CHEM SYSTEMS INTERNATIONAL LTD.
28 ST. JAMES'S SQUARE, LONDON SW1Y 4JH.
Telephone: 01-839 4652 Telex: 916636 CHEMSL G
Facsimile: 01-930 1504

STUDY ON THE COSTS BORNE BY THE REFINING INDUSTRY IN THE MEMBER STATES IN ORDER TO COMPLY WITH ENVIRONMENTAL LEGISLATION

Prepared for

COMMISSION OF THE EUROPEAN COMMUNITIES

June 1986

Registered No. 1120187 England Registered office as above. V.A.T. No. 239 5255 45

CONTENTS

Section **Page No.**

SECTION I

I INTRODUCTION

This study has been prepared for the Commission of the European Communities to evaluate the costs borne by the refining industry in order to comply with environmental legislation in the following member states:

- o Belgium
- o France
- o Germany
- o Italy
- o Netherlands
- o Spain
- o United Kingdom

Models were set up using Chem Systems proprietary linear program (LP) to simulate the current and future operation representative of typical refineries in the member states considered. Two types of refinery were evaluated, namely hydroskimming and conversion refineries.

Operation of each of the two refinery types was modelled for 1985 and 1993 for each of the member states. The crude oil slates used reflected as closely as possible the actual 1985 runs, the same crude oil slates were assumed for 1993. Using the refinery models an evaluation was made of the cost of compliance with evironmental standards, under differing current and future norms. Base cases were set up where the only environmental constraints considered were those needed to meet 1985 EEC Specifications for product qualities. The cost of compliance was then evaluated for each of the following cases, as a differential above the base case costs:

<u>Community Cases</u> - 1985 and 1993
- refinery site subject to EEC standards

<u>National Cases</u> - 1985 and 1993
- refinery site subject to EEC and national standards

The relevant environmental legislation includes:

- Regulations applicable to refinery sites (air, water, noise pollution)

- Official petroleum product specifications

- Regulations influencing customer's specification for petroleum products

For each case, a review was made of the relevant legislation to determine which regulations required the refineries to modify their operation to comply with environmental limit values. A review was then made of the appropriate technical measures available to comply with the environmental requirements. The selection was based on the following factors;

- Industry codes and practices
- Minimisation of investment and operating costs
- Operating experience (availability, technical problems etc)
- By-products disposal problems
- Other relevant criteria

The choice of technical measures was limited to proven technology. However, comment was provided in areas where anticipated improvements in technology are foreseen during the 1985-93 period. Having selected the 'best' technical solutions, the incremental investment and operating costs for installing them in an existing refinery were estimated for all the cases considered.

A copy of the complete terms of reference for the study are included for information.

TERMS OF REFERENCE

I. The refining industry is affected by environmental legislation in three respects :

- in its own production and sales units,
- where its products are concerned, and
- as a result of requirements as regards its customers.

In order to meet environmental protection requirements, investments are necessary and operating costs are entailed which are reflected in product prices.

II. The study will :

1) Cover seven countries : Belgium,Federal Republic of Germany, France, Italy, the Netherlands, Spain and the United Kingdom.
2) Consider 2 dates 1985 and 1993
3) Evaluate environmental costs for two types of refinery, namely a hydroskimming and a conversion refinery. National costs will be estimated by taking into account the proportion of each type in each country. This model refinery produces the full product range excluding lubricating oil and petrochemical products.
4) Use the true average proportions of low and high sulphur crude oil at national level. The percentage shall be the same for 1985 and 1993. Credit and debit to be discussed and agreed with consultant.
5) Use the same refined product pattern for every member state (and will more or less result from the type of refinery considered).
6) Assume that the output of the model refineries is disposed of wholly on the internal market.

7) Will estimate the costs of compliance with environmental standards for :
   - a base case in which the refinery is subject to no environmental constraints except for the quality of final products.
   - a community case in which the refinery is subject to EEC norms.
   - seven national cases in which the refinery is subject to EEC and national standards.

Costs to be defined in detail by the consultant and estimated consistently for all cases.

8) Take into consideration special constraints, like nickel content in crude oil for Germany.
9) Consider only federal, national legislations on environment, mention only the possibility of more stringent regulations at the regional level.
10) Include in the costs taxes or levies (e.g. on waste water).
11) Take the same factor of utilisation of 75% for 1985 and 1993, assuming about 100% for conversion.
NB) CONCAWE will be asked to support the consultant's work.

Form for environmental expenditure by oil refineries

Sheet :

1	2	3	4	5		6	
	Legislation	Requirement	Technical measure to comply with the provisions	Investment ECU		Operating costs ECU	
				Total	per tonne	Total	per tonne

Comments

Explanatory Notes

Column 1

Indicate in this column the individual components of the environment (air, water, noise, soil, waste, etc.) and the parameters to be assessed (SO_2, NO_x, hydrocarbons, waste water purification, cooling water system).

Column 2

Indicate the legislation which imposes requirements on refineries. If there are no relevant specific provisions indicate whether standardised general official regulations apply. (cf. CONCAWE report 84/65. Published national regulatory guidelines of environmental concern to the oil industry in Western Europe).

Column 3

Indicate the limit values from the provisions indicated in column 2 or practical technical measures called for (e.g. SO_2 limit value 2,500 mg/m^3 until 1993" or "maximum permissible sulphur content in fuel oil for own consumption 2.0% by weight" or "double edge seal for floating roof tanks").

Column 4

If limit values are indicated in column 3, details should be given in column 4 as to how they are complied with e.g. compliance with the SO_2 limit value by means of fuel selection (oil/gas ratio in the case of mixed firing or flue-gas desulphurisation; in the case of waste water, e.g. "API separator" or "completely biological purification").

Column 5

Indicate the investment required in order to implement this measure. The years considered should be 1985 and 1993. It should be borne in mind that new refineries are no longer being established in Europe. The requirements should therefore be met by existing facilities. Consequently, the value indicated should include a supplement for incorporation into an existing complex.

In determining the cost per tonne in the sub-column, account should be taken of the fact that crude oil capacity is not fully utilised and that other residual material is processed. The cost per tonne should therefore relate to total production rather than crude oil capacity.

Column 6

Indicate the operating costs resulting either from the operating costs arising from the emission reduction facilities in column 5 or in respect of specific use of machinery or the like. For example, if an SO_2 emission limit value is met by using gas, the price differential between the residue available in the refinery and bought-in natural gas should be indicated.

As regards determining the specific operating costs (ECU per tonne), the same applies as for column 5.

Assessment :

Investments and operating costs should be accumulated separately for the components of the environment and also summed up.

Particular points :

In the "products table" it should be indicated what proportion of the production corresponds to the relevant Community directives (e.g. lead in petrol 0.4 g/l, 0.15 g/l; gasoil : 0.3% by weight of sulphur).

SECTION II

II SUMMARY

A. INTRODUCTION

Environmental legislation has in the past and will continue to have in the future, a significant impact on refinery operation. The following areas were investigated in this study, first to establish the environmental constraints and then subsequently to estimate the compliance costs:

- Product Qualities
  - Gasoline
  - Gas Oil
  - Residual Fuel Oil

- Air Quality
  - SO_2 Related
  - NO_x Related
  - Other (including stack monitoring and hydrocarbon emission control)

- Liquid Effluent

- Other (including the cost of electricity)

Two reference years were considered (1985 and 1993) and the compliance costs associated with EEC and National Legislative measures were evaluated separately. The measures identified to have the largest impact for the 1993 evaluations were the EEC Directive (85/210/EEC) for the introduction of unleaded gasoline and the National Regulations of TA Luft and GFAVO applicable in Germany.

B. REFINERY DATA

The environmental compliance cost assessments were made for two types of refinery, namely a hydroskimming and conversion refinery. Overall "National Costs" were estimated by taking into account the proportion of each type of refinery in the member states considered. Estimates of the proportion of each refinery type are given in Table II.B.1. It should be borne in mind that many simplifying assumptions have to be made in order to categorise the refineries under two such broad headings, the proportion of each refinery type was based on 1985 installed capacity data for the seven member states. For simplification refineries with visbreaking or thermal cracking units only (in addition to distillation and reforming etc) were categorised under hydroskimming type and those with fluid catalytic cracking, hydrocracking or coking were categorised under conversion type refineries.

Data on the country by country refinery intakes are given in Table II.B.2. Production estimates can be made by multiplying these data by a factor of 0.95 (ie assuming a 5 percent usage for fuel and loss).

TABLE II.B.1

PROPORTION OF HYDROSKIMMING AND CONVERSION TYPE REFINERIES IN THE MEMBER STATES (1985)

(percentage of refineries)

Country	Hydroskimming Type	Conversion Type
Belgium	18	82
France	3	97
Germany	11	89
Italy	43	57
Netherlands	39	61
Spain	48	52
United Kingdom	5	95

TABLE II.B.2

REFINERY INTAKES FOR MEMBER STATES (MID 1984 - MID 1985)

(Million metric tons per year)

Country	Intake(1)
Belgium	19.9
France	76.2
Germany	89.9
Italy	74.8
Netherlands	57.1
Spain	44.5
United Kingdom	80.0

Note:

(1) Including Crude Oil, NGL and other feedstocks.

Source of Information: "Oil and Gas Statistics 1985", International Energy Agency (OECD)

C. ENVIRONMENTAL COMPLIANCE COSTS (EXCLUDING CAPITAL CHARGES)

Full details of the estimated environmental compliance costs for the two refinery types for each of the cases considered are given in Section V. By taking account of the proportion of hydroskimming and conversion type refineries in each country, an assessment of the investment and operating costs for "typical" refineries expressed per metric ton of total refined products in each of the countries considered was made. The data presented does not include any allowance for capital charges, the operating costs quoted are "cash costs" and exclude depreciation, return on investment and interest charges. A separate analysis including an allowance for these capital charges is carried out later in the section.

No specific compliance costs were estimated for environmental noise control measures or soil clean up at refinery sites, as these are too site specific for typical refinery costs to be meaningful. Instead, order of magnitude cost allowances for the national cases have been included in the summary tables in this section, to cover these and any other miscellaneous environmental costs which may have been overlooked. All of the costs given were determined as differentials above the base case costs as defined in the terms of reference.

Three cases were evaluated;

- o 1985 EEC and National Requirements
- o 1993 EEC Requirements
- o 1993 EEC and National Requirements

The main results, expressed in ECUs per metric ton of refinery production, are summarised in Figure II.C.1 (excluding capital charges).

1. 1985 EEC and National Case

There were no environmental compliance costs identified relative to the base case resulting from EEC Directives for the reference year of 1985. Investment and operating costs resulting from national legislative measures in 1985 are given in Table II.C.1. As can be seen these costs

FIGURE II.C.1.

REFINERY OPERATING COSTS FOR ENVIRONMENTAL COMPLIANCE (EXCLUDING CAPITAL CHARGES)

(ECU per metric ton of total production)

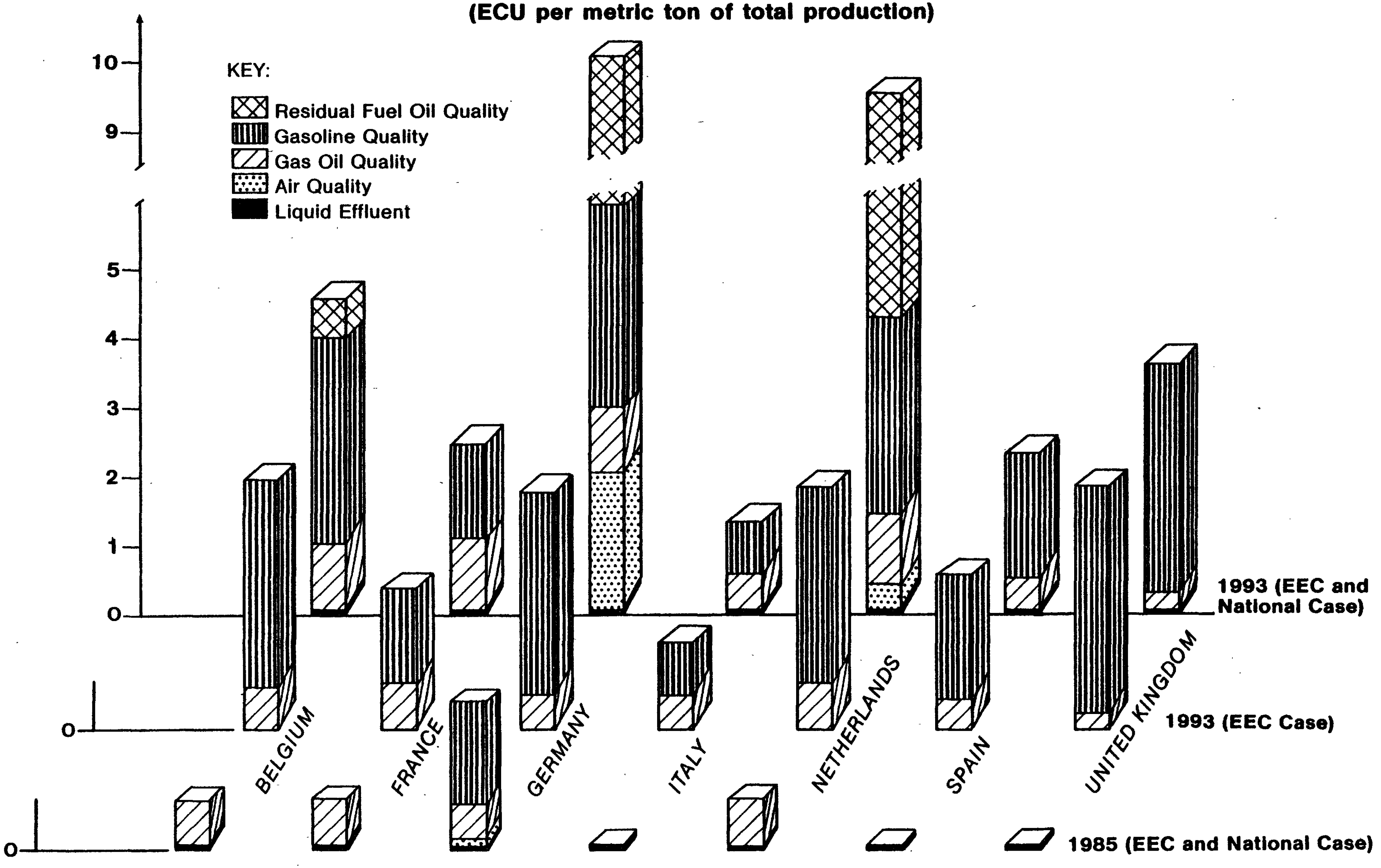


TABLE II.C.1

ENVIRONMENTAL COMPLIANCE COSTS FOR TYPICAL REFINERY (EXCLUDING CAPITAL CHARGES)

1985 : EEC AND NATIONAL CASE

(ECUs per metric ton (1))

Environmental Constraint	Belgium		France		Germany		Italy		Netherlands		Spain		United Kingdom	
	Invest.	Operat.	Invest.	Operat	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.
Product Quality														
Gasoline	-	-	-	-	2.79	1.48	-	-	-	-	-	-	-	-
Gas Oil	-	0.64	-	0.68	-	0.51	-	-	-	0.67	-	-	-	-
Residual Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Product Quality	-	0.64	-	0.68	2.79	1.99	-	-	-	0.67	-	-	-	-
Air Quality														
SO_2 Related	-	-	-	-	0.97	0.11	-	-	-	-	-	-	-	-
NO_x Related	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Air Quality	-	-	-	-	0.97	0.11	-	-	-	-	-	-	-	-
Liquid Effluent	0.71	0.08	0.71	0.08	0.68	0.06	0.68	0.06	0.68	0.06	0.54	0.06	0.42	0.06
Total Liquid Effluent	0.71	0.08	0.71	0.08	0.68	0.06	0.68	0.06	0.68	0.06	0.54	0.06	0.42	0.06
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General (2)	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08
Total Other	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08
Overall Total	0.81	0.80	0.81	0.84	4.54	2.24	0.78	0.14	0.78	0.81	0.64	0.14	0.52	0.14

Notes:

(1) Investment costs in ECUs per metric ton of total annual refinery production, operating costs in ECUs per metric ton of refinery production. (Operating costs include cash costs only).

(2) Environmental noise, site clean up etc.

were made up of compliance requirements with respect to gasoline production, gas oil product quality, air quality and effluent water quality.

a) Gasoline Product

Germany was the only country to incur costs as a result of gasoline quality requirements. This was as a direct result of their legislative measures limiting the amount of lead which can be blended into premium and regular gasoline to 0.15 g/l. Investment costs were required for upgrading of the reforming units to allow operation at higher severities in order to meet the increased gasoline pool octane requirements. Associated operating costs resulted largely from the need to process additional crude oil in order to meet the octane specifications, while maintaining the same product slate.

b) Gas Oil Product

Belgium, France, Germany and the Netherlands were all subject to operating costs as a result of their need to meet a gas oil sulphur specification of 0.3 wt percent. No capital investment was required, as adequate existing gas oil hydrotreating capacity was available.

c) Air Quality (SO_2 Related)

Germany was the only country subject to compliance costs associated with the sulphur content of atmospheric emissions. These costs resulted from additional measures to meet the efficiency requirements for sulphur recovery units (greater than 98 percent). It was assumed that "Sulfreen Units" were installed to meet this specification.

d) Liquid Effluent

All the member states considered were identified as subject to capital expenditure and associated operating costs resulting from effluent water treatment requirements. These were in part from good practice measures as well as specific legislative requirements.

2. 1993 EEC Case

Compliance costs resulting from EEC Directives for the reference year of 1993 were identified for measures relating to gasoline production and gas oil product quality.

A summary of the relevant investment and operating costs is given in Table II.C.2. Assumptions regarding 1993 gas oil quality were provided by the Commission.

a) Gasoline Product

EEC Directive 85/210/EEC requires that a single "Euro-grade" unleaded gasoline (95 RON, 85 MON) should be marketed in all member states by 1.10.89 or sooner. There is however, no single EEC standard for leaded gasoline. National standards vary in octane specification, lead level and other respects. Also the changeover to unleaded gasoline will be faster in some countries than others.

Minimum octane pool requirements (RON clear) for all the base cases in 1985 and Chem Systems best estimates for 1993 are summarised in Table II.C.3.

TABLE II.C.3

GASOLINE POOL REQUIREMENTS

(RON, Clear)

Country	1985	1993	ΔRON
Belgium	92.6	95.4	2.8
France	92.1	93.7	1.6
Germany	92.4 (1)	94.3	1.9
Italy	92.9	93.7	0.8
Netherlands	92.1 (2)	95.3	3.2
Spain	88.0	92.2	4.2
United Kingdom	92.2	95.3	3.1

Notes:

(1) The National case is quoted, EEC requirements are less stringent and would have required a gasoline pool of 89.7 RON (Clear).

(2) Base case assumes a proportion of "low lead" premium gasoline production for export.

TABLE II.C.2

ENVIRONMENTAL COMPLIANCE COSTS FOR TYPICAL REFINERY (EXCLUDING CAPITAL CHARGES)

1993 : EEC CASE

(ECUs per metric ton (1))

Environmental Constraint	Belgium		France		Germany		Italy		Netherlands		Spain		United Kingdom	
	Invest.	Operat.	Invest.	Operat	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.
Product Quality														
Gasoline	10.53	2.98	4.23	1.37	9.68	2.94	2.66	0.76	10.38	2.85	2.81	1.81	12.37	3.32
Gas Oil	-	0.64	-	0.68	-	0.51	0.82	0.51	-	0.67	1.00	0.45	-	0.23
Residual Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Product Quality	10.53	3.62	4.23	2.05	9.68	3.45	3.48	1.27	10.38	3.52	3.81	2.26	12.37	3.55
Air Quality														
SO_2 Related	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NO_x Related	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Air Quality	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid Effluent	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liquid Effluent	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Overall Total	10.53	3.62	4.23	2.05	9.68	3.45	3.48	1.27	10.38	3.52	3.81	2.26	12.37	3.55

Note:

(1) Investment costs in ECUs per metric ton of total annual refinery production, operating costs in ECUs per metric ton of refinery production. (Operating costs include cash costs only).

It can be seen from Table II.C.2 that Belgium, Germany, Netherlands and the United Kingdom are the countries subject to the highest capital investment costs. This directly results from their high gasoline pool octane requirements for 1993 and large Δ RON requirements relative to 1985. The investment costs calculated for France, Italy and Spain are lower due to the assumption made that they will all retain a level of 0.4g Pb/l in the their leaded gasoline grades in 1993, as opposed to the the 0.15g Pb/l, assumed for Belgium, Germany, Netherlands and the United Kingdom.

In order to assess the compliance cost on a consistent basis, the techniques for increasing the gasoline pool octane were confined to three basic technologies and the application was approached sequentially as follows:

- Firstly, the octane level from reforming was increased to the maximum economically practical. This was assumed to be achieved by operating existing units at higher severities and installing new CCR units as appropriate.
- Secondly, when the limits of reforming were reached an isomerisation unit capable of upgrading light virgin naphtha was assumed to be installed.
- Finally, if the octane specifications were still not reached then it was assumed that the required amount of FCC naphtha was catalytically reformed.

The associated operating costs with the above were seen to follow a similar trend to the capital investment requirements.

b) Gas Oil Product

For all the cases it was assumed that by 1993 an EEC Directive would be in place limiting the maximum allowable sulphur content in the gas oil to 0.3 wt percent. In order to meet these requirements only Italy and Spain will be required to install additional gas oil hydrotreating facilities (and hence incur investment costs). This is due largely to the fact that they process the highest average sulphur content crude oils of 1.25 and 1.37 wt percent respectively. All the member states were seen to incur operating costs in order to meet the assumed specifications.

3. 1993 EEC and National Case

Investment and operating costs for compliance with both national and EEC legislative measures for 1993 are presented on Table II.C.4. In addition to the EEC legislative costs already discussed, compliance costs were identified for meeting the national requirements related to gas oil product quality, residual fuel oil product quality, air quality, effluent water quality as well as higher electricity prices associated with increased generating costs. As can be seen, Germany and the Netherlands are subject to the highest costs for this reference year although, as discussed below, care should be taken when analysing the cost data presented. An element of the costs identified result from the terms of reference defined for the study and may not be incurred in full in actual operation.

a) Gas Oil Product

It was assumed that by 1993 Belgium, France, Germany and the Netherlands would all have adopted national legislative measures limiting the sulphur content in the gas oil product to a maximum of 0.2 wt percent. Table II.C.4 shows that all these countries are required to invest in new gas oil hydrotreating capacity and incur the associated investment and operating costs.

b) Residual Fuel Oil

Specific constraints resulting from national legislative measures relating to the sulphur content of residual fuel oil were identified for Belgium, Germany and the Netherlands.

For refineries which cannot meet the lower residual fuel oil sulphur specification for 1993, the following options exist:

- o Export or exchange the residual fuel oil outside the home market

TABLE II.C.4

ENVIRONMENTAL COMPLIANCE COSTS FOR TYPICAL REFINERY (EXCLUDING CAPITAL CHARGES)

1993 : EEC AND NATIONAL CASE

(ECUs per metric ton (1))

Environmental Constraint	Belgium		France		Germany		Italy		Netherlands		Spain		United Kingdom	
	Invest.	Operat.	Invest.	Operat	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.	Invest.	Operat.
Product Quality														
Gasoline	10.53	2.98	4.23	1.37	9.68	2.94	2.66	0.76	10.38	2.85	2.81	1.81	12.37	3.32
Gas Oil	2.37	0.97	2.88	1.02	0.76	0.93	0.82	0.51	0.98	1.00	1.00	0.45	-	0.23
Residual Fuel Oil	1.88(2)	0.56(2)	-	-	12.97(2)	3.88(2)	-	-	17.53(2)	5.27(2)	-	-	-	-
Total Product Quality	14.78	4.51	7.11	2.39	23.41	7.75	3.48	1.27	28.89	9.12	3.81	2.26	12.37	3.55
Air Quality														
SO_2 Related	-	-	-	-	7.14(3)	0.97(3)	-	-	-	0.35	-	-	-	-
NO_x Related	-	-	-	-	3.33	1.10	-	-	-	-	-	-	-	-
Other (4)	-	-	-	-	2.05	(0.06)	-	-			-	-	-	-
Total Air Quality	-	-	-	-	12.52	2.01	-	-	-	0.35	-	-	-	-
Liquid Effluent	0.71	0.08	0.71	0.08	0.71	0.08	0.70	0.08	0.70	0.08	0.70	0.08	0.71	0.08
Total Liquid Effluent	0.71	0.08	0.71	0.08	0.71	0.08	0.70	0.08	0.70	0.08	0.70	0.08	0.71	0.08
Other														
Electricity Costs (5)	-	-	-	-	-	0.17	-	-	-	-	-	-	-	-
General (6)	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08
Total Other	0.10	0.08	0.10	0.08	0.10	0.25	0.10	0.08	0.10	0.08	0.10	0.08	0.10	0.08
Overall Total	15.59	4.67	7.92	2.55	36.74	10.09	4.28	1.43	29.69	9.63	4.61	2.42	13.18	3.71

Notes:

(1) Investment costs in ECUs per metric ton of total annual refinery production, operating costs in ECUs per metric ton of refinery production. (Operating costs include cash costs only).

(2) Assuming desulphurisation of residual fuel oil.

(3) Assuming all gas firing for refinery fuel.

(4) Continuous stack monitoring, gasoline vapour recovery units and general hydrocarbon emission requirements.

(5) Increased electricity price due to electricity industry environmental compliance costs.

(6) Environmental noise, site clean up etc.

- Switch to lower sulphur crude oil (subject to availability)
- Desulphurise the residual fuel oil (subject to technological limitations)
- Leave the market and build residue upgrading facilities such as cokers

In practice, a refinery will always prefer the lowest cost solution-ie the first two options listed above. To date these have been adequate to meet the demands for low sulphur fuel oil in Western Europe. It is probable that they will also be able to meet the known specifications for 1993. However, these options will only be applicable for as long as there is a substantial market for high sulphur fuel oil within a reasonable distance. If all the member states adopted a low sulphur (one percent S) fuel oil specification, it is highly unlikely that the demand could be met without resorting to other, more costly, measures.

The fourth option, residue conversion processing, has to date been largely applied to balance changes in fuel oil demand, rather than to solve a fuel oil quality problem. It does however also provide a means of disposing of unsaleable high sulphur residues.

Residual fuel oil desulphurisation, the third option above, is technically proven, but uneconomic under current market conditions. Nevertheless this option has been selected for the 1993 base case evaluations, since it is in line with the terms of reference and provides an estimate of the maximum cost of environmental compliance. For comparison purposes alternative cases based on product export have also been evaluated for Germany and the Netherlands and are shown in Tables II.C.5 and II.C.6. These represent the minimum possible costs of compliance with the 1993 regulations.

Further discussion on this complex issue is provided in Section V of the study.

TABLE II.C.5

ENVIRONMENTAL COMPLIANCE COSTS FOR TYPICAL GERMAN REFINERY (EXCLUDING CAPITAL CHARGES)

1993 : EEC AND NATIONAL CASE

(ECUs per metric ton (1))

Environmental	Base Case (2)		Alternative One (3)		Alternative Two (4)	
Constraint	Investment	Operating	Investment	Operating	Investment	Operating
Product Quality						
Gasoline	9.68	2.94	9.68	2.94	9.68	2.94
Gas oil	0.76	0.93	0.76	0.93	0.76	0.93
Residual Fuel Oil	12.97	3.88	-	2.00(3)	12.97	3.88
Total Product Quality	23.41	7.75	10.44	5.87	23.41	7.75
Air Quality						
SO_2 Related	7.14	0.97	7.14	0.97	18.95(4)	2.75(4)
NO_x Related	3.33	1.10	3.33	1.10	3.33	1.10
Other(5)	2.05	(0.06)	2.05	(0.06)	2.05	(0.06)
Total Air Quality	12.52	2.01	12.52	2.01	24.33	3.79
Liquid Effluent	0.71	0.08	0.71	0.08	0.71	0.08
Total Liquid Effluent	0.71	0.08	0.71	0.08	0.71	0.08
Other						
Electricity Cost (6)	-	0.17	-	0.17	-	0.17
General (7)	0.10	0.08	0.10	0.08	0.10	0.08
Total Other	0.10	0.25	0.10	0.25	0.10	0.25
Overall Total	36.74	10.09	23.77	8.21	48.55	11.87

Notes:

(1) Investment costs in ECUs per metric ton of total annual refinery production, operating costs in ECUs per metric ton of refinery production. (Operating costs include cash costs only).
(2) Assuming desulphurisation of residual fuel oil and all gas firing for refinery fuel.
(3) Assuming export of residual fuel oil outside of the home market.
(4) Assuming flue gas desulphurisation applied.
(5) Continuous stack monitoring, gasoline vapour recovery units and general hydrocarbon emission requirements.
(6) Increased electricity price due to higher generation costs.
(7) Environmental noise, site clean up etc.

TABLE II.C.6

ENVIRONMENTAL COMPLIANCE COSTS FOR TYPICAL NETHERLANDS REFINERY
(EXCLUDING CAPITAL CHARGES)
1993 : EEC AND NATIONAL CASE

(ECUs per metric ton (1))

Environmental Constraint	Base Case (2)		Alternative Evaluation 1	
	Investment	Operating	Investment	Operating
Product Quality				
Gasoline	10.38	2.85	10.38	2.85
Gas oil	0.98	1.00	0.98	1.00
Residual Fuel Oil	17.53	5.27	-	2.14(3)
Total Product Quality	28.89	9.12	11.36	5.99
Air Quality				
SO_2 Related	-	0.35	-	0.35
NO_x Related	-	-	-	-
Other	-	-	-	-
Total Air Quality	-	0.35	-	0.35
Liquid Effluent	0.70	0.08	0.70	0.08
Total Liquid Effluent	0.70	0.08	0.70	0.08
Other				
General (4)	0.10	0.08	0.10	0.08
Total Other	0.10	0.08	0.10	0.08
Overall Total	29.69	9.63	12.16	6.50

Notes:

(1) Investment costs in ECUs per metric ton of total annual refinery production, operating costs in ECUs per metric ton of refinery production. (Operating costs include cash costs only).
(2) Assuming desulphurisation of residual fuel oil.
(3) Assuming export of residual fuel oil outside of home market.
(4) Environmental noise, site clean up etc.

c) General Air Quality

Air quality control requirements can be identified with respect to four major areas, largely applicable in Germany;

- SO_2 related
- NO_x related
- General Hydrocarbon Emissions
- Continuous Stack Monitoring

o SO_2 Related

SO_2 emission requirement constraints were identified for two countries for the 1993 reference year, Germany and the Netherlands.

For refineries which cannot meet the required SO_2 emission regulations the following options exist;

- Blend some of the high sulphur components of the refinery fuel into the residual fuel oil, exchanging them for low sulphur components in order to meet the required specifications.

- Burn LPG in place of liquid fuel, increasing the residual fuel oil product.

- Import natural gas (subject to availability) and convert over to gas firing, increasing the residual fuel oil product.

- Apply flue gas or other desulphurisation techniques.

For all the cases except Germany (where it was not applicable) the first option was assumed and, where relevant, compliance costs assessed as a result of their impact on the residual fuel oil product quality. For Germany the last two options were evaluated and the results are presented in Table II.C.5.

Sulphur Recovery Unit efficiency requirements are also specified by the national legislative measures applicable in Germany.

o NO_x Related

Germany is the only country within the group studied which applies quantitative NO_x emission limits on refinery units. Combustion sources are regulated by GFAVO and FCC units are included in the most recent version of the TA Luft. Interpretation of the regulations is complex and certain simplifying assumptions were made when carrying out the evaluation of compliance costs resulting from meeting these regulations. It was assumed that a combination of the application of low NO_x burners and catalytic $DeNO_x$ flue gas treatment units would be required.

o Hydrocarbon Emissions

The only regulations which refer directly to hydrocarbon emission limits are the national regulations in Germany. The TA Luft (of 27.2.86) requires the application of a number of technical measures specified as "good practice requirements" designed to reduce hydrocarbon emission. The TA Luft also requires the installation of vapour recovery units at loading installations in refineries and depots.

o Continuous Monitoring

German legislation requires that continuous monitoring is carried for CO, particulates, NO_x, SO_2 and O_2 on each stack.

d) Liquid Effluent

All of the member states considered were subject to capital expenditure and operating costs associated with effluent water treatment requirements.

e) Electricity Costs

Environmental control measures applied to the electricity generating industry in Germany have increased the cost of electricity. An estimate was made of the resulting incremental increase in the price of purchased electric power.

D. NATIONAL COMPLIANCE COSTS

Table II.D.1 gives the estimated national environmental compliance costs relative to the base case (as defined in the terms of reference) for each of the member states considered. These estimates have been derived by multiplying the costs per metric ton estimated for the typical refineries by the actual production rate (1985) for each of the countries. Allowances for capital charges have not been included.

Again these data should be treated with caution in the light of the selected control measures assumed for the evaluations.

TABLE II.D.1

NATIONAL ENVIRONMENTAL COMPLIANCE COSTS FOR THE MEMBER STATES (EXCLUDING CAPITAL CHARGES)

Country	1985		1993			
	EEC + National Case		EEC Case		EEC + National Case	
	Investment (Million ECUs)	Operating Cost (Million ECUs per year)	Investment (Million ECUs)	Operating Cost (Million ECUs per year)	Investment (Million ECUs)	Operating Cost (Million ECUs per year)
Belgium	15.3	15.1	199.1	68.4	294.7(1)	88.3(1)
France	58.6	60.8	306.2	148.4	573.3	184.6
Germany	387.7	191.3	826.7	294.6	3 137.8(2)	861.7(2)
Italy	55.4	9.9	247.3	90.2	304.1	101.6
Netherlands	42.3	43.9	563.1	190.9	1 610.5(1)	522.4(1)
Spain	27.1	5.9	161.1	95.5	194.9	102.3
United Kingdom	39.5	10.6	940.1	269.8	1 001.7	282.0
Total	625.9	337.5	3 243.6	1 157.8	7 117.0	2 142.9

Notes:

(1) Assuming desulphurisation of residual fuel oil.

(2) Assuming desulphurisation of residual fuel oil and all gas firing for refinery fuel.

E. ENVIRONMENTAL COMPLIANCE COSTS (INCLUDING CAPITAL CHARGES)

In any evaluation of this kind it is always difficult to select a single definition of costs to cover capital charges (depreciation, return on investment and interest charges), for this reason allowances for these have not been included in the cost summaries outlined so far.

On consultation with the EEC Commission it was agreed to present an alternative cost summary for the cases considered, with annual capital charges of 25 percent of the investment costs added to the operating costs. These evaluations are given in Tables II.E.1 to II.E.3.

TABLE II.E.1

ENVIRONMENTAL COMPLIANCE COSTS FOR TYPICAL REFINERY INCLUDING CAPITAL CHARGES (1)

1985 : EEC AND NATIONAL CASE

(ECUs per metric ton (2))

Environmental Constraint	Belgium	France	Germany	Italy	Netherlands	Spain	United Kingdom
Product Quality							
Gasoline	-	-	2.18	-	-	-	-
Gas oil	0.64	0.68	0.51	-	0.67	-	-
Residual Fuel Oil	-	-	-	-	-	-	-
Total Product Quality	0.64	0.68	2.69	-	0.67	-	-
Air Quality							
SO_2 Related	-	-	0.35	-	-	-	-
NO_x Related	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total Air Quality	-	-	0.35	-	-	-	-
Liquid Effluent	0.26	0.26	0.23	0.23	0.23	0.20	0.17
Total Liquid Effluent	0.26	0.26	0.23	0.23	0.23	0.20	0.17
Other							
General (3)	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Total Other	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Overall Total	1.01	1.05	3.38	0.34	1.01	0.31	0.28

Notes:

(1) Compliance costs include cash operating costs plus an annual capital charge assumed to be 25 percent of investment costs.
(2) ECUs per metric ton of refinery production.
(3) Environmental noise, site clean up etc.

TABLE II.E.2

ENVIRONMENTAL COMPLIANCE COSTS FOR TYPICAL REFINERY INCLUDING CAPITAL CHARGES (1)

1993 : EEC CASE

(ECUs per metric ton (2))

Environmental Constraint	Belgium	France	Germany	Italy	Netherlands	Spain	United Kingdom
Product Quality							
Gasoline	5.61	2.43	5.36	1.43	5.45	2.51	6.41
Gas oil	0.64	0.68	0.51	0.72	0.67	0.70	0.23
Residual Fuel Oil	-	-	-	-	-	-	-
Total Product Quality	6.25	3.11	5.87	2.15	6.12	3.21	6.64
Air Quality							
SO_2 Related	-	-	-	-	-	-	-
NO_x Related	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total Air Quality	-	-	-	-	-	-	-
Liquid Effluent	-	-	-	-	-	-	-
Total Liquid Effluent	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total Other	-	-	-	-	-	-	-
Overall Total	6.25	3.11	5.87	2.15	6.12	3.21	6.64

Notes:

(1) Compliance costs include cash operating costs plus an annual capital charge assumed to be 25 percent of investment costs.
(2) ECUs per metric ton of refinery production.

TABLE II.E.3

ENVIRONMENTAL COMPLIANCE COSTS FOR TYPICAL REFINERY
INCLUDING CAPITAL CHARGES (1)
1993 : EEC AND NATIONAL CASE

(ECUs per metric ton (2))

Environmental Constraint	Belgium	France	Germany	Italy	Netherlands	Spain	United Kingdom
Product Quality							
Gasoline	5.61	2.43	5.36	1.43	5.45	2.51	6.41
Gas oil	1.56	1.74	1.12	0.72	1.25	0.70	0.23
Residual Fuel Oil	1.03(3)	-	7.12(3)	-	9.65(3)	-	-
Total Product Quality	8.20	4.17	13.60	2.15	16.35	3.21	6.64
Air Quality							
SO_2 Related	-	-	2.76(4)	-	0.35	-	-
NO_x Related	-	-	1.93	-	-	-	-
Other (5)	-	-	0.45	-	-	-	-
Total Air Quality	-	-	5.14	-	0.35	-	-
Liquid Effluent	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Total Liquid Effluent	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Other							
Electricity Costs (6)	-	-	0.17	-	-	-	-
General (7)	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Total Other	0.11	0.11	0.28	0.11	0.11	0.11	0.11
Overall Total	8.57	4.54	19.28	2.52	17.07	3.58	7.01

Notes:

(1) Compliance costs include cash operating costs plus an annual capital charge assumed to be 25 percent of investment costs.
(2) ECUs per metric ton of refinery production.
(3) Assuming desulphurisation of residual fuel oil.
(4) Assuming all gas firing for refinery fuel.
(5) Continuous stack monitoring, gasoline vapour recovery units and general hydrocarbon emission requirements.
(6) Increased electricity price due to electricity industry compliance costs.
(7) Environmental noise, site clean up etc.

SECTION III

III REVIEW AND ASSESSMENT OF ENVIRONMENTAL LEGISLATION

A. INTRODUCTION

The environmental regulations which may affect the costs of petroleum refining can be classified under three categories:

- Regulations applicable to refinery sites (air, water and noise pollution).
- Official petroleum product quality specifications (sulphur, lead, benzene, etc, content).
- Regulations which may influence specifications imposed by purchasers of petroleum products.

The legislation and regulations which apply in each category are reviewed and assessed in the following sections.

The size of the combustion source is one parameter which is frequently applied in drawing up environmental regulations. Different heat release units are used by different countries in specifying combustion source sizes. To facilitate inter-country comparison and to assist in visualising the physical size of the different combustion source categories, Table III.A.1 provides a set of conversion factors for the different units in common use.

TABLE III.A.1

APPROXIMATE CONVERSION FACTORS FOR HEAT RELEASE RATES

(LHS X factor = top)

	MWth	GJ/hr	Gcal/hr	Therm/hr	10^6Btu/hr	Steam Raised (6) (t/hr)	Annual Fuel Use for 8 000 hr	Annual Fuel Use for 3 500 hr
							(tonnes heavy fuel oil) (7)	
MWth (1)	1	3.600	0.860	34.1	3.41	1.2	710	310
GJ/hr (2)	0.278	1	0.239	9.48	0.948	0.33	200	85
Gcal/hr (3)	1.163	4.186	1	39.7	3.97	1.4	825	360
Therm/hr (4)	0.0293	0.105	0.0252	1	0.10	0.035	21	9
10^6Btu/h (5)	0.293	1.05	0.252	10	1	0.35	210	90

Notes

(1) Megawatt thermal
(2) Gigajoule (10^9 joule) per hour
(3) Gigacalorie (10^9 calorie) per hour
(4) British therm (100 000) Btu)
(5) 10^6 British thermal units per hour
(6) Corresponding steam raised in typical boiler plant
(7) Typical values-net calorific value basis

B. AIR QUALITY REGULATIONS APPLICABLE TO REFINERY SITES

1. Background

The major air pollution problem at refinery sites is undoubtedly sulphur emissions, primarily in the form of sulphur dioxide (SO_2). Other pollutants include oxides of nitrogen, hydrocarbons, particulates and refinery odours.

The approach to control varies between pollutants and countries, but in general the regulations will fit into one of the categories in the following framework.

- o Air quality standards
- o Emission limits for specified pollutants
- o Fuel quality specifications for fuel used on the site
- o Mandatory technical control measures (best practicable means)

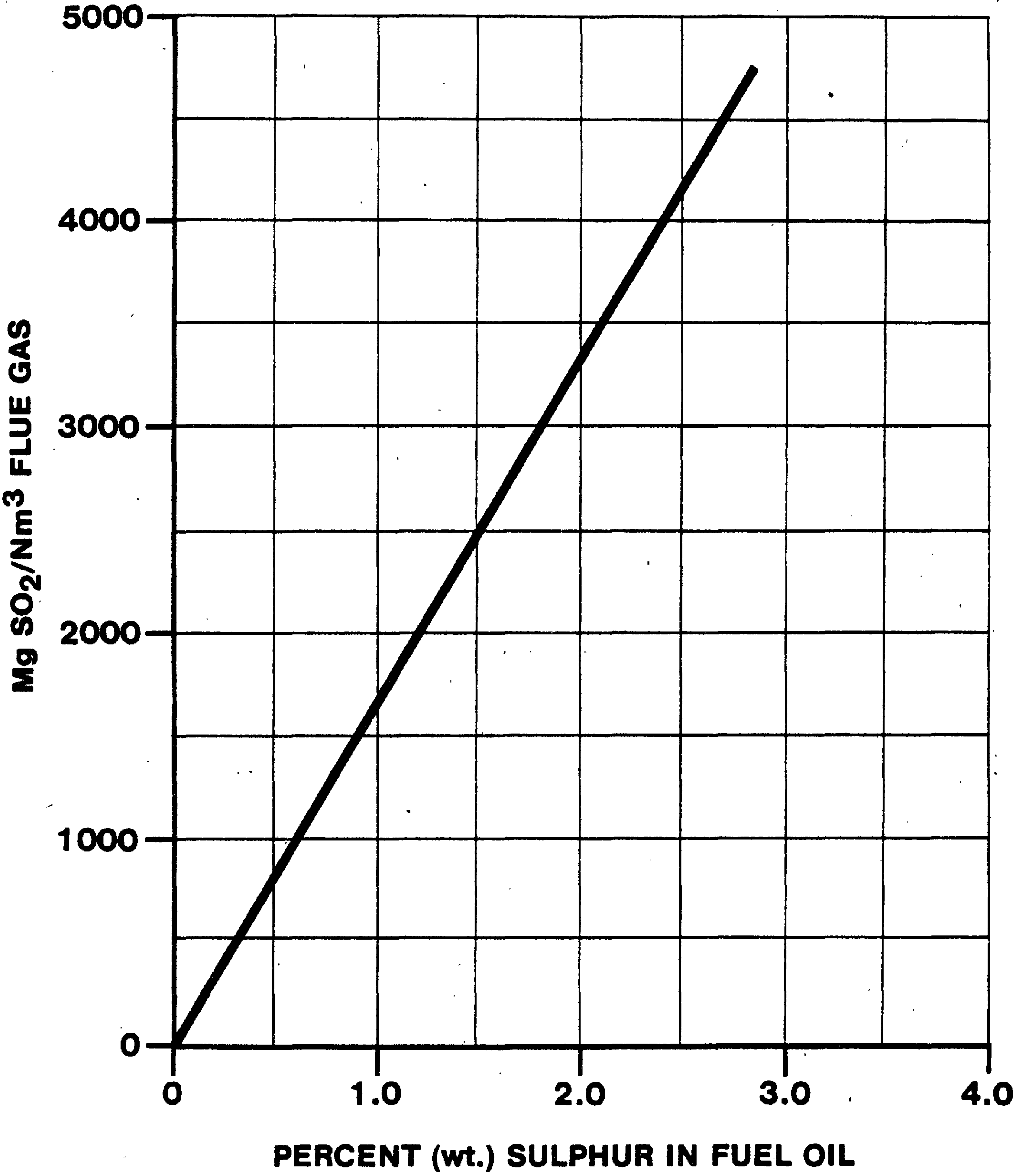
There are more or less direct relationships between the different types of regulations. For example, the emission limit for sulphur and the maximum fuel sulphur content are directly and quantitatively related. Figure III.B.1 shows this relationship. Emissions and air quality in the locality are also obviously related, but the relationships are extremely complex and not completely understood. Specified technical control measures also relate fairly directly to emission levels, assuming that the equipment is properly operated and maintained.

From the above discussion, it follows that there may well be overlaps and conflicts between the various regulations applying to refinery sites. In such cases, it is essential to determine which of the applicable regulations will actually control the refinery operation.

FIGURE III.B.1.

RELATIONSHIP BETWEEN FUEL OIL SULPHUR CONTENT and SO_2 EMISSION

(BASIS: 3 percent oxygen in flue gas)



D863179

2. Sulphur Compounds

a) EEC Directives

The Commission currently has two Directives adopted and one under consideration which have a bearing on sulphur dioxide emissions from refineries. These are:

80/779/EEC	Directive on air quality limit values and guide values for sulphur dioxide and suspended particulates. (OJ L229, 1980.08.30)
84/360/EEC	Directive on the combating of air pollution from industrial plant. (OJ L188, 1984.07.16)
COM(83)704	Proposal for a Directive on the limitation of emissions of pollutants into the air from large combustion plants. (OJ C49, 1984.02.21)

The two Directives in place do not directly affect refinery operations, since they do not dictate quantitative emission limits or other direct operating constraints. The air quality standards Directive could theoretically impinge on the operation of a refinery located in a heavily polluted area, but only through the actions of the local authorities concerned. As far as we are aware, this Directive has not constrained the operation of any European refinery. The other Directive is a framework Directive to provide the basis for setting future emission limits and control procedures.

The proposed large combustion source Directive, which is more or less based on the German legislation, would have a significant effect on refinery operations if it were adopted in its present form.

b) National Legislation

Table III.B.1 below indicates the type of quantifiable restrictions on sulphur emissions which apply to refinery sites in each of the seven member states considered in this study. The detailed regulations are summarised in Table III.B.8 appended to this section. An outline of the regimes applying in each of the seven member states follows.

TABLE III.B.1.

RESTRICTIONS ON SULPHUR EMISSIONS FROM REFINERY SITES

Country	Quantitative Restrictions			Remarks
	Fuel	Emitted Sulphur		
	Sulphur	mg/m3 limit	wt limit	
Belgium	X	X		Lower limits apply in "special protection areas".
France			X	Local regulations, but broadly similar framework across the country.
Germany	X	X		Also specified limits on Claus plant emissions.
Italy	X			No national regulations. Fuel sulphur subject to regional restrictions.
Netherlands		X		National regulations effective 1.6.86
Spain		X	X	
UK				No national regulations, but individual sites must satisfy HM Industrial Air Pollution Inspectorate

Belgium

Emissions to atmosphere are controlled by national regulations and emission standards implemented by Royal decrees. The items relevant to refinery sites include:

- The creation of special protection zones. (All Belgium refineries are sited within these zones).

- Regulations concerning air pollution from industrial furnaces, which provide for the following direct and indirect procedures:

  - standards for SO_2 and particulate emissions
  - maximum sulphur content of liquid fuels. This may be waived if the emission limits are met by flue gas desulphurisation
  - regulation of stack height (by calculation formula)
  - use of low sulphur fuel in periods of severe atmospheric pollution
  - obligation to maintain installations in good working condition.

The sulphur limits which apply are set out in Table III.B.2 below. In fact the regulations have not yet been fully applied, as the table shows. We expect the regulations to be fully in force by 1993.

TABLE III.B.2

SULPHUR CONTROL REGULATIONS AT BELGIAN REFINERY SITES

	Official Regulations	Currently Allowed
Fuel Sulphur (wt percent) (1)	2.2	3.0
SO_2 Emission (mg/m^3)	3 700	5 000 (approx.)

Notes:

(1) For refineries, the maximum fuel sulphur limit applies to the average fuel sulphur content of the total refinery fuel mix of gaseous and liquid fuels.

France

Control of refinery emission is by a permit system, administered by local government authorities. Each refinery has a SO_2 emission quota (metric tons per day maximum). The quotas take account of the refinery size and location, but the framework is broadly similar across the country. The quotas are independent of actual operating rates, hence easier to meet at reduced capacity operation.

The emission quotas for most refineries appear to lie in the range of 6-10 metric tons per day SO_2 for each million metric tons per year of primary distillation capacity. To quantify the effect on refinery operation, an average emission quota of 8 metric tons per day SO_2 per million metric tons per year distillation capacity has been taken as the typical industry regulation.

Germany

Refinery combustion sources are covered by the 13th ordinance of the Federal Immission Control Act (GFAVO) of 23.6.1983, which applies to large combustion sources. In addition, all combustion sources (unless gas fired) must comply with the Technical Requirements of the Administrative Guidelines for Air Quality (TA Luft) of 27.2.86. TA Luft requirements also apply to Claus unit operation (sulphur recovery units) and to various other refinery units, as detailed in later sections. Finally, the State Governments have powers to impose additional regulations in heavily polluted areas.

The GFAVO legislation is extremely complex, drawing distinctions between old and new plant, type of fuel and size of combustion source. Sulphur emission regulations for liquid fuel fired furnaces (the relevant regulations for refineries) are summarised in Table III.B.3. Their application and interpretation for refinery sites is discussed below.

TABLE III.B.3

SULPHUR CONTROL REGULATIONS AT GERMAN REFINERY SITES

Boilers and Furnaces (Existing Plant, Liquid Fuels) (1)

Furnace Size (2) (MWth)	Remaining Life (hours)	SO_2 Emission Limits (3) (mg/m^3)	Equivalent Fuel Sulphur (percent)
> 300	< 10 000	As originally licensed	
	10-30 000	2 500	1.5
	> 30 000	400 and 85 percent S removal (4)	
50-300	< 10 000	As originally licensed	
	> 10 000	2 500	1.5

Notes:

(1) Under GFAVO regulations.

(2) Rated thermal input.

(3) Valid until 1.4.93. After that date, as for new plant.

(4) By flue gas desulphurisation.

Boilers and Furnaces (New Plant, Liquid Fuels) (1)

Furnace Size (2) (MWth)	SO_2 Emission Limits (mg/m^3)	Equivalent Fuel Sulphur (percent)
> 300	400 and 85 percent S removal or 0.3 percent S gas oil firing	
100-300	1 700 and 60 percent S removal or 0.3 percent S gas oil firing	
50-100	1 700	1.0 (2)

Notes:

(1) Applies to all plants from 1.4.93.

(2) Also applies to smaller furnaces under TA Luft requirements.

TABLE III.B.3 (Contd)

Other Process Units (TA Luft Requirements)

Process Unit	Size (t/d S)	Sulphur Emission Limit
Claus Plant	< 20	97 percent recovery
Claus Plant	20-50	98 percent recovery
Claus Plant	> 50	98 percent current recovery 99.5 percent future recovery (1)
FCC Unit	All	1 700 mg/m^3 max SO_2 in regenerator flue gas (2)

Notes:

(1) from 1996.

(2) Implementation schedule uncertain.

o Combustion Source Size

All German refiners have reduced their total liquid fuel or mixed fuel (see below) firing to < 300 MWth, by installation of sufficent dedicated gas firing. Hence the regulations for > 300 MWth sources are, in practice, not relevant.

The GFAVO does not distinguish between different types of combustion plant and in theory treats each stack as a separate combustion source. Not surprisingly, this has led to a number of problems in implementation, since basically similar refineries can be treated quite differently depending on whether flue gases are discharged through a common stack, or individual stacks for each process unit, or some in-between arrangement. Interpretation by different local government authorities (who have the responsibility for implementing the national legislation) varies. For the 1993 case, we have made the assumption that refineries will be treated as a 'single stack' source.

- Mixed Oil and Gas Firing

Special regulations (the "Major Fuel Concept") apply to refinery furnaces. The effect is to permit partial use of up to 3 wt percent sulphur residues in existing furnaces, if they provide less than 50 percent of total heat input. The extent to which they may be used is shown in Figure III.B.2.

- Future Regulations

The effect of the GFAVO regulations to be brought into effect in 1993 will be to require refiners to install flue gas desulphurisation equipment or to switch all refinery boilers and furnaces to gas firing. Given the ready availability of natural gas, the second option is the probable outcome.

Additional sulphur emission limits imposed on other refinery process units by the TA Luft regulations also are listed in Table III.B.3.

Italy

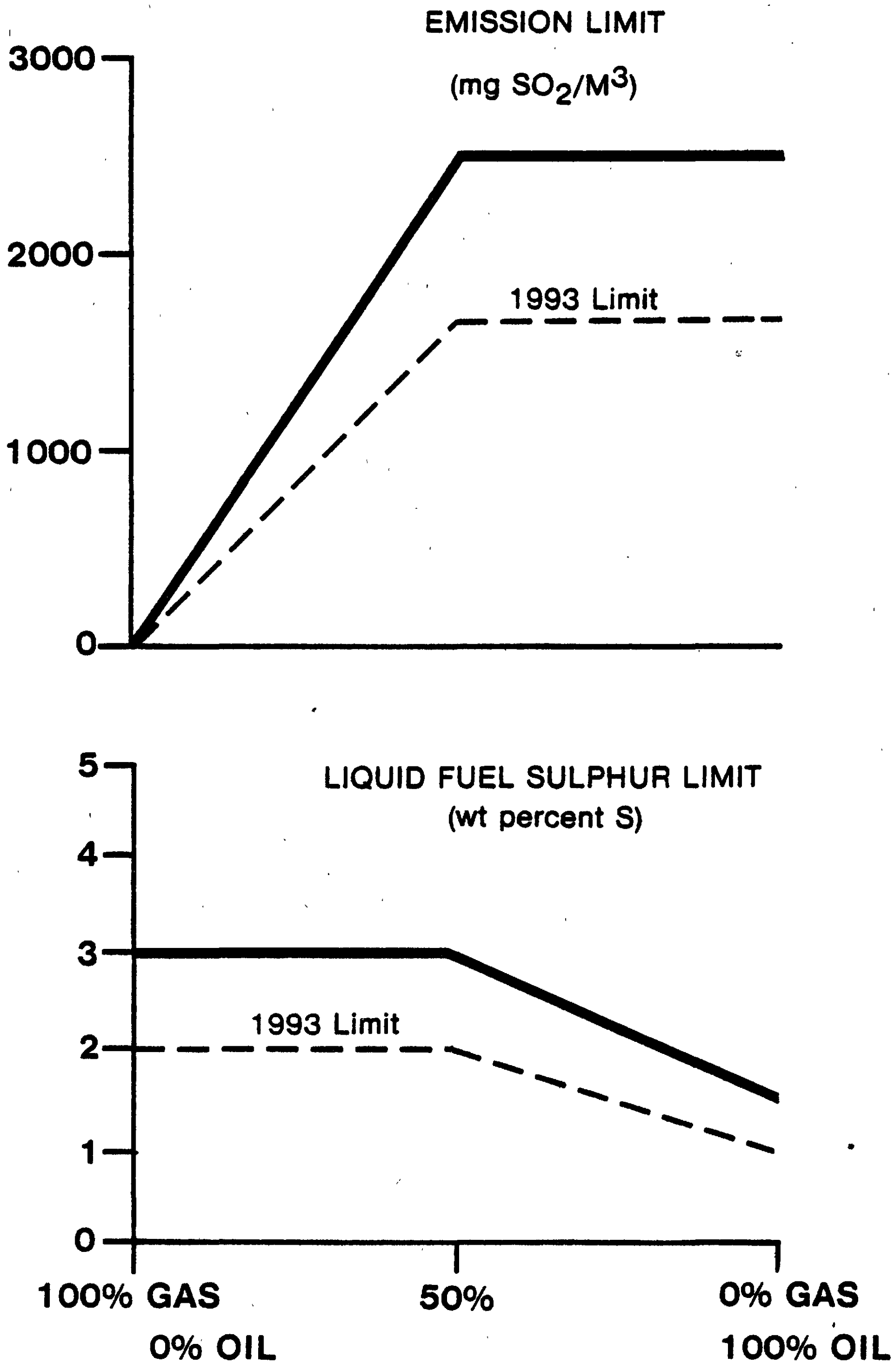
There are no national emission standards applied in Italy. Significant pollution sources require operating permits, issued by the regional authorities. These may set site specific emission limits, on the basis of achieving acceptable ground level air quality.

Netherlands

Current national legislation in the Netherlands limits the sulphur content of heavy fuel oil (and average refinery fuel) to 2.0 percent max. New national legislation, coming into effect in 1986, applies overall SO_2 emission limits to refinery flue gas. A single overall limit (ave mg/m^3) applies to all refinery sites. The means by which the limit is met is left to the refiner.

FIGURE III.B.2.

MIXED FUEL FIRING LIMITS IN REFINERY FURNACES
(GFAVO Regulations)



Local government authorities are also involved with environmental control. They have responsibility for issuing operating permits for industrial installations and can decide environmental control conditions to be applied.

Current and future sulphur emission limits applying to refineries are shown in Table III.B.4 below.

TABLE III.B.4

SUPLHUR CONTROL REGULATIONS AT NETHERLANDS REFINERY SITES

Date	SO_2 Emission Limits (mg/m^3)	Equivalent Fuel Sulphur (wt percent)
Current	3 400	2.0 (1)
From 1.1.86	2 500 (2)	1.5
From 1.1.91	2 000 (2)	1.2
From 1.1.96	1 500 (2)	0.9

Notes:
(1) Current regulation.
(2) Future regulations.

Spain

National legislation (Decree 233 of 6.2.75) specifies nationwide emission limits for a variety of sources, including oil refineries. In areas declared by the Government to be "Polluted Areas" the local authorities can propose more stringent regulations, either on a continuous basis or during periods of high pollution.

The national limits applying to refineries are summarised in Table III.B.5 below. A progessive reduction of emission limits was envisaged in the original legislation, but has not been put into practice.

TABLE III.B.5

SULPHUR CONTROL REGULATIONS AT SPANISH REFINERY SITES

Existing Installations	SO_2 Emission Limits	Equivalent Fuel Sulphur (wt percent)
Boilers and Furnaces	5 900 mg/m^3	3.5
Other	3 400 mg/m^3	2.0
Total site	7xC t/d (1)	
New Installations		
Boilers and Furnaces	5 000	3.0
Other	3 400	2.0
Total site	5xC t/d (1)	

Notes:
(1) Where C = crude distillation capacity in million metric tons per year.

United Kingdom

The United Kingdom has no national regulations for fuel sulphur or SO_2 emissions. Regulation of major industries (including refineries) is carried out by the Industrial Air Pollution Inspectorate. The Inspectors decide, in consultation with industry, on the control measures to be applied at each site, taking account of local conditions, economics and the current state of technology. In practice, the approach to SO_2 emission control is usually to employ tall stacks to ensure acceptable ground level air quality in the locality.

3. Nitrogen Oxides

Germany is the only country which has applied quantitative NO_x emission limits to refinery sites. Combustion sources are regulated by the GFAVO and FCC units are included in the most recent version of the TA Luft. The current and proposed future regulations are listed in Table III.B.6. The proposed future regulations are 'technology forcing' and would require catalytic denitrification, at least on the > 300 MWth plants. Also, it appears that the interpretation of these regulations will be to consider a refinery site as a single emission source, which would place most refiners in the >300 MWth group.

TABLE III.B.6

NITROGEN OXIDE CONTROL REGULATIONS OF REFINERY SITES
(maximum concentration in flue gas)

Country (1)	Liquid Fuel (2) (mg/m^3) (4)	Gas Fired (3) (mg/m^3)
Germany - Current Regulations (5)		
'Existing' Combustion Sources (6)	700	500
'New' Combustion Sources (7)	450	350
Germany - Proposed Regulations		
'Existing' Combustion Sources		
>300 MWth	150	100
100-300 MWth		350
50-300 MWth	450	
'New' Combustion Sources		
>300 MWth	150	100
100-300 MWth		200
50-300 MWth	300	
FCC Units	700	

Notes:

(1) No regulations in other countries studied.
(2) >50 MWth.
(3) >100 MWth.
(4) Measured as nitrogen dioxide.
(5) Also, best current technology to reduce NO_x emissions to be used.
(6) Licensed before 1.7.83.
(7) Licensed after 1.7.83.

The regulations which will apply in 1993 are still under discussion. However, a tightening of current emission limits appears probable. In order to assess the economic implications of more severe limits, the cases shown in Table III.B.9 have been assumed.

4. Hydrocarbon Emissions

The only regulations setting specific hydrocarbon emission limits are the German TA Luft (of 27.2.1986). The technical requirements applicable to petroleum refineries include a number of good practice requirements designed to minimise hydrocarbon emissions from storage tanks, pumps, compressors, flanges, valves, etc.

The TA Luft also requires the installation of vapour recovery units at loading installations in refineries (para 3.3.4.4.1) and depots (paras 3.1.8.6 and 3.3.9.2.1). The emissions from these vapour recovery units will be subject to the (already existing) emission limits for organic materials in waste gas streams. The applicable limit (para 3.1.7) is 150 mg/m^3 of vent gas.

From a technical standpoint, this limit is unrealistic (It corresponds to a recovery efficiency in the range of 99.95-99.99 percent) and is far more restrictive than standards applied in the USA and elsewhere. We anticipate that the regulations will eventually be modified to correspond with the technical capability of good modern technology (eg activated carbon adsorption).

5. Other Emissions

a) Particulates

Germany is the one country within the group studied which applies quantitative restrictions on particulate emissions from refinery and other liquid and gas fired combustion sources. The regulations on combustion sources are contained in GFAVO and on FCC units in the 1986 version of TA Luft. The limits are shown in Table III.B.7.

The effect of these regulations on refinery operation is not great, since the extensive use of the major fuel concept and mixed firing (gas + liquid) generally keeps emissions below the specified limits. The main impact of these regulations is the constraint placed on fuel oil blending (nickel content) by the heavy metal emission limit.

The technical implications of the new particulate emission limit for FCC units are not yet clear, but it appears unlikely that current dust removal equipment (cyclones) will be able to satisfy the new regulations.

TABLE III.B.7

PARTICULATE EMISSION CONTROL REGULATIONS AT REFINERY SITES

Germany

Existing Combustion Sources

Total Particulates	100 mg/m^3 at 50 000 m^3/h flue gas rate with linear decrease to 50 mg/m^3 at 100 000 m^3/h flue gas and greater
Heavy Metals (As, Pb, Cd, Cr, Co, Ni)	2 mg/m^3

New Combustion Sources

Total Particulates	50 mg/m^3
Heavy Metals	2 mg/m^3

FCC Units

Total Particulates	50 mg/m^3

b) Carbon Monoxide

Under the GFAVO, the following emission limits apply:

Liquid Fuelled Combustion Plant - 175 mg/m^3
Gas Fuelled Combustion Plant - 100 mg/m^3

These regulations are included here for the sake of completeness, but are not significant for the purposes of this study.

6. Monitoring Costs

Continious monitoring of emissions is required by the German legislation. The substances which must be continuously measured are SO_2, NO_x, CO, O_2 and particulates

7. Summary

The emission limits which must be met for refinery operations to comply with the known air quality regulations for SO_2 and NO_x emissions are summarised in Tables III.B.8 and III.B.9.

TABLE III.B.8

SUMMARY OF CONTROLLING SULPHUR DIOXIDE EMISSION LIMITS

Country	1985 Case		1993 Case (1)	
	Emission (SO_2)	Fuel Sulphur (wt percent)	Emission (SO_2)	Fuel Sulphur (wt percent)
Belgium	5 000mg/m^3	3.0	3 700mg/m^3	2.2
France (2)	8 x C t/d (3)		8 x C t/d (3)	
Germany				
Combustion Sources	2 500mg/m^3		1 700mg/m^3 and FGDS or all gas firing	
FCC Units	-		1 700mg/m^3	
Claus Plants	98 percent S recovery		98 percent S recovery	
Italy(4)		3.0		3.0
Netherlands		2.0	2 000mg/m^3	
Spain				
Boilers and Furnaces	5 900mg/m^3		5 900mg/m^3	
Other Units	3 400mg/m^3		3 400mg/m^3	
Total Site	7 x C t/d(3)		7 x C t/d(3)	
United Kingdom (5)		-		-

Notes:

(1) Basis Existing Legislation only.

(2) 'Typical' figure (Chem Systems estimate).

(3) C = Crude distillation capacity (million metric tons per year).

(4) Maximum fuel oil sulphur specification assumed to apply to average refinery fuel. May be relaxed to 4.0 percent by local authorities.

(5) No National Standards.

TABLE III.B.9

SUMMARY OF CONTROLLING NO_x EMISSION LIMITS

Country	1985 Case mg/m^3	1993 Case (1) mg/m^3	
		Liquid Fuel	Gaseous Fuel
Germany			
Combustion Sources			
Minimum Control Case	700	700	500
Maximum Control Case	700	150	100
Intermediate Control Case	700	450	350
FCC Units	-	700	

Note:

(1) Three cases were chosen to cover possible future regulations (see Table III.B.6).

C. PRODUCT QUALITY SPECIFICATIONS

1. Gasoline

The cost of producing gasoline of saleable quality has been increased by environmental control measures to:

- Phase out the use of lead compounds as octane improvers.
- Limit the benzene content.

In principle, the effect of both changes is to force the refiner to use other (and more expensive) means to achieve the required octane specifications. In practice, the impact of lead removal will be the major problem for refiners.

Agreement has been reached to adopt a single 'Euro-grade' unleaded gasoline (95 RON, 85 MON), to be marketed in all member states by 1.10.89 or sooner. (EEC Directive 85/210/EEC). This Directive also specifies a maximum benzene content of 5.0 volume percent for all gasolines sold in the Community from 1.10.89.

There is however, no single EEC standard for leaded gasoline. National standards vary in octane specification, lead level and other respects. Also, the changeover to unleaded gasoline will be faster in some countries than others. Hence, during the transition period both the specifications and the quantities sold of leaded gasoline will vary significantly between countries. Estimates of the gasoline pool in each country, for 1985 and 1993, are presented in Section IV (Table IV.B.11). This table also indicates the current and future gasoline specifications in each of the countries studied.

2. Gas Oil

The current legislation regulating the sulphur content of gas oil is EEC Directive 76/716/EEC. The Directive specifies two types of gas oil, viz

Type A - 0.3 wt percent sulphur max
Type B - 0.5 wt percent sulphur max

The authorities in the member states are effectively free to choose either type as a national or local standard.

The Commission has proposed a further reduction to 0.3 and 0.2 wt percent sulphur for type A and type B respectively (COM(85)377), but the Proposal was not adopted by the Council.

For the purposes of this study, the assumptions shown in Table III.C.1 have been agreed with the Commission for the analysis of the 1993 situation.

TABLE III.C.1

MAXIMUM SULPHUR CONTENT IN GAS OIL
(wt percent sulphur)

Country	1985	1993
Belgium	0.3	0.2
France	0.3	0.2
Germany	0.3	0.2
Italy	0.5	0.3
Netherlands	0.3	0.2
Spain	0.5	0.3
United Kingdom	0.5	0.3

3. Heavy Fuel Oil

a) Introduction

There are no EEC Council Directives regulating the quality of residual fuel oil. Most of the member states do have national and/or local regulations restricting the sulphur content of heavy fuel oil, either directly or indirectly through limits on the concentration of SO_2 in flue gas from combustion sources. Restrictions on the metal content of heavy fuel oil apply in Germany.

The regulations applying in each of the member states considered in this study are outlined below and the fuel specifications summarised in Table III.C.2 for 1985 and 1993. The 1993 specifications take account only of known legislation.

b) Belgium

Both emission limits and fuel oil sulphur contents are specified by national legislation in Belgium. The latter do not apply if the emission limit is achieved by flue gas desulphurisation, but this provision is of theoretical interest only at present. The sulphur limit in heavy fuel oil depends on the size, type and location of the consuming installation. To further complicate matters, a relaxation from the sulphur limits specified in the official regulations currently applies.

As Table III.C.2 shows, there is a wide range of specifications for heavy fuel oil sulphur content. Full enforcement of the existing regulations, expected to take place before 1993, will reduce the sulphur limits by 20-50 percent depending on the type of user. Calculations of an accurate weighted average sulphur specification for Belgium would require collection of a great deal of detailed market data (ie a breakdown of all fuel oil customers by sales volume and location). Collection of such data is neither practicable nor justified for the purposes of this study. The specification for a large user within the special protection zones is judged to be a reasonable proxy for the national average suphur specification, and these values (3.0 percent in 1985 and 2.2 percent in 1993) have been used as a basis for the compliance cost estimates developed in Section V of the study.

TABLE III.C.2

MAXIMUM SULPHUR CONTENT IN RESIDUAL FUEL OIL

(wt percent sulphur)

Country	Use/Location	Plant Capacity	1985 (1)	1993 (2)
Belgium	Power Stations		4.5 (3)	3.0
	Other (4)	> 1 Gcal/hr	3.5	2.8
	Other/Special Protection Areas (5)	< 1 Gcal/hr	1.0	0.5
		1-20 Gcal/hr	2.6	1.9
		> 20 Gcal/hr	3.0	2.2

Notes:

(1) Currently permitted.
(2) Official regulations.
(3) Special permits.
(4) Outside special protection areas.
(5) The five main population centres are Special Protection Areas.

Country	Grade	1985	1993
France	HFO No. 1 (15-110 cSt @ 50°C)	2.0	2.0
	HFO No. 2 (> 110 cSt @ 50°C)	4.0	4.0
	HFO No. 2 BTS (1)	2.0	2.0
	HFO No. 2 TBTS (2)	1.0	1.0

Notes:

(1) Low sulphur grade.
(2) Very low sulphur grade.

Country	Grade	1985	1993
Germany	Regular	1.8	1.0
	Low Sulphur	1.0	0.3 (1)
	Average (est)	1.65	1.0

Notes:

(1) Required if use of flue gas desulphurisation on sources > 50 MWth to be avoided.

TABLE III.C.2 (Contd)

Country	Grade	1985	1993
Italy	Regular Grade	4.0	4.0
	Restricted Zones	3.0 (1)	3.0
	Low Sulphur (2)	1.0	1.0

Notes:
(1) 4.0 percent in furnaces of 1 Gcal/hr or more, if local authority permits.
(2) For use when ground level ambient air limits exceeded.

Country	Grade	1985	1993
Netherlands		2.0	1.0 (1)

Note:
(1) From 1.6.86.

Country	Grade	1985	1993
Spain	HFO No. 1 (1)	2.7	2.7
	HFO No. 2 (2)	3.6	3.6

Notes:
(1) Only in installations of 0.6 MWth minimum.
(2) Only in installations of 1.2 MWth minimum.

Country	Grade	1985	1993
United Kingdom	Light and Medium Fuel Oils	3.5	3.5
	Heavy and Extra Heavy Fuel Oils	4.0	4.0

c) France

The standard grade of heavy fuel oil in France is 4.0 wt percent sulphur maximum. Lower sulphur grades (2.0 and 1.0 percent) are required in "Zones of Special Protection" (Paris, Lyon, Lille, Strasbourg (planned)). The only change in the current regulations known to be under consideration is the creation of a zone of special protection at Strasbourg.

d) Germany

As already discussed in Section III.B, the emission regulations applying in Germany are complex. Effectively, the limit on sulphur in heavy fuel oil is set by the allowable emissions under the requirements of the TA Luft and the GFAVO (large combustion sources regulations). Broadly, the TA Luft applies to liquid fuelled combustion sources of below 50 MWth and the GFAVO to large sources. Both the TA Luft and GFAVO are being progressively implemented in existing installations. Table III.C.3 below shows the regulations applying to different sizes of combustion source. The estimated overall effect on the sulphur content of marketable fuel oil is shown in the summary Table III.C.2.

Similiarly, limits on particulate and heavy metal emissions from large combustion sources (GFAVO) limit the content of ash and nickel in heavy fuel oil, as shown in Table III.C.4.

TABLE III.C.3

SULPHUR CONTROL REGULATIONS FOR HEAVY FUEL OIL IN GERMANY

Combustion Plant Size (MWth)	Fuel Oil Sulphur Max (wt percent)	Implementation New Plant	Implementation Existing Plant
< 1	Gas Oil (0.3)	In force	
< 50	1.0	In force	1991 (approx)
50-100	1.5		1988
	1.0	In force	1993
100-300	1.5		1988
	0.3 or 2.5 max + FGDS (1)	In force	1993
> 300	1.5		1988
	0.3 or 2.0 max + FGDS (2)	In force	1993

Notes:

(1) 60 percent S removal.

(2) 85 percent S removal.

TABLE III.C.4

LIMITS ON METAL CONTENT OF HEAVY FUEL OIL IN GERMANY

	Flue Gas Emission Limit (mg/Nm^3 max)	Max Content in HFO (1) (mg/kg)
Total Particulates	50 (2)	600(3)
Nickel	2	24

Notes:

(1) To meet flue gas limit.

(2) Largest users (> 100 000 Nm^3/h flue gas).

(3) Total ash.

e) Italy

The national standard for heavy fuel oil in Italy is 4.0 wt percent sulphur. Its use is subject to local authority approval in restricted zones (zone A and zone B), where the standard normally applied is 3.0 percent sulphur. A low sulphur grade (1.0 percent S) may be required if ground level air quality limits are exceeded.

The restricted zones are mainly the large towns and cities, or areas where adverse conditions exist.

f) Netherlands

Sulphur limits in heavy fuel oil will be cut from 2.0 to 1.0 percent in June 1986. This change is almost irrelevant, since the Netherlands inland market for heavy fuel oil has largely disappeared and largest local market is ships bunkers.

g) Spain

There are two grades of heavy fuel oil (2.7 and 3.6 percent S), as shown in Table III.C.2. Reductions have been proposed, but not implemented.

h) United Kingdom

There are no national regulations for sulphur in heavy fuel oil. The figures shown in Table III.C.2 are from technical standards. In practice, the sulphur content is generally lower, around 3 percent or less.

D. AQUEOUS EFFLUENT QUALITY

1. Introduction

Two different approaches are possible in setting effluent quality standards:

- o Limit Values - ie a maximum concentration of a pollutant in the effluent stream or a maximum quantity of pollutant per unit of plant throughput or product.
- o Receiving Water Quality - emission standards for each discharge are set on the basis of the absorptive capacity and intended use of the receiving water. Limits will therefore be site specific, taking account of factors such as other effluent discharges, dilution and self-purification.

Both approaches are recognised in the EEC legislation which regulates the discharge of aqueous effluents to the environment.

This difference in approach is one of the principal differences between individual member state's legislation. Other major differences in approach are the application of national discharge limits versus regional or local standards and central government control versus local government control over the setting and enforcement of effluent quality standards.

The result is that the effluent quality limits in the different member states are a mix of national discharge limits, regional limits, guidelines and case-by-case site specific limits. Differences in analytical methods and sampling procedures further complicate intercountry comparisons.

2. Effluent Quality Limits and Regulations

Regulations on refinery effluents, are compared in Table III.D.1. This table shows that the national effluent quality limits, where they exist, are broadly similar across the member states. Table III.D.2 summarises the control regime applying in the different member states.

TABLE III.D.1

LIQUID EFFLUENT DISCHARGE LIMITS FOR REFINERY SITES

Water Quality Effluent Quality	Temp ^{o}C	pH	Settleable Solids (mg/1)	Suspended Solids (mg/1)	BOD (mg/1)	COD (mg/1)	Hydrocarbons (mg/1)	Phenols (mg/1)	Sulphides Plus Mercaptans (mgS/1)	Total N (mg/1)	Pb (mg/1)	Total Cr (mg/1)	Cr6+ (mg/1)
Belgium - Simple	30	6.5 - 9.0	0.5	60	35	200	20	0.5		10	0.05	0.5	0.05
- Complex	30	6.5 - 9.0			35	250	20	1.0		30	0.05	0.5	0.05
France - Simple	30	5.5 - 8.5		30	30	120	20	0.5			0.1		0.05
- Complex	30	5.5 - 8.5		30	40	150	20	1.0			0.1		0.05
Germany		6 - 9	0.3		25	100	5	0.2	1.0				
Italy 1985		5.5 - 9.5	2.0	80-200	40-250	160-500	10	1.0	2.0		0.3	4.0	0.2
from 1.3.86		5.5 - 9.5	0.5	20	40	160	5	0.5	1.0		0.2	2.0	0.2
Netherlands (typical) (requirements established for each refinery)						100-200	10						
Spain - River		6 - 9			30	10					0.1		0.05
UK	No general standards - depends on individual authority, based on effect on receiving water												

TABLE III.D.2

LIQUID EFFLUENT CONTROL REGIMES FOR REFINERIES

Belgium:	National effluent quality standards Standards differ for three types of refinery, viz - simple hydroskimming - complex - complex plus lubes or petrochemicals
France:	National regulations and effluent specifications Regional and local authorities may require stricter limits Standards differ for three types of refinery (as Belgium) Taxes are levied on effluents by the regional authorities.
Germany:	National regulations and effluent specifications Regulations include "commonly accepted rules of technology" Effluent tax law with penalties for exceeding discharge limits
Italy:	National regulations Intentional dilution of effluents forbidden No specific refinery standards - effluents must conform to quality specifications for industrial effluents
Netherlands:	Requirements are established for each refinery Licensing controlled by local/regional authorities Best practicable means technology required with respect to dangerous substances (EEC List I) Type and age of refinery taken into account
Spain:	National legislation on refinery effluents Regional and local authorities can impose additional legislation (and taxes) Standards differ for different types of refinery (see Belgium above)
United Kingdom:	No national discharge standards Discharge "consent" regulations are set for each refinery based on absorptive capacity and Environmental Quality Objective of the receiving water Regional Water Authorities are the administering agency

As well as effluent quality limits, national legislation in France imposes limits on the quantity of liquid effluents. These limits, expressed as cubic metres per metric ton of crude distillation capacity, are:

Simple hydroskimming	0.5
Complex refinery	0.8

A few older refineries with once through cooling water systems have authorisation for higher discharge levels.

The tax level on effluents is set independently and annually by each of the six regional water authorities. The tax has three elements, proportional respectively to the quantities of hydrocarbons, COD and suspended matters discharged. Proceeds of the tax are retained by the regional authority to meet its annual budget.

E. NOISE

1. Background

Noise control measures on refinery sites are normally necessary to meet occupational health and safety regulations regarding work area noise. This is a health and safety cost rather than an environmental cost, but is described here in general terms to put the total noise problem into context.

All the countries considered in this study have some form of control on exposure to noise in the work place, to protect the hearing of employees. These regulations are a mix of national legislation and official guidelines. More recently, an EEC Directive on noise protection has been adopted.

In addition to these official regulations, several of the major oil companies apply their own company-wide standards for control of work area noise, which in some cases may be more stringent than national requirements.

2. Environmental Noise

Environmental noise is by definition noise affecting the environment in the region immediately surrounding the refinery site. The level of environmental noise will in general be be reduced by the application of any measures to reduce work area noise.

It is important to distinguish between the cost of these measures to protect employee health, which are not environmental control costs, and additional costs which are incurred solely to meet environmental regulations limiting noise levels outside the refinery site.

Environmental noise limits are a mixture of national, regional and local regulations, which, as discussed below, are difficult to compare in an unambiguous way. Also even in the absence of specific noise limits, there are generally other legal remedies (eg. nuisance by-laws) available to people subjected to unreasonable industrial noise levels.

It has not been possible to identify any important country differences in the costs of environmental noise control arising solely from differences in national legislation. This is because the site specific differences are of far more significance than any differences between national regulations. The obvious site specific differences include distance from residential and business areas, topography and weather conditions. In addition the noise limits themselves may vary within a country, depending on regional and local regulations. Finally, the differences between the technical parameters adopted in the regulations, and their interpretation in practice, make assessment and comparison of the regulations itself an extremely complex process.

F. MISCELLANEOUS

Another environmental problem which is emerging as significant for the industry is clean up on refinery and distribution terminal sites. Although it is subject to local rather than national regulations, the subject is included here for the sake of completeness. While problems can arise on operating sites, the major cost impact arises when an operation is shut down and soil clean up is necessary to adopt the site to alternative uses.

Site clean up costs will vary enormously, depending mainly on the age and condition of the site. The type of new activity on the site is also an important variable. Specific clean up requirements are a matter for local negotiation, and country differences do not appear to be a material factor.

SECTION IV

IV MODEL REFINERY SIMULATIONS

A. INTRODUCTION

1. Objective

Models were set up to simulate the current and future operation representative of typical refineries in the member states considered. The models generated refinery balances including product yields, product blends and utility consumptions on a strictly consistent basis. The simulations were carried out assuming optimum operation within the imposed constraints of crude oil feed, refinery configuration, plant capacities and product qualities as defined for each case.

The results from these simulations facilitated the assessment of changes in refinery operation resulting from compliance with the environmental regulations considered.

2. Methodology

The refinery balance calculations were carried out using Chem Systems proprietary linear program (LP) for refinery modelling and planning. The refining processes and products considered are listed in Tables IV.A.1 and 2. The models were kept as simple as possible, without prejudicing the accuracy of the evaluation carried out. This was achieved primarily by minimising the number of refinery streams, processing options and blending specification carried out.

TABLE IV.A.1

REFINERY PROCESS OPERATIONS

Process	Modes of Operation	Feedstock
Atmospheric Distillation(1)	One	Crude Oil
Vacuum Distillation(1)	One	Atmospheric Residue
Naphtha Reforming	Three Severities (90, 97 and 101 RON clear)	Heavy Naphtha (2)
Fluid Catalytic Cracking /Alkylation	One	Vacuum Distillate
Visbreaking	One	Vacuum Residue
Kerosine Hydrotreating	80% Desulphurisation	Kerosine
Gas Oil Hydrotreating	80% Desulphurisation	Gas Oils
Bitumen	One	Vacuum Residue
Isomerisation (3)	Recycle Operation	Light Naphtha

Notes:
(1) Yields crude dependent.
(2) FCC naphtha also processed for selected cases.
(3) Not included unless essential to meet specifications.

TABLE IV.A.2

PRODUCTS AND SPECIFICATIONS

Product	Quality Specifications
LPG	None (1)
Naphtha	None (2)
Gasoline Pool (Clear)	RON, MON, RVP
Kerosine	Sulphur (2)
Gas Oil	Cetane Index, Sulphur
Residual Fuel Oil	Viscosity, Sulphur
Bitumen	None (2)

Notes:
(1) Yield crude dependent.
(2) Fixed production for all cases.

The crude rate was the same for all of the refineries with a fixed yield of naphtha (4 wt percent), kerosine (6 wt percent) and bitumen (4 wt percent) independent of the feed or mode of operation selected. The balance of these streams being further processed or blended into other products.

Nominal product values were assumed in the model to aid the optimisation of the operation, typical current market rates were assumed. Sensitivity to any fluctuation in these values is not great.

3. Definition of Cases for Simulation

In line with the terms of reference, the models were set up to simulate two types of refinery:

Type 1 - Hydroskimming Refinery

Process Units	Capacity
Atmospheric Distillation	5 million metric tons per year
Vacuum Distillation	
Catalytic Reformer	
Gas Oil Desulphurisation	
LPG Recovery	
Bitumen Plant	

Offsites

Boiler House (including electricity generation)
Air and Cooling Water Systems
Tankage - Crude and Products
Crude Unloading
Product Loading

Type II - Conversion Refining (additional to Type 1)

Process Units

Fluid Catalytic Cracker (FCC)
Visbreaker

The FCC capacity was fixed at 20 wt percent of crude oil feed, which is typical of many European conversion refineries.

The units for which capacities were not specified were assumed to be adequate to handle the available feed streams. This is a safe simplifying assumption in view of the fact that the specified operating rates for the model refineries are well below design capacities. It also reflects the reality of the current operation in the refining industry.

Operation of each of the two refinery types was modelled for 1985 and 1993 in each of the following seven member states:

- Belgium
- France
- Germany
- Italy
- Netherlands
- Spain
- United Kingdom

The same utilisation rate of 75 percent was assumed for all cases with the exception of the conversion units where 100 percent was assumed (subject to requirements in the optimised mode of operation).

In principle, the refined product pattern was similar for each member state, the variation resulting from the different composition of the crude oil feeds and different final product specifications. Consistent operational constraints, representative of industry practice (eg minimising fuel output, using lower value fuel for own consumption etc) were applied in calculating the refinery balances. Subject to meeting the base case environmental contraints, the refineries were assumed to operate in a cost minimising mode. The significant differences between the inputs for the two base years being the difference in product specification and known changes in environmental measures.

For each case the following were prepared:

- Refinery Balance

    - crude oil consumption
    - product yields and product blending
    - fuel consumption and loss

- Process Units Operation (Main units)
  - material balances
  - utility consumptions
  - emissions to atmosphere (where applicable)

- Utility and Offsite Operation (where applicable)
  - fuel consumption
  - emissions to atmosphere
  - liquid effluents

B. INPUT DATA AND ASSUMPTIONS

1. Refinery Configuration

The product slate of an oil refinery is dependent on its configuration and the type of crude run. Two basic refinery configurations were assumed for the evaluations.

- "Hydroskimming" which is the simplest type of refinery consisting of crude atmospheric distillation, vacuum distillation (for bitumen feedstock) hydrotreating and naphtha catalytic reforming. The mode of operation for this type of refinery is effectively fixed, with the production rate of the vacuum distillation unit dictated by the requirement for bitumen feedstock. No outlet apart from for fuel was assumed available for the associated vacuum distillate produced.

- "Conversion" also known as complex refineries. Here the vacuum distillate produced is fed for upgrading to the fluid catalytic cracker. Vacuum residue as well as being used for bitumen feedstock is fed to a visbreaker for further processing (viscosity reduction).

Simplified flow diagrams for these two types of refinery configurations are shown in Figures IV.B.1 and 2.

2. Crude Slates

Average crude oil slates were calculated for each of the member states, forming the basis of the evaluations. The information used was provided by the Commission of the European Communities (Directorate-General for Energy) with the exception of data for Spain, this was extracted from International Energy Agency (IEA) statistics. Adjustment was made to the United Kingdom data to take account of the processing of "own production" crude oil. The period covered by the data was July 1984 to June 1985. A summary of these crude oil slates is given in Table IV.B.1.

FIGURE IV.B.1.
SIMPLIFIED FLOW DIAGRAM FOR HYDROSKIMMING REFINERY

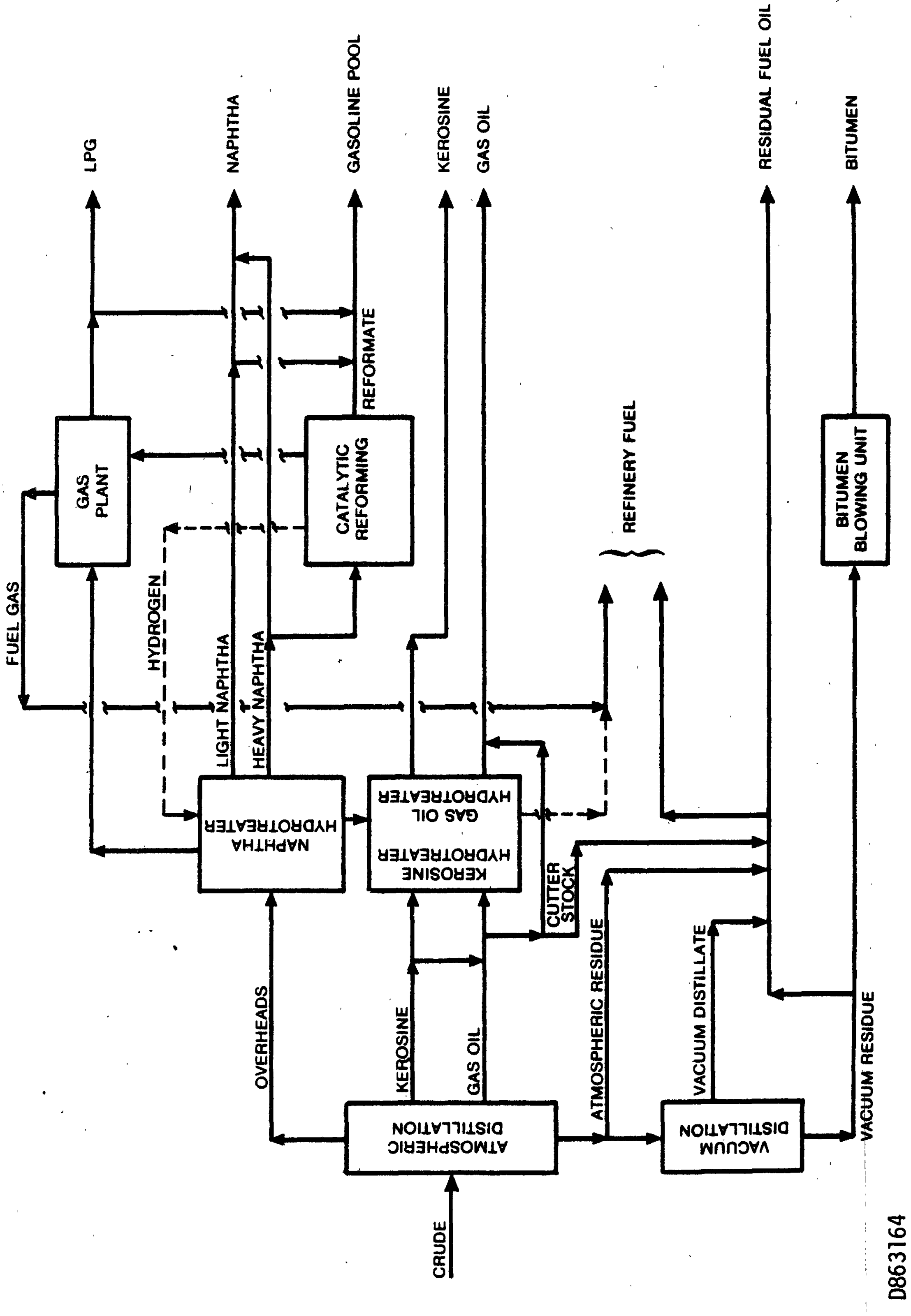
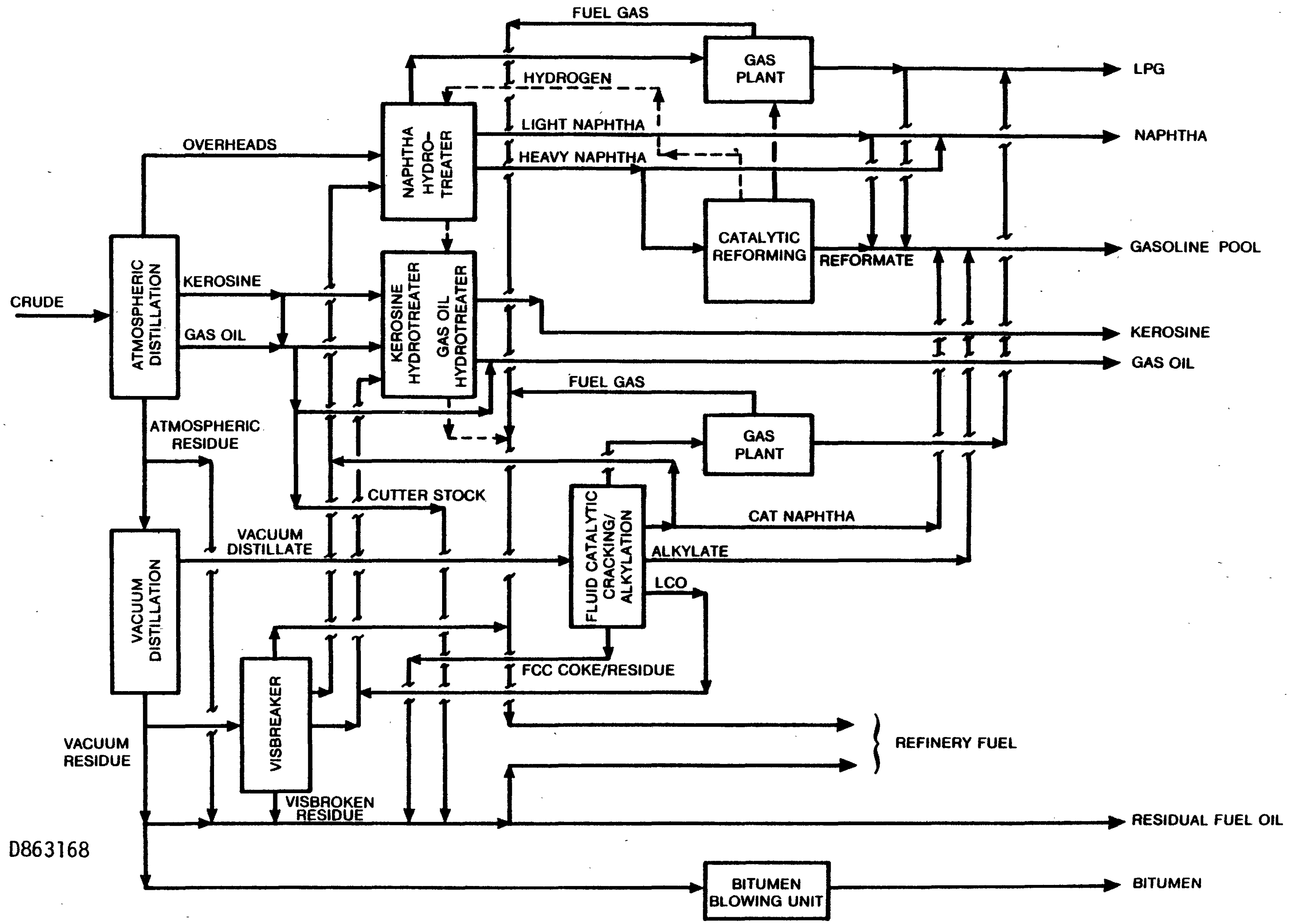


FIGURE IV.B.2.
SIMPLIFIED FLOW DIAGRAM FOR CONVERSION REFINERY



D863168

TABLE IV.B.1

CRUDE OIL SLATES
(MID 1984-85)

Crude Oil Type (wt %)	API Gravity	Belgium	France	Germany	Italy	Netherlands	Spain	United Kingdom
Arabian Light	(34°)	-	2.9	0.2	6.7	-	-	-
Arabian Medium	(31°)	4.3	0.3	2.1	1.0	-	5.4	-
Arabian Heavy & Khafji	(27°)	1.8	4.1	6.3	2.6	1.0	-	5.6
Iranian Light	(34°)	8.9	1.7	0.3	2.2	2.0	5.1	0.6
Iranian Heavy	(31°)	-	2.1	0.4	5.6	-	5.1	0.3
Murban & Zakum	(39°)	-	2.8	1.1	-	-	-	-
Iraq - Basrah	(35°)	-	-	-	-	-	-	-
Iraq - Kirkuk	(36°)	13.9	6.6	1.8	13.2	0.9	10.3	1.5
Kuwait	(31°)	1.4	0.3	0.3	1.7	14.0	0.3	0.8
Libya	(40°)	-	3.5	15.8	20.7	1.0	8.1	0.6
Algeria	(44°)	-	7.2	4.2	1.3	0.7	3.3	-
Nigeria	(34°)	16.4	13.0	19.4	6.0	9.4	9.1	6.3
Venezuela Light	(34°)	-	-	3.8	-	-	-	-
Venezuela Medium	(26°)	-	0.3	1.5	-	-	3.2	-
Venezuela Heavy	(17°)	4.0	0.8	5.6	0.6	-	-	3.8
Indonesia	(34°)	-	-	-	-	-	-	-
Qatar Dukhan & Marine	(40°)	-	3.2	0.5	1.3	0.2	1.4	-
North Sea	(38°)	39.0	27.8	30.6	7.9	51.2	4.2	71.8
Mexican Isthmus	(34°)	-	5.2	0.2	0.4	5.8	20.5	0.1
USSR	(33°)	-	3.9	0.7	2.5	2.2	2.2	0.5
Other		10.3	14.3	5.2	26.3	11.6	21.8	8.1
Total		100.0	100.0	100.0	100.0	100.0	100.0	100.0
Sulphur Content (wt %)		1.02	0.99	0.79	1.25	0.93	1.37	0.68

Source of Information: Directorate - General for Energy (Commission of the European Communities). Spain Data from "Oil and Gas Statistics 1985", International Energy Agency (OECD).

3. Refinery Processes and Yields

A detailed technical discussion of the major refinery processes is outside the scope of this report, but an outline of the function of the available processes, yields and modes of operation assumed is presented below.

a) Atmospheric and Vacuum Distillation

The purpose of a crude distillation unit is to separate crude oil into narrow fractions (or cuts), suitable for subsequent processing. These cuts are the overhead stream, side streams used for middle distillate production and bottoms (also known as atmospheric or long residue) which contains all of the heavier fractions.

The C4 and lighter fraction in the overhead stream are sent to the gas plant which also collects light hydrocarbon streams from other refinery processes. The gas plant recovers C4's which are used for LPG production (blended with C3) and for gasoline blending. The C5-C6 fraction (light virgin naphtha) is generally routed directly to gasoline blending while the C6 cut (heavy naphtha) is sent to catalytic reforming. The whole C5 plus cut is generally sold as naphtha for petrochemical application. The middle distillates being blended to form kerosine and gas oil products.

Distilling the atmospheric residue under vacuum (vacuum distillation) lowers the gas liquid equilibrium temperature so that a heavy distillate cut can be separated from the vacuum residue without causing thermal cracking. The main use for this vacuum residue is as feedstock for bitumen production, any remaining material being disposed of in the fuel oil pool after the addition of a suitable cutter stock or further processing in a visbreaking unit. The vacuum distillate cut is used as a feedstock to the fluidised catalytic cracker for further conversion or for the hydroskimming refinery case, blended into the fuel oil pool.

Yields for both atmospheric and vacuum distillation are dependent on the type of crude run. Table IV.B.2 reports typical yields for each of the crude oils considered in this study. Representative theoretical yields for each of the member states were calculated using the average crude oil slates and yield data for the individual crude oils, these are in given in Table IV.B.3. These theoretical yields were processed in the model to represent yield patterns, representative of actual operation, with the naphtha (for chemical feedstock) and kerosine production being fixed and the gas oil products combined.

b) Catalytic Reforming

The purpose of this process, which can be regarded as the refiners tool to control the gasoline octane level, is to produce gasoline blending stocks (reformates) in the typical range of 92 to 102 unleaded Research Octane Number (RON) from low octane naphthas. Reformates account for a high proportion of the refinery gasoline pool.

Conventional reformer feedstocks are straight run naphthas in the boiling range 90 to 185°C. In certain cases in this study it was required to further improve the catalytically produced naphtha by reforming before blending to gasoline. Octane improvement is achieved by converting paraffins and naphthenes into aromatics. In the process, hydrogen and light saturated hydrocarbon gas are produced as byproducts. Reformate yields being dependent on the feedstock quality, which is measured by the PNA (paraffin, naphthenes and aromatics content), the required reformate RON and unit operating conditions (especially pressure). In the models used three modes of operation were allowed, producing reformate of 90, 97 and 101 RON. The mode/modes of operation were selected by the model to optimise the overall refinery operation.

TABLE IV.B.2

YIELD DATA FOR DIFFERENT CRUDE OILS

(wt percent on feed)

		Atmospheric Distillation							Vacuum Distillation	
Crude Oil Type	API Gravity	C4-	Light Naphtha (C5-90°C)	Heavy Naphtha (90-185°C)	Kerosine (185-240°C)	Light Gas Oil (240-300°C)	Heavy Gas Oil (300-360°C)	Atmospheric Residue (360°C+)	Vacuum Gas Oil (360-530°C)	Vacuum Residue (530°C+)
Arabian Light	(34°)	1.3	5.9	14.8	9.7	11.1	9.6	47.6	59.7	40.3
Arabian Medium	(31°)	1.5	7.7	10.5	7.2	10.8	10.7	51.6	48.4	51.6
Arabian Heavy & Khafji	(27°)	2.2	5.2	10.7	6.2	9.8	9.3	56.6	43.6	56.4
Iranian Light	(34°)	1.5	6.8	14.4	8.0	11.8	11.0	46.5	62.6	37.4
Iranian Heavy	(31°)	1.8	6.6	13.6	6.8	11.6	9.6	50.0	52.0	48.0
Murban & Zakum	(39°)	1.7	9.0	18.4	4.7	18.9	11.2	36.1	68.1	31.9
Iraq - Kirkuk	(36°)	1.9	8.9	16.4	6.3	14.4	11.2	40.9	57.2	42.8
Kuwait	(31°)	2.0	5.8	13.3	5.0	11.6	8.8	53.5	49.2	50.8
Libya	(40°)	1.6	6.8	20.5	8.2	12.8	12.8	37.3	53.6	46.4
Algeria	(44°)	2.1	9.9	21.6	4.2	19.5	11.8	30.9	69.9	30.1
Nigeria	(34°)	1.5	6.6	16.2	15.5	13.5	12.7	34.0	76.2	23.8
Venezuela Light	(34°)	1.2	5.5	13.7	9.2	9.0	10.7	50.7	53.6	46.4
Venezuela Medium	(26°)	0.8	4.8	9.3	9.4	6.3	9.5	59.9	48.7	51.3
Venezuela Heavy	(17°)	0.0	1.0	2.0	5.7	5.4	10.3	75.6	43.1	56.9
Qatar Dukhan & Marine	(40°)	2.5	9.4	18.2	6.8	15.2	11.3	36.6	66.9	33.1
North Sea	(38°)	2.4	8.8	18.5	9.1	10.3	11.2	39.7	67.0	33.0
Mexican Isthmus	(34°)	1.3	5.9	14.8	9.7	11.1	9.6	47.6	59.7	40.3
USSR	(33°)	1.9	8.7	15.1	9.4	17.9	6.1	40.9	57.2	42.8
Other		1.9	6.7	12.9	6.3	10.7	9.5	52.0	55.2	44.8

TABLE IV.B.3

ATMOSPHERIC AND VACUUM DISTILLATION - YIELD DATA

(wt percent on feed)

Country	Atmospheric Distillation							Vacuum Distillation	
	C_4^-(1)	Light Naphtha	Heavy Naphtha	Kerosine	Light Gas Oil	Heavy Gas Oil	Atmosph. Residue	Vacuum Gas Oil	Vacuum Residue
Belgium	1.9	7.6	15.7	9.0	11.4	11.1	43.3	63.1	36.9
France	1.9	7.7	16.4	8.6	12.6	10.8	42.0	63.0	37.0
Germany	1.8	7.1	16.2	9.3	11.6	11.4	42.6	61.8	38.2
Italy	1.8	7.2	15.9	7.8	12.2	10.7	44.4	57.5	42.5
Netherlands	2.2	7.6	16.5	8.7	11.2	10.6	43.2	62.8	37.2
Spain	1.7	7.0	15.1	8.4	12.0	10.5	45.3	58.9	41.1
United Kingdom	2.2	7.9	16.8	8.9	10.5	11.0	42.7	64.0	36.0

Note:

(1) Split for LPG/Light gas is approximately 90/10

All reforming process use an expensive platinum based catalyst. Old units use a fixed bed reactor train (semi-regenerative process) and shut down to regenerate the catalyst every 6 to 18 months, depending on the severity of operation. The modern trend is towards the use of CCR (continuous catalytic reforming) where the catalyst is continually withdrawn from the reactor section, regenerated and fed back to the reactors. These modern units also often operating at lower pressure which gives higher reformate yield and lower energy consumption.

For this evaluation operation intermediate between the semi-regenerative and continuous reforming have been simulated in order to match the estimated average operation of commercial units. Some modification and expenditure to existing units is required to meet the requirement for production of the 1993 gasoline pool, these are discussed in more detail later in the report.

The yields for a typical hydrotreated heavy naphtha feedstock are given in Table IV.B.4.

TABLE IV.B.4

CATALYTIC REFORMING - YIELD DATA
(wt percent on feed)

	Reformate RON (clear)		
Product	90	97	101
Hydrogen	1.80	2.20	2.50
Light Gas	5.18	7.00	9.37
LPG	7.26	9.82	13.13
Reformate	85.76	80.98	75.00
	100.00	100.00	100.00

c) Distillate Hydrotreating

The main purpose of hydrotreating distillates is to lower their sulphur content. In the process other impurities such as organic nitrogen and oxygen are also removed and olefins saturated. The distillates are made to react with hydrogen over a catalyst bed (cobalt-molybdenum or nickel-molybdenum). Under appropriate conditions of temperature and hydrogen partial pressure, the organic sulphur in the distillates is transformed to H_2S, which can then be easily removed from the hydrocarbon stream. The desulphurisation achieved is high, normally being in the range of 80 to 90 percent (80 percent assumed in this study). In the process, hydrogen is consumed and negligible amounts of light hydrocarbons (due to very mild hydrocracking) are formed.

Naphtha is hydrotreated in order to meet catalytic reforming feedstock specifications in units called "naphtha hydrotreaters". Ideally the levels of organic sulphur and nitrogen should be reduced to less than 1 ppm. For this study it was assumed that all naphtha fed to the reforming unit was hydrotreated.

Kerosine and gas oils are hydrotreated under more severe conditions, often in the same unit, mainly to meet sulphur specification. However, because of the hydrogenation of olefinic hydrocarbons, colour, odour and stability are also improved. Some catalysts also permit a partial hydrogenation of aromatics in order to slightly improve smoke point (kerosine) and cetane index (automotive gas oil).

In order that required operating levels could be assessed it was assumed that the kerosine and gas oil hydrotreating were carried out separately, the throughput of these units being dictated by the feed quality and required product specification. In all cases a product yield of 99.7 wt percent was assumed with a hydrogen consumption of 1 wt percent based on feed.

d) Fluid Catalytic Cracking/Alkylation

For simplicity a combined Fluid Catalytic Cracker and Alkylation complex was assumed in the refinery models.

Fluid Catalytic Cracking (FCC) is a mature process which is playing a key role in the West European refinery industry because of its flexibility to accept a range of heavy feedstocks and make a variety of lighter products at low cost compared to other upgrading processes. Historically FCC was aimed at converting heavy gas oil into gasoline but it is now more generally and extensively used to upgrade vacuum distillates into light products. The FCC process uses a zeolite catalyst which is fed to a reactor and mixed with vaporised heavy hydrocarbons which are then cracked under appropriate conditions of temperature and contact time. The operating pressure is generally 2 to 3 bars and the products of cracking are separated in cyclones from the catalyst. The products are fractionated into suitable refinery streams, while the catalyst, coated with coke produced in the cracking process, is sent to the regenerator where the coke is burned with air. The regenerated catalyst is then cycled back to the reactor. The heat produced by the combustion of the coke is partly used to meet the unit internal energy requirements and the balance recovered as steam.

The present operational trend is towards processing heavier feedstocks which tend to have higher metals (catalyst poisons) and asphaltenes contents. The incremental yields from heavier feedstocks are poorer and the catalyst replacement rate increases considerably. The optimum feedstock composition is determined by economic considerations. The poisoning effect of metals on catalyst is a reduction of activity (vanadium) and a much increased yield in light gases (nickel).

The present efforts in the design of new units and catalyst development are mainly aimed at improving the quality of the products, at allowing the handling of heavier feedstock and at increasing middle distillates yields. An increasingly important area of research and trade is in the use of catalysts which produce higher octane gasoline blending components.

Alkylation is a complementary process to fluid catalytic cracking. Effectively it increases the FCC yields of white products by upgrading part of the gas produced into valuable gasoline blending components. Alkylation reacts isobutane with butylenes (or a mixture of butylene and propylene) to form a highly branched high octane gasoline component. The ratio isobutane to olefin is about one to one on a molar basis. The alkylation reactions are catalysed by an acid which is usually hydrofluoric acid (some older units use sulphuric acid).

The FCC produces a much higher olefin to isobutane ratio than required by alkylation. Additional isobutane is available in the refinery from the naphtha reformer and from atmospheric distillation which recovers what is contained in the crude. Total refinery isobutane availability, is usually enough to alkylate only the butylene fraction, which is preferred to propylene because the resultant alkylate is of better quality. This is particularly true with the present operational emphasis on catalytic cracking which leads to an increasingly higher portion of crude being processed through the FCC. In order to alkylate propylene the refiner has either to buy isobutane or to build an isomerisation unit to isomerise normal butane.

The yield pattern used for the FCC/Aklylation processing vacuum distillate feedstock is given in Table IV.B.5.

TABLE IV.B.5

FLUID CATALYTIC CRACKING/ALKYLATION - YIELD DATA

(wt percent on feed)

Product	Yield
Light Gas	3.50
LPG	6.40
Alkylate (1)	8.60
FCC Naphtha	51.10
Light Cycle Oil	15.60
FCC Coke	8.70
FCC Residue	6.10
	100.00

Note:
(1) Assumed to be produced by processing all the FCC butylene.

e) Visbreaking

The purpose of this relatively simple process is to upgrade a heavy refinery stream via mild thermal cracking. The stream is heated in a furnace where the cracking of heavy molecules, mainly paraffins, to hydrocarbons in the distillate boiling range occurs. The maximum quantity of distillates, consistent with leaving the viscosity of the bottoms close to that of a saleable residual fuel oil, are then recovered.

When processing vacuum residue the upgrading effect is a significant viscosity reduction of the feed (hence the name "visbreaking"), which permits a reduction of the total residual fuel oil production by decreasing the addition of cutter stock (middle distillate) normally required for reducing the viscosity.

The quality of distillates from visbreaking is very poor and severe hydrotreatment is normally required before blending into finished products. The major advantage of visbreaking, which only permits a limited upgrading effect, is that it is a relatively inexpensive process.

The important operating variables are temperature and residence time, which can be balanced over a range to give the same conversion. The modern trend is toward operating the visbreaker furnace at lower temperature and increasing the residence time in the soaking drum. Most of the cracking process is then shifted from the furnace coils to the soaking drum and this allows lower investment and overall fuel consumption and significantly longer runs between furnace decokings. The visbreaker upgrading effect is limited by the tendency of the bottoms stream to become unstable at high severity of operation.

In Western Europe thermal cracking is a very common process which is expected to retain its importance for future refinery operations. Many cases exist where the thermal cracker is the only upgrading facility in a refinery and as a consequence fed with atmospheric residue. For these evaluations the thermal cracking is a complementary process to catalytic cracking in a refinery configuration where the FCC handles the vacuum distillate portion of the atmospheric residue and the visbreaker the vacuum residue.

The yield pattern used for the visbreaker processing vacuum residue feedstock is given in Table IV.B.6.

TABLE IV.B.6

VISBREAKING - YIELD DATA
(wt percent on feed)

Product	Yield
Light Gas	1.00
LPG	1.20
Cracked Light Naphtha	0.70
Heavy Naphtha	1.00
Cracked Gas Oil	2.90
Visbroken Residue	93.20
	100.00

f) Bitumen Production

The base or feedstock material used in bitumen production is vacuum residue. The bitumen is a black or dark brown material ranging from a highly viscous to almost solid black substance at ambient temperatures, depending on the amount of light fractions removed. On heating, bitumen softens gradually and eventually becomes fluid, the temperature at which it reaches a certain consistency is called the softening point. Commercial grades have softening points ranging from 25 to 135°C.

Bitumen can be oxidised, or more correctly dehydrogenated, by blowing air through it at high temperatures. "Blown" grades being somewhat rubbery in consistency and less temperature sensitive than the straight distillation grades. For this evaluation a 100 percent yield based on vacuum residue was assumed for production/blending of all grades.

g) Isomerisation

Although not originally included in either the hydroskimming or conversion refinery configurations, an isomerisation unit was added for some of the 1993 cases. The unit was only included when it was not possible to meet the required product specification (of gasoline pool) with the existing processing units.

This process boosts substantially the octane level (both RON and MON) of the refinery light virgin naphtha (a mixture of C5 and C6 paraffins) by isomerising straight chain molecules to highly branched isomers. Application of isomerisation is mainly in the production of low lead (0.15 g/l) or unleaded gasoline. A drawback of this process is that the RON improvement is followed by a vapour pressure increase and, as a consequence, less butane can be blended into the gasoline pool.

The isomerisation reactions, which are equilibrium reactions, are carried out over a platinum based catalyst in the presence of hydrogen. A small hydrogen consumption occurs. By-products, due to cracking, are negligible. A variation of the isomerisation process, the TIP (Total Isomerisation Process), can provide a high octane product stream virtually free of normal paraffins, by recycling the latter to extinction.

Typical properties of the C5/C6 feed and products are the following:

	Feed	Isomerisation	TIP
RON (clear)	71 - 75	80 - 82	89 - 91
MON (clear)	69 - 74	78 - 80	87 - 89
Vapour Pressure (psi)	7 - 17	10 - 18	13 - 20

It is important to note that it is possible to revamp a reforming unit into an isomerisation unit, with modest capital expenditure. This option is becoming increasingly attractive in light of the number of redundant old reforming units (most of the them currently mothballed) existing in West European refineries and the increasing importance of isomerisation in gasoline pool octane boosting

For this evaluation it was assumed that the Total Isomerisation Process was employed.

4. Processing Units Energy Requirements

The energy requirements, ie steam and fuel for processing crude oil were calculated by adding up the energy requirements for all the processing units involved in the operation. These requirements were estimated based on the data shown in Table IV.B.7, which expresses the fuel consumption as a function of the unit throughput. It is not necessary to differentiate between steam and direct fuel since the former is also raised in the refinery by burning fuel. It has been assumed that 11 tons of MP steam are equivalent to 1 ton of liquid fuel. The data presented is considered to be representative of the average operational efficiency of West European refineries.

TABLE IV.B.7

ENERGY REQUIREMENTS OF PROCESSING UNITS
(tons of standard refinery fuel per
100 tons of unit throughput)

Atmospheric Distillation	3.30
Vacuum Distilation	2.90
Catalytic Reforming (90 RON)	4.70
Catalytic Reforming (97 RON)	5.00
Catalytic Reforming (101 RON)	5.55
Distillate Hydrotreating	1.25
FCC plus Alkylation	3.89
Visbreaking	1.60
Bitumen	1.10
Isomerisation	2.90

Note:

1 metric ton of standard refinery fuel is equivalent to 9.6 Gcal/metric ton.

5. Sulphur Balances

Due to the significant impact of sulphur content in the crude oil feed on product qualities, mode of operation and environmental considerations, sulphur balances were carried out for all the cases considered. The sulphur contents for the streams produced by atmospheric and vacuum distillation for all the crude oils considered in this study are given in Table IV.B.8.

By combining the information in Table IV.B.8 with the crude oil slates for each of the member states, sulphur contents were calculated for each of the streams produced by the model refineries. The country by country product sulphur contents are given in Table IV.B.9. These data were used in the refinery models to carry out sulphur balances and select the mode of operation required to meet the product specifications.

TABLE IV.B.8

SULPHUR CONTENT OF PROCESS STREAMS FOR DIFFERENT CRUDE OILS

(wt percent sulphur)

Crude Oil Type	Sulphur in Crude Oil (%)	Atmospheric Distillation Light Naphtha	Heavy Naphtha	Kerosine	Light Gas Oil	Heavy Gas Oil	Atmospheric Residue	Vacuum Distillation Vacuum Gas Oil	Vacuum Residue
Arabian Light	1.70	0.01	0.03	0.15	0.67	1.66	3.04	2.36	4.04
Arabian Medium	2.43	0.04	0.06	0.24	0.89	2.08	4.04	2.89	5.12
Arabian Heavy & Khafji	2.97	0.00	0.03	0.26	1.06	2.18	4.67	3.09	5.09
Iranian Light	1.42	0.04	0.07	0.19	0.64	1.10	2.57	1.89	3.73
Iranian Heavy	1.57	0.09	0.13	0.36	0.82	1.37	2.59	1.79	3.46
Murban & Zakum	0.86	0.01	0.02	0.04	0.28	1.40	1.79	1.47	2.48
Iraq - Kirkuk	2.10	0.01	0.12	0.23	0.76	1.68	4.27	2.69	5.90
Kuwait	2.56	0.00	0.02	0.16	0.91	1.96	4.24	2.88	5.57
Libya	0.24	0.00	0.02	0.10	0.19	0.28	0.54	0.35	0.66
Algeria	0.10	0.00	0.00	0.00	0.01	0.12	0.26	0.20	0.37
Nigeria	0.16	0.01	0.01	0.05	0.12	0.18	0.30	0.28	0.50
Venezuela Light	1.17	0.00	0.00	0.05	0.24	0.66	1.99	1.32	2.65
Venezuela Medium	1.51	0.01	0.02	0.14	0.67	1.00	2.08	1.58	2.82
Venezuela Heavy	2.70	0.01	0.08	0.45	1.04	1.68	3.14	2.51	3.98
Qatar Dukhan & Marine	1.35	0.04	0.06	0.10	0.50	1.60	2.70	2.20	3.70
North Sea	0.28	0.00	0.00	0.02	0.08	0.16	0.68	0.42	1.39
Mexican Isthmus	1.70	0.01	0.03	0.14	0.64	1.58	3.01	2.25	3.85
USSR	2.10	0.01	0.11	0.23	0.76	1.68	4.27	2.69	5.90
Other	1.60	0.00	0.03	0.35	0.84	1.40	2.60	2.00	3.30

TABLE IV.B.9

SULPHUR CONTENT OF PRODUCT STREAMS

(wt percent sulphur)

Stream	Belgium	France	Germany	Italy	Netherlands	Spain	United Kingdom
Kerosine	0.10	0.09	0.06	0.12	0.08	0.13	0.06
Desulphurised Kerosine	0.02	0.02	0.01	0.02	0.02	0.03	0.01
Gas Oil	0.63	0.61	0.48	0.76	0.57	0.84	0.39
Desulphurised Gas Oil	0.13	0.12	0.10	0.15	0.11	0.17	0.08
Atmospheric Residue	2.00	1.99	1.57	2.39	1.84	2.57	1.35
Vacuum Distillate	1.44	1.41	1.06	1.68	1.24	1.85	0.93
Vacuum Residue	2.96	2.98	2.39	3.35	2.77	3.60	2.17
Light Cycle Oil (1)	0.40	0.39	0.30	0.47	0.36	0.52	0.26
FCC Coke	4.32	4.23	3.18	5.04	3.87	5.55	2.79
FCC Residue	2.88	2.82	2.12	3.36	2.58	3.70	1.86
Cracked Gas Oil (1)	0.26	0.26	0.21	0.29	0.24	0.32	0.19
Visbroken Residue	3.11	3.13	2.51	3.52	2.91	3.78	2.28

Note:

(1) Assuming product has been desulphurised.

6. Product Qualities

The models were set up to produce the following product streams;

- LPG
- Naphtha (for chemical feedstock)
- Gasoline Pool
- Kerosine
- Gas Oil
- Residual Fuel Oil
- Bitumen

Further information on these products and their associated quality constraints for the two base years (1985 and 1993) are given below;

a) LPG

No product quality constraints were imposed in the models, although the yields used were representative of LPG production of saleable quality.

b) Naphtha

In line with operation typical of West European refineries, the naphtha production for chemical feedstock was fixed at 4 wt percent on crude. No specific quality constraints were imposed.

c) Gasoline Pool

The following properties need to be considered in gasoline blending:

- Research Octane Number (RON)
- Motor Octane Number (MON)
- Reid Vapour Pressure (RVP)
- Density (required to permit blending calculations to be carried out on a volume basis).

Gasoline is made by blending several streams of different characteristics, produced by different processes. The blending stocks available for this analysis are listed in Table IV.B.10 together with their relevant properties. The composition of the gasoline pool is dependent on the relative availability of each blending stock, which in turn is dependent on the mode of opertion and crude processed. The LP model generated the optimum mode of operation based on the processing units available and the product quality constraints imposed.

TABLE IV.B.10

PROPERTIES OF THE GASOLINE BLENDING STOCKS

Product	RON (Clear)	MON (Clear)	RVP (PSI)	Specific Gravity
LPG (1)	94.1	90.2	55.0	0.60
Light Naphtha	74.2	73.1	16.1	0.67
FCC Naphtha (2)	92.0	79.2	8.0	0.76
Reformate 90	90.0	81.0	4.6	0.76
Reformate 97	97.0	86.4	4.2	0.78
Reformate 101	101.0	88.0	4.0	0.81
Alkylate (2)	97.0	94.0	7.0	0.70
Cracked Light Naphtha (2)	86.0	76.0	17.0	0.67
Isomerised Light Naphtha (3)	89.3	87.2	20.2	0.66

Notes:

(1) Properties of n-butane assumed.
(2) Only available in conversion refinery cases.
(3) Only available in certain product blends.

Reformates are the only blending stocks for which the octane can be adjusted by the refiner over a large range by varying the severity of operation of the reforming unit. Operationally little control can be exercised over the octane of the other blending stocks which are generally fixed by the processing unit employed.

The two basic rules for gasoline manufacture are meeting octane specifications (by selecting the required reformer severity) and then adding butane up to the maximum RVP limit. The refiner has no direct way of controlling the gasoline sensitivity, ie of increasing MON independently from RON.

Currently RON is generally the controlling octane specification, with MON automatically met (often with some giveaway). This situation changes as demands for high octane gasoline pools are required (ie lead phase out) and increasingly MON becomes a critical constraint in the blend. This is particularly true for refineries with FCC units due to the low MON value of the FCC naphtha produced.

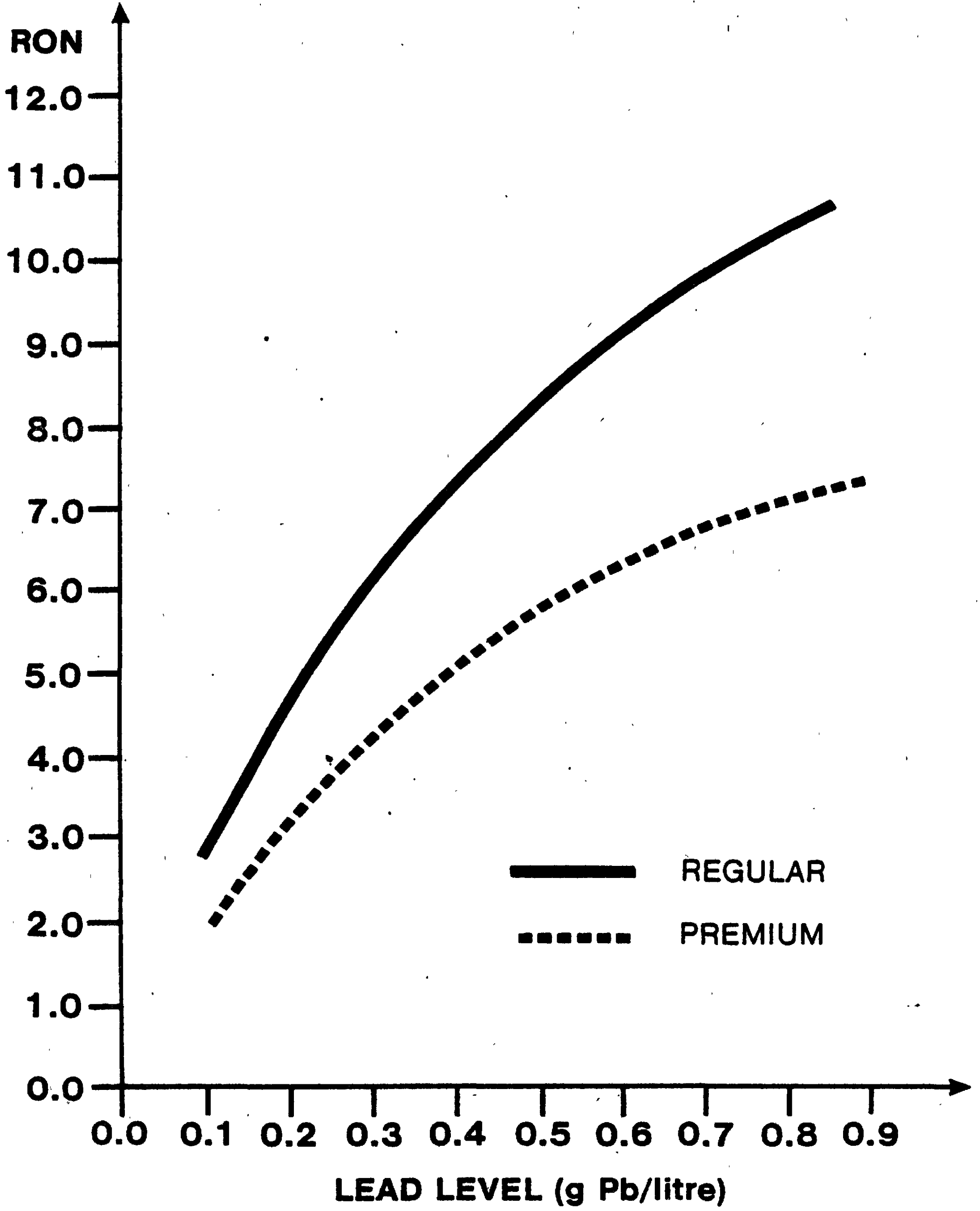
The relevant properties, ie RON, MON and RVP, were blended linearly in the models on a volume basis. This assumption produces in Chem Systems experience, results which are well within the overall accuracy of the study and the use of sophisticated blending techniques would only add unnecessary complexity to the evaluations.

As a further simplification the impact of lead addition is simulated by adjusting the RON and MON specifications, in this way only clear octane numbers are required for each blending stock. The lead susceptibility of the RON in the gasoline blends was estimated from the graph shown in Figure IV.B.3 which is based on extensive commercial data.

For the base cases (1985), West European gasoline was largely sold in two main grades 98 RON premium and 92 RON regular. In a few countries, a third, intermediate grade was also on sale. Specific octane ratings of the regular and premium gasolines varied a little from country to country and were set as much by custom and oil industry practise as by government regulations. There was though a considerable variation in the ratio of premium to regular in the different countries considered from 57 percent premium in Germany to 95 percent in Italy. Agreement has been reached to adopt a single "Euro-grade" unleaded gasoline (95 RON, 85 MON) to be marketed in all member states by 1.10.89 or sooner (EEC Directive 85/210/EEC).

FIGURE IV.B.3.

LEAD SUSCEPTIBILITY OF TYPICAL GASOLINE BLENDS RESEARCH OCTANE NUMBER



NOTE: Premium 98 RON at 0.4 g Pb/l
Regular 92 RON at 0.4 g Pb/l

There is however, no single EEC standard for leaded gasoline. National standards vary in octane specifications, lead level and other respects. Also, the changeover to unleaded gasoline wil be faster in some countries than others. Hence, during the transition period both the specifications and the quantities sold of leaded gasoline will vary significantly between countries. Estimates of the gasoline pool in each country, for 1985 and 1993, are presented in Table IV.B.11. As can be seen from the table, the MON specification was assumed to be 10 octane points lower than the RON specification.

The use of oxygenates as blending stock for octane improvement has not been considered in this report. This is considered to be a reasonable assumption as although oxygenates are likely to play an increasing role in gasoline production they are not a substitute for lead. While lead is an "additive" oxygenates are a "blending stock", significant quantities of which are required to noticeably affect the gasoline quality. Moreover, lead is far more efficient than oxygenates as far as total octane boosting effect and cost of incremental octane are concerned. Based on recent studies Chem Systems believe that the octane improvement cost by oxygenate addition is comparable to the cost achievable by conventional refining processes.

d) Kerosine

Kerosine finds a wide range of applications including,

- domestic heating and lighting
- aviation turbine engine fuel
- tractor engine fuel
- industrial solvent usage

Many properties are important in order to meet the stringent requirements for safe and efficient use in the above applications, however for this study the only blending constraint imposed was that of sulphur content. It was assumed that all the final product kerosine underwent hydrotreatment, fundamentally to remove sulphur impurities.

TABLE IV.B.11

GASOLINE POOL ASSUMPTIONS

	Gasoline Grades (%)				Pool Specifications			
	Leaded Premium (98 RON)	Leaded Regular (92 RON)	Unleaded Premium (95 RON)	Unleaded Regular (92 RON)	RON Clear (Min)	MON Clear (Min)	Lead Premium (g Pb/l max)	Lead Regular (g Pb/l max)
Belgium								
1985	91	9	-	-	92.6	82.6	0.40	0.40
1993	70	-	30	-	95.4	85.4	0.15	-
France								
1985	86	14	-	-	92.1	82.1	0.40	0.40
1993	75	-	25	-	93.7	83.7	0.40	-
Germany								
1985 Case 1 (3)	57	43	-	-	92.4	82.4	0.15	0.15
1985 Case 2 (4)	57	43	-	-	89.7	79.7	0.40	0.40
1993	45	-	25	30	94.3	84.3	0.15	-
Italy								
1985	95	5	-	-	92.9	82.9	0.40	0.40
1993	75	-	25	-	93.7	83.7	0.40	-
Netherlands								
1985	76	24	-	-	92.1	82.1	0.30	0.40
1993	60	-	40	-	95.3	85.3	0.15	-
Spain								
1985	80 (1)	20	-	-	88.0	78.0	0.60	0.48
1993	70 (2)	-	30	-	92.2	82.2	0.40	-
United Kingdom								
1985	87	13	-	-	92.2	82.2	0.40	0.40
1993	70	-	30	-	95.3	85.3	0.15	-

Notes:

(1) Leaded Premium 96 RON
(2) Leaded Premium 97 RON
(3) National Case
(4) EEC Case

Other properties such as freeze point and smoke point, which are important properties for the production of jet fuels and kerosine, although not directly considered in the blending evaluations were effectively accounted for by only allowing blending of streams which produce a marketable product. In line with operation typical of West European refineries the kerosine production was set at 6 wt percent of the crude oil feed, any additional material produced in the kerosine range being blended into the gas oil product pool.

e) Gas Oil

For simplification a single gas oil product was assumed in the modelling. Typical commercial application of these gas oil range products being;

- fuel for diesel engines
- fuel for domestic and industrial heating
- cutter stock for residual fuel oil blending

There are several performance characteristics which are important to ensure suitability of the product for the above applications, these include ignition quality (cetane index), volatility, fluidity, atomisation, cleanliness and stability. For this study two essential properties were considered directly in the blending, the cetane index and sulphur content. The other properties were catered for by careful selection of the streams available for use in the product blend. The minimum acceptable cetane index was set at 45 for all cases and the sulphur specifications for the member states in the two reference years are given in Table IV.B.12.

The sulphur specifications were met in the models by hydrotreating the required amount of straight run gas oil. It was assumed for all the cases that the gas oil produced from catalytic cracking and visbreaking underwent hydrotreating regardless of the final products specifications.

TABLE IV.B.12

GAS OIL SULPHUR SPECIFICATIONS

(wt percent sulphur)

Country	1985		1993
	EEC Case	National Case	
Belgium	0.5	0.3	0.2
France	0.5	0.3	0.2
Germany	0.5	0.3	0.2
Italy	0.5	0.5	0.3
Netherlands	0.5	0.3	0.2
Spain	0.5	0.5	0.3
United Kingdom	0.5	0.5	0.3

f) Residual Fuel Oil

The relevant properties of heavy residue streams for fuel oil blending are;

- o viscosity
- o sulphur content

In order to facilitate the viscosity calculation, viscosity blending factors were used which are calculated from the kinematic viscosity of the streams. By using these factors viscosity blending becomes linear, on a weight basis. An important element of the blending is the selection of a suitable cutter stock. In the evaluations, for those cases where the viscosity of the residual material did not meet specifications gas oil was used as the cutter. For all the cases the residual fuel oil was blended to meet a specification of 3 500 Redwood seconds at 38°C which corresponds to a typical marketed grade in Western Europe.

Using the refinery configurations defined for the study little or no flexibility existed to control the sulphur content of the residual fuel oil. In most cases, as the name suggests, the blend streams were residual and of effectively no other use. Within the models the sulphur content of the residual fuel was calculated but not constrained to a predetermined specification. Where is was considered necessary to investigate methods of reducing the sulphur content of the residual fuel, separate analyses were carried out on a case by case basis.

g) Refinery Fuel

In line with the objectives to optimise the mode of operation for the cases considered, refinery fuel was made up of the lowest value by-products. All of the light gases (of otherwise no value) were assumed to be burnt with additional requirements being met by the residual streams of least value for use as residual fuel oil blending components. This approach was adopted as the base mode of operation so that any requirements for the burning of alternative fuels due to environmental constraints could be assessed relative to a consistent basis.

h) Bitumen

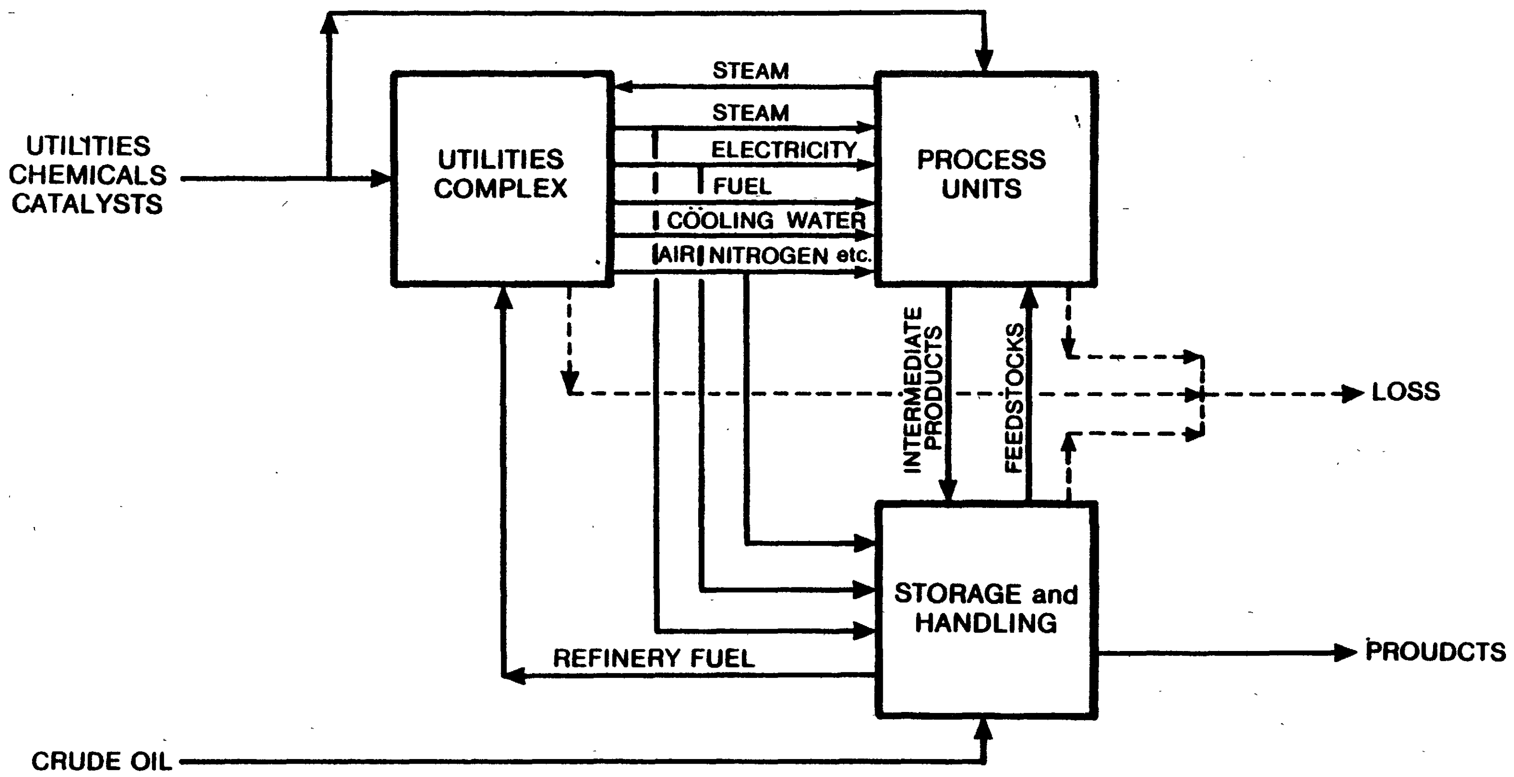
No quality constraints were imposed upon the production of bitumen, although the production rate was fixed for all cases at 4 wt percent of crude oil feed.

7. Offsite Facilities

The overall refinery complex is shown diagramatically in Figure IV.B.4. In addition to the basic processing units the following offsite facilities were assumed for all cases.

FIGURE IV.B.4.

SIMPLIFIED OVERALL REFINERY FLOW DIAGRAM



D863178

- <u>Boilerhouse</u>

A boilerhouse capable of producing all of the refinery steam demand. The steam being generated at high pressure (100 Bar) before being letdown through turbo-alternators down to 17 and 3 bars for refinery consumption as medium and low pressure steam. The turbo-alternator allows the co-generation of electricity for own consumption, the balance of requirements being imported from the local grids.

- <u>Cooling Water</u>

It was assumed that the refinery was served by a comprehensive "closed circuit" cooling water system. A discharge rate of 3 million metric tons of water was used for all cases, differences between the hydroskimming and conversion refineries being considered as minimal due to the extensive use of air cooling on the "newer" conversion units.

The decision to assume a closed circuit system was only taken after careful deliberation in light of the existence (albeit in the minority) of once through systems in some West European refineries. The most recent CONCAWE survey reported that in 1984, 57 of the 87 reporting refineries had liquid effluent discharge rates (largely consisting of cooling water) in the range of 1 to 10 million metric tons per year giving justification to the above assumption.

- <u>Storage and Handling</u>

The refineries were assumed to have a full range of crude oil, intermediate and final product storage, loading and unloading facilities, with loading/unloading taking placed by road, rail or sea as appropriate.

- <u>General Utilities</u>

All other standard utility systems including air, nitrogen, boiler feed water, domestic water and refinery fuel system were assumed available.

C. RESULTS

1. Refinery Balances

Refinery balances and relevant blended product qualities for each of the cases considered are given in Tables IV.C.1 through to IV.C.14. The balances presented represent a summary of the information produced by the LP models. Reproduction in full of all the calculations is not considered necessary but as an example a complete print out including full details of unit operations and product blends is attached in Appendix A, the evaluation shown is the "Germany 1985 National Case" for the conversion refinery configuration.

All of the balances were calculated on a consistent basis within the constraints of feedstock and processing units available as previously defined. The balances are presented as wt percentages based on crude oil processed, these can readily be converted to actual operating rates if required based on the assumed processing rate of 3.75 million metric tons per year for the typical refinery (ie 5 million metric tons per year capacity operated at 75 percent utilisation).

For convenience, fuel consumption and refinery loss are reported together. An average figure of 0.5 wt percent on crude was assumed for the loss component, regardless of the refinery configuration and type of crude processed. Refinery fuel requirements varied typically between 4.0 to 4.5 wt percent for the hydroskimming type to around 5.5 to 6.0 wt percent for the conversion refineries.

Also presented in the tables are the main product qualities which, along with the differences in crude oil slates, resulted in the differences between the balances from case to case. Product specifications were met for all the cases considered, albiet with the inclusion of an isomerisation unit for some of the 1993 evaluations. The only quality give away being in the gasoline pool where some octane give away of RON or MON (depending on which was limiting) occured. This should be considered in light of the fact that it is not possible to exactly meet the specification for both RON and MON together, but using the powerful tool of linear programming the give away can can be limited to, at worst, the equivalent of that achieved in actual refinery blending operations.

TABLE IV.C.1

BELGIUM 1985

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery		Conversion Refinery	
	EEC Case (1)	National Case (1)	EEC Case (1)	National Case (1)
Mass Balances (wt %)				
LPG	2.83	2.83	3.68	3.68
Naphtha	4.00	4.00	4.00	4.00
Gasoline Pool	16.62	16.62	29.18	29.18
Kerosine	6.00	6.00	6.00	6.00
Gas Oil	25.47	25.44	28.21	28.18
Residual Fuel Oil	36.48	36.39	18.86	18.76
Bitumen	4.00	4.00	4.00	4.00
Fuel/Loss	4.60	4.72	6.07	6.20
	100.00	100.00	100.00	100.00
Throughput of Major Units (wt % on Crude)				
Atm Distillation	100.0	100.0	100.0	100.0
Vacuum Distillation	10.8	10.8	31.7	31.7
Reforming	15.7	15.7	15.8	15.8
FCC/Alkylation	-	-	20.0	20.0
Visbreaking	-	-	5.9	5.8
Bitumen	4.0	4.0	4.0	4.0
Gasoline Pool				
RON (Clear)	92.6	92.6	92.6	92.6
MON (Clear)	83.9	83.9	83.0	83.0
Residual Fuel Oil				
Sulphur (wt %)	1.89	1.89	2.34	2.34
Gas Oil				
Sulphur (wt %)	0.5	0.3	0.5	0.3

Note:

(1) Assuming 0.4 g Pb/litre in gasoline.

TABLE IV.C.2

FRANCE 1985

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery		Conversion Refinery	
	EEC Case (1)	National Case (1)	EEC Case (1)	National Case (1)
Mass Balances (wt %)				
LPG	2.70	2.70	3.45	3.45
Naphtha	4.00	4.00	4.00	4.00
Gasoline Pool	17.58	17.58	30.32	30.32
Kerosine	6.00	6.00	6.00	6.00
Gas Oil	25.97	25.94	28.75	28.71
Residual Fuel Oil	35.13	35.03	17.42	17.31
Bitumen	4.00	4.00	4.00	4.00
Fuel/Loss	4.62	4.75	6.06	6.21
	100.00	100.00	100.00	100.00
Throughput of Major Units				
(wt % on Crude)				
Atm Distillation	100.0	100.0	100.0	100.0
Vacuum Distillation	10.8	10.8	31.8	31.8
Reforming	16.4	16.4	16.5	16.5
FCC/Alkylation	-	-	20.0	20.0
Visbreaking	-	-	5.8	5.7
Bitumen	4.0	4.0	4.0	4.0
Gasoline Pool				
RON (Clear)	92.1	92.1	92.1	92.1
MON (Clear)	83.8	83.8	82.9	82.9
Residual Fuel Oil				
Sulphur (wt %)	1.88	1.88	2.36	2.36
Gas Oil				
Sulphur (wt %)	0.5	0.3	0.5	0.3

Note:

(1) Assuming 0.4 g Pb/litre in gasoline.

TABLE IV.C.3

GERMANY 1985

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery		Conversion Refinery	
	EEC Case (1)	National Case (2)	EEC Case (1)	National Case (2)
Mass Balances (wt %)				
LPG	2.15	2.42	2.87	3.26
Naphtha	4.00	4.00	4.00	4.00
Gasoline Pool	17.53	17.06	30.37	29.65
Kerosine	6.00	6.00	6.00	6.00
Gas Oil	26.28	26.26	29.05	29.02
Residual Fuel Oil	35.52	35.62	17.71	17.91
Bitumen	4.00	4.00	4.00	4.00
Fuel/Loss	4.52	4.64	6.00	6.16
	100.00	100.00	100.00	100.00
Throughput of Major Units				
(wt % on Crude)				
Atm Distillation	100.0	100.0	100.0	100.0
Vacuum Distillation	10.5	10.5	32.4	32.4
Reforming	16.2	16.2	16.3	16.3
FCC/Alkylation	-	-	20.0	20.0
Visbreaking	-	-	6.1	6.3
Bitumen	4.0	4.0	4.0	4.0
Gasoline Pool				
RON (Clear)	89.7	92.4	89.7	92.4
MON (Clear)	82.0	84.0	81.0	83.0
Residual Fuel Oil				
Sulphur (wt %)	1.48	1.48	1.88	1.88
Gas Oil				
Sulphur (wt %)	0.5 (3)	0.3	0.5 (4)	0.3

Notes:

(1) Assuming 0.4 g Pb/litre in gasoline.

(2) Assuming 0.15 g Pb/litre in gasoline.

(3) Actual value lower than specification at 0.43 weight percent sulphur.

(4) Actual value lower than specification at 0.41 weight percent sulphur.

TABLE IV.C.4

ITALY 1985

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery		Conversion Refinery	
	EEC Case (1)	National Case (2)	EEC Case (1)	National Case (2)
Mass Balances (wt %)				
LPG	2.62	2.62	3.57	3.57
Naphtha	4.00	4.00	4.00	4.00
Gasoline Pool	16.56	16.56	29.06	29.06
Kerosine	6.00	6.00	6.00	6.00
Gas Oil	24.66	24.66	27.40	27.40
Residual Fuel Oil	37.54	37.54	19.69	19.69
Bitumen	4.00	4.00	4.00	4.00
Fuel/Loss	4.62	4.62	6.28	6.28
	100.00	100.00	100.00	100.00
Throughput of Major Units				
(wt % on Crude)				
Atm Distillation	100.0	100.0	100.0	100.0
Vacuum Distillation	9.4	9.4	34.8	34.8
Reforming	15.9	15.9	16.0	16.0
FCC/Alkylation	-	-	20.0	20.0
Visbreaking	-	-	8.8	8.8
Bitumen	4.0	4.0	4.0	4.0
Gasoline Pool				
RON (Clear)	92.9	92.9	92.9	92.9
MON (Clear)	84.2	84.2	83.2	83.2
Residual Fuel Oil				
Sulphur (wt %)	2.29	2.29	2.87	2.87
Gas Oil				
Sulphur (wt %)	0.5	0.5	0.5	0.5

Notes:

(1) Assuming 0.4 g Pb/litre in gasoline.

(2) All specifications as per EEC Case.

TABLE IV.C.5

NETHERLANDS 1985

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery		Conversion Refinery	
	EEC Case (1)	National Case (1)	EEC Case (1)	National Case (1)
Mass Balances (wt %)				
LPG	2.95	2.95	3.72	3.72
Naphtha	4.00	4.00	4.00	4.00
Gasoline Pool	17.65	17.65	30.35	30.35
Kerosine	6.00	6.00	6.00	6.00
Gas Oil	24.48	24.45	27.22	27.19
Residual Fuel Oil	36.34	36.23	18.65	18.55
Bitumen	4.00	4.00	4.00	4.00
Fuel/Loss	4.58	4.72	6.06	6.19
	100.00	100.00	100.00	100.00
Throughput of Major Units				
(wt % on Crude)				
Atm Distillation	100.0	100.0	100.0	100.0
Vacuum Distillation	10.8	10.8	31.9	31.9
Reforming	16.5	16.5	16.6	16.6
FCC/Alkylation	-	-	20.0	20.0
Visbreaking	-	-	5.9	5.8
Bitumen	4.0	4.0	4.0	4.0
Gasoline Pool				
RON (Clear)	92.1	92.1	92.1	92.1
MON (Clear)	83.8	83.8	82.9	82.9
Residual Fuel Oil				
Sulphur (wt %)	1.73	1.73	2.16	2.16
Gas Oil				
Sulphur (wt %)	0.5	0.3	0.5	0.3

Note:

(1) Assuming 0.3 g Pb/litre in premium gasoline and 0.4 g Pb/litre in regular gasoline.

TABLE IV.C.6

SPAIN 1985

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery		Conversion Refinery	
	EEC Case (1)	National Case (2)	EEC Case (1)	National Case (2)
Mass Balances (wt %)				
LPG	1.90	1.90	2.75	2.75
Naphtha	4.00	4.00	4.00	4.00
Gasoline Pool	16.68	16.68	29.33	29.33
Kerosine	6.00	6.00	6.00	6.00
Gas Oil	24.85	24.85	27.57	27.57
Residual Fuel Oil	38.02	38.02	20.21	20.21
Bitumen	4.00	4.00	4.00	4.00
Fuel/Loss	4.55	4.55	6.14	6.14
	100.00	100.00	100.00	100.00
Throughput of Major Unit				
(wt % on Crude)				
Atm Distillation	100.0	100.0	100.0	100.0
Vacuum Distillation	9.7	9.7	34.0	34.0
Reforming	15.1	15.1	15.2	15.2
FCC/Alkylation	-	-	20.0	20.0
Visbreaking	-	-	7.5	7.5
Bitumen	4.0	4.0	4.0	4.0
Gasoline Pool				
RON (Clear)	88.0	88.0	88.0	88.0
MON (Clear)	80.7	80.7	80.8	80.8
Residual Fuel Oil				
Sulphur (wt %)	2.46	2.46	3.01	3.01
Gas Oil				
Sulphur (wt %)	0.5	0.5	0.5	0.5

Notes:

(1) Assuming 0.6 g Pb/litre in premium gasoline and 0.48 g Pb/litre in regular gasoline.

(2) All specifications as per EEC Case.

TABLE IV.C.7

UNITED KINGDOM 1985

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery		Conversion Refinery	
	EEC Case (1)	National Case (2)	EEC Case (1)	National Case (2)
Mass Balances (wt %)				
LPG	3.10	3.10	3.87	3.87
Naphtha	4.00	4.00	4.00	4.00
Gasoline Pool	18.00	18.00	30.69	30.69
Kerosine	6.00	6.00	6.00	6.00
Gas Oil	24.38	24.38	27.13	27.13
Residual Fuel Oil	35.91	35.91	18.26	18.26
Bitumen	4.00	4.00	4.00	4.00
Fuel/Loss	4.61	4.61	6.05	6.05
	100.00	100.00	100.00	100.00
Throughtput of Major Units				
(wt % on Crude)				
Atm Distillation	100.0	100.0	100.0	100.0
Vacuum Distillation	11.1	11.1	31.3	31.3
Reforming	16.8	16.8	16.9	16.9
FCC/Alkylation	-	-	20.0	20.0
Visbreaking	-	-	5.4	5.4
Bitumen	4.0	4.0	4.0	4.0
Gasoline Pool				
RON (Clear)	92.2	92.2	92.2	92.2
MON (Clear)	83.8	83.8	82.9	82.9
Residual Fuel Oil				
Sulphur (wt %)	1.27	1.27	1.69	1.69
Gas Oil				
Sulphur (wt %)	0.5(3)	0.5(3)	0.5(4)	0.5(4)

Notes:

(1) Assuming 0.4 g Pb/litre in gasoline.

(2) All specifications as per EEC Case.

(3) Actual value lower than specification at 0.35 weight percent sulphur.

(4) Actual value lower than specification at 0.34 weight percent sulphur.

TABLE IV.C.8

BELGIUM 1993

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery (1)	Conversion Refinery (1)
Mass Balances (wt %)		
LPG	2.91	4.37
Naphtha	4.00	4.00
Gasoline Pool	16.68	28.24
Kerosine	6.00	6.00
Gas Oil	25.43	28.16
Residual Fuel Oil	36.11	18.79
Bitumen	4.00	4.00
Fuel/Loss	4.87	6.44
Total	100.00	100.00
Throughput of Major Units		
(wt % on Crude)		
Atm Distillation	100.0	100.0
Vacuum Distillation	10.8	31.7
Reforming	15.7	17.7
FCC/Alkylation	-	20.0
Visbreaking	-	5.8
Bitumen	4.0	4.0
Gasoline Pool		
RON (Clear)	95.4	95.7
MON (Clear)	86.9	85.4 (2)
Residual Fuel Oil		
Sulphur (wt %)	1.89	2.34
Gas Oil		
Sulphur (wt %)	0.2	0.2

Notes:

(1) Assuming the inclusion of an Isomerisation Unit.

(2) Some of the FCC naphtha catalytically reformed in order to meet specification.

TABLE IV.C.9

FRANCE 1993

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery (1)	Conversion Refinery (1)
Mass Balances (wt %)		
LPG	2.74	3.69
Naphtha	4.00	4.00
Gasoline Pool	17.74	30.12
Kerosine	6.00	6.00
Gas Oil	25.92	28.70
Residual Fuel Oil	34.71	17.11
Bitumen	4.00	4.00
Fuel/Loss	4.89	6.38
Total	100.00	100.00
Throughput of Major Units		
(wt % on Crude)		
Atm Distillation	100.0	100.0
Vacuum Distillation	10.8	31.8
Reforming	16.4	16.5
FCC/Alkylation	-	20.0
Visbreaking	-	5.5
Bitumen	4.0	4.0
Gasoline Pool		
RON (Clear)	93.7	93.7
MON (Clear)	85.7	84.4
Residual Fuel Oil		
Sulphur (wt %)	1.88	2.35
Gas Oil		
Sulphur (wt %)	0.2	0.2

Notes:

(1) Assuming the inclusion of an Isomerisation Unit.

TABLE IV.C.10

GERMANY 1993

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery (1)	Conversion Refinery (1)
Mass Balances (wt %)		
LPG	2.55	3.57
Naphtha	4.00	4.00
Gasoline Pool	17.02	29.31
Kerosine	6.00	6.00
Gas Oil	26.23	29.00
Residual Fuel Oil	35.38	17.78
Bitumen	4.00	4.00
Fuel/Loss	4.82	6.34
Total	100.00	100.00
Throughout of Major Units		
(wt % on Crude)		
Atm Distillation	100.0	100.0
Vacuum Distillation	10.5	32.4
Reforming	16.2	16.3
FCC/Alkylation	-	20.0
Visbreaking	-	6.2
Bitumen	4.0	4.0
Gasoline Pool		
RON (Clear)	94.3	94.3
MON (Clear)	86.0	84.7
Residual Fuel Oil		
Sulphur (wt %)	1.48	1.88
Gas Oil		
Sulphur (wt %)	0.2	0.2

Note:

(1) Assuming the inclusion of an Isomerisation Unit.

TABLE IV.C.11

ITALY 1993

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery (1)	Conversion Refinery (1)
Mass Balances (wt %)		
LPG	2.53	3.51
Naphtha	4.00	4.00
Gasoline Pool	16.91	29.34
Kerosine	6.00	6.00
Gas Oil	24.63	27.38
Residual Fuel Oil	37.16	19.33
Bitumen	4.00	4.00
Fuel/Loss	4.77	6.44
Total	100.00	100.00
Throughput of Major Units		
(wt % on Crude)		
Atm Distillation	100.0	100.0
Vacuum Distillation	9.4	34.8
Reforming	15.9	16.0
FCC/Alkylation	-	20.0
Visbreaking	-	8.5
Bitumen	4.0	4.0
Gasoline Pool		
RON (Clear)	93.7	93.7
MON (Clear)	85.6	84.3
Residual Fuel Oil		
Sulphur (wt %)	2.29	2.86
Gas Oil		
Sulphur (wt %)	0.3	0.3

Note:

(1) Assuming the inclusion of an Isomerisation Unit.

TABLE IV.C.12

NETHERLANDS 1993

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery (1)	Conversion Refinery (1)
Mass Balances (wt %)		
LPG	3.19	4.69
Naphtha	4.00	4.00
Gasoline Pool	17.46	28.93
Kerosine	6.00	6.00
Gas Oil	24.43	27.17
ResidualFuel Oil	36.05	18.75
Bitumen	4.00	4.00
Fuel/Loss	4.87	6.46
Total	100.00	100.00
Throughput of Major Units		
(wt % on Crude)		
Atm Distillation	100.0	100.0
Vacuum Distillation	10.8	31.9
Reforming	16.5	17.7
FCC/Alkylation	-	20.0
Visbreaking	-	6.0
Bitumen	4.0	4.0
Gasoline Pool		
RON (Clear)	95.3	95.7
MON (Clear)	86.8	85.3 (2)
Residual Fuel Oil		
Sulphur (wt %)	1.73	2.17
Gas Oil		
Sulphur (wt %)	0.2	0.2

Notes:

(1) Assuming the inclusion of an Isomerisation Unit.

(2) Some of the FCC naphtha catalytically reformed in order to meet specification.

TABLE IV.C.13

SPAIN 1993

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery	Conversion Refinery
Mass Balances (wt %)		
LPG	2.27	3.13
Naphtha	4.00	4.00
Gasoline Pool	16.02	28.64
Kerosine	6.00	6.00
Gas Oil	24.83	27.54
Residual Fuel Oil	38.20	20.39
Bitumen	4.00	4.00
Fuel/Loss	4.68	6.30
Total	100.00	100.00
Throughput of Major Units		
(wt % on Crude)		
Atm Distillation	100.0	100.0
Vacuum Distillation	9.7	34.0
Reforming	15.1	15.2
FCC/Alkylation	-	20.0
Visbreaking	-	7.7
Bitumen	4.0	4.0
Gasoline Pool		
RON (Clear)	92.2	92.2
MON (Clear)	83.9	82.9
Residual Fuel Oil		
Sulphur (wt %)	2.46	3.01
Gas Oil		
Sulphur (wt %)	0.3	0.3

TABLE IV.C.14

UNITED KINGDOM 1993

REFINERY BALANCES/PRODUCT QUALITIES

	Hydroskimming Refinery (1)	Conversion Refinery (1)
Mass Balances (wt %)		
LPG	3.28	4.76
Naphtha	4.00	4.00
Gasoline Pool	17.92	29.42
Kerosine	6.00	6.00
Gas Oil	24.37	27.12
Residual Fuel Oil	35.67	18.42
Bitumen	4.00	4.00
Fuel/Loss	4.76	6.28
Total	100.00	100.00
Throughtput of Major Units (wt % on Crude)		
Atm Distillation	100.0	100.0
Vacuum Distillation	11.1	31.3
Reforming	16.8	17.9
FCC/Alkylation	-	20.0
Visbreaking	-	5.6
Bitumen	4.0	4.0
Gasoline Pool		
RON (Clear)	95.3	95.6
MON (Clear)	86.9	85.3 (2)
Residual Fuel Oil		
Sulphur (wt %)	1.27	1.69
Gas Oil		
Sulphur (wt %)	0.3	0.3

Notes:

(1) Assuming the inclusion of an Isomerisation Unit.

(2) Some of the FCC naphtha catalytically reformed in order to meet specification.

2. Energy and Utility Balances

Detailed energy and utility balances for each of the individual cases considered have not been reported, although the case by case data was used when evaluating the compliance costs for implementation of the environmental control measures. As examples, detailed balances for both hydroskimming and conversion type refineries for the "Germany 1985 National Case" are given in Table IV.C.15. The data presented includes details of assumed capacities, actual operating rates, fired equipment rated duties and fuel, steam and electricity balances for each of the major plants considered. More detailed information of the utilities facilities including steam and electricity generation are given in Figures IV.C.I and 2. As can be seen, there is a significantly lower steam demand on the hydroskimming type than the conversion refinery largely as a result of fewer operating plants and lower throughput on some of the common units, notably the HVU.

3. Sulphur Balances

Under normal operation, sulphur entering a refinery is either emitted as SO_2 or leaves in products which include elemental sulphur from sulphur recovery units. All crude oils contain sulphur, the amount depending on the source. During refinery processing, sulphur is distributed between the various products, a small amount in the light products such as gases and gasoline, more in the middle distillates and the higher levels in the heavy and residual products. Sulphur removal (and subsequent recovery) is effected in order to meet product specifications, most notably in the middle distillate range.

Sulphur balances were carried out for all the cases considered,to provide the basis of further analysis with respect to the implications of environmental legislation measures, both current and foreseen. As examples, balances for both hydroskimming and conversion refineries for the "Germany 1985 National Case" are presented in Table IV.C.16. The following observations are apparent for the conversion refinery when compared to the hydroskimming case;

- o More sulphur is emitted as SO_2 due to higher refinery fuel consumption and higher residual material content in this fuel.
- o Lower sulphur in residual fuel oil due to lower percentage make.
- o Higher sulphur recovery due to high sulphur gas oil produced by catalytic and thermal processes.

TABLE IV.C.15

DETAILED PLANT, ENERGY AND UTILITY BALANCES

GERMANY 1985 NATIONAL CASE

		Atmospheric Distillation	Vacuum Distillation	Reforming	Visbreaking	FCC Plus Alkylation	Boilerhouse /Utilities	Other
Hydroskimming Refinery								
Plant Capacity	(t/d)	14 700	1 530	2 400	-	-	2 400(2)	-
Operating Rate	(t/d)	11 000	1 150	1 780	-	-	745	-
Fired Heating Duty	(MW)	160	12	56	-	-	100	-
Fuel Consumption (1)	(t/d)	260	20	90	-	-	68	19
Steam Consumption	(t/d)	480	115	-	-	-	(745)	150
Electricity Consumption	(MW)	5.5	0.5	1.5	-	-	(3.6)	4.5
Conversion Refinery								
Plant Capacity	(t/d)	14 700	4 750	2 400	800	2 200	3 600(3)	-
Operating Rate	(t/d)	11 000	3 560	1 780	700	2 200	1 400	-
Fired Heating Duty	(MW)	160	37	56	6	20(4)	150	-
Fuel Consumption (1)	(t/d)	260	60	90	14	44	127	30
Steam Consumption	(t/d)	480	350	-	-	390	(1 400)	180
Electricity Consumption	(MW)	5.5	1.3	1.5	0.3	1.2	(6.5)	5.2

Notes:

(1) Standard Refinery Fuel equivalent to 9.6 G cal/metric ton.

(2) Assuming 3 x 800 metric ton per day boilers.

(3) Assuming 3 x 1 200 metric ton per day boilers.

(4) Net duty.

FIGURE IV.C.1.

UTILITES BALANCE FOR HYDROSKIMMING REFINERY
GERMANY 1985 NATIONAL CASE

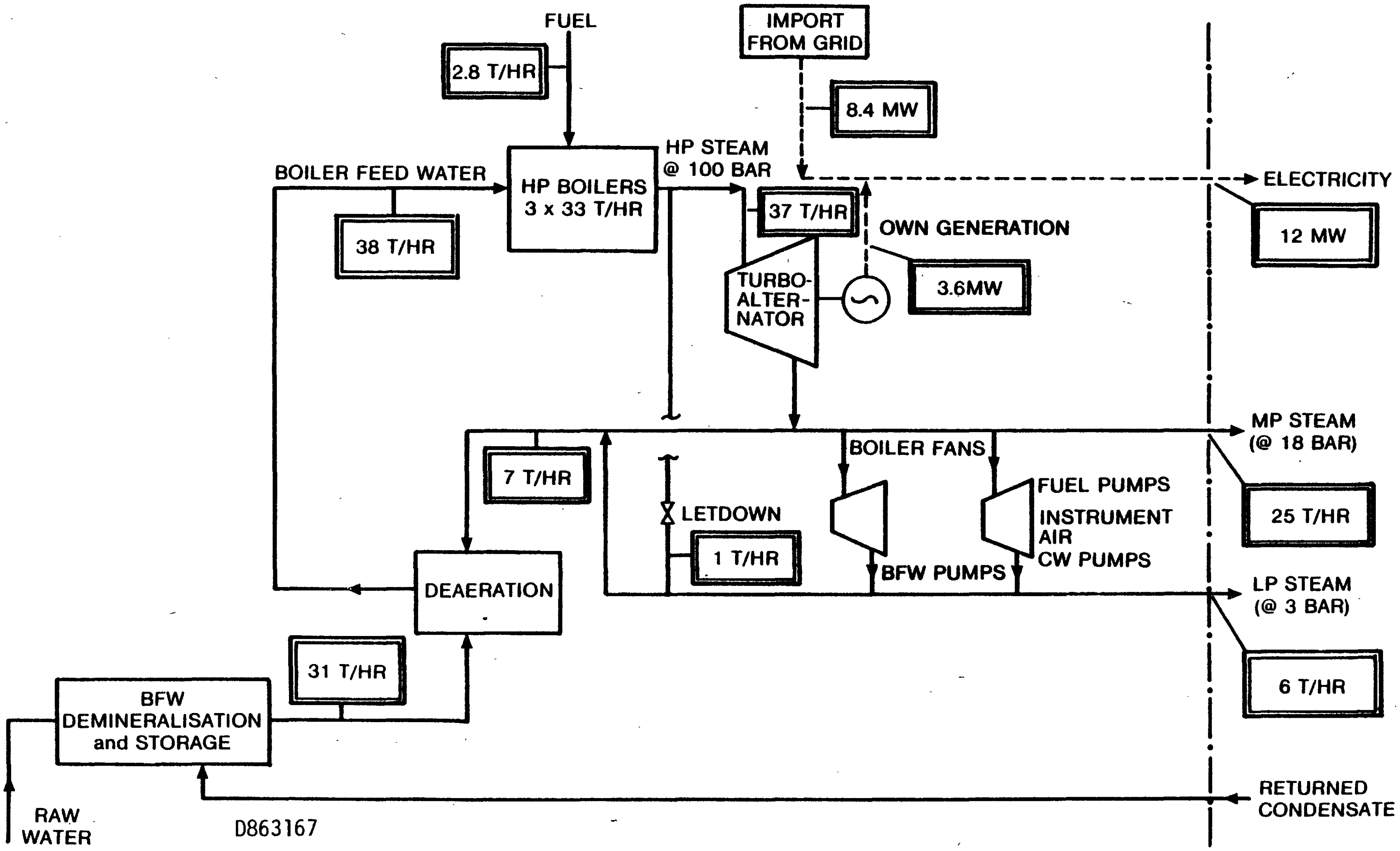


FIGURE IV.C.2.

UTILITES BALANCE FOR CONVERSION REFINERY GERMANY 1985 NATIONAL CASE

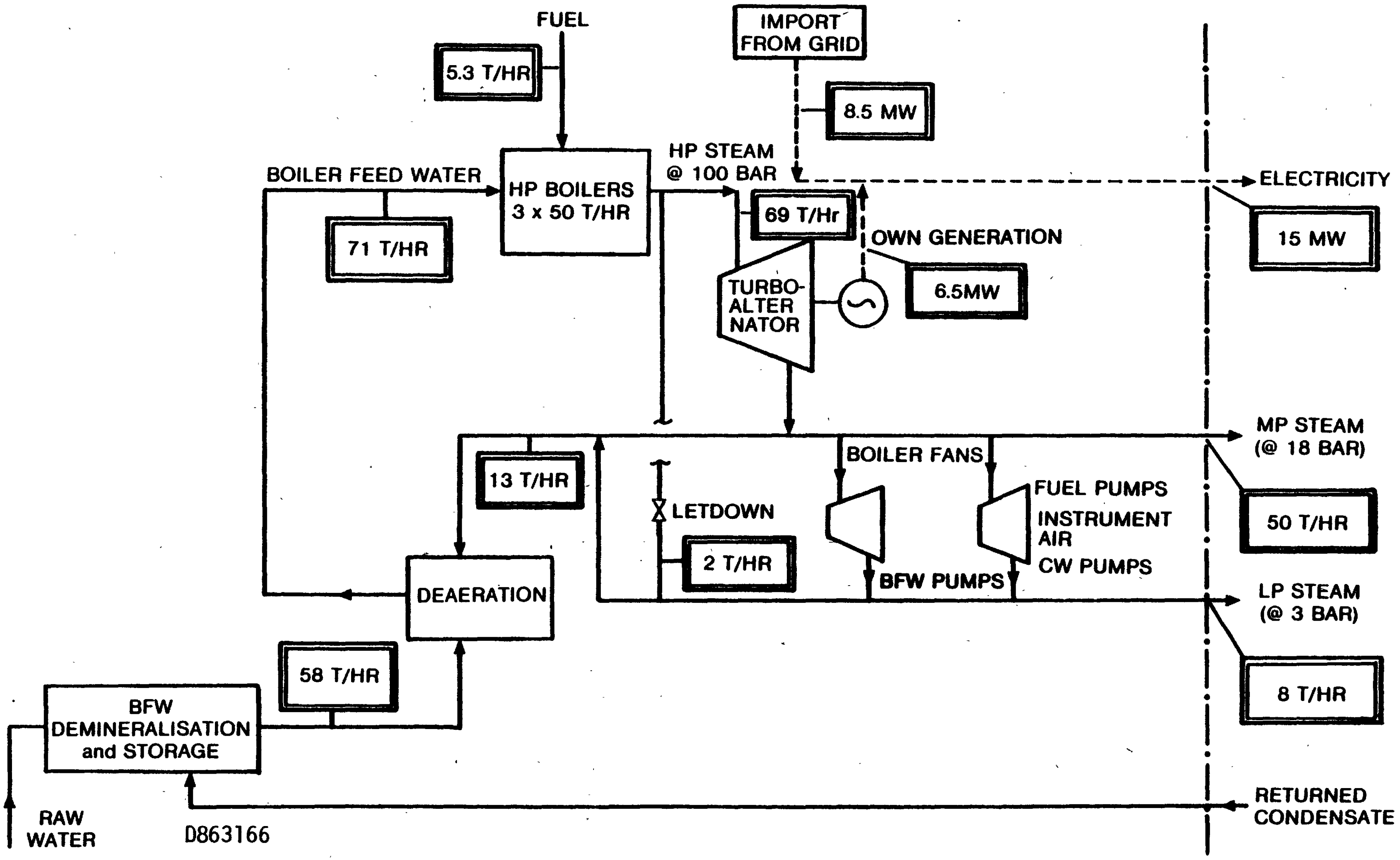


TABLE IV.C.16

SULPHUR OUTPUT FROM REFINERIES

GERMANY 1985 NATIONAL CASE

(wt percent of total sulphur intake)

Category	Hydroskimming Refinery	Conversion Refinery
Sulphur in SO_2 emissions	5	12
Sulphur in distillate products	11	12
Sulphur in residual fuel oil	64	47
Sulphur in non fuel products	11	12
Sulphur recovered	7	12
Unaccounted/loss	2	5
	100	100

SECTION V

V ENVIRONMENTAL COMPLIANCE COSTS

A. INTRODUCTION

This section covers the evaluation of the costs incurred by the refineries in order to comply with the various environmental standards, under the different current and future norms. For the base cases, the only environmental constraints are those required to meet 1985 EEC specifications for product qualities (ie gas oil and gasoline) and the least stringent national specification for heavy fuels.

The cost of environmental compliance were determined for each of the following cases, as a differential above the base case cost.

Community Cases	- 1985 and 1993 - refinery site subject to EEC standards
National Case	- 1985 and 1993 - refinery site subject to EEC and national standards

These cases were considered for both hydroskimming and conversion type refineries in each of the seven member states as previously defined. For each case the relevant legislation was reviewed to determine which environmental constraints are limiting. Having identified limiting constraints for each case, a comprehensive review was carried out of technical measures available which would enable refineries to comply with these environmental requirements. The selection of the most appropriate measures was made on the basis of the following factors:

- o Industry codes and practices
- o Minimisation of investment and operating costs
- o Operating experience (availability, technical problems, etc)
- o By-product disposal problems
- o Other relevant criteria

The choice was limited to technical measures which, in Chem Systems opinion, are proven commercial technology in refineries or related industries. Having selected the "best" technical solution, the incremental investment and associated operating costs for installing it in an existing refinery were estimated. The first step in the procedure was to identify the specific environmental constraints applicable to the individual cases considered.

B. IDENTIFICATION OF ENVIRONMENTAL CONSTRAINTS

By combining the environmental legislation information outlined in detail in Section III with the individual refinery models as defined in Section IV, the limiting environmental constraints were identified for each of the cases considered. For convenience these have been classified under the following headings:

- Gasoline Related
- Sulphur Related (Product Quality)
- Sulphur Related (Air Quality)
- NO_x Related
- Other Air Quality Related
- Other Product Quality
- Liquid Effluent Related
- Other

These are described in detail below:

1. Gasoline Related

The production of gasoline of saleable quality in 1993 will be constrained by the agreement to adopt a single "Euro-grade" unleaded gasoline (95 RON, 85 MON), to be marketed in all member states by 1.10.89 or sooner (EEC Directive 85/210/EEC). This Directive also specifies a maximum benzene content of 5.0 volume percent for all gasoline sold in the Community from 1.10.89.

Minimum octane pool requirements (RON Clear) for all of the base cases in 1985 and Chem Systems best estimates for 1993 are summarised in Table V.B.1. Full details and the assumptions made in estimating the evolution of the gasoline pools are given in Section IV.B.6 (Gasoline Pool Product Qualities). In all cases the MON (Clear) requirements have been assumed to be 10 octane points lower than the RON (Clear).

The technical measures and associated costs to meet these higher octane requirements are discussed later in the report.

TABLE V.B.1

GASOLINE POOL REQUIREMENTS

(RON, Clear)

Country	1985	1993	ΔRON
Belgium	92.6	95.4	2.8
France	92.1	93.7	1.6
Germany	92.4 (1)	94.3	1.9
Italy	92.9	93.7	0.8
Netherlands	92.1	95.3	3.2
Spain	88.0	92.2	4.2
United Kingdom	92.2	95.3	3.1

Note:

(1) The National case is quoted, EEC requirements are less stringent and would have required a gasoline pool of 89.7 RON (Clear).

The requirement to meet 5.0 volume percent benzene in the gasoline pool is a little more difficult to assess quantitatively within the scope and assumptions defined for this study. The benzene content varies significantly between the different gasoline pool blending stocks as shown in Table V.B.2. Points of relevance are:

- The benzene content of straight run naphthas depends on the type of crude and the distillation range. It increases as the distillation range is narrowed around the benzene boiling point (80°C).

- Reformates are the refinery streams with high benzene contents. Benzene is formed via naphtha reforming starting from C6 paraffins and naphthenes. The initial boiling point of the reformer feedstock is the most important variable affecting the reformate benzene content. In this respect other important variables are feedstock crude origin, reforming severity and operating pressure. Benzene yield increases with the severity of operation and by a lowering of the reactor pressure.

- Modest amounts of benzene are also produced by processing cracked residues to lighter products. In these cases benzene ends up in the naphtha boiling range fraction. Cracked naphthas tend to have a higher benzene contents than straight run materials. Reformates from cracked naphtha also show the same trend.

- Pyrolysis gasolines (a by-product of petrochemical manufacture and hence not considered in this study) are, by a wide margin, the blending stocks with the highest benzene contents. Their use in gasoline blending will be significantly reduced after the introduction of the Directive.

- The benzene content of FCC gasoline depends on severity of operation, catalyst used and type of feedstock processed. In the full range naphtha (C5 to 200°C) the benzene content rarely exceeds 1.5 volume percent.

- The hydroskimming refineries tend to produce gasoline with a higher benzene content than the conversion refineries with FCC units because of the higher percentage of reformate, hence aromatics, in the mogas pool.

TABLE V.B.2

BENZENE RANGES FOR COMMON GASOLINE BLENDING STOCKS

(volume percent benzene)

	Range	Typical
Light Virgin Naphtha	0.2-4.0	1.5
Light Cracked Naphtha	0.2-6.0	1.8
Reformate - Low Severity	2.0-5.0	2.5
Reformate - Medium Severity	2.5-6.0	3.0
Reformate - High Severity	3.0-8.0	3.6
FCC Gasoline	0.5-1.5	0.9
Alkylate and LPG	0.0	0.0
Pyrolysis Gasoline(1)	18-40	30.0

Note:

(1) Pyrolysis Gasoline was not considered as a blending component in this study.

Directionally the benzene content increases with the gasoline octane level. Lead phase out will therefore have the effect of increasing the percentage of benzene in gasoline.

However, it should be possible to contain this increase within acceptable limits. Production of unleaded gasoline with a maximum benzene content of 5 percent volume, is considered on an aggregate basis to be a technically achievable target. Using the typical benzene ranges for the model refinery operations analysed in this study, the maximum benzene content was not exceeded. Some individual refiners will, however, find this specification a constraint to their operation.

From a refinery operation perspective, the most important move to reduce the benzene content in the gasoline blend is to reduce the C6 fraction in the reformer feedstock by increasing the naphtha initial boiling point. A draw-back though is the higher amount of LVN to be absorbed in the mogas pool, either directly or via isomerisation. Another possibility, useful if the refinery is producing more than one grade of gasoline, is splitting reformate and other blending stocks, such as FCC gasoline, into light and heavy cuts. By creating more streams with different benzene contents it is possible to slightly reduce the aromatic content of the premium grades at the expense of the regular grades.

Benzene removal from the mogas pool by aromatic extraction processes is not considered a viable proposition because of the high cost involved and the disposal problem of the benzene produced.

2. Sulphur Related (Product Quality)

Sulphur related product quality legislation affects two main refinery product streams, gas oil and residual fuel oil. Further details of the impact of the environmental constraints are given below:

a) Gas Oil

The current legislation regulating the sulphur content of gas oil in the EEC is Directive 76/716/EEC. The Directive specifies two types of gas oil.

Type A - 0.3 wt percent sulphur max
Type B - 0.5 wt percent sulphur max

The authorities in the member states are effectively free to choose either type as a national or local standard.

The Commission has proposed a further reduction to 0.3 and 0.2 wt percent sulphur for type A and type B respectively (COM(85)377), but the Proposal has not been adopted by the Council.

For the purposes of this study, the assumptions shown in Table V.B.3 have been agreed with the Commission.

TABLE V.B.3

MAXIMUM ALLOWABLE SULPHUR CONTENT IN GAS OIL
(wt percent sulphur)

Country	1985		1993
	EEC Case	National Case	
Belgium	0.5	0.3	0.2
France	0.5	0.3	0.2
Germany	0.5	0.3	0.2
Italy	0.5	0.5	0.3
Netherlands	0.5	0.3	0.2
Spain	0.5	0.5	0.3
United Kingdom	0.5	0.5	0.3

b) Residual Fuel Oil

The discussions outlined in Section III have already shown the complexity of measures, current and future, related to sulphur limitations in residual fuel oil (or heavy fuel oil as it is often known). Table V.B.4 summarises the sulphur content of the residual fuel oils calculated in the LP models for the individual cases considered. The data presented assumes a pooling of all the residual products streams, assuming no specific further processing for sulphur reduction has been applied.

TABLE V.B.4

SULPHUR CONTENT OF "UNTREATED" RESIDUAL FUEL OIL

(wt percent sulphur)

	1985		1993	
	Hydroskimming Refinery	Conversion Refinery	Hydroskimming Refinery	Conversion Refinery
Belgium	1.89	2.34	1.89	2.34
France	1.88	2.36	1.88	2.35
Germany	1.48	1.88	1.48	1.88
Italy	2.29	2.87	2.29	2.86
Netherlands	1.73	2.16	1.73	2.17
Spain	2.46	3.01	2.46	3.01
United Kingdom	1.27	1.69	1.27	1.69

This information was used in conjunction with the known legislative measures outlined in Section III to identify the limiting environmental constaints for each case. There are no EEC Council Directives regulating the quality of residual fuel oil and so all the constraints outlined below are resultant from national and/or local regulations restricting the sulphur content in heavy fuel oil.

- Belgium

As Table III.C.2 shows, there are five different sulphur limits applying to heavy fuel oils. Determining the average sulphur content of fuel oil sold would require detailed market analysis and preparation of inherently uncertain forecasts. For the purposes of this study we have therefore made the conservative assumption that the grade with the largest market (large users in the special protection zones) is the specification to be met. The 1985 specification was 3.0 wt percent, which is expected to reduce to 2.2 wt percent by 1993. As can be seen from Table V.B.4 this required the evaluation of compliance costs required to reduce the sulphur content of the residual fuel oil for the "1993 Conversion Refinery Case" from 2.34 to 2.2 wt percent. All other cases were unaffected by the specifications.

- Germany

For Germany the regulations are complex. Effectively the limit on sulphur in heavy fuel oil is set by the allowable emissions under the requirements of TA Luft and GFAVO. The absolute level of allowable sulphur in the fuel varies depending on the size of the combustion sources as well as the stack gas treatment facilities installed (ie Flue Gas Desulphurisation).

Without carrying out detailed sales/user analyses for the current and future German heavy fuel oil market, it is not possible to predict a clear picture of future development. The residual fuel oil market has already shunk dramatically from around 28 million metric tons in 1973 to around 10 million metric tons in 1984/5.

What is foreseen is a continued reduction in size of the home market for heavy fuel oil, with many of the larger users (100 MW+) switching over to gas rather than install FGD units. It is also considered likely that what heavy fuel oil market does remain in 1993 will be reserved for sales to the smaller users, with the high sulphur material being burnt in facilities with FGD units installed. Much of the development outlined above will depend upon technological progress made in the field of FGD/NO_x clean up in the years leading up to 1993.

For the 1985 base cases it was assumed that the residual fuel oil "as produced" could be sold in the home market without the need for further processing. For the 1993 cases sulphur content in the heavy fuel oil product of 1.0 wt percent was assumed.

As can be seen from Table V.B.4 this required the evaluation of compliance costs required to reduce the sulphur contents from 1.48 and 1.88 wt percent sulphur for the hydroskimming and conversion type refineries respectively.

o <u>Netherlands</u>

In Chem Systems view the cut in sulphur content from 2.0 to 1.0 weight percent in June 1986 will have little effect on refinery operation, since the Netherlands inland market for heavy fuel oil has largely disappeared, with the largest local market being for ships bunkers. But in line with the terms of reference of the study, compliance costs will be estimated for the 1993 cases.

o <u>France, Italy, Spain and United Kingdom</u>

For these countries, the current and known future sulphur limits can be met by segregation of high and low sulphur fuel oil components as currently practiced in refinery blending. As a result, no additional control measures or expenditure were considered.

3. Sulphur Related (Air Quality)

Of the sulphur entering the refinery in the crude oil feed, typically around 6 wt percent for the hydroskimming type and 12 wt percent for the conversion type is discharged to atmosphere as sulphur dioxide (SO_2). Around 70 percent of this SO_2 is attributable to the refinery fuel fired in the boilers and process furnaces, and around 10 percent arises from the sulphur recovery plants with the remainder coming from other sources such as fluid catalytic crackers (from coke burn-off) and refinery flare systems.

The quantity of SO_2 discharged to atmosphere from a refinery depends upon the sulphur content in the crude oil feed, processing units available, mode of operation and product quality constraints.

During the LP modelling, sulphur balances were carried out for all the cases and the sulphur content of the refinery fuels (the largest contribution of SO_2 to the atmosphere) are given Table V.B.5.

The legislative measures pertaining to SO_2 emission for each of the member states were described in detail in Section III. A summary of the relevant limits is given in Table V.B.6. All of these limits relate to national legislation as the current EEC Directives do not impose specific emission limits on the operation of European Refineries. A summary of the specific constraints relating to sulphur emission from within the refinery fence resulting from the national legislative measures are outlined on a country by country basis below:

- Belgium

It is considered that all current, and future legislative measures can be met without needing to modify the mode of operation simulated by the LP models. As a result, no additional control measures or expenditure were considered.

TABLE V.B.5

AVERAGE SULPHUR CONTENT OF REFINERY FUEL (LIQUID AND GAS)

(wt percent sulphur)

	1985		1993	
	Hydroskimming Refinery	Conversion Refinery	Hydroskimming Refinery	Conversion Refinery
Belgium	1.23	2.13	1.31	2.04
France	1.25	2.16	1.34	2.20
Germany	1.01	1.68	1.05	1.69
Italy	1.48	2.45	1.62	2.58
Netherlands	1.16	1.99	1.19	1.82
Spain	1.86	2.99	1.70	2.81
United Kingdom	0.82	1.46	0.86	1.35

TABLE V.B.6

SUMMARY OF CONTROLLING SULPHUR DIOXIDE EMISSION LIMITS

Country	1985 Case		1993 Case (1)	
	Emission (SO_2)	Fuel Sulphur (wt percent)	Emission (SO_2)	Fuel Sulphur (wt percent)
Belgium	5 000mg/m^3	3.0	3 700mg/m^3	2.2
France (2)	8 x C t/d (3)		8 x C t/d (3)	
Germany				
Combustion Sources	2 500mg/m^3		1 700mg/m^3 and FGDS or all gas firing	
FCC Units	-		1 700mg/m^3	
Claus Plants	98 percent S recovery		98 percent S recovery	
Italy (4)		3.0		3.0
Netherlands		2.0	2 000mg/m^3	
Spain				
Boilers and Furnaces	5 900mg/m^3		5 900mg/m^3	
Other Units	3 400mg/m^3		3 400mg/m^3	
Total Site	7 x C t/d(3)		7 x C t/d(3)	
United Kingdom (5)		-		-

Notes:

(1) Basis Existing Legislation only.

(2) 'Typical' figure (Chem Systems estimate).

(3) C = Crude distillation capacity (million metric tons per year).

(4) Maximum fuel oil sulphur specification assumed to apply to average refinery fuel. May be relaxed to 4.0 percent by local authorities.

(5) No National Standards.

o **France**

The only potentially limiting legislation is the requirement to restrict the total SO_2 emission from the refineries to within a typical limit of "8 x C" metric tons per day, where "C" is the installed crude distillation capacity (in million metric tons per year). The total SO_2 emissions for all the cases considered are given in Table V.B.7 and it can be seen that they all lie within the required limit. No additional control measures or expenditure were therefore considered.

TABLE V.B.7

SULPHUR DIOXIDE EMISSIONS TO ATMOSPHERE FROM FRENCH REFINERIES
(metric tons per day SO_2)

Type	1985(1)	1993(1)
Hydroskimming Refinery	2.8xC(2)	3.2xC(2)
Conversion Refinery	6.6xC(2)	6.8xC(2)

Notes:

(1) Assumming 5 million metric tons per year distillation capacity operating at 75 percent utilisation.
(2) C = Crude distillation capacity (million metric tons per years).

o **Germany**

Refinery combustion sources are covered by two main national legislative acts, the 13 ordinance of the Federal Immission Control Act (GFAVO) of 23.6.83, which applies to large combustion sources and the Technical Requirements of the Administrative guideline for the Air Quality (TA Luft) of 27.2.86. The application of the these is complex and has been extensively covered in Section III. A summary of the controlling factors on sulphur emission is given in Table V.B.6.

For the 1985 cases the emission limits were 2 500 mg/m^3 which is equivalent to around 1.5 wt percent sulphur in the fuel. Although, as shown in Table IV.B.5, the sulphur content of the refinery fuel was calculated to be marginally above this value for the "1985 Conversion Type Refinery" it was considered that by switching some of the high sulphur liquid fuel with the lower sulphur blend components of the residual fuel oil product that the specifications could be met. As a result, no cost need be allocated for control measures. All cases were though required to meet a constraint of 98 percent recovery on the sulphur recovery units.

For the 1993 cases, the legislative measures will become significantly tighter meaning a reduction of the allowable sulphur in stack gases down to 1 700 mg/m^3 and flue gas desulphurisation or all gas firing. The limit of 1 700 mg/m^3 will also apply to burn off gases emitted from the FCC's. At the time of writing, the required sulphur removal efficency on the Claus plants was also expected to increase to 99.5 percent for all units greater than 50 metric tons per day capacity for future years. The legislation has now fixed this as a requirement for implementation by 1996 although this was included for the 1993 cases. For the 1993 cases, the assumption was made that the refinery would be treated as a single stack source, and hence the GFAVO regulations will be controlling.

- <u>Italy</u>

There are no relevant national emission regulations applied in Italy. The controlling regulation is therefore the maximum fuel sulphur content of either 3.0 (or 4.0) percent, which is comfortably met.

- <u>Netherlands</u>

The LP models for the base case condition in 1985 indicated that the average sulphur content of the refinery fuel was below the 2 wt percent level required by legislation for all the relevant cases. Evaluation of additional control measures and expenditure was not therefore required. More stringent limits, equivalent to a maximum of 1.2 wt percent sulphur, will result from legislation coming into force in 1991.

o Spain

The only potentially limiting legislation is the requirement to restrict the total SO_2 emission from the refineries to within "7 x C" metric tons per day, where "C" is the installed crude distillation capacity (million metric tons per year).

The total SO_2 emissions for all the cases considered are given in Table V.B.8 and it can be seen that the hydroskimming refinery cases all lie within the required limit. No additional control measures or expenditure were therefore considered. For the "1985 and 1993 Conversion Refinery Cases" the levels slightly exceed the limits. Exchange of high sulphur fuel with low sulphur blend components from the residual fuel oil product allow the refinery emission limits to be meet without exceeding the sulphur specification limits of the residual fuel oil product.

TABLE V.B.8

SULPHUR DIOXIDE EMISSIONS TO ATMOSPHERE FROM SPANISH REFINERIES
(metric tons per day SO_2)

Type	1985(1)	1993(1)
Hydroskimming Refinery	4.0xC(2)	3.8xC(2)
Conversion Refinery	9.0xC(2)	8.4xC(2)

Notes:
(1) Assuming 5 million metric tons per year distillation capacity operating at 75 percent utilisation.
(2) C = Crude distillation capacity (million metric tons per year).

o United Kingdom

There are no relevant national emission regulations applied in the United Kingdom.

4. NO_x Related

Different types of refinery emit different quantities of NO_x depending on their configuration, mode of operation and the crude oil being processed. Sources of NO_x emissions from refineries may be subdivided as follows:

- Process Heaters
- Steam Boilers
- Fluid Catalytic Cracking Units (and associated CO boiler)
- Internal Combustion Engines, Gas Turbines etc
- Flaring of Waste Gases etc

For the purpose of this study only the first three sources have been considered in any detail as they form the major contribution of NO_x. The NO_x is formed during combustion, by the reaction of atmospheric nitrogen and oxygen at flame temperature. In general terms the higher the flame temperature and longer the residence time the more NO_x is formed. If the fuel contains nitrogen compounds then this nitrogen will also be partly converted to NO_x but this effect is small compared to the mechanism mentioned above.

Trying to quantify case by case emissions of NO_x for the individual refineries evaluated is neither practical nor particularly meaningful. Drawing up correlations for the emission levels from the information presentented in the terms of reference was therefore not attempted. For simplification it was assumed that the NO_x emission level was 500 mg/Nm^3 in the flue gas of the average European refinery (as reported by CONCAWE report No. 7/84). This figure was used in all of the compliance requirement assessments.

Germany is the only country within the group studied which applies quantitative NO_x emission limits on refinery units. Combustion sources are regulated by the GFAVO and FCC units are included in the most recent version of the TA Luft. Interpretation of the regulations is complex and certain simplifying assumption were made when carrying out the evaluation of compliance costs resulting from meeting these regulations.

For 1985 it was assumed that the average level of NO_x emitted from refinery stack gas was within the limits set by the regulations. The regulations applicable to 1993 are still under discussion and as a result three cases were considered in order to fully assess the potential impact of the range of regulations which might apply in that year. These are summarised in Table V.B.9.

TABLE V.B.9

CONTROLLING NO_x LIMITS FOR GERMAN REFINERIES IN 1993(2)

(NO_x mg/Nm^3)

Case	Liquid Fuel (1)	Gaseous Fuel (1)
Minimum Control Case	700	500
Maximum Control Case	150	100
Intermediate Control Case	450	350

Notes:

(1) Only known legislation considered.
(2) For FCC units a limit of 700 mg/Nm^3 NO_x assumed for all cases.

5. Other Air Quality Related

The following items are considered under this heading. All of them arise from legislative measures relating to German refineries.

- Hydrocarbon Emissions
- Particulates
- Continuous Monitoring

a) Hydrocarbon Emissions

The only regulations which refer directly to hydrocarbon emission limits are again only applicable to Germany. The TA Luft (of 27.2.86) requires the application of a number of technical measures generally defined as "good practice requirements" designed to reduce hydrocarbon emissions. These measures cover a significant portion of the emissions which make up the identifiable component of the refinery loss, which themselves cover approximately 50-70 percent of the total refinery loss (already discussed as being around 0.5 wt percent on crude oil feed).

The areas broadly covered by the legislation include the minimisation of emissions from storage tanks, pumps, compressor, flanges, valves, flaring, API oil separators, gas collection systems, relief systems, sampling etc. The TA Luft also requires the installation of vapour recovery units at loading installation in refineries and depots. All of these areas were evaluated with respect to compliance requirements for the 1993 cases.

b) Particulates

Germany is again the one country within the group studied which applies quantitative restrictions on particulate emissions from refinery and other liquid and gas fired combustion sources. The regulations on combustion sources are contained in GFAVO and for FCC units in the 1986 version of TA Luft.

The effect of these regulations on refinery operation are not easy to assess due to the lack of reliable data on particulate emissions. However, it is reasonably certain that these regulations are not a constraint on refinery operation, since the actual fuel mix contains a substantial proportion of gas.

It is worth noting that a further reduction in particulate emission will result indirectly from the significant increase in gas firing which is likely to occur in order to achieve the outlined requirements for reduction in NO_x and SO_2 emissions.

The technical implications of the new particulate emission limits for FCC units are not as yet clear. In light of this uncertainty technical measures for the reducing the levels below those achievable using conventional dust cyclones were not investigated in depth.

c) Continuous Stack Monitoring

A further requirement in Germany is the need to carry out continuous monitoring of stack emission levels. Continuous monitoring facilities in each stack are required for CO, particulates, NO_x, SO_2 and O_2.

6. Other Product Quality

a) Nickel Content of Heavy Fuel Oil

Future German legislation will limit the allowable nickel content from air borne emissions to 2 mg/m^3 which is equivalent to limiting the nickel content of the residual fuel oil to 24 ppm. Meeting this specification will need to be considered when assessing the components of the residual fuel oil blend. Typical nickel contents in the vacuum residue for various crude oils are given in Table V.B.10.

TABLE V.B.10

TYPICAL NICKEL CONTENTS OF VACUUM RESIDUE FROM VARIOUS CRUDE OILS

(ppm Nickel)

Crude Oil	Nickel Content
Arabian Medium	35
Iranian Light	55
Iraq-Kirkuk	30
Kuwait	40
Libya	30
Algeria	5
Nigeria	15
Venezuela Medium	150
Qatar	10
North Sea	10
Mexican	150

7. Liquid Effluent Related

The effluent quality limits in the different member states are a mix of national discharge limits, regional limits, guidelines and case by case site specific limits. Differences in analytical methods and sampling procedures further complicate intercountry comparisons.

The applicable regulations for the member states are summarised in Table V.B.11. For the purposes of this study information on actual installed facilities was used to assess the impact of the legislative measures. Table V.B.12 gives details of the proportion of each of the main types of treatment applied in refineries in the member states considered, these ratios were used to assess the compliance costs for the 1985 cases. For 1993 it was assumed that all of the refineries would be equipped with full three stage treatment facilities. This is likely to be achieved by means of gradual evolutionary upgrading as opposed to a direct response to specific legislative measures.

TABLE V.B.11

LIQUID EFFLUENT CONTROL REGIMES FOR REFINERIES

Belgium:	National effluent quality standards Standards differ for three types of refinery, viz - simple hydroskimming - complex - complex plus lubes or petrochemicals
France:	National regulations and effluent specifications Regional and local authorities may require stricter limits Standards differ for three types of refinery (as Belgium) Taxes are levied on effluents by the regional authorities.
Germany:	National regulations and effluent specifications Regulations include "commonly accepted rules of technology" Effluent tax law with penalties for exceeding discharge limits
Italy:	National regulations Intentional dilution of effluents forbidden No specific refinery standards - effluents must conform to quality specifications for industrial effluents
Netherlands:	Requirements are established for each refinery Licensing controlled by local/regional authorities Best practicable means technology required with respect to dangerous substances (EEC List I) Type and age of refinery taken into account
Spain:	National legislation on refinery effluents Regional and local authorities can impose additional legislation (and taxes) Standards differ for different types of refinery (see Belgium above)
United Kingdom:	No national discharge standards Discharge "consent" regulations are set for each refinery, based on absorptive capacity and Environmental Quality Objective of the receiving water Regional Water Authorities are the administering agency

TABLE V.B.12

EFFLUENT WATER TREATMENT FACILITIES (1985)

(percentage of refineries)

Country	Type A (1)	Type A + B (2)	Type A + B + C (3)
Belgium	-	-	100
France	-	-	100
Germany	-	10	90
Italy	-	15	85
Netherlands	-	10	90
Spain	40	-	60
United Kingdom	60	10	30

Notes:

(1) Type A = Gravity Separation Only.
(2) Type A + B = Gravity Separation and Advanced Treatment.
(3) Type A + B + C = Gravity Separation, Advanced Treatment and Biological Treatment.

8. Other

a) Environmental Noise

Compliance with environmental noise legislation has been identified as a problem although the degree of the problem is very specific to the location of the individual refinery. As an indication of the potential impact of the legislation, an industry study in Germany indicated that less than 5 percent of the total environmental control expenditure over a ten year period was accountable to environmental noise control. It should though be borne in mind that where a problem is identified the cost of effecting significant noise reductions can be very high.

b) Site Clean Up

Soil clean up, particularly on redundant refinery sites, is emerging as a general industry problem. Again the costs involved are highly variable and depend almost totally on the specific site conditions.

C. SELECTION OF TECHNICAL CONTROL MEASURES

The constraints arising from the current and future environmentally related legislation were summarised in the last section for the seven member states considered in this study. This section provides a review of technical measures available to comply with the legislation outlined. Information is given on capital investment costs as well as technical details for the processes considered. Associated operating costs were also estimated, these costs including:

- Catalysts
- Chemicals
- Utilities such as fuel (unless otherwise stated), power and cooling water
- Labour
- Maintenance (assumed to be 3 percent per year of installed capital cost)
- Site Overheads
- By-product credits
- Waste-disposal costs

Depreciation and return on investment were not taken into account and should be assessed separately if required. For convenience the operating costs were expressed as a percentage per year of the installed capital costs although it should be borne in mind that deriving "typical" operating costs is not an easy task since they tend to be very site specific. We are however confident that the order of magnitude of the data presented is representative of average European operation.

Cost estimation for revamp work is difficult due to great variances possible for the application of the same modificaton on different sites, particularly if available space or access are limited. The data used were obtained and cross checked from many established sources including Engineering Contractors, Refinery Project Departments and Equipment Suppliers. The major utility and labour costs assumed in the evaluations are given in Table V.C.1.

TABLE V.C.1

UTILITY AND LABOUR COSTS (MID 1985)

(ECUs per unit)

	Unit	Cost
Power	MWh	45
Heavy Fuel Oil	t	185
Steam (LP)	t	15
Steam (MP)	t	18
Cooling Water	kt	23
Operator	Man-yr	16 250
Foreman	Man-yr	22 500
Supervisor	Man-yr	33 500

All of the cost data is based on Typical mid 1985 values and the following exchange rates were assumed. Full details of the exchange rates assumed for each of the member states considered in the study are given in Appendix B.

1 ECU = 0.8 US Dollars
1 ECU = 0.6 UK Pounds
1 ECU = 2.4 German DM

No account was taken of the costs associated with the refinery downtime required to effect the modifications nor of the potential impact on plant reliability resulting from the new installations.

The choice of technical measures has been limited to proven technology, although where considered relevant comment has also been made of anticipated development or improvement in technology likely to occur between now and 1993. The selection of "best" technical solution based on economic considerations is not always clear cut and where considered relevant, alternative evaluations were carried out for comparison.

For consistency and ease of reference, the same section headings as used under Section V.B (Identification of Environmental Constraints) are adopted.

1. Gasoline Related

Removing lead from the gasoline pool forces the refiner to increase the average octane number of the pool. This can directionally be achieved by:

- Increasing the aromatic content, which is primarily done by producing reformates of higher octane.
- Increasing the degree of isomerisation. The direct way is via isomerisation of light virgin naphthas, but it should also be remembered that addition of more alkylate or polygas to the blends leads to the same effect.
- Addition of high octane blending stocks such as oxygenates.

The first route is by far the most important and this will force the refiner to refocus his attention (which during the last decade has been devoted primarily to residue upgrading facilities), to reforming operations. The contribution of the second alternative is also significant. The third possibility is perhaps of less general importance, though it will prove quite useful to several refiners.

From an overall refinery balance point of view, lead phase out from the gasoline pool has the effect of increasing the percentage of LPG and/or residual fuel oil in the product slate. This is a consequence of the higher light hydrocarbons production (lighter than C_4) associated with the increased reforming severity. Most of the incremental gas, in fact, ends up in the refinery fuel system, displacing liquid fuel oil which, in turn is routed to the residual fuel oil pool after addition of a suitable amount of cutter stock. Part of the incremental gas (the C_3 and C_4 fraction) is assumed to be recovered as LPG. Another effect is an increased refinery energy requirement, due to the more severe operations, which is reflected in a higher refinery fuel and losses percentage on total crude processed.

When assessing the operating costs associated with the introduction of unleaded gasoline, consideration was given to the need to process more crude oil to produce effectively the same product slate.

Table V.C.2 summarises the possible processing alternatives open to the refiner to increase the octane of the gasoline pool.

TABLE V.C.2

WAYS OF INCREASING THE GASOLINE POOL OCTANE

Refinery Configuration		Action
Hydroskimming	o	Increasing reforming severity
	o	Adding light naphtha isomerisation
Conversion	o	Increasing reforming severity
	o	Using octane specific FCC catalyst (usually no effect on MON)
	o	Producing more alkylate/polygas by: - Adding more capacity, - Isomerising n-butane to isobutane, - Producing more olefins in the FCC at the expense of cracked gasoline. - Upgrading to gasoline all the available propylene.
	o	Producing MTBE from FCC butylenes (alternative to alkylation)
	o	Adding light naphtha isomerisation
	o	Reforming a portion of the FCC naphtha

The most important tool available to the refiner when looking to increase the octane of the gasoline pool is catalytic reforming. As previously outlined many different types of reformer are installed throughout Western Europe, capable of differing modes of operation. A summary of the most important parameters are given in Table V.C.3. It should be understood that the values shown are indicative and are meant to represent feasible commercial operation over prolonged periods. It could be possible, for short periods to exceed these limits.

TABLE V.C.3
PRACTICAL OCTANE CEILING FOR WEST EUROPEAN REFORMING UNITS

	Reactor Pressure (bars)	Octane Ceiling (1) (RON clear)
Semi-Regenerative Process		
Old units (2)	30-35	95-96
Revamped (3)	20-25	96-98
New units (4)	17-18	98-100
CCR Process	8-13	102

Notes:

(1) Indicative, assuming a "poor" feedstock and minimum cycle length of 6 months

(2) Using monometallic catalyst

(3) Units originally designed for monometallic catalyst or high pressure operation and converted to low pressure, using modern high stability bimetallic catalysts

(4) Units specifically designed for low pressure operation and high stability bimetallic catalyst.

In order to maintain consistency, the techniques for increasing the gasoline pool octane were confined to three basic technologies and their application was aproached sequentially as follows:

- firstly, the octane level from reforming was increased to the maximum economically practical,

- secondly, when the limits of the above were reached an isomerisation unit capable of upgrading the light virgin naphtha was made available to the models,

- finally, if the octane specification was still not reached the model was allowed to catalytically reform the required amount of FCC naphtha to meet requirements.

The above was carried out on a consistent basis using the LP models for each case. A summary of the appropriate capital investment costs for the installation of these measures is given in Table V.C.4.

TABLE V.C.4

INSTALLED CAPITAL COSTS FOR OCTANE IMPROVEMENT PROCESSES (MID 1985)

	Capacity (t/d)	Capital Cost (million ECUs)
Revamping Existing Semi-Regenerative Units		
95-96 RON increased to 98 RON	2 400	31
96-98 RON increased to 100 RON	2 400	19
New CCR Unit (102 RON maximum)	2 400	65
Isomerisation Unit	600	10

Operating costs for the above were estimated to be 18 percent of capital costs per year, of which the major component is for fuel requirements Offsite and storage requirements were considered separately.

2. Sulphur Related (Product Quality)

The product qualities affected by environmental legislation related to sulphur content were gas oil and heavy fuel oil. The technical measures required to meet the appropriate product specification are discussed below.

a) Gas Oil

In order to reduce the sulphur content of the gas oil product from the base case level of 0.5 wt percent down to 0.2 or 0.3 wt percent (depending on case under consideration) additional desulphurisation was assumed to be carried out.

All of the refinery cases assessed were assumed to have existing hydrodesulphurisation (HDS) units. In order to quantitatively assess the costs associated with additional desulphurisation it was required to ascertain a representative capacity for the existing HDS units. In a survey carried out by CONCAWE in 1984 (Report No. 11/84) it was reported that in 1982 (latest data available) the average West European installed HDS capacity was 20 percent of the installed primary distillation capacity. Further it was reported that the intake of this installed capacity was around 75 percent of the nominal capacity, very much in line with the terms of reference of this study. The report also indicated that the maximum utilisation of this installed capacity could never exceed 90 percent on average, due to seasonality effects. HDS capacity of 20 percent of installed distillation capacity is equivalent to 27 percent based on crude oil processed (assuming 75 percent utilisation of distillation capacity). Using the average maximum utilisation factor of 90 percent outlined above this is equivalent to 24 percent usable capacity based on crude oil feed, this was assumed to be the existing base capacity for all the cases considered. Of this 24 percent, 6 percent was required for the desulphurisation of the kerosine product leaving a useful HDS throughput of 18 percent for the gas oil products. Table V.C.5 gives the gas oil production, sulphur content and required desulphurisation throughput for all the cases considered. As can be seen the existing HDS capacity (18 percent) was adequate to meet all of the 1985 cases. Table V.C.6 gives the new HDS capacity required for the 1993 cases (ie that over and above the existing 18 percent available).

TABLE V.C.5

GAS OIL HYDRODESULPHURISATION REQUIREMENTS

Country	1985				1993	
	Hydroskimming Refinery		Conversion Refinery		Hydroskimming Refinery	Conversion Refinery
	EEC Case	National Case	EEC Case	National Case		
Belgium						
Gas Oil Product (wt % on crude)	25.47	25.44	28.21	28.18	25.43	28.16
Sulphur Content (wt %)	0.5	0.3	0.5	0.3	0.2	0.2
Total HDS Throughput (wt % on crude)	3.46	13.63	5.90	17.17	18.71	22.79
France						
Gas Oil Product (wt % on crude)	25.97	25.94	28.75	28.71	25.92	28.70
Sulphur Content (wt %)	0.5	0.3	0.5	0.3	0.2	0.2
Total HDS Throughput (wt % on crude)	3.09	13.67	5.48	17.20	18.94	23.04
Germany						
Gas Oil Product (wt % on crude)	26.28	26.26	29.05	29.02	26.23	29.00
Sulphur Content (wt %)	0.5	0.3	0.5	0.3	0.2	0.2
Total HDS Throughput (wt % on crude)	-	8.81	3.3	11.81	15.70	19.43
Italy						
Gas Oil Product (wt % on crude)	24.66	24.66	27.40	27.40	24.63	27.38
Sulphur Content (wt %)	0.5	0.5	0.5	0.5	0.3	0.3
Total HDS Throughput (wt % on crude)	8.64	8.64	11.51	11.51	16.71	20.47
Netherlands						
Gas Oil Product (wt % on crude)	24.48	24.45	27.22	27.19	24.43	27.17
Sulphur Content (wt %)	0.5	0.3	0.5	0.3	0.2	0.2
Total HDS Throughput (wt % on crude)	0.87	11.49	2.74	14.85	16.79	20.74
Spain						
Gas Oil Product (wt % on crude)	24.85	24.85	27.57	27.57	24.83	27.54
Sulphur Content (wt %)	0.5	0.5	0.5	0.5	0.3	0.3
Total HDS Throughput (wt % on crude)	10.06	10.06	13.12	13.12	17.44	21.30
United Kingdom						
Gas Oil Product (wt % on crude)	24.38	24.38	27.13	27.13	24.37	27.12
Sulphur Content (wt %)	0.5	0.5	0.5	0.5	0.3	0.3
Total HDS Throughput (wt % on crude)	-	-	2.75	2.75	4.01	6.62

TABLE V.C.6

NEW GAS OIL HYDRODESULPHURISATION REQUIREMENTS
(wt percent on crude)

Country	1993	
	Hydroskimming Refinery	Conversion Refinery
Belgium	0.71	4.79
France	0.94	5.04
Germany	-	1.43
Italy	-	2.47
Netherlands	-	2.74
Spain	-	3.30
United Kingdom	-	-

A summary of the costs associated with the installation of new HDS capacity are given below:

Basis:

HDS unit of 2 200 metric tons per day capacity and sulphur removal efficiency of 80 percent.

Installed Capital Cost:

31 million ECUs (including incremental costs for associated amine treating, sulphur recovery and hydrogen purification units).

Operating Costs

12 percent per year of installed capital cost, of which approximately half is for fuel requirements.

b) Residual Fuel Oil

As previously identified, environmental legislation is likely to increasingly limit the allowable sulphur content of marketable heavy fuel oil. Constraints were identified for the 1993 reference year in Belgium, Germany and the Netherlands.

For refineries which cannot meet the tighter residual fuel oil specifications for 1993, the following options exist;

- o Export or exchange the residual fuel oil outside of the home market
- o Desulphurise the residual fuel oil (subject to technology limitations)
- o Leave market and build residue upgrading facilities such as cokers
- o Switch to lower sulphur crude oil feed (subject to availability)

For the purposes of this study the first two options were considered when investigating the relevant environmental compliance cost. Quantitative assessment of the last two options were not considered practical within the terms of reference of this study.

Techniques for the reduction of the sulphur content in residual streams are fairly well established as a result of the impact of similar legislation imposed over the last couple of decades outside of Europe, particularly in Japan. The technology available is first reviewed and then the quantitative requirements assessed in more detail on a country by country basis.

o <u>Residue Hydrodesulphurisation</u>

The major application for residue hydrodesulphurisation is for the production of low sulphur fuel oil. Several installations exist in Japan and the Western Hemisphere. In Europe, on the other hand, it has been possible to meet low sulphur fuel oil demand by processing sweet crudes. Consequently this process has not in the past been needed. The present emphasis in heavy residue upgrading is, however, focusing interest on desulphurisation to pretreat feedstocks for upgrading processes, both thermal and catalytic, in order to improve yields and products quality. This interest could increase in Europe if, as a result of the legislation discussed, low sulphur heavy fuel oil production is required.

Residue hydrodesulphurisation is conceptually very similar to light distillate hydrotreating. The major differences are more severe operating conditions and a much higher hydrogen consumption, which increases substantially as the quality of the feedstock worsens. Because of the higher operating temperature, residue hydrodesulphurisation always involves some cracking.

From this point of view there is not an exact line of demarcation between residue hydrodesulphurisation and hydrocracking.

The degree of desulphurisation usually achieved is in the order of 70-90 percent for FCC feedstocks (vacuum distillates or equivalent) and decreases to about 60-80 percent for heavier feedstock like vacuum residue. Hydrodesulphurisation removes sulphur, which is transformed into H_2S, and also other impurities like organic nitrogen and oxygen (as NH_3 and H_2O respectively). Metals content is reduced too, simply because metals remain adsorbed on the catalyst. Feedstocks with very high metal contents (more than 250 ppm) would poison and/or deactivate the catalyst too quickly and cannot be processed in conventional fixed bed units.

Amongst the major refinery catalytic processes, hydrotreating uses the cheapest catalysts. In residue hydrodesulphurisation, unlike distillates hydrotreating, the catalyst is very seldom regenerable and has to be replaced at the end of each operating cycle. The length of the operating cycle is usually from 3 months to one year depending on the amounts of feedstocks contaminants present.

For the purposes of the study a simple process was assumed consisting of treating the residue at high temperature and pressure using a fixed bed desulphurisation unit. The main problems with fixed bed units are the deactivation of the catalyst eg by metals and fouling of the reactor. Because of this it was assumed that (in line with industrial experience) cracked residues were unsuitable as a feedstock and were therefore not considered. The two feedstocks considered were vacuum distillate and atmospheric residue with assumed desulphurisation efficiences of 80 and 70 percent respectively. Changes in viscosity resultant from the processing were not considered. For simplification it was assumed that the plant could be largely stand alone with the light ends produced being used as hydrogen plant feed, supplemented, as required, by refinery gases which in turn are balanced within the refinery by the use of the desulphurised product as refinery fuel. The onsite facilities considered included a hydrogen plant and sulphur recovery and tail gas treatment facilities where appropriate.

The energy requirements and losses of the process are quite high and can be broken down into three main elements;

- the sulphur (production is separately assessed)
- energy requirements and losses
- carbon lost as CO_2 in H_2 production

A typical figure of 15 wt percent based on feed was used, which can be considered as equivalent to an overall yield of 85 wt percent.

Capital and operating costs used for the evaluation are given below.

Basis:

2 500 metric tons per day hydrodesulphurisation unit (plus associated facilities).

Installed Capital Cost:

85 million ECUs.

Operating Costs:

30 percent per year of installed capital cost, of which the major component is for own use fuel consumption.

Although this cost may appear low for a residue desulphurisation unit (ref CONCAWE) it must be borne in mind that the feedstocks assumed were relatively low sulphur content (1.0 to 2.0 wt percent) vacuum distillates and atmospheric residues compared to the more commonly quoted high sulphur (4.0 to 5.0 wt percent) atmospheric and vacuum residues.

The quantitative requirements on a country by country basis are given below:

- Belgium

Residue desulphurisation could be used for the conversion type refinery to meet the 1993 specification of 2.2 wt percent sulphur. The composition and sulphur content of the untreated products are given in Table V.C.7.

TABLE V.C.7

BELGIUM RESIDUAL FUEL OIL PRODUCT (1993)

	Conversion Refinery	
	Quantity (wt percent on crude)	Sulphur Content (wt percent)
Gas Oil	0.55	0.63
Atmospheric Residue	11.60	2.00
FCC Residue	1.22	2.88
Visbroken Residue	5.42	3.11
Total	18.79	2.34

In order to reduce the sulphur content down to the specified level of 2.2 it was required to desulphurise 1.9 wt percent on crude of the atmospheric residue.

o Germany

For the 1993 cases, it was assumed that the residual fuel oil sulphur content must be reduced to 1.0 wt percent. The composition and sulphur content of the untreated products are given in Table V.C.8.

TABLE V.C.8

GERMANY RESIDUAL FUEL OIL PRODUCT (1993)

	Hydroskimming Refinery		Conversion Refinery	
	Quantity (wt percent on crude)	Sulphur Content (wt percent)	Quantity (wt percent on crude)	Sulphur Content (wt percent)
Gas Oil	-	-	0.54	0.48
Vacuum Distillate	6.47	1.06	-	-
Atmospheric Residue	28.91	1.57	10.24	1.57
FCC Residue	-	-	1.22	2.12
Visbroken Residue	-	-	5.78	2.51
Total	35.38	1.48	17.78	1.88

In order to reduce the sulphur content down to the specified level of 1.0 wt percent it was required to desulphurise 15.4 wt percent on crude for the hydroskimming refinery. For the conversion refinery this specification could not be met, desulphurisation of all the atmospheric residue only reduced the sulphur content of the residual fuel oil product down to 1.25 wt percent.

As a point of interest, the sulphur produced by such a process is quite high. Assuming 95 percent recovery of the sulphur removed would result in the production of 6 350 and 4 200 metric tons per year respectively for the hydroskimming and conversion type refineries (assuming 3.75 million tons per year of crude processed in each).

o Netherlands

For the 1993 cases, it was assumed that the residual fuel oil sulphur content must be reduced to 1.0 wt percent. The composition and sulphur content of the untreated products are given in Table V.C.9.

TABLE V.C.9

NETHERLANDS RESIDUAL FUEL OIL PRODUCT (1993)

	Hydroskimming Refinery		Conversion Refinery	
	Quantity (wt percent on crude)	Sulphur Content (wt percent)	Quantity (wt percent on crude)	Sulphur Content (wt percent)
Gas Oil	-	-	0.55	0.57
Vacuum Distillate	6.75	1.24	-	-
Atmospheric Residue	29.29	1.84	11.35	1.84
FCC Residue	-	-	1.22	2.58
Visbroken Residue	-	-	5.62	2.91
Total	36.04	1.73	18.74	2.17

In order to reduce the sulphur content down to the specified level of 1.0 wt percent it was required to desulphurise 20.4 wt percent on crude for the hydroskimming refinery. For the conversion refinery the specification could not be met, desulphurisation of all the atmospheric residue only reduced the sulphur content of the residual fuel oil product down to 1.39 wt percent.

3. Sulphur Related (Air Quality)

For refineries which cannot meet the required SO_2 emission regulations for 1993 the following options exist;

- Blend some of the high sulphur components of the refinery fuel into the residual fuel oil exchanging them for low sulphur components in order to meet the required specifications.

- Burn LPG in place of liquid fuel, increasing the residual fuel oil product.

- Import natural gas (subject to availability) and convert over to gas firing, increasing the residual fuel oil product.

- Apply flue gas or other desulphurisation techniques.

For all cases except for Germany (where it was not applicable) the first option was assumed and, where relevant, compliance costs assessed as a result of their impact on the residual fuel oil product quality. For Germany the last two options were evaluated.

A review was carried out of the technical measures suitable for reducing the SO_2 content of refinery atmospheric emissions to within the limits set by German legislation. The sources of SO_2 considered were:

- Process Furnaces and Boilers
- Sulphur Recovery Units
- Fluid Catalytic Crackers

The technical measures reviewed were flue gas desulphurisation, sulphur recovery with tail gas treatment and specialised techniques applicable to FCC's.

a) Flue Gas Desulphurisation

A number of stack gas desulphurisation processes are already commerically available and installed, but only a limited number can be found in refineries and petrochemical installations. Most commerical experience is in coal fired power stations. The technology for removing SO_2 from stack gases can be divided into two categories, regenerable processes and non regenerable processes. In each category a distinction can be made between wet and dry processes. The regenerable processes have the advantage of a lower chemical consumption and in many instances, a lower production of undesirable by-products compared to the non regenerable processes (often only sulphur and sulphuric acid). In the first type, the following processes are considered to be the most suitable for refinery flue gas treatment.

- IFP Stackpol (wet process)
- Davy Mckee/Wellman Lord (wet process)
- Shell/UOP SFGT (dry process)

These processes could also in theory be used to treat Claus unit tail gas although more directly applicable techniques are discussed later.

o IFP Stackpol (Wet Process)

L'Institut Francais du Petrole has developed a wet absorption process for cleaning-up sulphur dioxide containing waste gases in which the flue gas is scrubbed with water containing ammonium sulphite. The dissolved and chemically bound SO_2 is liberated in a stripper while any ammonium sulphate formed is reduced to sulphite at high temperature in a special reactor.

One drawback in this processes is that a by-product is produced which has to be disposed of as sludge. Desulphurisation is about 90 percent.

o <u>Wellman-Lord (Wet Process)</u>

The Wellman-Lord process is also based on wet absorption, the absorbing fluid being a sodium sulphite solution.

The process is based upon the chemistry of sodium sulphite/bisulphite, where SO_2 is absorbed by a sodium sulphite solution to give sodium bisulphite;

$$\begin{array}{ccccccc} SO_2 & + & Na_2SO_3 & + & H_2O & \rightleftharpoons & 2NaHSO_3 \\ \text{(Sulphur Dioxide)} & & \text{(Sodium Sulphite)} & & \text{(Water)} & & \text{(Sodium Bisulphite)} \end{array}$$

The sodium bisulphite solution is then regenerated by thermal decompositon using crystallisation/evaporation to give a concentrated SO_2 stream with can be sent to a Claus unit for sulphur recovery.

Side reactions also lead to the formation of sodium sulphate. The treating of this by-product is possible, but is uneconomical when the unit size is small. There are over 40 commerical installations in operation. Most of them are related to large power plants although recently a 600 000 cubic metres per hour unit was installed in an Austrian refinery to treat process and boiler stack gases. Desulphurisation is typically greater than 85 percent. A simplified flowscheme of the process is shown in Figure V.C.1.

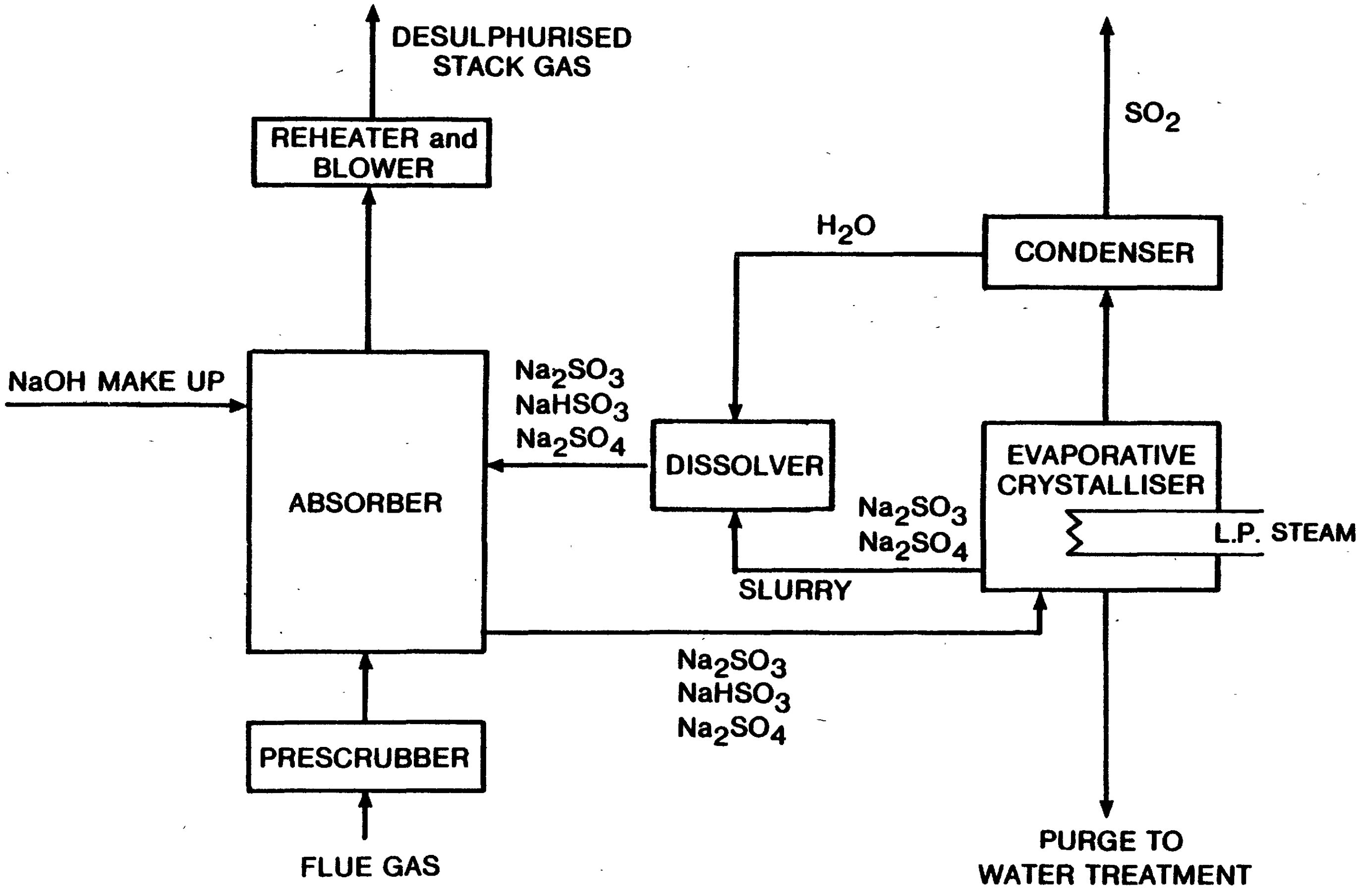
o <u>Shell/UOP Flue Gas Treating (Dry Process)</u>

The Shell/UOP flue gas treating process is a dry cyclic regenerable process, the sour flue gas is led over an acceptor reactor bed, which chemically absorbs the sulphur dioxide. When the acceptor reactor bed is saturated the flue gas is led to a second reactor and the first reactor is regenerated by a hydrogen containing gas stream flowing counter currently to the normal flow.

Although non regenerable processes in general have lower capital costs, they were not considered in this study due to the need for significant waste removal (ie gypsum) which was considered undersirable for integration on an existing refinery.

FIGURE V.C.1.

**FLUE GAS DESULPHURISATION WET PROCESS
(WELLMAN-LORD PROCESS)**



D863169

Typical installed capital costs for the processes available are given in Figure V.C.2. Operating materials consumed and the by-products produced in such systems depend upon the SO_2 content of the stack gas, other contaminants present, and degree of desulphurisation required. For this reason, along with the limited experience of such systems for similar applications it is difficult to estimate specific costs. Operating cost were therefore conservatively estimated to be 15 percent of capital costs per year. It should be noted that the investment costs quoted assume that space and access are not limiting for the installation. In reality costs would need to be assessd on a case by case basis and in some cases installation may not be possible, depending on the complexity of the existing installations.

b) Sulphur Recovery Units and Tail Gas Treatment

During refinery operation significant quantities of sulphur rich gases are produced, notably hydrogen sulphide (H_2S) rich streams from hydrotreating units. The major tools used by refineries to recover the sulphur from these streams are sulphur recovery units (often known as Claus Units). The majority if not all of the Western European Refineries have such facilities.

o Sulphur Recovery Units

The purpose of the unit is to transform H_2S into sulphur according to the following reactions;

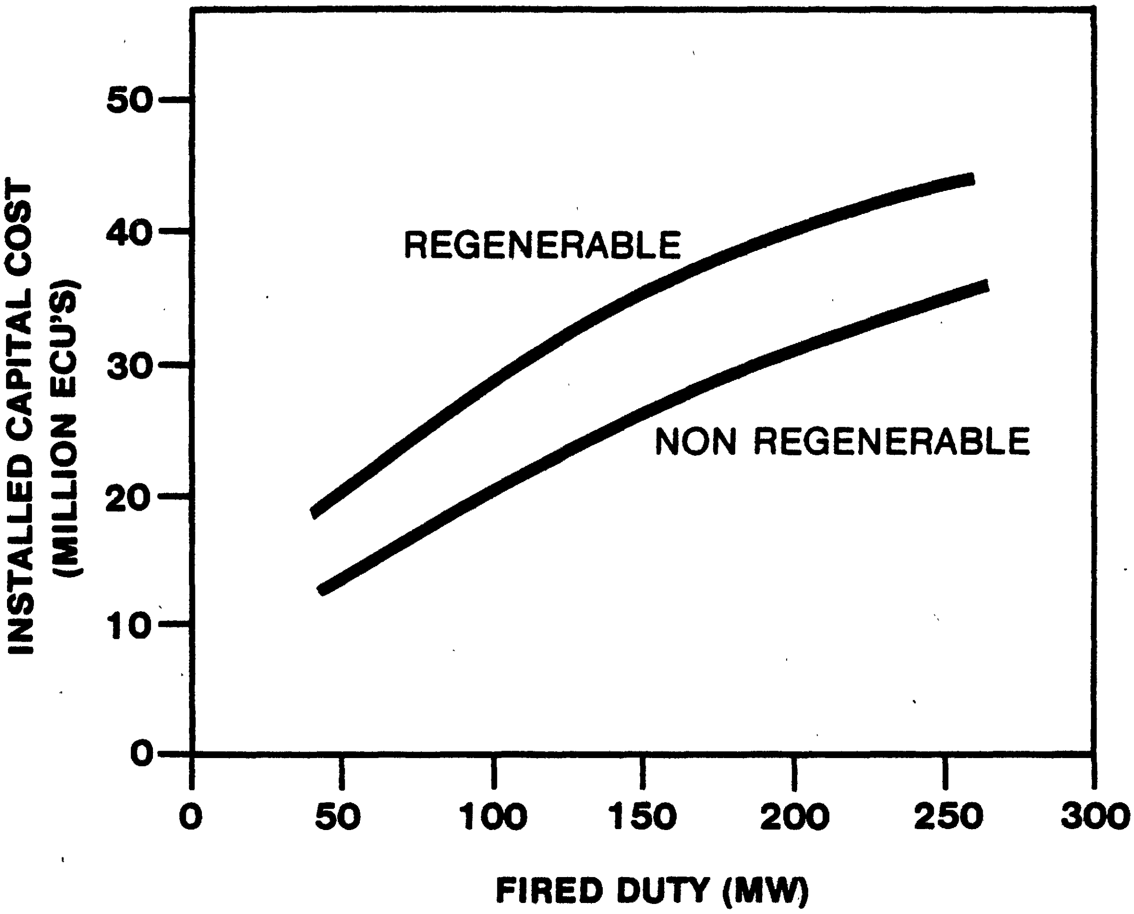
$$H_2S + 3/2\ 02 \rightleftharpoons H_2O + SO_2$$
$$2\ H_2S + SO_2 \rightleftharpoons 3S + 2H_2O$$

In its simplest form, the gas stream that contains hydrogen sulphide is sent to a furnace in which 33 percent of the H_2S gas with sufficient oxygen is converted into sulphur dioxide. The gas mixture is then sent through a series of reactors, in which the remaining hydrogen sulphide and sulphur dioxide further react over a catalyst bed.

Sulphur removal efficiency varies depending on the quantity of H_2S in the feed and the hydrocarbon content. Even when operating under optimised conditions the conversion of H_2S into sulphur is normally restricted to around 95 percent.

FIGURE V.C.2.

FLUE GAS DESULPHURISATION
INSTALLED CAPITAL COSTS (MID 1985)



In cases where higher removal efficiences are required "add on" Tail Gas Treatment (TGT) processees need to be applied. Commerically available TGT processes can be divided into two groups; catalytic and hydrogenating.

Catalytic TGT Processes

These are based on a continuation of the Claus reaction and produce sulphur. Typical processes available are;

- o Sulfreen
- o Amoco-CBA
- o IFP Clauspol 1500

o Sulfreen Process

This process was developed by SNEA and Lurgi. Claus tail gas is passed through a reactor with an activated alumina catalyst. The Claus reaction continues at a low temperature of 120 to 140°C. Sulphur condenses and adsorbs on the catalyst bed, which has to be regenerated batchwise. Regeneration takes place approximately once per 48 hours in a closed loop with a gas heated at 300°C by an indirectly fired heater. Desorbed sulphur is condensed in a sulphur condenser.

The bed is then cooled and placed back on reaction cycle. An overall sulphur recovery (Claus plus Sulfreen) of approximately 98 to 98.5 percent can be achieved. A simplified flow diagram for the process is shown in Figure V.C.3.

o Amoco - CBA Process

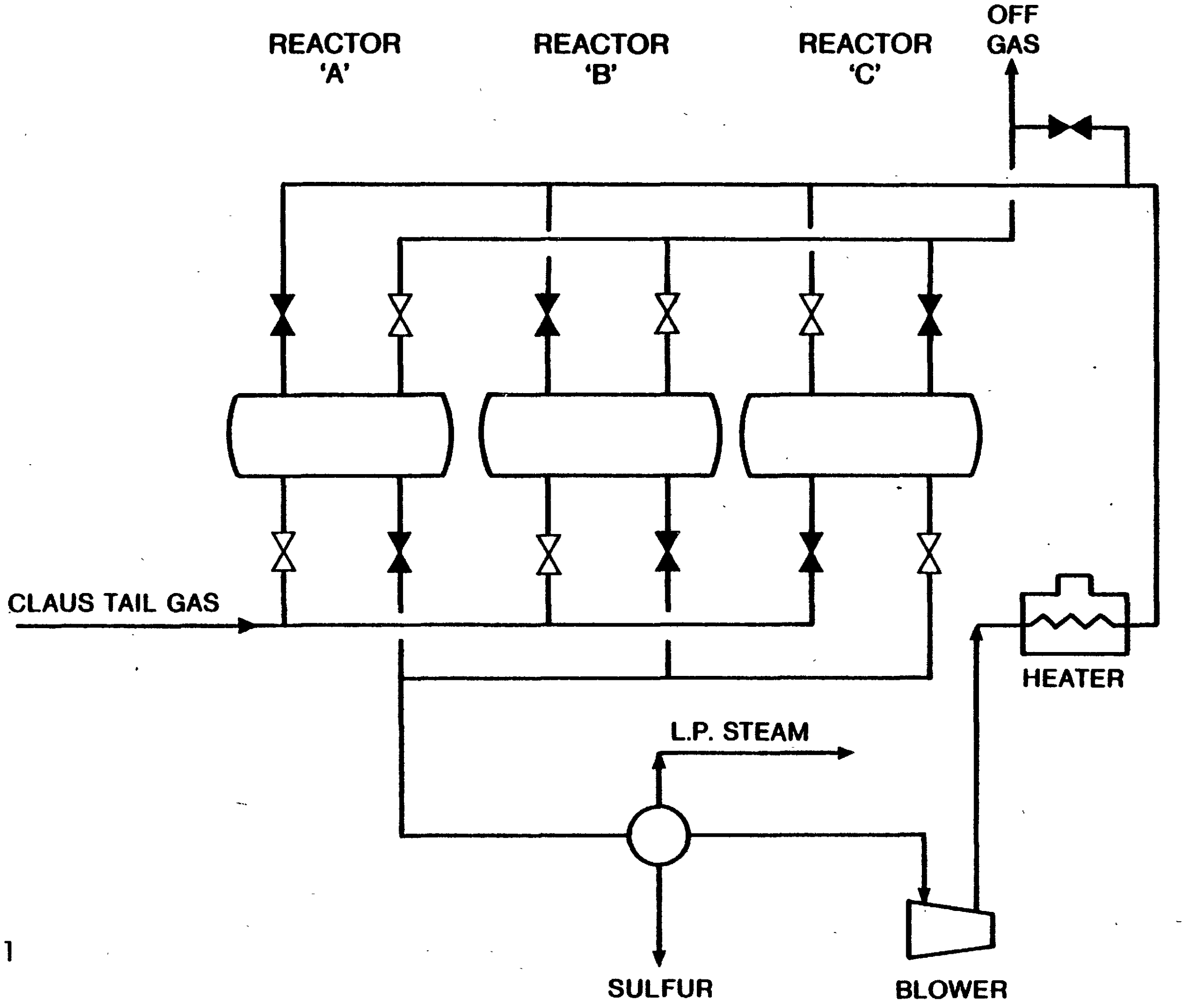
This process is similar to the Sulfreen process except that it uses process gas for regeneration and cooling.

o IFP-Clauspol 1500 Process

The process introduces the tail gas into a vertical packed tower where the gas is countercurrently contacted by polyethylene glycol solvent containing a metal salt catalyst. The Claus reaction takes place in the solvent at a temperature of 120 to 130°C.

FIGURE V.C.3.

**TAIL GAS TREATMENT (TGT)
SULFREEN PROCESS**



D863171

Liquid sulphur produced is separated at the bottom of the tower. Overall sulphur recovery (Claus plus Clauspol) of 98 to 98.5 percent can be achieved.

Hydrogenation TGT Processes

These are based on reduction of sulphur compounds to H_2S followed by an absorption or reaction stage. Two commercially available processes were considered:

- SCOT
- Beavon

SCOT Process

The process was developed by Shell. Claus tail gas is heated to 300°C and hydrogenated by either hydrogen or a reducing gas containing hydrogen over a cobalt-molybdenum catalyst. All sulphur compounds are reduced or hydrolysed to H_2S. After cooling and quenching by water, during which the water vapour in the Claus tail gas is also condensed, the flue gas is passed to an amine treater in which the amine is used for selective absorption of H_2S. The H_2S gas from the amine regenerator is recycled to the Claus plant. Overall sulphur recovery of over 99.9 percent can be achieved. A simplified flowscheme for the process is shown in Figure V.C.4.

Beavon Process

The process was developed by Parsons and Union Oil Company. As in the SCOT process, all sulphurous components are hydrogenated to H_2S, followed by cooling and quenching. Flue gas is then passed to a Stretford plant for conversion of H_2S into elemental sulphur. An overall recovery of over 99.9 percent can be reached.

For the study it was assumed that the Sulfreen process would be applied for sulphur recover requirements of up to 98.5 percent and the SCOT process where recoveries in excess of 99.5 were required. A typical mass balance flowscheme for a combined SRU and TGT system is shown in Figure V.C.5.

FIGURE V.C.4.

TAIL GAS TREATMENT (TGT) (SCOT PROCESS)

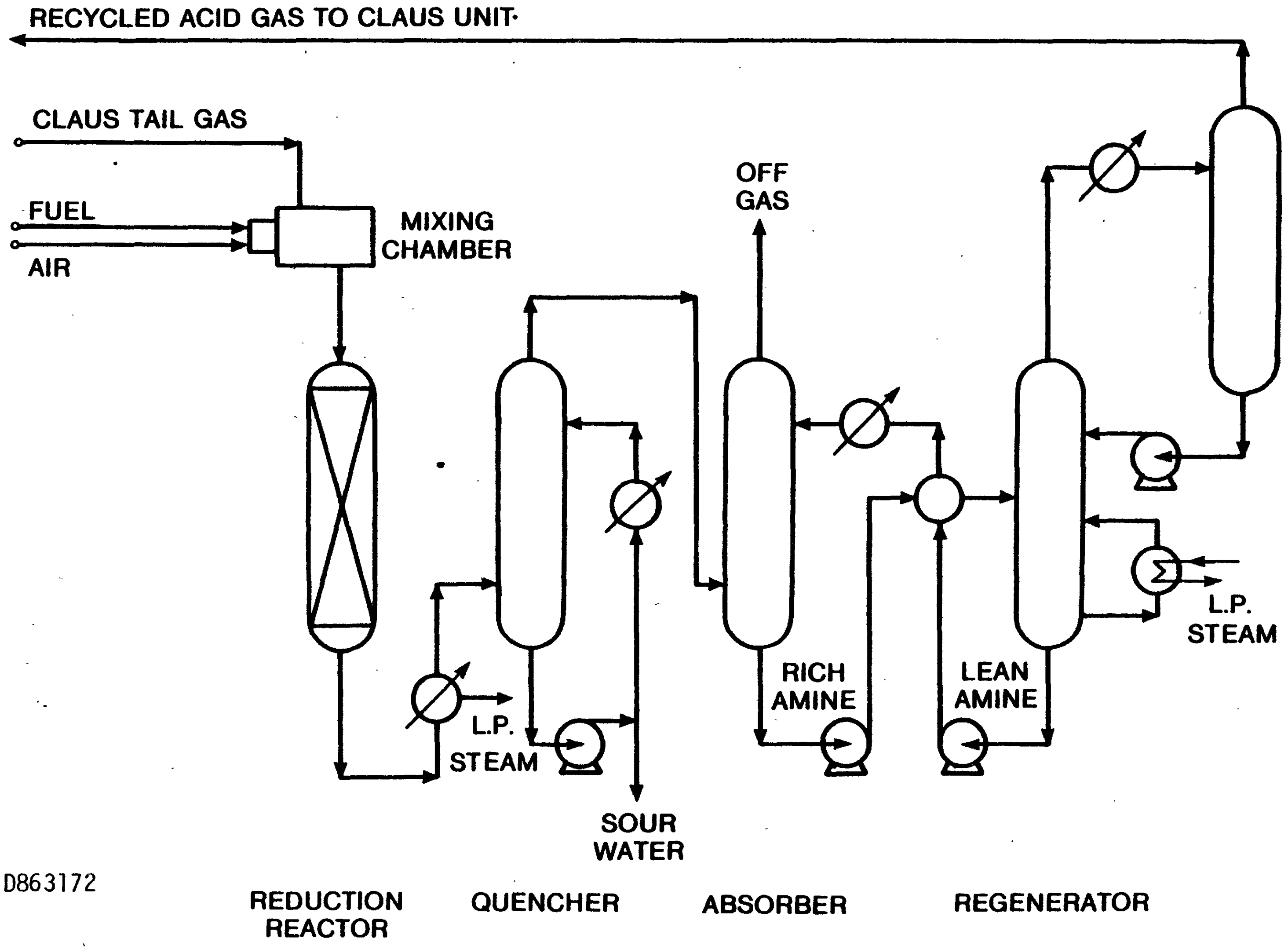
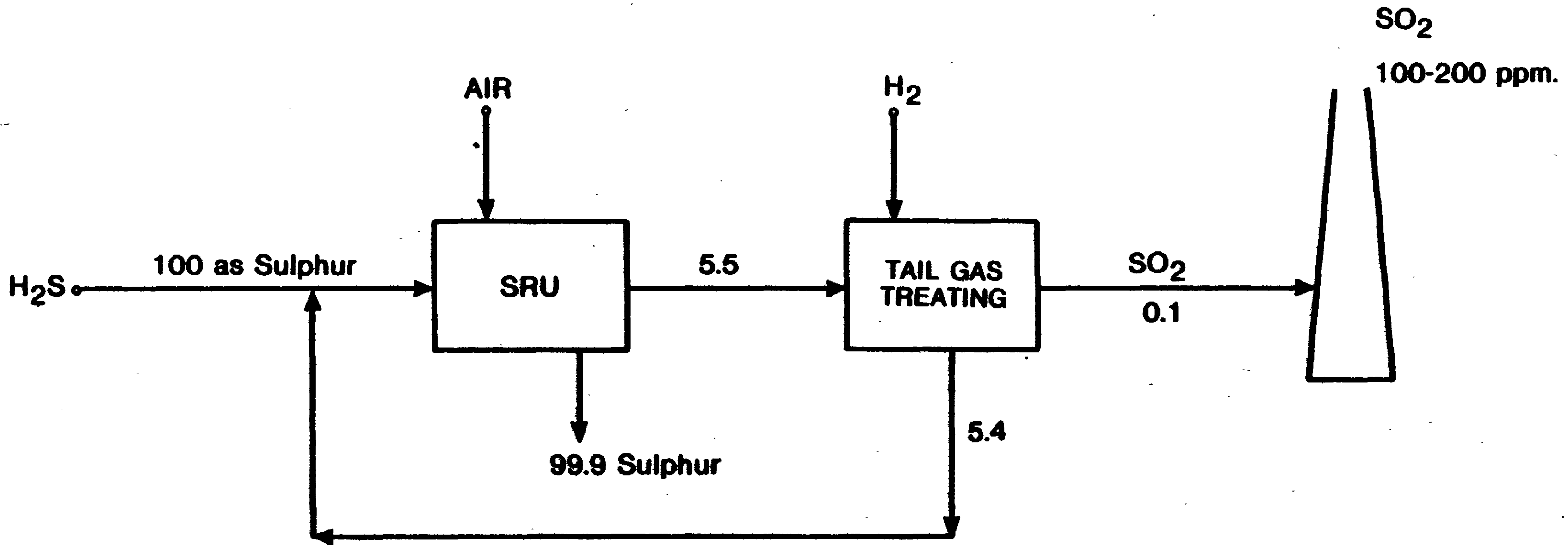


FIGURE V.C.5.

TYPICAL MASS BALANCE FOR SULPHUR RECOVERY and TAIL GAS TREATING (SHELL - SCOT)



D863173

The installed capital cost for an 80 metric ton per day (of sulphur equivalent) sulphur recovery unit was estimated to be 6 million ECUs. Table V.C.10 summarises the costs for the various options for TGT units giving details for cost when supplied integrally with SRU's as well as costs for "add on" revamp installation. Operating costs were estimated to be 10 percent of capital cost per year (including by-product credit for sulphur produced).

TABLE V.C.10

INSTALLED CAPITAL COST FOR SULPHUR RECOVERY UNITS AND TAIL GAS TREATMENT UNITS

(Mid 1985)

	Factor of Base SRU Cost (1)
SRU	1.0
SRU with integral Sulfreen Unit (2)	1.4
SRU with integral Scot Unit	1.9
"Add On" Sulfreen Unit	0.5
"Add On" Scot Unit	1.1

Note:

(1) Base cost for 80 metric tons per day SRU estimated to be 6 million ECUs.

(2) Can be further upgraded to allow 99.5 percent recovery for 0.6 times base SRU cost.

c) Fluid Catalytic Cracking Sulphur Control

Control of SO_2 in the burn off gases from the FCC regeneration is not as technically or commercially advanced as the other areas of removal techniques covered. The following is a summary of experience quoted from techniques being applied in the US to meet environmental legislation controls. Both feed desulphurisation and regenerator flue gas scrubbing techniques can be applied to meet the required levels of sulphur reduction but both methods require large capital investment and relatively high operating costs. Use of reducing agents or transfer catalysts are in comparison extremely simple requiring no equipment addition and comparatively small operating costs.

o Transfer Catalysts

The transfer agent, a metal oxide which converts to a metal sulphate with SO_3 produced in the regenerator, moves sulphur along with the regenerated catalyst into the reactor where it is converted to H_2S by reaction with hydrogen. Some of the metal sulphate, however, is converted to metal sulphide by the hydrogen. In turn, the metal sulphide reacts with water to form hydrogen sulphide and metal oxide. All the metal oxide recycles with the catalyst to the regenerator, completing the cycle. Hydrogen sulphide leaves with the product where it is removed in the gas treating system. Quoted sulphur recovery efficiencies are typically greater than 80 percent.

4. NOx Related

NOx refers to both NO and NO_2. Normally NO has no detrimental effects at the concentrations found in refineries. NO_2 on the other hand, is considered to be of greater concern. At present the most severe regulations are those covering Japan and the US power generation boilers. The most commonly applied technique for controlling NOx emission is the use of low NOx burners. If more stringent regulations need to be applied then flue gases must also be treated. The processes available are similar to those employed for flue gas desulphurisation with two main types of process available, thermal DeNOx and catalytic DeNOx.

o Low NOx Burners

Low NOx burners stage either air or fuel addition with the aim of reducing the peak flame temperature and residence time, thereby decreasing the two major factors affecting NOx formation. The decreases achieved by retrofitting these type of burners on existing furnaces and boilers are between 20 to 60 percent reduction in NOx, typically the average being around 40 percent.

Low NOx burners can be retrofitted to many furnaces and boilers in existing refineries although application must be assessed on a case by case basis. Currently operation is not fully proven for systems using high intensity burners nor systems burning highly viscous fuel oils.

Typically the cost of revamping a furnace or boiler of 60 MW duty with 20 burners was estimated to be in the order of 400 000 ECUs. Additional operating costs were assumed negligible.

o <u>Thermal DeNOx</u>

Thermal DeNOx is a non-catalytic process for removing oxides of nitrogen from flue gas by gas phase reaction with ammonia at high temperature (900-1 200°C). Ammonia is injected through multiple nozzles into the radiant or convective section of process furnaces and boilers. To achieve good mixing, a small amount of ammonia is injected along with a carrier gas, usually air or steam. NOx reductions of around 60 percent are generally achieved.

o <u>Catalytic DeNOx</u>

The catalytic DeNOx process converts nitrogen oxide by mixing ammonia vapour with the flue gas. The mixture is then passed through a catalyst bed where the NOx is reduced to nitrogen and water vapour.

A typical process is the Mitsubishi Dry Selective Catalytic NOx removal system (SCR). A simplified flowscheme for the process is shown in Figure V.C.6. The basic process reactions are:

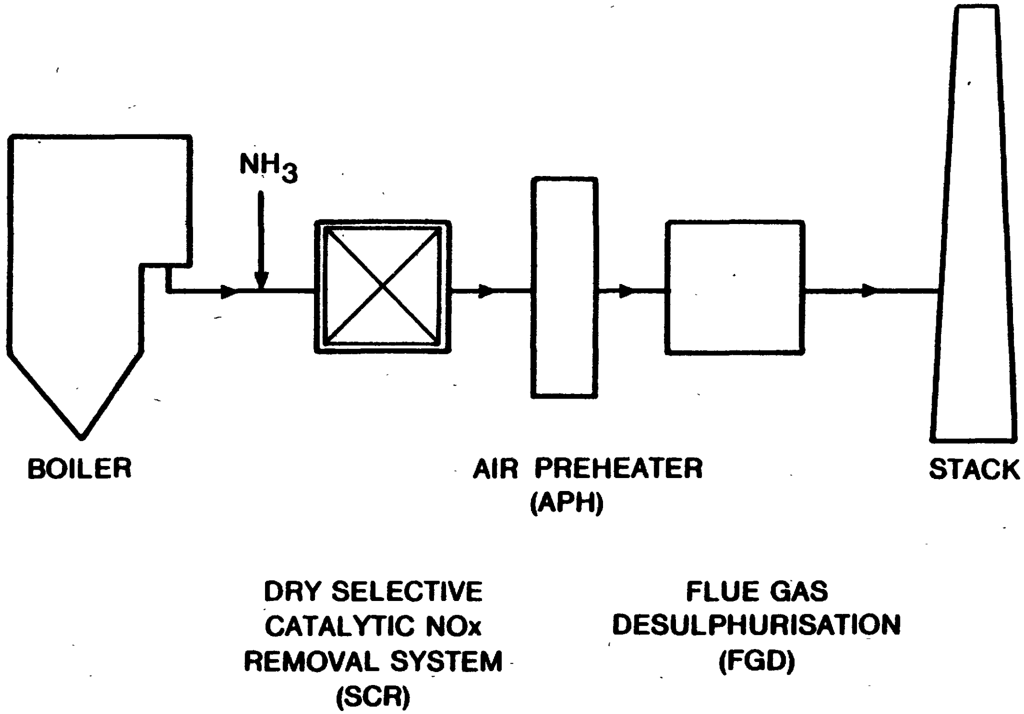
$$\underset{\text{(Nitrogen Monoxide)}}{4NO} + \underset{\text{(Ammonia)}}{4NH_3} + \underset{\text{(Oxygen)}}{O_2} \xrightarrow{\text{CATALYST}} \underset{\text{(Nitrogen)}}{4N_2} + \underset{\text{(Water)}}{6\ H_2O}$$

$$\underset{\text{(Nitrogen Dioxide)}}{2NO_2} + \underset{\text{(Ammonia)}}{4NH_3} + \underset{\text{(Oxygen)}}{O_2} \xrightarrow{\text{CATALYST}} \underset{\text{(Nitrogen)}}{3N_2} + \underset{\text{(Water)}}{6\ H_2O}$$

The process requires temperatures of around 400°C and therefore must be located upstream of any air preheater or FGD units (if installed). NOx removal efficiencies in excess of 80 percent are generally achievable. Due to the need for high temperatures the units are quite large and space limitations can often be restrictive. Work is currently in hand developing similar systems which can operate at lower temperatures.

FIGURE V.C.6.

DRY SELECTIVE CATALYTIC NOx REMOVAL SYSTEM (MITSUBISHI HEAVY INDUSTRIES LTD)



D863174

Typical installed costs for SCR systems are given in Figure V.C.7. A significant proportion of the capital cost for these systems is the catalyst (up to 60 percent) which depending on the service can last for anything between 1 to 5 years. Operating costs were therefore estimated to be quite high at around 30 percent of the capital costs per year, largely as a result of the high catalyst replacement costs.

Future Development

Although not considered in the evaluation of suitable control measures, for completeness a review was carried out of techniques under development. Currently two main areas of advancement are emerging with respect to emission control particularly related to SOx and NOx removal. Of interest are:

- Co-Generation
- Combined NOx, SO_2 and particulate removal system.

o Co-Generation

There are interesting possibilities in the refining industry for co-generation, by converting existing fired heaters into gas turbine based co-generation systems. With such a system, the gas turbine exhaust is used as preheated combustion air to the burners, the exhaust being at around 500°C with 16 volume percent oxygen. Co-generation of electricity from the gas is used to back out import requirements from the grid.

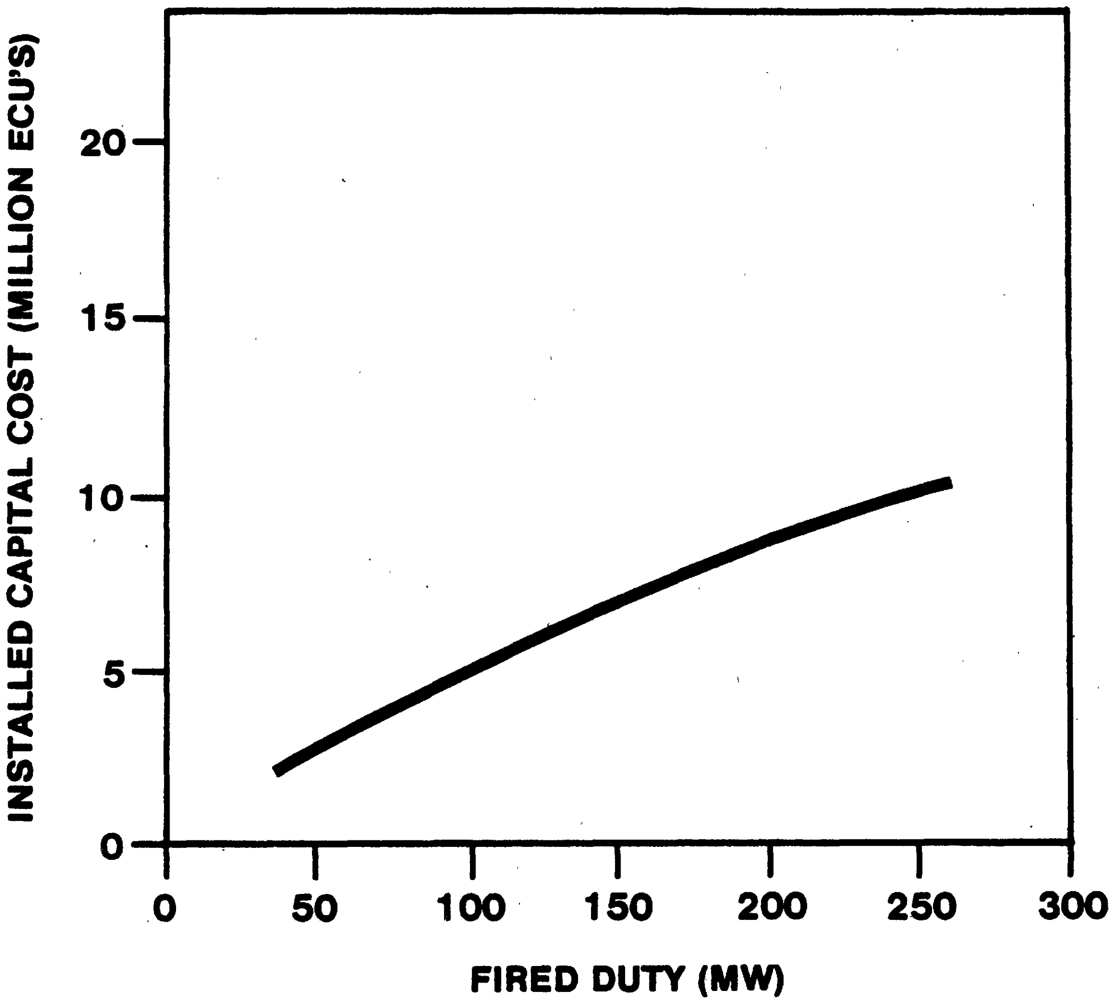
Two main factors contribute to reducing the emissions:

- A lower quantity of fuel is fired, therefore the SO_2 and NOx emission in the absolute sense are reduced.

- Combustion in the furnace occurs at lower peak temperature, resulting in lower NOx formation.

FIGURE V.C.7.

TYPICAL INSTALLED CAPITAL COSTS
FOR CATALYTIC DENOx UNITS (MID 1985)



The economics of such systems need to be assessed on a case by case basis but are often found to have acceptable paybacks on a stand alone basis. The major disadvantage is the question of reliability, if the gas turbine trips the furnace and boiler associated with it would also trip, affecting overall plant reliability. These systems are only applicable for gas firing applications.

o Combined NOx, SO_2 and Particulate Removal

Combined systems are likely to play increasingly important roles where a reduction in NOx, SO_2 and particulates are required. Currently commercial application is limited but development is continuing. A typical system is offered by KTI (under license from Bergbau-Forschung/Mitsui). This process is suitable for treating either fired heater stack gas or FCC flue gases with claimed removal efficiencies in excess of 80 and 90 percent for NOx and SO_2 respectively along with significant particulate removal. The technology is based on a two bed adsorption system using an activated coke moving bed. The removal of SO_2 is effected by reaction with oxygen and water, and NOx by reaction with ammonia. Desorption is achieved in a separate regeneration section by the application of temperatures up to 400°C. The only additional treatment required is for the SO_2 produced to be sent to the Claus plant for sulphur removal. A typical flowscheme for the process is shown in Figure V.C.8.

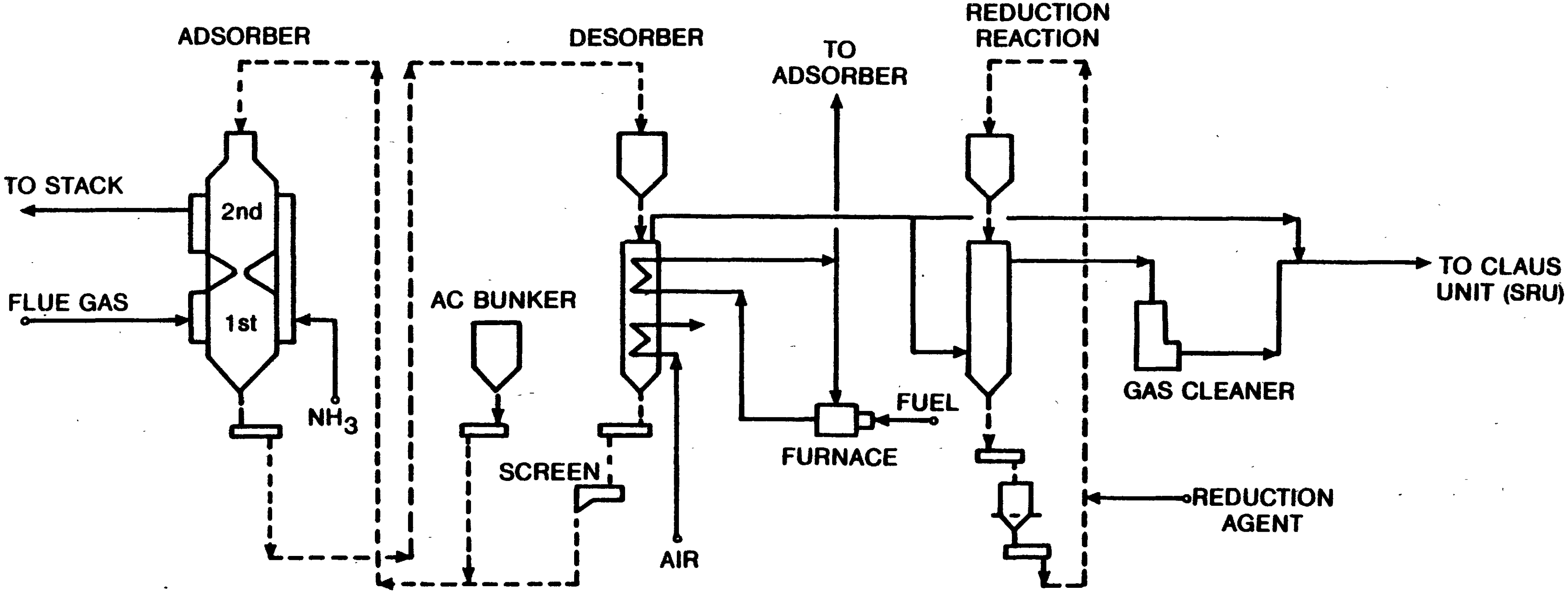
5. Other Air Quality Related

a) Hydrocarbon Emissions

As previously discussed the areas covered under this heading are numerous and it is not intended to provide detailed summaries of the individual "good practice" measures applicable. The cost for the compliance though cannot be so readily dismissed and will be covered in more detail. The one area which is considered worthy of more detailed description is the application of vapour recovery units.

FIGURE V.C.8.

MITSUI-BF SIMULTANEOUS SOx and NOx REMOVAL SYSTEM



D863176

o Vapour Recovery Units

This section relates to the application of vapour recovery systems applied for the recovery of light hydrocarbon vapours during the process of loading (and where applicable unloading) of gasoline. Gasoline vapour recovery has been widely applied in the United States for nearly twenty years. However, the technology is still evolving with significant developments having occurred in the last few years. The applications are largely driven by emission control legislation but economic return on investment can also play an important role in system application.

The early days of vapour recovery in the United States involved vapour recovery from both top and bottom loading facilities. The trend to bottom loading has been so pronounced that very few top loading systems for gasoline remain in the United States. The evolution of loading practices in Western Europe will play an important role in system of application and efficiency. The hydrocarbon content of the air displaced from trucks varies widely depending on the type of loading and the condition of the truck. Bottom loading tends to generate less vapour than top loading. Trucks with well maintained hatches that are leak free tend to give dramatically higher vapour concentrations than trucks with hatches that leak. General rules are as follows for trucks with well maintained hatches.

Type Loading	Vapour Concentration Percent of Saturation
Bottom	50%
Top Submerged	70%

The United States has seen several vapour recovery technologies. These evolved to meet industry demands for lower operating costs (primarily power and maintenance) and government demands for better recovery efficiencies. The unit of mg/l quoted below refers to mg of emitted hydrocarbon per litre of gasoline loaded and is commonly used in the US. A summary of the applicable technology development in the US is given below.

The compression-refrigeration-absorption system was the first widely accepted technology. This technology was offered by several companies. It had high power consumption, high maintenance on the compressors and vapour holder tanks, and suffered freezing problems in cold climates. Its ultimate capability was an emission control level of about 125mg/l. These systems are no longer sold in the United States although a few are still in operation. No equivalent system is being offered in Europe.

The lean oil system had the advantage of eliminating the need for a vapour holding tank. It could reduce emissions to about 80mg/l and had about the same power consumption as the compression-refrigeration-absorption system. A lean oil technology similar to the above is now offered in Europe, however, its operating ability has not been established.

The refrigeration vapour recovery system was introduced in the United States in 1972 by Edwards Engineering and remains a viable technology today. The first design involved a chilled brine system which was used to cool vapours. Early systems involved two stage refrigeration to about -50°C but current models are three stage systems to about -75°C which is required to meet 80mg/l and even lower temperature systems are offered to meet 35mg/l. A chilled brine system similar to the first Edwards Engineering system (-50°C) is offered in Europe by an Italian manufacturer.

The combustion emission control system has been and continues to be offered by several U.S. companies and is currently being made available in Europe by McGill International. However, no current demand exists for this control technique in Europe, recovery being preferred.

The Adsorption-Absorption Vapour Recovery System was introduced in the United States in 1976. Current US emission standards of 35mg/l are written around this unit and the carbon technology is the most widely applied technology in the United States today. The carbon system attains the low (35mg/l) emission at very low power cost as compared to other technologies. McGill International began offering the carbon technology in Europe in 1979 and there are now seven of these units in operation with a further 365 units operational world-wide.

The Adsorption-Absorption Vapour Recovery System is shown schematicaly in Figure V.C.9. Vapours flow directly from trucks through one of two adsorption beds using activated carbon adsorbent. Hydrocarbons are adsorbed onto the surface of the activated carbon and clean air vented from the top of the adsorption vessel. After a preset period of time, the adsorption beds are switched and the hydrocarbons are removed from activated carbon using vacuum plus heated stripping air. The hydrocarbons exit the vacuum pump and are absorbed into gasoline in a conventional absorber after being separated from the vacuum pump seal water.

As previously discussed the only legislation relating to vapour recovery in Western Europe is the TA Luft regulation (of 27.2.1986) applicable in Germany. Interpretation of this is difficult due to the apparent demands for unrealistic recovery levels of 99.95 to 99.99 percent, whereas best available technology can currently only achieve around 95 percent. It was therefore assumed that the regulation will be revised to correspond to within the capabilities of best available technology. The costs for a typical activated carbon recovery system as given below.

Basis:

Gasoline vapour recovery system for a 600 000 cubic metres per year loading facility.

Installed Capital Cost:

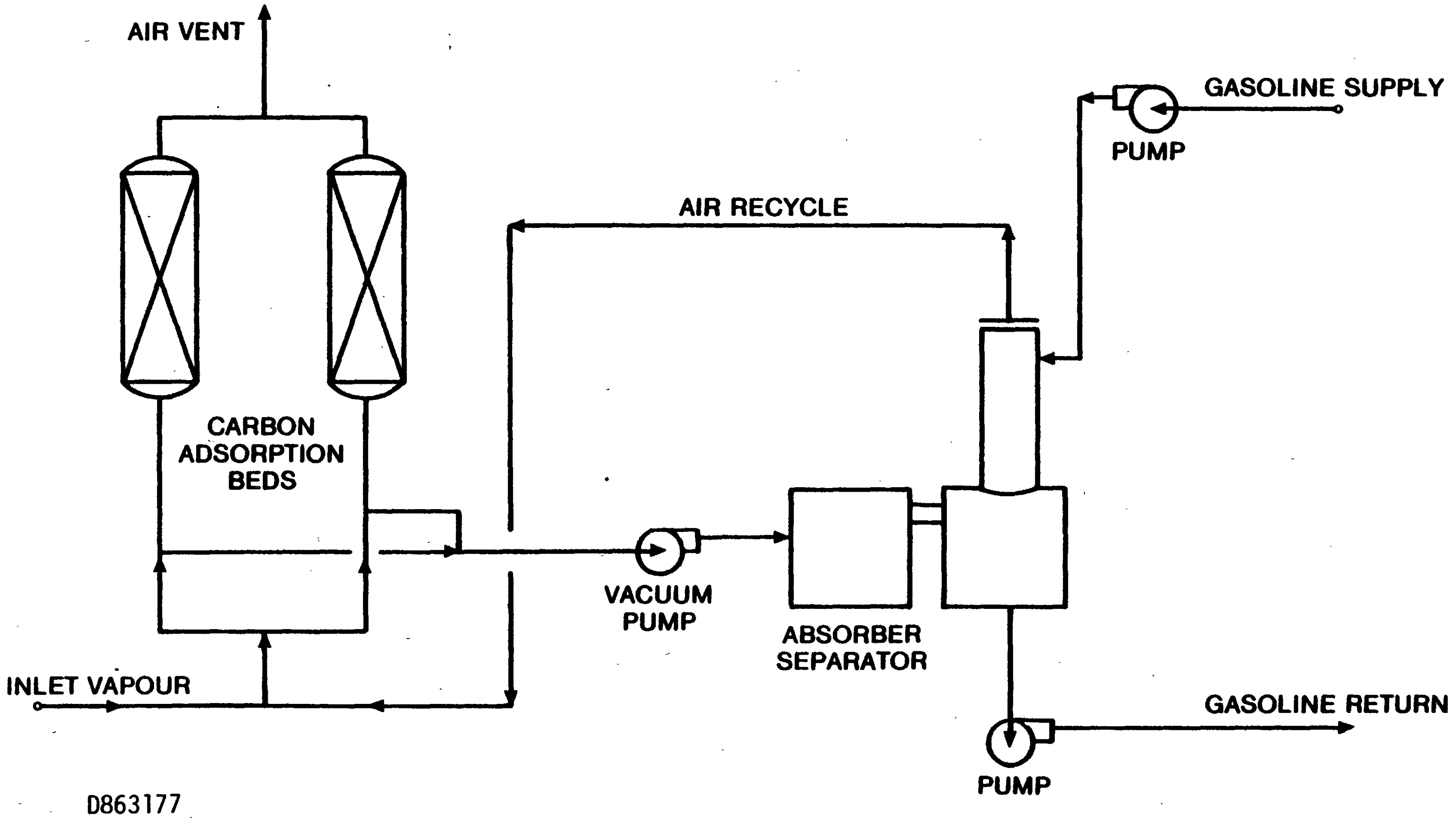
1 million ECUs.

Operating Costs:

Due to high value of recovered vapours, the system would generate benefits equivalent to typically 20 percent of installed cost per year (taking account of utility labour and maintenance etc. costs). Obviously these benefits vary significantly as a result of the amount and value of the recovered vapour. The figure quoted above was calculated for typical 1985 market rates, assuming that duty payments were not included in the gasoline value.

FIGURE V.C.9.

ADSORPTION/ABSORBTION GASOLINE RECOVERY SYSTEM (McGILL INCORPORATED)



b) Particulates

As previously discussed particulate emissions are not foreseen to be a significant problem as a result of known legislation with the possible exception of the legislation applicable to FCC's in Germany.

Particulate removal technology is commercially proven although with only limited refinery related activities. Available techniques include:

- Cyclones (one, two on three stage)
- Baghouse Filters
- Wet Gas Scrubbing Systems
- Electrostatic Precipitators

Cyclones are already employed on FCC's for catalyst recovery/fines removal. Because little is known about quantitative levels of particulate emission it is not clear whether the use of cyclones would suffice to meet the German regulations. It is known that electrostatic precipitation has been applied to an FCC plant in France although it was not installed to meet emission requirements.

c) Continuous Monitoring

German legislation requires that continuous monitoring is carried out for CO, particulates, NOx, SO_2 and O_2 on each stack. Costs have been estimated at around 150 000 ECUs for installation per stack, plus 100 000 ECUs for a common (to all stacks) computer system. Operating costs were estimated to be 25 percent per year of the installed capital costs. These operating costs are quite high due to the need for significant laboratory and technical support for such system as well as inherent reliability limitations.

6. Other Product Quality

a) Nickel Content of Heavy Fuel Oil

Quantitative assessment of the control of Nickel content in residual fuel oil in Germany is not straightforward. The likely consequence of this legislation is a restriction in the use of crude oil feeds of high nickel content such as those orginating from Mexico and Venezuela.

Nickel removal from crude oil or any of the product streams is not considered a viable proposition because of the high cost involved.

7. Liquid Effluent

A very large number of contaminants can be detected in the waste water from oil refineries. Some originate from the crude oil while others are produced in the manufacturing processes, particularly in the conversion units.

Some contaminants are not inherent in petroleum refining operations but could be traced back to additives used for product blending, conditioning agents for steam raising and cooling water, products of corrosion of equipment, etc.

The number and the type of pollution parameters to be monitored differ from location to location but the quality of the effluent can generally be assessed by monitoring;

- oil/hydrocarbons
- oxygen demand
- phenols, sulphides and ammonia
- suspended matter

There are a number of water treatment processes which can be used singly or in the combination to remove oil and other contaminants from waste water prior to discharge from refineries.

For the purposes of this report they have been divided into the following categories:

- Gravity separation eg. API separation, plate interceptors, tank separation etc.

- Advanced treatment eg. flocculation, air flotation, sedimentation, filtration etc.

- Biological treatment eg. bio-filters, activated sludge, aerated ponds etc.

Site specific requirements and installed costs for the above would need to be assessed on a case by case basis. For this study though, typical costs have been used for the application of the three levels of treatment.

Basis:

Total effluent water discharge of 3 million metric tons per year of which 20 percent is segregated for secondary and tertiary treatment.

Installed Capital Costs:

- Gravity Separation = 1 million ECUs
- Advanced Treatment = 700 000 ECUs
- Biological Treatment = 800 000 ECUs

Operating Costs:

10 percent of installed capital costs per year.

These figures are relatively low as a result of the assumption made for this study that the "typical refineries" are served by relatively up to date "closed circuit" cooling water systems with a discharge rate of 3 million metric tons per year. Obviously both investment and operating costs would vary significantly if evaluations were carried out on a site specific basis.

8. Other

a) Environmental Noise

There are many technical measures available for effecting the reduction of noise from major process equipment:

- o Modification or replacement of noisy equipment
- o Vibration reduction
- o Silencers
- o Accoustic insulation (thermal insulation also has limited noise reduction qualities)
- o Encapsulation of noisy equipment
- o Relocation of noisy equipment

The applications of these measures are very site specific and no attempt was therefore made to generalise compliance costs for a typical refinery.

D. ASSESSMENT OF COMPLIANCE COSTS

Having identified the environmental constraints and selected the "best" technical solutions, incremental investment and operating costs for installing them in an existing refinery were estimated. Operating costs were included, where relevent, for the higher utilisation of existing plant as well as those associated with the new installations. All of the costs presented are differentials above the base case costs as defined in the terms of reference. All costs for new installations were based on an "incremental" basis, ie as a proportion of the cost of a commercial scale unit. In line with good design practices 20 percent overcapacity was included.

The costs were first identified with repect to the individual components of the environment considered and then accumulated to give an assessment on a country by country basis for the two reference years for each type of refinery. All costs quoted are typical mid 1985 values for the two refinery types as defined in the terms of reference.

1. Gasoline Related

A summary of the investment costs associated with meeting the gasoline pool requirements for 1993 are given in Table V.D.1. The costs have been itemised under the headings of Isomerisation, Reforming/Hydrotreating and Special Offsite considerations.

The associated operating costs are presented in Table V.D.2, the major cost element for all the cases considered was the cost of the additional crude oil required by the higher severity processing operations needed to meet the gasoline pool octane requirements while maintaining approximately the same product slate. The value of the incremental crude oil processed was assummed to be 250 ECUs per metric ton (typical mid 1985 market price). The other operating costs were made up of those associated with running the existing units at higher throughputs and severity and those resulting from the operation of the new processing installations.

TABLE V.D.1

CAPITAL INVESTMENT COSTS FOR GASOLINE POOL REQUIREMENTS (1993)

(million ECUs)

Country	Isomerisation	Reforming /Hydrotreating	Special Offsites	Total
Belgium				
Hydroskimming Refinery	10.0	8.8	-	18.8
Conversion Refinery	10.0	31.3	-	41.3
France				
Hydroskimming Refinery	7.5	5.0	-	12.5
Conversion Refinery	7.5	7.5	-	15.0
Germany				
Hydroskimming Refinery	8.8	3.8(1)	4.0(3)	16.6(1)
Conversion Refinery	8.8	12.5(2)	4.0(3)	25.3(2)
Italy				
Hydroskimming Refinery	5.0	3.8	-	8.8
Conversion Refinery	5.0	5.0	-	10.0
Netherlands				
Hydroskimming Refinery	10.0	10.0	-	20.0
Conversion Refinery	10.0	37.5	-	47.5
Spain				
Hydroskimming Refinery	-	10.0	-	10.0
Conversion Refinery	-	10.0	-	10.0
United Kingdom				
Hydroskimming Refinery	10.0	8.8	-	18.8
Conversion Refinery	10.0	35.0	-	45.0

Notes:

(1) Excluding the 8.8 million ECUs required to meet National 1985 low lead requrements.

(2) Excluding the 10.0 million ECUs required to meet National 1985 low lead requirements.

(3) As a result of marketing three gasoline grades.

TABLE V.D.2

OPERATING COSTS FOR GASOLINE POOL REQUIREMENTS (1993)
(million ECUs per year)

Country	Incremental Crude(1)	General Operating(2)	Total
Belgium			
Hydroskimming Refinery	5.3	0.9	6.2
Conversion Refinery	9.5	2.0	11.5
France			
Hydroskimming Refinery	2.3	0.6	2.9
Conversion Refinery	4.1	0.8	4.9
Germany			
Hydroskimming Refinery	2.3	0.8	3.1(3)
Conversion Refinery	4.1	1.3	5.4(4)
Italy			
Hydroskimming Refinery	1.5	0.4	1.9
Conversion Refinery	2.8	0.5	3.3
Netherlands			
Hydroskimming Refinery	5.5	1.0	6.5
Conversion Refinery	10.0	2.4	12.4
Spain			
Hydroskimming Refinery	3.8	0.5	4.3
Conversion Refinery	7.9	0.5	8.4
United Kingdom			
Hydroskimming Refinery	5.4	0.9	6.3
Conversion Refinery	9.8	2.2	12.0

Notes:

(1) Incremental crude oil requirements at 250 ECUs per metric ton.

(2) Excluding fuel.

(3) Excluding 3.0 million ECUs per year required to meet National 1985 low lead requirements.

(4) Excluding 5.5 million ECUs per year required to meet National 1985 low lead requirements.

2. Sulphur Related (Product Quality)

Sulphur related product quality legislation affects two refinery product streams gas oil and residual fuel oil.

a) Gas Oil Product

It was assumed that new desulphurisation capacity would be required when use of the existing capacity had been maximised as defined in Section V.C.2, and investment costs were calculated accordingly. A summary of the investment costs associated with meeting the gas oil product requirements for 1993 are given in Table V.D.3.

The operating costs associated with higher utilisation requirements of existing plant to meet the National Regulations in 1985, and those for existing and new capacity in 1993 are presented in Table V.D.4.

b) Residual Fuel Oil Product

A summary of the investment costs associated with the inclusion of Residue Desulphurisation capacity in order to meet the product requirements for 1993 are given in Table V.D.5. As previously discussed, even when assuming desulphurisation of all of the atmospheric residue it was not possible to meet the 1 percent sulphur content required for the conversion refinery cases in Germany and the Netherlands. Maximum desulphuration was assumed for the cases presented.

The operating costs resulting from the residue desulphurisation are presented in the Table V.D.6, these include the cost associated with the estimated yield of 85 wt percent on feed assumed.

For comparison, alternative evaluations were carried out for the German and Netherlands cases assumming 80 percent of the heavy fuel oil is exported due to the failure to meet local sulphur content requirements. No specific export market or refinery location was assumed but costs of 10 ECUs and 12 ECUs per metric ton for transportation were assumed for the Netherlands and Germany repectively. Using these data, the annual costs for heavy fuel oil export were calculated and the results are summarised in Table V.D.7.

TABLE V.D.3

CAPITAL INVESTMENT COSTS FOR GAS OIL PRODUCT DESULPHURISATION (1993)

(million ECUs)

Country	Gas Oil Desulphurisation(1)
Belgium	
Hydroskimming	1.5
Conversion	9.9
France	
Hydroskimming	1.9
Conversion	10.4
Germany	
Hydroskimming	-
Conversion	3.0
Italy	
Hydroskimming	-
Conversion	5.1
Netherlands	
Hydroskimming	-
Conversion	5.7
Spain	
Hydroskimming	-
Conversion	6.8
United Kingdom	
Hydroskimming	-
Conversion	-

Note:
(1) Based on new capacity requirements, to meet foreseen future regulations as defined by the Commission.

TABLE V.D.4

OPERATING COSTS FOR GAS OIL PRODUCT DESULPHURISATION (1985 and 1993)

(million ECUs per year)

Country	1985(1)	1993(2)
Belgium		
Hydroskimming Refinery	2.1	3.2
Conversion Refinery	2.3	3.5
France		
Hydroskimming Refinery	2.2	3.3
Conversion Refinery	2.4	3.6
Germany		
Hydroskimming Refinery	1.8	3.2
Conversion Refinery	1.8	3.3
Italy		
Hydroskimming Refinery	-	1.7
Conversion Refinery	-	1.9
Netherlands		
Hydroskimming Refinery	2.2	3.3
Conversion Refinery	2.5	3.7
Spain		
Hydroskimming Refinery	-	1.5
Conversion Refinery	-	1.7
United Kingdom		
Hydroskimming Refinery	-	0.8
Conversion Refinery	-	0.8

Notes:

(1) Required to meet National Regulations.

(2) Required to meet foreseen future regulations as defined by the Commission.

TABLE V.D.5

CAPITAL INVESTMENT COSTS FOR RESIDUAL FUEL OIL DESULPHURISATION (1993)

(million ECUs)

Country(1)	Residue Desulphurisation(2)
Belgium	
Hydroskimming Refinery	-
Conversion Refinery	8.1
Germany	
Hydroskimming Refinery	65.5
Conversion Refinery	43.5(3)
Netherlands	
Hydroskimming Refinery	85.0
Conversion Refinery	48.2(3)

Notes:

(1) No capital investment required in France, Italy, Spain and United Kingdom.

(2) Required to meet National Regulations.

(3) Maximum desulphurisation assumed, although did not meet product quality specifications.

TABLE V.D.6

OPERATING COSTS FOR RESIDUAL FUEL OIL DESULPHURISATION (1993)

(million ECUs per year)

Country(1)	Operating Costs(2)
Belgium	
Hydroskimming Refinery	-
Conversion Refinery	2.4
Germany	
Hydroskimming Refinery	19.7
Conversion Refinery	13.0(3)
Netherlands	
Hydroskimming Refinery	25.5
Conversion Refinery	14.5(3)

Notes:

(1) No additional operating costs in France, Italy, Spain and United Kingdom.

(2) Required to meet National Regulations.

(3) Maximum desulphurisation assumed, although did not meet product quality specifications.

TABLE V.D.7

COSTS ASSOCIATED WITH RESIDUAL FUEL OIL EXPORT (1993)

(million ECUs per year)

Country	Export Costs
Germany	
Hydroskimming Refinery	12.7(1)
Conversion Refinery	6.4(1)
Netherlands	
Hydroskimming Refinery	10.8(2)
Conversion Refinery	5.6(2)

Notes:

(1) Assumming transportation costs of 12 ECUs per metric ton.

(2) Assumming transportation costs of 10 ECUs per metric ton.

3. Sulphur Related (Air Quality)

Of the member states considered only Germany and the Netherlands were identified to be subject to compliance costs associated with the sulphur content of atmospheric emissions.

o Germany

For the 1985 cases it was required that the sulphur removal efficiency of the sulphur recovery units should be greater than 98 percent. It was assumed that "Sulfreen Units" were installed to meet these requirements.

For 1993 the regulations are much tighter and include control of stack gas emissions. It was assumed that "Scot Units" were installed on the sulphur recovery units and flue gas desulphurisation applied to the two main stacks (boilerhouse and crude distillation unit). The other units were assumed to burn the available refinery gas. A summary of the investment costs associated with meeting the sulphur related air quality requirements for Germany in 1985 and 1993 are given in Table V.D.8, and the associated operating costs in Table V.D.9.

As an alternative evaluation, an estimate was made of the costs associated with switching over to all gas firing and exporting the liquid fuel. The capital cost was estimated to be 15.0 million ECUs for the hydroskimming type and 18.0 million ECUs for the conversion type refinery. This includes the costs associated with furnace/boiler safeguarding requirements when operating on dedicated gas firing. The operating costs were estimated at 2.2 million ECUs per year for the hydroskimming type and 2.7 million ECUs per year for the conversion type refinery (assuming the natural gas cost to be 5 percent higher than German quality heavy fuel oil and liquid fuel export costs of 12 ECUs per metric ton).

o Netherlands

The only identified constraint for the Netherlands was the need to reduce the average sulphur content of the refinery fuel from the calculated 1.82 wt percent down to the required level of 1.2 wt percent for the "1993 Conversion Type Refinery case".

This was assumed to be achieved by blending some of the high sulphur components of the liquid refinery fuel into the residuel fuel oil, exchanging them for low sulphur components in order to meet the required specifications. It was assumed that this resulted in a loss in "sulphur premium" in the sale of the exchanged fuel oil of 15 ECUs per metric ton, at an estimated overall cost of 2.0 million ECUs per year.

TABLE V.D.8

CAPITAL INVESTMENT COSTS FOR SULPHUR RELATED AIR QUALITY REQUIREMENTS IN GERMANY (1985 AND 1993)

(million ECUs)

Year	Hydroskimming Refinery	Conversion Refinery
1985		
Sulphur Recovery ("add on" Sulfreen)	3.0	3.5
Total	3.0	3.5
1993		
Sulphur Recovery ("add on" Scot)	6.6	7.7
Flue Gas Desulphurisation	55.0	60.0
Total	61.6	67.7

TABLE V.D.9

OPERATING COSTS FOR SULPHUR RELATED AIR QUALITY REQUIREMENTS IN GERMANY (1985 AND 1993)

(million ECUs per year)

Year	Hydroskimming Refinery	Conversion Refinery
1985	0.3	0.4
1993	9.0	9.8

4. NO_x Related

Three cases were assessed for the control of NO_x in Germany in 1993 minimum, maximum and intermediate control. The following assumptions were made for each;

- Minimum Control Case:
  - No modifications.

- Maximum Control Case:
  - Installation of Catalytic $DeNO_x$ Units on major stacks (ie crude distillation, catalytic reformer, high vacuum unit and boilerhouse).

- Intermediate Control Case:
  - Installation of low NO_x burners.

The capital investment and operating costs assocated with these cases are given in Tables V.D.10 and V.D.11.

It is difficult to predict which of the above control cases is most likely to be adopted by 1993. When evaluating the country by country assessment costs, it was assumed that the required measures would fall somewhere between the intermediate and maximum control cases quoted. Investment costs of 10 million ECUs and 12 million ECUs and operating costs of 3 million ECUs per year and 4 million ECUs per year were assumed for the hydroskimming and conversion type refineries repectively.

TABLE V.D.10

CAPITAL INVESTMENT COSTS FOR NO_x RELATED AIR QUALITY REQUIREMENTS IN GERMANY (1993)

(million ECUs)

Case	Hydroskimming Refinery	Conversion Refinery
Minimum Control Case	-	-
Maximum Control Case	15.0	20.0
Intermediate Control Case	5.0	4.0

TABLE V.D.11

OPERATING COSTS FOR NO_x RELATED AIR QUALITY REQUIREMENTS IN GERMANY (1993)

(million ECUs per year)

Case	Hydroskimming Refinery	Conversion Refinery
Minimum Control Case	-	-
Maximum Control Case	4.5	6.0
Intermediate Control Case	-	-

5. Other Air Quality Related

Three categories were considered under this heading relating to German legislative measures.

a) Hydrocarbon Emission

A summary of the investment costs associated with reduction in hydrocarbon emissions for 1993 are given in Table V.D.12. These have been broken down into costs associated with the installation of vapour recovery systems for gasoline loading and the other measures which are described in more detail in Section V.B.5. The associated operating costs are given in Table V.D.13, but as can be seen in all cases the investments in fact generate positive benefits.

TABLE V.D.12

CAPITAL INVESTMENT COSTS FOR HYDROCARBON EMISSION REQUIREMENTS IN GERMANY (1993)

(million ECUs)

Control Measure	Hydroskimming Refinery	Conversion Refinery
Vapour Recovery System	0.8	1.0
Other	5.0	5.0
Total	5.8	6.0

TABLE V.D.13

OPERATING COSTS FOR HYDROCARBON EMISSION REQUIREMENTS IN GERMANY (1993)

(million ECUs per year)

Control Measure	Hydroskimming Refinery(1)	Conversion Refinery(1)
Vapour Recovery system	(0.2)	(0.2)
Other	(0.3)	(0.3)
Total	(0.5)	(0.5)

Note:

(1) Figures in brackets indicate negative valves (ie benefits).

b) Particulates

No compliance costs were estimated for particulate related environmental measures.

c) Continuous Monitoring

Compliance costs were estimated for the application of continuous stack emission monitoring equipment on all major stacks, this was assumed to be 6 stacks for the hydroskimming type and 8 stacks for the conversion type refinery.

Investment costs of 1 million ECUs and 1.3 million ECUs were estimated for the hydroskimming and conversion type refineries respectively. Operating costs were estimated to 0.3 million ECUs per year for each case.

6. Other Product Quality

a) Nickel Content of Heavy Fuel Oil

No attempt was made to quantify the costs which may be associated with the limitation of the Nickel content in heavy fuel oil. It is considered that any constraints (if they materialise) would be overcome by careful selection of the crude oil slate processed.

7. Liquid Effluent

In order to estimate the costs associated with the compliance with 1985 legislative measures the actual proportion of gravity separation, advanced and biological treatment facilities for each of the countries considered was assumed. For 1993 it was assumed that three stage treatment would be adopted for all cases.

The investment and operating costs for each of the member states considered are given in Tables V.D.14 and V.D.15.

TABLE V.D.14

CAPITAL INVESTMENT COSTS FOR EFFLUENT WATER TREATMENT REQUIREMENTS (1985 and 1993)(1)

(million ECUs)

Country	1985(1)	1993(1)
Belgium	2.50	2.50
France	2.50	2.50
Germany	2.42	2.50
Italy	2.38	2.50
Netherlands	2.42	2.50
Spain	1.90	2.50
United Kindgom	1.52	2.50

Note:

(1) Costs for Hydroskimming and Coversion Type Refineries were the same in each case.

TABLE V.D.15

OPERATING COSTS FOR EFFLUENT WATER TREATMENT REQUIREMENTS (1985 and 1993)(1)

(million ECUs per year)

Country	1985(1)	1993(1)
Belgium	0.25	0.25
France	0.25	0.25
Germany	0.24	0.25
Italy	0.24	0.25
Netherlands	0.24	0.25
Spain	0.19	0.25
United Kindgom	0.15	0.25

Note:

(1) Costs for Hydroskimming and Conversion Type Refineries were the same in each case.

8. Other

No specific compliance costs were estimated for environmental noise control measures or soil clean up at refinery sites, as these are too site specific for a typical refinery cost to be meaningful. Instead we have included in the Section II Summary Tables the following order of magnitude cost allowances for all national cases, to cover these and any other miscellaneous environmental costs which may have been overlooked.

Investment:	0.1 ECU per annual metric ton production
Operating Costs:	0.08 ECU per metric ton production

9. Electricity Costs

Due to the impact of environmental measures on the electricity generating industry in Germany, an estimate was made of the additional cost of an increase in the price to the refinery of electricity of 20 percent. Although these increases in generating costs began to impact before 1985, the additional cost was only included when evaluating the 1993 cases when the full impact is likely to have been passed on to the consumer.

For both the hydroskimming type refinery (electricity import of 8.4MW) and conversion type refinery (electricity import 8.5MW) the additional cost was estimated to be 0.6 million ECUs per year.

10. Country Summary

A summary of the compliance costs for all of the cases considered are given in Tables V.D.16 through to V.D.36.

The following explainatory notes should be read in conjuction with the Tables.

Column 1

Gives the individual component of the environment considered and the specific parameters assessed.

Column 2

Indicates the legislation which imposes the identified constraints.

Column 3

Indicates the limit values from the provision indicated in column 2 or the practical measures called for.

Column 4

Gives details of the technical measures selected for compliance with the environmental constraints identified.

Column 5

Indicates the investment required for each of the hydroskimming and conversion type refineries as defined in the terms of reference in order to implement the measure. The total investment is presented as well as the incremental cost per metric ton of total annual production. It should be noted that the actual production rates for the hydroskimming and conversion type refineries vary slightly due to different fuel and loss requirements.

Column 6

Indicates the operating costs for each of the hydroskimming and conversion type refineries as defined in the terms of reference arising from the emission reduction facilities applied. Annual operating costs are quoted as well as the operating costs per metric ton of total production. It should be noted that the actual production rates for the hydroskimming and conversion type refineries vary slightly due to different fuel and loss requirements.

TABLE V.D.16

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
BELGIUM : 1985 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	National Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.1	0.58
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Total				2.5	0.69	2.4	0.66
Conversion Type							
Product Quality, Gas Oil	National Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.3	0.65
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Total				2.5	0.71	2.6	0.73

TABLE V.D.17

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
FRANCE : 1985 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	National Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.2	0.61
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Total				2.5	0.69	2.5	0.69
Conversion Type							
Product Quality, Gas Oil	National Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.4	0.68
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Total				2.5	0.71	2.7	0.76

TABLE V.D.18

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
GERMANY : 1985 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	National Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	1.8	0.50
Product Quality, Gasoline	National Regulation	0.15g Pb/l	Increase Pool Octane	8.8	2.44	3.0	0.83
Air, Claus Unit Recovery	TA Luft	98 percent S recovery	TGT installation	3.0	0.83	0.3	0.08
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.4	0.67	0.2	0.06
Total				14.2	3.94	5.3	1.47
Conversion Type							
Product Quality, Gas Oil	National Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	1.8	0.51
Product Quality, Gasoline	National Regulation	0.15g Pb/l	Increase Pool Octane	10.0	2.83	5.5	1.56
Air, Claus Unit Recovery	TA Luft	98 percent S recovery	TGT installation	3.5	0.99	0.4	0.11
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.4	0.68	0.2	0.06
Total				15.9	4.50	7.9	2.24

TABLE V.D.19

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
ITALY : 1985 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost ECU	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.4	0.67	0.2	0.06
Total				2.4	0.67	0.2	0.06
Conversion Type							
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.4	0.68	0.2	0.06
Total				2.4	0.68	0.2	0.06

TABLE V.D.20

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
NETHERLANDS : 1985 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	National Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.2	0.61
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.4	0.67	0.2	0.06
Total				2.4	0.67	2.4	0.67
Conversion Type							
Product Quality, Gas Oil	National Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.5	0.71
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.4	0.68	0.2	0.06
Total				2.4	0.68	2.7	0.77

TABLE V.D.21

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
SPAIN : 1985 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	1.9	0.53	0.2	0.06
Total				1.9	0.53	0.2	0.06
Conversion Type							
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	1.9	0.54	0.2	0.06
Total				1.9	0.54	0.2	0.06

TABLE V.D.22

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
UNITED KINGDOM : 1985 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Water, Effluent Quality	Regional Requirements	General Quality	Three Stage Treatment	1.5	0.42	0.2	0.06
Total				1.5	0.42	0.2	0.06
Conversion Type							
Water, Effluent Quality	Regional Requirements	General Quality	Three Stage Treatment	1.5	0.42	0.2	0.06
Total				1.5	0.42	0.2	0.06

TABLE V.D.23

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
BELGIUM : 1993 EEC CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.1	0.58
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	18.8	5.22	6.2	1.72
Total				18.8	5.22	8.3	2.30
Conversion Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.3	0.65
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	41.3	11.70	11.5	3.26
Total				41.3	11.70	13.8	3.91

TABLE V.D.24

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
FRANCE : 1993 EEC CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.2	0.61
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	12.5	3.47	2.9	0.81
Total				12.5	3.47	5.1	1.42
Conversion Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.4	0.68
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	15.0	4.25	4.9	1.39
Total				15.0	4.25	7.3	2.07

TABLE V.D.25

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
GERMANY : 1993 EEC CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	1.8	0.50
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	25.4	7.06	6.1	1.69
Total				25.4	7.06	7.9	2.19
Conversion Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	1.8	0.51
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	35.3	10.0	10.9	3.09
Total				35.3	10.0	12.7	3.60

TABLE V.D.26

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES

ITALY : 1993 EEC CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	1.7	0.47
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	8.8	2.44	1.9	0.53
Total				8.8	2.44	3.6	1.00
Conversion Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	5.1	1.44	1.9	0.54
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	10.0	2.83	3.3	0.93
Total				15.1	4.27	5.2	1.47

TABLE V.D.27

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
NETHERLANDS : 1993 EEC CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.2	0.61
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	20.0	5.56	6.5	1.81
Total				20.0	5.56	8.7	2.42
Conversion Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	2.5	0.71
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	47.5	13.46	12.4	3.51
Total				47.5	13.46	14.9	4.22

TABLE V.D.28

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
SPAIN : 1993 EEC CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	1.5	0.42
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	10.0	2.78	4.3	1.19
Total				10.0	2.78	5.8	1.61
Conversion Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	6.8	1.93	1.7	0.48
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	10.0	2.83	8.4	2.38
Total				16.8	4.76	10.1	2.86

TABLE V.D.29

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
UNITED KINGDOM : 1993 EEC CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	0.8	0.22
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	18.8	5.22	6.3	1.75
Total				18.8	5.22	7.1	1.97
Conversion Type							
Product Quality, Gas Oil	Future Directive	0.3 wt percent S	Gas Oil Desulphurisation	-	-	0.8	0.23
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	45.0	12.75	12.0	3.40
Total				45.0	12.75	12.8	3.63

TABLE V.D.30

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES

BELGIUM : 1993 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Regulation	0.2 wt percent S	Gas Oil Desulphurisation	1.5	0.42	3.2	0.89
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	18.8	5.22	6.2	1.72
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Total				22.8	6.33	9.7	2.69
Conversion Type							
Product Quality, Gas Oil	Future Regulation	0.2 wt percent S	Gas Oil Desulphurisation	9.9	2.80	3.5	0.99
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	41.3	11.70	11.5	3.26
Product Quality, Residual Fuel Oil	National Regulation	2.2 wt percent S	Residue Desulphurisation	8.1	2.29	2.4	0.68
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Total				61.8	17.50	17.7	5.01

TABLE V.D.31

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
FRANCE : 1993 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Regulation	0.2 wt percent S	Gas Oil Desulphurisation	1.9	0.53	3.3	0.92
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	12.5	3.47	2.9	0.81
Water, Effluent Quality Fuel Oil	National Regulations	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Total				16.9	4.69	6.5	1.81
Conversion Type							
Product Quality, Gas Oil	Future Regulation	0.2 wt percent S	Gas Oil Desulphurisation	10.4	2.95	3.6	1.02
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	15.0	4.25	4.9	1.39
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Total				27.9	7.91	8.8	2.49

TABLE V.D.32

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
GERMANY : 1993 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Regulation	0.2 wt percent S	Gas Oil Desulphurisation	-	-	3.2	0.89
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	25.4	7.06	6.1	1.69
Product Quality, Residual Fuel Oil	GFAVO/ TA Luft	1.0 wt percent S	Residue Desulphurisation	65.5(1)	18.19(1)	19.7(1)	5.47(1)
Air, Claus Unit Recovery	TA Luft	99.5 percent S recovery	TGT Installation	6.6	1.83	0.7	0.19
Air, SO_2 Stack Gases	GFAVO	Gas Firing	Switch to Gas	15.0(2)	4.17(2)	2.2(2)	0.61(2)
Air, NO_x Stack Gases	GFAVO/ TA Luft	NO_x Removal	General $DeNO_x$ measures	10.0	2.78	3.0	0.83
Air, Hydrocarbon Emission (Vapour Recovery)	TA Luft	Vapour Recovery	Gasoline Vapour Recovery Unit	0.8	0.22	(0.2)	(0.06)
Air, Hydrocarbon Emission (General)	TA Luft	General Measures	Good Practice Measures	5.0	1.39	(0.3)	(0.08)
Air, Hydrocarbon Emission (Stack Monitoring)	GFAVO	Monitoring	Continuous Analysers	1.0	0.28	0.3	0.08
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Electricity Cost				-	-	0.6	0.17
Total				131.8	36.61	35.6	9.87

Notes:

(1) Alternative evaluation assuming export of residual fuel oil requires no investment costs but has associated operating costs of 12.7 million ECUs/year (3.53 ECUs/tonne).

(2) Alternative evaluation assuming the use of flue gas desulphurisation requires investment costs of 55.0 million ECUs (15.28 ECUs/tonne) and operating costs of 8.3 million ECUs per year (2.31 ECUs/tonne).

TABLE V.D.32 (Contd)

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES

GERMANY : 1993 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Conversion Type							
Product Quality, Gas Oil	Future Regulation	0.2 wt percent S	Gas Oil Desulphurisation	3.0	0.85	3.3	0.93
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	35.3	10.00	10.9	3.09
Product Quality, Residual Fuel Oil	GFAVO/ TA Luft	1.0 wt percent S	Residue Desulphurisation	43.5(3)	12.32(3)	13.0(3)	3.68(3)
Air, Claus Unit Recovery	TA Luft	99.5 percent S recovery	TGT Installation	7.7	2.18	0.8	0.23
Air, SO_2 Stack Gases	GFAVO	FGD	FGD	18.0(4)	5.10(4)	2.7(4)	0.76(4)
Air, NO_x Stack Gases	GFAVO/ TA Luft	NO_x Removal	General $DeNO_x$ Measures	12.0	3.40	4.0	1.13
Air, Hydrocarbon Emission (Vapour Recovery)	TA Luft	Vapour Recovery	Gasoline Vapour Recovery Unit	1.0	0.28	(0.2)	(0.06)
Air, Hydrocarbon Emission (General)	TA Luft	General Measures	Good Practice Measures	5.0	1.42	(0.3)	(0.08)
Air, Hydrocarbon Emission (Stack Monitoring)	GFAVO	Monitoring	Continuous Analysers	1.3	0.37	0.3	0.08
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Electricity Cost				-	-	0.6	0.17
Total				129.3	36.63	35.4	10.01

Notes:

(3) Alternative evaluation assuming export of residual fuel oil requires no investment costs but has associated operating costs of 6.4 million ECUs/year (1.81 ECUs/tonne).

(4) Alternative evaluation assuming the use of flue gas desulphurisation requires investment costs of 60.0 million ECUs (17.00 ECUs/tonne) and operating costs of 9.0 million ECUs per year (2.55 ECUs/tonne).

TABLE V.D.33

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
ITALY : 1993 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	1.7	0.47
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	8.8	2.44	1.9	0.53
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Total				11.3	3.13	3.9	1.08
Conversion Type							
Product Quality, Gas Oil	Future Regulation	0.3 wt percent S	Gas Oil Desulphurisation	5.1	1.44	1.9	0.54
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	10.0	2.83	3.3	0.93
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Total				17.6	4.98	5.5	1.55

TABLE V.D.34

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
NETHERLANDS : 1993 EEC NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Regulation	0.2 wt percent S	Gas Oil Desulphurisation	-	-	3.3	0.92
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	20.0	5.56	6.5	1.81
Product Quality, Residual Fuel Oil	National Regulation	1.0 wt percent S	Residue Desulphurisation	85.0(1)	23.61(1)	25.5(1)	7.08(1)
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Total				107.5	29.86	35.6	9.89
Conversion Type							
Product Quality, Gas Oil	Future Regulation	0.2 wt percent S	Gas Oil Desulphurisation	5.7	1.61	3.7	1.05
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	47.5	13.46	12.4	3.51
Product Quality, Residual Fuel Oil	National Regulation	1.0 wt percent S	Residue Desulphurisation	48.2(2)	13.65	14.5(2)	4.11(2)
Air, S content Refinery Fuel	National Regulation	1.2 wt Percent S	Fuel Oil Segregation	-	-	2.0	0.57
Water, Effluent Quality	Nationals Regulations	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Total				103.9	29.43	32.9	9.32

Notes:

(1) Alternative evaluation assuming export of residual fuel oil requires no investment costs but has associated operating costs of 10.8 million ECUs/year (3.00 ECUs/tonne).

(2) Alternative evaluation assuming export of residual fuel oil requires no investment costs but has associated operating costs of 5.6 million ECUs/year (1.59 ECUs/tonne).

TABLE V.D.35

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
SPAIN : 1993 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	1.5	0.42
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	10.0	2.78	4.3	1.19
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Total				12.5	3.47	6.1	1.69
Conversion Type							
Product Quality, Gas Oil	Future Regulation	0.3 wt percent S	Gas Oil Desulphurisation	6.8	1.93	1.7	0.48
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	10.0	2.83	8.4	2.38
Water, Effluent Quality	National Regulations	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Total				19.3	5.47	10.4	2.94

T V.D.36

SUMMARY OF ENVIRONMENTAL EXPENDITURE BY OIL REFINERIES
UNITED KINGDOM : 1993 EEC AND NATIONAL CASE

1	2	3	4	5		6	
	Legislation	Requirement	Technical Measure to comply with the provisions	Investment Cost		Operating Cost	
				Total (million ECUs)	per tonne (ECUs)	Total (million ECUs per year)	per tonne (ECUs)
Hydroskimming Type							
Product Quality, Gas Oil	Future Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	0.8	0.22
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	18.8	5.22	6.3	1.75
Water, Effluent Quality	Regional Requirements	General Quality	Three Stage Treatment	2.5	0.69	0.3	0.08
Total				21.3	5.91	7.4	2.05
Conversion Type							
Product Quality, Gas Oil	Future Regulation	0.3 wt percent S	Gas Oil Desulphurisation	-	-	0.8	0.23
Product Quality, Gasoline	Directive 85/210/EEC	Unleaded Gasoline	Increase Pool Octane	45.0	12.75	12.0	3.4
Water, Effluent Quality	Regional Requirements	General Quality	Three Stage Treatment	2.5	0.71	0.3	0.08
Total				47.5	13.46	13.1	3.71

APPENDICES

APPENDIX A

GERMANY 1985 NATIONAL CASE (CONVERSION TYPE REFINERY)

SUMMARY REPORT

Feedstocks	Quantity (wt percent on crude)	Price ($/t)	Min (wt percent on crude)	Max (wt percent on crude)
German Crude	100.00	200.00	0.00	100.00
Total Feedstocks	100.00			
Products				
Gasoline Pool	29.65	-290.00	0.00	100.00
Kerosine Production	6.00	-250.00	6.00	6.00
Gas Oil Production	29.02	-250.00	0.00	100.00
Heavy Fuel Oil	17.91	-190.00	0.00	100.00
Naphtha	4.00	-240.00	4.00	4.00
Bitumen	4.00	-300.00	4.00	4.00
LPG	3.26	-220.00	0.00	100.00
Total Products	93.84			

GERMANY 1985 NATIONAL CASE (CONVERSION TYPE REFINERY)

ATMOSPHERIC DISTILLATION

	Quantity (wt percent on crude)
Feedstocks	
Hydrogen	0.07
German Crude	100.00
Total Feedstocks	100.07
Products	
Light Gas	0.17
LPG	1.70
Light Naphtha	3.10
Naphtha	4.00
Heavy Naphtha	16.20
Kerosene	9.30
Gas Oil	23.00
Atmospheric Residue	42.60
Total Products	100.07

VACUUM DISTILLATION

	Quantity (wt percent on crude)
Feedstocks	
Atmospheric Residue	32.36
Total Feedstocks	32.36
Products	
Vacuum Distillate	20.00
Vacuum Residue	12.36
Total Products	32.36

GERMANY 1985 NATIONAL CASE (CONVERSION TYPE REFINERY)

BITUMEN PLANT

	Quantity (wt percent on crude)
Feedstocks	
Vacuum Residue	4.00
Total Feedstocks	4.00
Products	
Bitumen	4.00
Total Products	4.00

CATALYTIC REFORMING

	Quantity (wt percent on crude)
Feedstocks	
Heavy Naphtha	16.26
Total Feedstocks	16.26
Products	
Hydrogen	0.36
Light Gas	1.13
LPG	1.58
Reformate 90	0.33
Reformate 101	0.00
Reformate 97	12.86
Total Products	16.26

GERMANY 1985 NATIONAL CASE (CONVERSION TYPE REFINERY)

FLUID CATALYTIC CRACKING

	Quantity (wt percent on crude)
Feedstocks	
Hydrogen	0.01
Vacuum Distillate	20.00
Total Feedstocks	20.01
Products	
Light Gas	0.71
LPG	1.28
C4 Alkylate	1.72
Cat Naphtha	10.22
LCO	3.12
FCC Coke	1.74
FCC Residue	1.22
Total Products	20.01

VISBREAKING

	Quantity (wt percent on crude)
Feedstocks	
Vacuum Residue	6.34
Total Feedstocks	6.34
Products	
Light Gas	0.07
LPG	0.08
Heavy Naphtha	0.06
Cracked Light Naphtha	0.04
Cracked Gas Oil	0.18
Visbroken Residue	5.91
Total Products	6.34

GERMANY 1985 NATIONAL CASE (CONVERSION TYPE REFINERY)

KEROSINE DESULPHURISATION

	Quantity (wt percent on crude)
Feedstocks	
Hydrogen	0.01
Kerosene	6.01
Total Feedstocks	6.02
Products	
Light Gas	0.02
Desulphurised Kerosine	6.00
Total Products	6.02

GAS OIL DESULPHURISATION

	Quantity (wt percent on crude)
Feedstocks	
Hydrogen	0.01
Gas Oil	8.53
Total Feedstocks	8.54
Products	
Light Gas	0.03
Desulphurised Gas Oil	8.51
Total Products	8.54

GERMANY 1985 NATIONAL CASE (CONVERSION TYPE REFINERY)

GASOLINE POOL

	Quantity (wt percent on crude)	RON (clear)	MON (clear)	RVP (psi)
LPG	1.38	94.10	90.20	55.00
Light Naphtha	3.10	74.20	73.10	16.10
Reformate 90	0.33	90.00	81.00	4.60
C4 Alkylate	1.72	97.00	94.00	7.00
Cat Naphtha	10.22	92.00	79.20	8.00
Cracked Lt Naphtha	0.04	86.00	76.00	17.00
Reformate 97	12.86	97.00	86.40	4.20
Total	29.65	92.40	83.04	10.00

KEROSINE PRODUCT

	Quantity (wt percent on crude)	Cetane	Sulphur (wt percent)
Desulphurised Kerosine	6.00	50.00	0.01
Total	6.00	50.00	0.01

GERMANY 1985 NATIONAL CASE (CONVERSION TYPE REFINERY)

GAS OIL PRODUCT

	Quantity (wt percent on crude)	Cetane	Sulphur (wt percent)
Kerosine	3.29	50.00	0.06
Gas Oil	13.92	50.00	0.48
LCO	3.12	28.00	0.30
Cracked Gas Oil	0.18	37.00	0.21
Desulphurised Gas Oil	8.51	50.00	0.10
Total	29.02	47.77	0.30

HEAVY FUEL OIL PRODUCT

	Quantity (wt percent on crude)	Viscosity (BEV)	Sulphur (wt percent)
Gas Oil	0.54	2.00	0.48
Atmospheric Residue	10.24	6.40	1.57
FCC Residue	1.22	6.40	2.12
Visbreaken Residue	5.91	6.50	2.51
Total	17.91	6.30	1.88

GERMANY 1985 NATIONAL CASE (CONVERSION TYPE REFINERY)

REFINERY FUEL

	Quantity (wt percent on crude)	Sulphur (wt percent)
Hydrogen	0.26	0.00
Light Gas	2.14	0.00
Vacuum Residue	2.02	2.39
FCC Coke	1.74	3.18
Total	6.16	1.68

APPENDIX B

EXCHANGE RATES FOR THE MEMBER STATES

(typical mid 1985 values)

Country	Rate	Unit
Belgium	47.80	BFR/ECU
France	7.23	FFR/ECU
Germany	2.40	DM/ECU
Italy	1540.00	LIRE/ECU
Netherlands	2.67	DFL/ECU
Spain	140.00	PESETAS/ECU
United Kingdom	0.60	POUNDS/ECU