in the coke yard and covered shed in the sulphur yard at a cost of ₹ 52 crore. However, despite passage of more than one year, the contract for construction of the above facilities was yet to be awarded (November 2016). Consequently, the pollution hazards caused by these units were not mitigated.

The Company replied (November 2016) that it took all effort to comply with the conditions laid down by the KSPCB to avoid contamination of water and air pollution.

The fact remains that none of the suggestions made by KSPCB in March 2015 were complied with as yet (November 2016).

Ministry did not furnish any reply.

5.4 Inadequate creation and management of water resources

Refinery needs a large quantum of water to process crude. The Company had to shut down its refinery in April 2012 (12 April 2012 to 27 April 2012) due to water scarcity.

As the Company had not fixed any norms for water consumption for all processing stages of its production, based on the advice (April 2014) of KSPCB, it requested National Productivity Council (NPC) to conduct a comprehensive water audit study in its refinery for Phase I and II.

The NPC, among other things, recommended (November 2014) to maximise condensate recovery in plant to reduce the water intake from the resource and conserve water in order to reduce pumping cost, demineralisation cost and load on Effluent Treatment Plant. It identified four locations for recovering rain water. It also recommended deployment of storm water harvesting technique and proper channelization of water to capture uncontaminated storm water and not let out rain water to drains.

The Company was yet (November 2016) to take action on any of the above recommendations.

The Company replied (November 2016) that it was conducting a feasibility study to set up a Desalination Plant and initiated action for setting up a Reverse Osmosis Unit for tertiary treatment of effluent water. Further, the Company stated that they would establish water foot print bench mark by the use of best practices or best available technologies or by selecting the water foot print achieved by the best performers in the Oil sector.

Ministry did not furnish any reply.

5.5 Non-participation in the Clean Development Mechanism

United Nations Framework Convention on Climate Change (UNFCCC) in Kyoto protocol introduced Clean Development Mechanism (CDM) concept to achieve stabilization of Green House Gases concentrations in the atmosphere at a level that would prevent dangerous interference with the climate system. As India is a signatory to Kyoto protocol, GoI established (April 2004) National Clean Development Mechanism Authority (NCDMA) so that entities whether private / public or non-governmental could participate in CDM process.

Audit observed that the Company did not have any proposal to register any of its projects which had potential for getting benefits under CDM in the form of 'Certified Emission Reduction' (CER) credit, which are tradable.

The Company replied (November 2016) that it would initiate necessary steps for registering projects under CDM.

Ministry did not furnish any reply.

Chapter 6 Conclusion and Recommendations

6.1 Conclusion

The Phase III expansion project of the Company was conceived in 2006 to increase the capacity of the refinery from 11.82 MMTPA to 15 MMTPA and to produce value added products. In the year 2009, a Poly Propylene Unit was added to the scope of expansion and then in the year 2010 a Single Point Mooring facility was also conceived. The total cost of the project was estimated at ₹ 15,008 crore out of which the Company had incurred an amount of ₹ 14,832 crore till March 2016. The Phase III Expansion Project, supposed to be commissioned by October 2011, was completed in September 2014. Similarly, Poly Propylene Unit (PPU) was commissioned after a delay of 34 months in June 2015. The Single Point Mooring (SPM) facility was commissioned in August 2013 after a delay of 16 months.

The major issues noticed during the course of review of the planning and execution of the Phase III Expansion Project are summarised below:

- Deficiencies in planning, were noticed which led to change in the scope at project conceptualisation stage resulting in time overrun of more than two years and cost overrun of ₹ 2,509 crore.
- External borrowings were arranged without hedging the associated foreign currency fluctuation risk. This resulted in loss of ₹ 13.70 crore (net of currency hedging cost) on loan repayments till September 2016. Funds for the project were drawn in excess of requirement which resulted in idling of ₹ 768.46 crore in non-interest bearing current account.
- In the selected 87 major contracts, there were delays in execution of formal contract in 84 cases.
- Delayed commissioning of Captive Power Plant resulted in idling of various units even though they were mechanically complete.
- Even though SPM was commissioned in August 2013, it could not be utilised effectively due to non completion of associated Cavern by Indian Strategic Petroleum Reserves Limited (ISPRL). Consequently, the objective of setting up of SPM facility such as savings in freight, avoidance of demurrage and improvement in Gross Refinery Margin (GRM) could not be achieved.
- Non synchronisation of revamped Hydrocracker units with Petrochemical Fluidized Catalytic Cracking unit (PFCCU) led to production of low value products in place of high value products during the period from 2011-12 to 2014-15 and consequent loss of revenue of ₹ 6328.76 crore.

- Non production of Propylene, as per the designed yield and its non conversion to Poly Propylene, a high value product, in the PPU during the period from August 2014 to May 2015 resulted in a loss of margin of ₹ 382.83 crore.
- There was excess consumption of Steam in various utilities during 2015-16 which resulted in extra expenditure of ₹ 231.94 crore.
- There were delays on the part of the Company in complying with environmental directives issued by the statutory authorities.

6.2 Recommendations

- In future, the Company may draw up a comprehensive plan before finalising the projects in order to avoid time and cost overrun. Requirement of funds for the projects may be made on a realistic basis to avoid excess drawal of funds.
- The Company may ensure timely completion of utilities like Power Plants which have cascading effect on commissioning of other units. The Company may also ensure sequential completion and proper integration of the processing units to avoid their idling and underutilisation.
- The Company may make urgent efforts to optimise the utilisation of SPM.
- The Company may ensure optimum capacity utilisation of all the processing units.
- The Company may evolve a system for evaluating the consumption of utilities by the various processing units so as to ensure optimum utilisation of these utilities.

New Delhi
Dated: 18 July 2017

(NAND KISHORE)
Deputy Comptroller and Auditor General
and Chairman, Audit Board

Countersigned

New Delhi
Dated: 18 July 2017

(SHASHI KANT SHARMA)
Comptroller and Auditor General of India

Annexures

Annexure I

(Referred to in Paragraph 1.5)

Statement showing revision in configuration of processing units

Sl. No.	Units	Year 2006	Year 2008	Year 2009	Year 2010	Objective	Reasons for revision
1.	CDU III	Not envisaged	3.00 MMTPA	No change	No change	To increase the refining capacity.	To provide flexibility in processing low value high acid crudes
2	PFCCU	2.07 MMTPA	2.20 MMTPA	No change	No change	Additional throughput and production of Propylene. Operate on Low Sulphur feedstock and aromatic rich FCC Naphtha.	Based on revised & optimized LP runs for 5.5 MMTPA Mumbai High crude and 9.5 MMTPA Arab Heavy crude.
3.	DHDT	3.25 MMTPA	3.70 MMTPA	No change	No change	Upgrade High Sulphur & Low Cetane SR gas oil and cracked Diesel range streams into Diesel fuel of BS III & IV specifications.	Light Naphtha hydro treatment was also considered as a part of Diesel hydro treatment and hence increased.
4.	DCU	3.18 MMTPA	3.00 MMTPA	No change	No change	To minimize Fuel Oil production by upgrading the High Sulphur Short Residue into distillates and Naphtha.	Considering the increased capacity of DHDT.
5.	CHTU	Not planned	0.65 MMTPA	No change	No change	To process the HCGO stream from DCU and straight run VGO so as a feeder unit to PFCCU.	To overcome the high modifications with long shut down period of HCU revamping.
6.	HGU	47 KTPA	70 KTPA	No change	No change	To meet the requirement of Hydrogen in processing unit.	Based on the actual requirement as per Licensor data with margins, keeping in view the criticality of Hydrogen.

Sl. No.	Units	Year 2006	Year 2008	Year 2009	Year 2010	Objective	Reasons for revision
7.	SRU	315 TPD	555 TPD	No change	No change	To recover the Sulphur from Amine.	Considering the Hydro treating in CHTU the capacity increased.
8.	LOBS	0.25 MMTPA	Dropped	No change	No change	To produce Lube, Oil etc. from the unconverted Hydro cracker bottom stream by use of MH Crude VGO and Coker Heavy Gas Oil.	Deleted based on the feedback from the Licensor that desired quality was not possible and also lower long term market growth.
9.	PPU	Not envisaged	Not envisaged	0.44 MMTPA	No change	To produce Polypropylene from Propylene.	-
10.	SPM	Not envisaged	Not envisaged	Not envisaged	Included	To ensure smooth discharge of imported crude, through larger vessels at the nearby Mangalore Port	-

Annexure II

(Referred to in Paragraph 1.5)

Statement showing estimated cost in 2006 and further revisions

(₹ in crore)

Sl No	Details	2006	2008	2009	2010
1	Land	10	91	91	91
2	Site Development	30	192	192	192
3	Process know how/Basic Engineering	76	109	109	109
4	PMC/Det. Engg./etc.	456	828	828	828
5	Plant and Machinery	5,841	8,964	8,712	8,712
6	Water Supply & Public health	-	100	100	100
7	Buildings	30	50	50	50
8	Construction site facilities	29	45	45	45
9	Owners construction Period expenses	78	124	124	124
10	Start up and commissioning	58	108	108	108
11	Contingency 10%	661	1,061	1,061	1,061
12	Working Capital margin	120	153	153	153
13	Financing Charges	554	587	587	587
	Total	**7,943**	**12,412**	**12,160**	**12,160**
14	PPU	**-**	**-**	1804	1804
15	SPM	**-**	**-**	-	1044
	Total Cost	**7,943**	**12,412**	**13,964**	**15,008**

Annexure III

(Referred to in Paragraph 3.2)

Working of revenue loss due to export of excess products

Product	Average domestic sales value (₹ per MT)	Average export value (₹ per MT)	Average differ-ence (₹ per MT) [2]-[3]	Qty. exported (MT)	Less realisation (₹ in crore) [4]x[5]	Cost (₹ per MT)	Difference (₹ per MT) [7]-[3]	Cost not recovered (₹ in crore) [8]x[5]
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
2011-12								
ATF	49,031	48,328	703	8,30,000	58.35	48,268		
Furnace Oil	36,075	32,307	3,768	16,10,000	606.65	32,270		
HSD	48,551	46,669	1,882	7,20,000		47,541	872	62.78
Naphtha	48,518	46,153	2,365	11,10,000		47,517	1,364	151.40
Total					**665.00**			**214.19**
2012-13								
ATF	55,382	54,314	1,068	11,40,000		54,354	40	4.56
HSD	53,761	51,258	2,503	11,80,000		53,762	2,504	295.47
Naphtha	53,202	48,949	4,253	13,40,000		51,233	2,284	306.06
Total					**0.00**			**606.09**
2013-14								
ATF	59,473	58,014	1,459	14,10,000	205.72	57,140		
HSD	56,696	57,253	-557	7,10,000		58,130	877	62.27
Naphtha	56,881	55,157	1,724	13,60,000	234.46	54,877		
Total					**440.18**			**62.27**
2014-15								
ATF	50,709	46,183	4,526	8,10,000		50,426	4,243	343.68
Furnace Oil	33,426	30,158	3,268	13,30,000	434.64	28,603		
HSD	41,590	42,190	-600	6,30,000		46,308	4,118	259.43
Naphtha	52,057	44,511	7,546	9,70,000	731.96	43,403		
Total					**1,166.61**			**603.12**
2015-16								
ATF	31,274	27,746	3,528	5,70,000		29,565	1,819	103.68
Furnace Oil	19,702	17,316	2,386	3,00,000	71.58	15,110		
HSD	29,319	24,925	4,394	3,80,000		26,965	2,040	77.52
MS BS III	39,415	34,856	4,559	20,000	9.12	28,838		
Naphtha	33,246	28,708	4,538	9,30,000	422.03	27,109		
Total					**502.73**			**181.20**
Grand Total					**2,774.52**			**1,666.86**

Annexure IV

(Referred to in Paragraph 3.3)

Loss of revenue due to non-achievement of Design Yield

HCU – I

Major Products	Design yield (percent)	Design Yield (MT)	Actual Production (MT)	Difference [4]-[3]	Sales realization per MT (₹)	Differential Amount (₹ in crore) [5]x[6]
[1]	[2]	[3]	[4]	[5]	[6]	[7]
2011-12 (Feed 13,58,308 MT)						
LPG	2.62	35,588	37,255	1,667	44,298	7.39
Naphtha	15.51	2,10,674	2,77,379	66,705	48,518	323.64
Kerosene & HSD	81.61	11,08,515	9,83,657	-1,24,858	48,551	-606.20
2012-13 (Feed 13,85,747 MT)						
LPG	2.62	36,307	40,938	4,631	52,543	24.33
Naphtha	15.51	2,14,929	3,15,252	1,00,323	53,202	533.74
Kerosene & HSD	81.61	11,30,908	8,52,407	-2,78,501	53,761	-1,497.25
2013-14 (Feed 14,64,476 MT)						
LPG	2.62	38,369	46,101	7,732	58,468	45.21
Naphtha	15.51	2,27,140	3,27,193	1,00,053	56,881	569.11
Kerosene & HSD	81.61	11,95,159	8,55,698	-3,39,461	56,696	-1,924.61
2014-15 (Feed 14,50,229 MT)						
LPG	2.62	37,996	29,597	-8,399	43,754	-36.75
Naphtha	15.51	2,24,931	2,59,564	34,633	52,057	180.29
Kerosene & HSD	81.61	11,83,532	10,12,214	-1,71,318	41,590	-712.51
Total loss of revenue - HCU 1						**-3,093.61**

HCU – II

Major Products	Design yield (percent)	Design Yield (MT)	Actual Production (MT)	Difference [4]-[3]	Sales realization per MT (₹)	Differential Amount (₹ in crore) [5]x[6]
[1]	[2]	[3]	[4]	[5]	[6]	[7]
2011-12 (Feed 15,52,452 MT)						
LPG	2.55	39,588	23,861	-15,727	44,298	-69.67
Light Naphtha	7.11	1,10,379	1,61,145	50,766	48,518	166.90
Heavy Naphtha	13.60	2,11,133	1,94,768	-16,365		
Kerosene	27.60	4,28,477	2,57,272	-1,71,205	48,984	-838.63
Diesel	43.60	6,76,869	7,56,304	79,435	48,551	385.66
2012-13 (Feed 15,11,598 MT)						
LPG	2.55	38,546	36,295	-2,251	52,543	-11.83
Light Naphtha	7.11	1,07,475	1,38,306	30,831	53,202	-22.16
Heavy Naphtha	13.60	2,05,577	1,70,581	-34,996		
Kerosene	27.60	4,17,201	3,65,804	-51,397	55,034	-282.86
Diesel	43.60	6,59,057	5,46,771	-1,12,286	53,761	-603.66
2013-14 (Feed 15,46,985 MT)						
LPG	2.55	39,448	46,653	7,205	58,468	42.13
Light Naphtha	7.11	1,09,991	1,62,717	52,726	56,881	255.70
Heavy Naphtha	13.60	2,10,390	2,02,617	-7,773		
Kerosene	27.60	4,26,968	3,54,685	-72,283	58,133	-420.20
Diesel	43.60	6,74,485	5,60,714	-1,13,771	56,696	-645.04
2014-15 (Feed 16,67,480 MT)						
LPG	2.55	42,521	39,500	-3021	43,754	-13.22
Light Naphtha	7.11	1,18,558	1,44,672	26114	52,057	-44.07
Heavy Naphtha	13.60	2,26,777	1,92,198	-34579		
Kerosene	27.60	4,60,224	3,56,744	-103480	52,644	-544.76
Diesel	43.60	7,27,021	5,85,295	-141726	41,590	-589.44
Total loss of revenue - HCU II						**-3,235.15**
Grand Total – loss of revenue in HCI 1 and HCU 2						**-6,328.76**

Note: Average sales realisation for Naphtha considered for both Light and Heavy Naphtha as separate rates not available.

Annexure V A

(Referred to in Paragraph 3.6.2)

Loss due to delay in commissioning of Poly Propylene unit resulting in avoidable diversion of Propylene into LPG pool (August 2014 to May 2015)

Period	Quantity fed in PFCCU (MT)	Actual Yield (MT)	
		LPG	Propylene
August 2014 to March 2015	5,16,050	2,27,614	2,413
April 2015	81,002	24,657	1,306
May 2015	99,870	30,623	232
Total	**6,96,922**	**2,82,894**	**3,951**
Actual yield of Propylene in percentage (Actual Yield MT/Total Quantity fed x 100)		[A]	0.57%
Design yield (in percent)		[B]	20.60%
Lower yield of propylene (in per cent) **[B]-[A]**		[C]	20.03%
Propylene shortage (MT) (C x Quantity fed in PFCCU)		[D]	1,39,615
Propylene actually produced (MT)		[E]	3,951
Propylene which should have been produced (MT) **[D]+[E]**		[F]	1,43,566
Design yield of Propylene to Poly Propylene		[G]	99.60%
Quantity of Poly Propylene not achieved (MT) **[F]x[G]**		[H]	1,42,992

Product	Margin ₹/MT	Qty (MT)	Loss (₹)
Poly Propylene less produced	31,005	1,42,992	4,43,34,66,960
Less: LPG produced	4,215	1,43,566	(60,51,30,690)
Loss of margin			**3,82,83,36,270**

Annexure V B

(Referred to in Paragraph 3.6.3)

Loss due to low yield of Propylene in PFCCU after commissioning of PPU (June 2015 to March 2016)

Period	Quantity fed in PFCCU (MT)	Yield (MT)	
		LPG	Propylene
June 2015 to March 2016	14,14,595	3,90,263	154611
Yield in percentage (Yield/Quantity fed x 100)		**[A]**	10.93%
Design yield (in percent)		**[B]**	20.60%
Lower yield of Propylene **[B]-[A]**		**[C]**	9.67%
Propylene shortage **[C]** x **Quantity fed**		**[D]**	136791
Design yield of Propylene to Poly Propylene		**[E]**	99.60%
Quantity of Poly Propylene not achieved **[E]** x **[D]**		**[F]**	1,36,244

Product	Margin ₹/MT	Quantity (MT)	Loss (₹)
Poly Propylene less produced	31,005	1,36,244	4,22,42,45,220
Less: LPG produced	4,215	1,36,791	(57,65,74,065)
Loss of margin			**3,64,76,71,115**

Annexure VI

(Referred to in Paragraph 4.3.2)

Details of unit-wise total shutdown hours

(in Hours)

Sl. No.	Unit	2012-13	2013-14	2014-15	2015-16
1.	Crude Distillation Unit-1				30
2.	Crude Distillation Unit-2		25	28	9
3.	Crude Distillation Unit-3		563	720	326
4.	Hydrocracker Unit-1	30	99	32	99
5.	Hydrocracker Unit-2		128		67
6.	Diesel Hydro Desulphurisation Unit		309	362	73
7.	Coker Heavy Gas Oil Hydrotreater			235	173
8.	Petro-Fluid Catalytic Cracking Unit			272	166
9.	Delayed Coking Unit			395	52
10.	Poly Propylene Unit				63
11.	Gas Oil Hydro Desulphuriser Unit		42		73
12.	Isomerization Unit		36		146
13.	Continuous Catalytic Reforming-1		34		70
14.	Continuous Catalytic Reforming-2		17		34
	Total	**30**	**1,253**	**2,044**	**1,381**

Glossary and Abbreviations

Glossary

S. No.	Item	Details
1.	Crude Distillation Unit (CDU)	Distil and separate valuable distillates (LPG, Naphtha, Kerosene, Diesel etc) and bottom from the crude at normal atmospheric pressure. Various fractions are further processed in other units.
2.	Continuous Catalytic Reformer Unit (CCR)	It convert lower octane value naphtha into higher octane products.
3.	Delayed Coker Unit (DCU)	Converts low value residue into valuable products (Naphtha, Diesel and Coker gas oil) and Pet Coke.
4.	Diesel Hydro Desulphurisation Treating Unit (DHDT)	The unit removes Sulphur, Nitrogen and metal impurities of the feed received from different units.
5.	Fuel & Loss	Fuel & Loss refers to the cost that refineries incur due to the fuel consumed to run the refineries and the fuel lost in the system while processing crude into petroleum products.
6.	Gas Oil Hydro De-Sulphurisation (GOHDS) Unit	Removes Sulphur from Light Gas Oil (LGO), Heavy Gas Oil (HGO), and Vacuum Gas Oil (VGO) which is converted into ultra-low sulfur diesel to meet the sulfur specification of diesel.
7.	Gross Refinery Margin (GRM)	The Gross Refinery Margin (GRM) is the difference between the total value of petroleum products coming out of an oil refinery (output) and the price of the crude used for producing the petroleum products. GRM is typically expressed in US dollars per barrel.
8.	Heavy Coker Gas Oil Hydrotreating Unit (CHTU)	This unit is a feed preparation unit for downstream PFCCU. It produces feed stock of low sulfur, low nitrogen feed hydro treated Heavy Coker Gas Oil feed stock for downstream PFCC unit.
9.	Hydrocracker Unit (HCU)	Unit in which heavier fractions of VGO from the VDU and Vis-breaker units are cracked into lighter, more valuable middle distillates using hydrogen
10.	Hydrogen Generation Unit (HGU)	Produces hydrogen by steam reforming of Naphtha

11.	Light or Heavy Crude	Crude with High API (American Petroleum Index) is light crude and crude with low API is heavy crude
12.	Lump Sum Turn Key (LSTK)	In LSTK contract, the contractor is entrusted with the work/services at a fixed cost along with all associated risks till the handing over of the project/asset.
13.	Open Book Execution (OBE)	In an OBE contract, the buyer and seller of work/services agree on remunerable cost and margin that the supplier can add to these costs. The project is invoiced to the customer based on the actual cost plus the agreed margin.
14.	Petrochemical Fluidized Catalytic Cracking Unit (PFCCU)	Produces fuel gas, LPG, polymer grade Propylene, Naphtha and light cycle oil from unconverted bottoms from HCU, hydro-treated heavy Coker gas oil from CHTU and low Sulphur VGO from CDU/VDU.
15.	Poly Propylene Unit (PPU)	Petrochemical unit for production of Poly Propylene from Propylene, output of PFCCU.
16.	Sulphur Recovery Unit	Unit recovers Sulphur from the feed.
17.	Sweet or Sour Crude	Crude containing low sulphur content is termed as sweet crude and crude with high sulphur content is termed as sour crude.
18.	Throughput	The total tonnage of crude oil fed into an oil refinery is its throughput.
19.	Vacuum Distillation Unit (VDU)	Distills the residue crude from the bottom of the CDU to valuable gas oils.
20.	Vis-breaker Unit (VBU)	Upgrades short residues coming from the bottom of vacuum distillation column by thermally cracking into lighter, reduced viscosity products.

Abbreviation

Acronyms	Stands for
ATF	Aviation Turbine Fuel
CCR	Continuous Catalytic Reformer Unit
CDU	Crude Distillation Unit
CHTU	Heavy Coker Gas Oil Hydrotreating Unit
CPP	Captive Power Plant
DCU	Delayed Coker Unit
DFR	Detailed Feasibility Report
DHDT	Diesel Hydro Desulphurisation Treating Unit
GOHDS	Gas Oil Hydro De-Sulphurizer
GRM	Gross Refinery Margin
HCU	Hydro Cracker Unit
HGU	Hydrogen Generating Unit
HSD	High Speed Diesel
IRR	Internal Rate of Return
LOBS	Lube Oil Base Stock
LPG	Liquefied Petroleum Gas
LSTK	Lump Sum Turn Key
MS	Motor Spirit
OBE	Open Book Execution
OIDB	Oil Industry Development Board
PAEC	Project Appraisal & Execution Committee
PFCCU	Petrochemical Fluidized Catalytic Cracking Unit
PMC	Project Management Consultant
PPU	Poly Propylene Unit
SPM	Single Point Mooring
SRU	Sulphur Recovery Unit
UCO	Unconverted Oil
VBU	Vis-Breaker Unit
VDU	Vacuum Distillation Unit
VGO	Vacuum Gas Oil
VLCC	Very Large Crude Container