Petroleum refineries for SO_2, NOx and TSP

Index

0 Introduction

0.1 General information

The purpose of refining is to convert natural raw materials such as crude oil into useful saleable products. Crude oil and natural gas are naturally occurring hydrocarbons found in many areas of the world in varying quantities and compositions. In refineries, they are separated and transformed into different products :

- ✓ Fuels for cars, trucks, airplanes, ships and other forms of transport;
- ✓ Combustion fuels for the generation of heat and power for industry and households;
- ✓ Raw materials for the petrochemical and chemical industries;
- ✓ Specialty products such as lubricating oils, paraffins/waxes and bitumen;
- ✓ Energy as a by-product in the form of heat (steam) and power (electricity).[1]

In order to manufacture these products, the raw materials are processed in a number of different refining facilities. The combination of these processing units to convert crude oil and natural gas into products, including its auxiliary units and facilities, is called a **refinery** [1].

Figure 1 shows the capacity of refinery in 25 Countries in Europe [8, 9]. Italy, Germany, France and UK have the largest capacities which represent more than 50% of the total capacity in Europe.

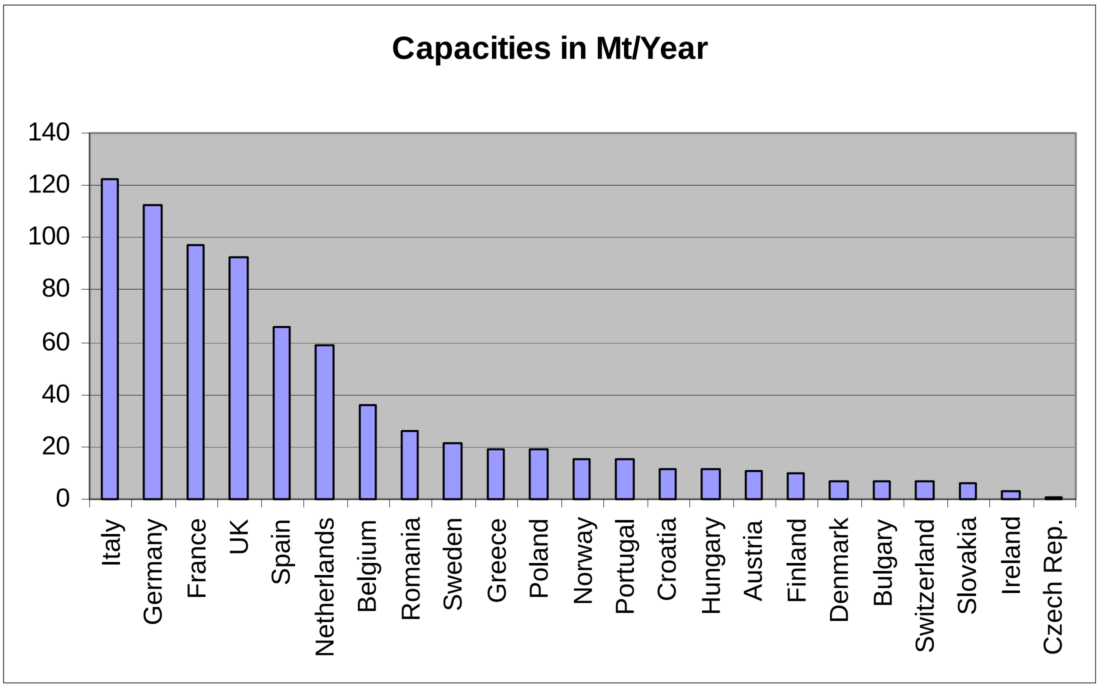


Figure 1: Refinery capacity in some European countries (for the year 2000)

The complexity of refineries has increased in the European Union with the installation of additional conversion units (thermal-, catalytic- and hydrocrackers). Now it must also be recognized that no two sites are the same, and the cost of installing particular facilities on one site may be very different from that for the same facilities on a different site – particularly if it is located in a different country.[2]

0.2 Pollutants

The main air emissions from a refinery are SO_2, NO_x and particulates, plus VOC which are not considered here.

CONCAWE [2] made a study on SO_2 released into the atmosphere from 70 refineries. In this report the relevant sources of SO_2 are mentioned. As can be seen from the next table the largest source of SO_2 (some 60 %) are fuel fired furnaces / boilers.

Table 0.1: sources of SO_2 emissions in refinery [3]

	Percentage of refinery SO_2 emissions (%)
Fuel fired in furnaces /boilers	59.4
FCC units	13.5
Sulphur Recovery Units	10.7
Flares	5.0
Miscellaneous	11.4
Total	100

Two main sources of particulates exist in refineries :

1. Process heaters and boilers (burning oil)
2. Fluid catalytic Cracking Units (FCCU) and more specifically the catalyst regenerators of such units.

In general, fuel firing in furnaces and boilers represents the most important source of pollutants in a refinery.

1 Data currently used in the RAINS model

1.1 Sectoral aggregation of emission sources for the refinery sector

Table 1.1: RAINS sector of the SO_2/NO_x modules for stationary sources and their relation to the main activity groups of the CORINAIR inventory

RAINS sector Primary	RAINS sector Secondary	CORINAIR SNAP97 code
Fuel production and conversion (other than power plants) (CON)	- **Combustion (CON_COMB)** - Losses (CON_LOSS)	**0103**, 0104, 0105, 05
Industry (IN)	- Combustion in boilers, gas turbines and stationary engines (IN_BO) - Other combustion (IN_OC) - **Process emissions (IN_PR)**	0301 03 exc. 0301[1] **04**

Source: *Sulfur emissions, abatement technologies and related costs for Europe in the RAINS model database*. IIASA. June 1998.

Table 1.2: RAINS sector of the PM modules for refinery sector and their relation to the main activity groups of the CORINAIR inventory

RAINS sector	RAINS code	SNAP sector
Fuel combustion in industrial boilers		
Combustion in boilers	IN_BO	**010301-03,** 010501-03, 0301
Combustion in boilers, grate combustion	IN_BO1	
Combustion in boilers, fluidized bed combustion	IN_BO2	
Combustion in boilers, pulverized fuel	IN_BO3	
Other combustion	IN_OC	**010304-06,** 010504-06, 0302, 0303
Other combustion, grate combustion	IN_OC1	
Other combustion, fluidized bed combustion	IN_OC2	
Other combustion, pulverized fuel combustion	IN_OC3	
Other industrial processes		
Petroleum refining	PR_REF	

Source: *Modelling particulate emissions in Europe. A framework to estimate reduction potential and control costs*. IIASA. 2002.

1.2 NO_x abatement techniques used in the RAINS model

The following section presents brief characteristics of the emission control technologies available for stationary sources. RAINS contains the following NO_x control options for boilers and furnaces:

- Combustion modification (CM): Air staged Low NO_x Burner (LNB), flue gas recirculation LNB, fuel staged LNB, fuel injection or reburning, fluidized bed combustion.
- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Combined measures (combustion modification and SCR or SNCR)

Table 1.3: Main groups of NO_x emission control technologies for stationary sources considered in RAINS

RAINS Sector/Technology	Technology abbreviation	Removal efficiency %
Industrial boilers (IN_BO) and furnaces (IN_OC):		
CM - Solid Fuels	ISFCM	50
CM - Oil&Gas	IOGCM	50
CM+SCR Solid Fuels	ISFCSC	80
CM+SCR Oil &Gas	IOGCSC	80
CM+ Selective non-catalytic reduction (SNCR) Solid Fuels	ISFCSN	70
CM+SNCR Oil &Gas	IOGCSN	70
Process emissions:		
Stage 1 control	PRNOX1	40
Stage 2 control	PRNOX2	60
Stage 3 control	PRNOX3	80

Source: *Nitrogen oxides emissions, abatement technologies and related costs for Europe in the RAINS model database*. IIASA. October 1998.

Cost evaluation methodology

The model uses **investment functions** where these cost components are aggregated into one function. The shape of the function is described by its coefficients ci^f and ci^v. The coefficients *ci* are given separately for three capacity classes: less than 20 MWth, from 20 to 300 MWth and above 300 MWth. When existing plant is retrofitted with add-on controls (SCR, SNCR) investments are multiplied by a retrofit cost factor *r*.

$$I = (ci_1^f + \frac{ci_1^v}{bs}) + (ci_2^f + \frac{ci_2^v}{bs}) * (1 + r) + \lambda^{cat} * ci^{cat}$$

where:

ci_1^f, ci_1^v, ci_2^f, ci_2^v – coefficients of investment function; ci_1 have non-zero values only for combinations of technologies (e.g., CM plus SCR)

bs – boiler size

λ^{cat} catalyst volume

ci^{cat} unit cost of catalysts

r retrofit cost factor

Table 1.4: Coefficients of the investment function for add-on technologies and combined measures used in boilers and furnaces.

Technology abbreviation	ci_1^f,	ci_1^v	ci_2^f	ci_2^v	Capacity range MWth
ISFCSC	6.30	0	19.60	0	< 20
	5.18	22.50	14.60	102	20-300
	52.33	876.50	5.10	2950	> 300

IOGCSC	5.67 4.66 2.10	0 20.25 788.85	14.63 11.25 4.73	0 68.85 1991.25	< 20 20-300 > 300
…					

Source: *Nitrogen oxides emissions, abatement technologies and related costs for Europe in the RAINS model database*. IIASA. October 1998.

Table 1.5: Other technology-specific parameters for add-on control technologies (secondary and combined measures)

Parameter	Unit	Value
Retrofit coefficient r Fixed O+M cost f Catalyst cost ci^{cat}	%/100 %/100/yr kECU/m^3	0.5 0.06 10
Electricity demand λ^e - coal boilers - oil and gas boilers	 GWh/PJ fuel input	 0.36 0.30
Catalyst volume λ^{cat} Brown coal boilers Hard coal, dry bottom boilers Hard coal, wet bottom boilers Oil and gas boilers	 m^3/MWth	
Sorbent demand λ^s, technology PBCSCR, PHCSCR, POGSCR PBCCSC, POGCSC PHCCSC, ISFCSC, IOGSCS ISFSCN, IOGCSN	t/t NO_x	 0.390 0.117 0.173 0.390

Source: *Nitrogen oxides emissions, abatement technologies and related costs for Europe in the RAINS model database*. IIASA. October 1998.

1.3 SO_x abatement techniques used in the RAINS model

Table 1.6: Main groups of SO2 emission control technologies considered in RAINS

Technology name	RAINS abbreviation	Removal efficiency %
Use of low sulfur fuels (coal, and heavy fuel oil)		(·)
Limestone injection Industry	LINJ	50
Industry, Wet FGD (flue gas desulfurization)	IWFGD	85
Power plants, Wet FGD, already retrofitted	PRWFGD	90
Power plants, Wet FGD	PWFGD	95
High efficiency FGD	RFGD	98
Process emissions:		
Stage 1 control	SO2PR1	50
Stage 2 control	SO2PR2	70
Stage 3 control	SO2PR3	80

(·) The control efficiency depends on the initial sulfur content of the fuel to be replaced

Source: *Sulfur emissions, abatement technologies and related costs for Europe in the RAINS model database*. IIASA. June 1998.

Conventional Wet Flue Gas Desulfurization Processes
Wet limestone flue gas desulfurization (WFGD) is the most commonly used flue gas desulfurization technique in Europe. In the early 1990s about 50.000 MWel of coal fired power plants were equipped with flue gas desulfurization, of which more than 80 percent were wet scrubbers (Vernon and Soud, 1990). This technology produces gypsum as a byproduct, which can be further used for a variety of industrial applications. WFGD processes have been installed in power plants, waste incineration plants and to some industrial heating plants. Early installations of WFGD processes were designed for sulfur removal efficiencies between 85 and 90 percent, while the latest installations reach up to 95 percent sulfur removal.

High-efficiency Flue Gas Desulfurization
In order to mark the upper end of available SO_2 removal options, RAINS also considers high-efficiency processes while taking into account the increased costs of these options. There are several technical approaches to achieve sulfur removal rates up to 99 percent, e.g., specially designed wet FGD processes or the Wellman-Lord technology. RAINS uses the Wellman-Lord process to derive the typical economic and technical properties representative for such high-efficiency desulfurization techniques.
This regenerative desulfurization method produces instead of waste material SO_2 rich gas(about 97% SO_2) that can be used as raw input to chemical industry to produce sulfuric acid or even elementary sulfur. Caustic soda (NaOH) is used as a sorbent. Spent absorber liquid is regenerated so that the losses of the sorbent are small. The desulfurization process is based on converting SO_2 to sodium sulfates. Typical reduction efficiencies achieved have been more than 97 %.

For add-on control options data distinguish technology-specific and country-specific parameters. The technology-specific parameters are common for all countries in Europe.
The coefficients for calculating the investment functions are estimated separately for three capacity classes :

- < 20 MWth
- 20-300 MWth
- >300 MWth

Table 1.7: Technology-specific parameters for add-on control technologies

Parameter	Unit	Limestone injection	Wet FGD	Advanced FGD
Removal efficiency η	%	50	95	98
Retrofit coefficient *r*	%/100	0.3	0.3	0.3
Fixed O+M cost *f*	%/100/yr	0.04	0.04	0.04
Labor demand	man-yr/GWth	10.8	10.8	25.2
Electricity demand	GWh/PJ fuel inp.	0.5	1	2.2
Sorbent demand	t/tSO2	4.68	1.56	0.01
Byproducts	t/tSO2	7.8	2.6	0.5

Source: *Sulfur emissions, abatement technologies and related costs for Europe in the RAINS model database*. IIASA. June 1998.

1.4 PM abatement techniques used in the RAINS model

Table 1.8: Size-fraction specific removal efficiencies for abatement options used in RAINS for power plants and industry.

Control technology	RAINS code	Removal efficiency		
		> PM_{10}	Coarse(1)	Fine(2)
Cyclone	CYC, _CYC	90 %	70 %	30 %
Wet scrubber	WSCRB, _WSCRB	99.9 %	99 %	96 %
Electrostatic precipitator, 1 field	ESP1, _ESP1	97 %	95 %	93 %
Electrostatic precipitator, 2 fields	ESP2, _ESP2	99.9 %	99 %	96 %
Electrostatic precipitator, 3 fields and more	ESP3P, _ESP3P	99.95 %	99.9 %	99 %
Wet electrostatic precipitator	PR_WESP	99.95 %	99.9 %	99 %
Fabric filters	FF, _FF	99.98 %	99.9 %	99 %
Regular maintenance, oil fired boilers	GHIND	30 %	30 %	30 %

(1): coarse particles: (> 2.5 and < 10 microns)
(2): fine particles (< 2.5 microns)
Source: *Modelling particulate emissions in Europe. A framework to estimate reduction potential and control costs*. IIASA. 2002.

The petroleum refining industry converts crude oil into more than 2500 refined products, including liquid fuels (gasoline, diesel, residual oil), by-product fuels and feedstocks (e.g., asphalt, lubricants), and primary petrochemicals (e.g., ethylene, toluene, xylene).

RAINS Sector: PR_REF

IIASA decided to use the value from the Dutch inventory [14].

Table 1.9: Emission factors used in the RAINS model for refineries [kg/t crude oil].

Sector	RAINS code	$PM_{2.5}$	Coarse	PM_{10}	>PM_{10}	TSP
Petroleum refining	PR_REF	0.096	0.024	0.120	0.002	0.122

Source: *Modelling particulate emissions in Europe. A framework to estimate reduction potential and control costs*. Page 69. IIASA. 2002.

The RAINS model includes cyclones, bag filters and electrostatic precipitators as control options for refineries.

Activities in some countries for the RAINS sector PR_REF
The baseline for the EU-15 of the energy pathway is the PRIMES model.

Table 1.10: Activity for some countries of the EU-15 (Mt)

Country	1990	1995	2000	2005	2010
Belgium	27.20	25.63	29.60	30.51	31.52
France	75.40	79.45	85.08	99.62	96.77

Italy	89.10	79.52	85.50	75.91	72.31
Germany New Länder	15.70	17.42	18.10	17.80	17.51
Germany Old Länder	78.20	86.91	90.29	88.80	87.33
Spain	54.60	54.93	61.53	71.08	72.98
United Kingdom	89.60	86.63	78.51	90.09	92.41
…					

Others information such as Emission factors can be found in the Web PM module:
http://www.iiasa.ac.at/~rains/cgi-bin/rains_pm

2 Combustion in refinery

2.1 General information

SNAP CODE: 01 03 01 -> 01 03 03 + 01 03 06 **NFR**: 1b
Sector activity unit: PJ fuel input

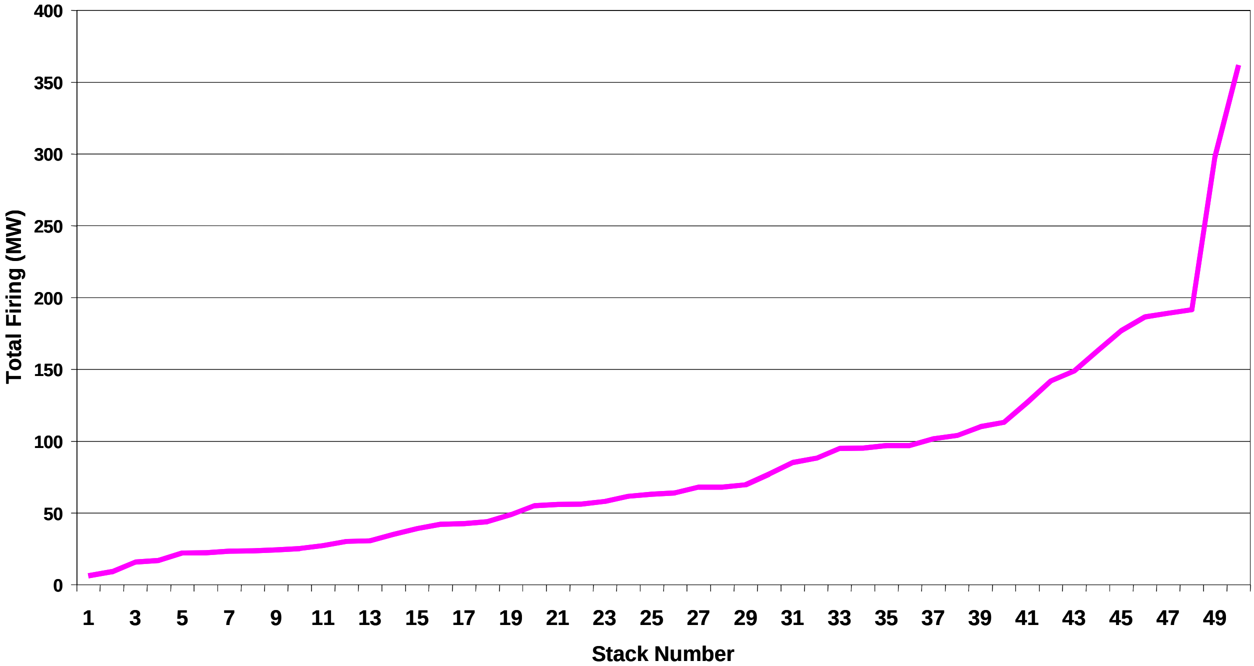
SO_2	NO_x	PM	VOC	NH_3
X	X	X	-	-

This sector covers emissions from **power plants in refineries** producing steam and/or electricity . Combustion engines and gas turbines are not included.
The **combustion processes in refineries** for the heating of petroleum products without direct contact between flame or flue gas and products are considered too.

2.2 Definition of reference installation/process

Fired boilers and furnaces generate substantial SO_2, NO_x and particulate emissions, particulary when **heavy fuel oil** is used. **Gas**-fired boilers generate hardly any dust and low SO_2 emissions, when the refinery gases are cleaned in amine scrubbers. NO_x emissions are also much lower than those of oil-fired boilers.
CONCAWE leaded a "Review of the Cost Effectiveness of NO_x Control Measures on Combustion Units in European Refineries" (Input to UN-ECE EGTEI). This document gives data on range of sizes of combustion units in European refineries derived from survey data on some 100 combustion units.

Variation of Total Heat Fired Across Surveyed Refineries



There are some 100 Refineries in Europe and each of those Refineries will have several heaters/furnaces; something of the order of a 1000. CONCAWE does not have information on all those heaters but has enough data to do a representative sample, a selection of 50. Their size varied from 7MW up to 386 MW. Here the range 30-150 MW was taken as representative. The heaters were geographically dispersed from Scandinavia to Italy. According these statistics, the expert group choose a capacity of 50 MW_{th}.

Table 2.1: Reference installations

Reference Code	Technique	Fuel	Capacity [MWth]	Life time [a]
01	Combustion unit	Heavy fuel oil	50	30
02	Combustion unit	Gas	50	30

2.3 Emission abatement techniques and costs

This chapter considers the emission abatement techniques for combustion processes in a refinery, the cost of installing and operating them and their performance. In refineries, secondary measures are only applied to larger units, since new units are rarely built and the specific costs for retrofitting of smaller units are considerably higher than for large units. In some cases, retrofitting secondary measures is not technically feasible due to space constraints. The most representative measures considered in the EU-countries are mentioned below.

2.3.1 PM emissions

No dust abatement techniques are installed in refinery boilers.

Table 2.2: TSP emissions level for each reference installation

Description	EF TSP [mg/Nm³] mean value	EF TSP [g/GJ fuel input] mean value
Reference Installation 01		
Uncontrolled	200-1000	56-280
Reference Installation 02		
Uncontrolled	5	1.35

Remarks:

1. An average conversion factor (F_{conv}) between concentrations of pollutants (in mg/Nm^3) and specific mass flows of pollutants (emission factor, in g per **GJ fuel input**) [4]

Concentration of pollutant emitted (in mg/Nm^3) x F_{conv} = Specific mass flow of pollutant emitted (in mg/GJ fuel input)

For liquid fuels: $F_{conv} = 280\ Nm^3/GJ\ (3\ \%\ O_2,\ dry)$

For gaseous fuels: $F_{conv} = 270\ Nm^3/GJ\ (3\ \%\ O_2,\ dry)$

2. To determine exactly the TSP Emission factor for liquid fuel firing, three parameters are needed :
    - E_{dust}: Total dust emissions in a given country (from emission inventory)
    - $E_{cons\ gas}$: Gas consumption (GJ)
    - $E_{cons\ fuel}$: Liquid fuel consumption (GJ)

The dust emissions caused by gas firing $E_{dust\ GF}$ is equal to the *EF TSP for the reference installation 2* $\cdot$ $E_{cons\ gas}$.

Then the dust emissions caused by liquid fuel firing: $E_{dust\ LF} = E_{dust} - E_{dust\ GF}$.
Knowing the liquid fuel consumption, the EF for the reference installation 1 can be determined.

3. To abate the dust emission of heavy fuel firing boilers, a fuel switch with gas can be used. The application rate of this fuel switch is country-specific.

2.3.2 NO_x emissions

2.3.2.1 Abatement measures

✓ Low NO_x burner

Low NO_x burners have the aim of reducing peak flame temperature, reducing oxygen concentration in the primary combustion zone and reducing the residence time at high temperature, thereby decreasing thermally formed NO_x.[2]

✓ SNCR

For the SNCR technology, an additive (ammonia or urea) is injected into the combustion chamber of the waste incineration plant. The conversion of nitrogen oxides into nitrogen and water takes place at temperatures between 850 and 1,100°C without a catalyst. In order to achieve satisfactory performance of the SNCR technology, the required temperature window has to be respected. It is necessary that the injection nozzles are disposed at several locations in the combustion chamber to overcome the inhomogeneous composition of waste, as well as the resulting variations in the temperature profile within the combustion chamber.

✓ SCR

In SCR De-NO_x systems, NO_x contained in many kinds of exhaust gases is reduced by ammonia (NH_3), urea [$(NH_2)_2CO$], etc. called "Ammonia like material" to nitrogen (N_2) and water (H_2O), on a catalyst.
The most suitable reducing agent can be selected out of ammonia like materials based on economics, handling and safety criteria. SCR De-NO_x system mainly consists of a reactor, reducing agent, injection system and catalyst. After injection and complete mixing of reducing agent with the gas at the inlet of reactor, the exhaust gas is led into a catalyst bed. NO_x is converted into N_2 and H_2O on the catalyst surface. When reducing agent is NH_3, chemical reactions are represented as follows :

4NO+4NH3+O2 -> 4N2+6H2O

6NO2 +8NH3 -> 7N2+12H2O

Table 2.3: NO_x abatement measures for each reference installation

Description	EF NO_x [mg/Nm³] mean value	EF NO_x [g/GJ fuel input] mean value	Abatement efficiency for NO_x [%]
Reference Installation 01			
Uncontrolled	600	168	-
Low NO_x Burner	420	101	30
SNCR(1)	170	48	60
SCR(1)	65	18	85
Reference Installation 02			

Uncontrolled	200	54	
Low NO_x Burner	100	27	50
SNCR(1)	40	11	60
SCR(1)	15	4	85

(1): after having installed the low NO_x burner technology .

2.3.2.2 Costs

For determining the different costs, information provided by CONCAWE and by ADEME have been used [1, 15].

- ✓ **Low NO_x burner**

Reference Capital Costs for 28 MW Unit: 200-600 k€
Reference Operating Cost for 28 MW Unit: Zero
Cost vs Unit Size = Cost Ref · [MW/Mwref]^0.8

In the case of a reference installation with a capacity of 50MW,

Capital Costs for 50 MW liquid fuel firing Unit = 400·[50/28]^0.8

= 636 k€

Capital Costs for 50 MW gas firing Unit = 250·[50/28]^0.8

= 400 k€

The different investments costs proposed by ADEME, which are derived from French refineries [15] are detailed in the Excel sheet established. From these costs, the average investment is 450 k€ for fuel firing boiler and 300 k€ for gas firing boiler.

- ✓ **SNCR**

Reference Capital Costs for 28 MW Unit: 400-900 k€
Reference Operating Cost for 28 MW Unit: 25-70 k€/y
Cost vs Unit Size = Cost Ref · [MW/Mwref]^0.6

In the case of a reference installation with a capacity of 50MW,

Capital Costs for 50 MW liquid fuel firing Unit = 650·[50/28]^0.6

= 920 k€

Capital Costs for 50 MW gas firing Unit = 500·[50/28]^0.6

= 700 k€

The different investments costs proposed by ADEME, which are derived from French refineries [15] are detailed in the Excel sheet established. From these costs, the average investment is 920 k€ for fuel firing boiler and 700 k€ for gas firing boiler.

- ✓ **SCR**

Reference Capital Costs for 28 MW Unit: 2.8-3.2 M€
Reference Operating Cost for 28 MW Unit: 150 k€/y
Cost vs Unit Size = Cost Ref · [MW/Mw$_{ref}$]^0.6

In the case of a reference installation with a capacity of 50MW,

Capital Costs for 50 MW liquid fuel firing Unit = 3·[50/28]^0.6

= 3.89 M€

Capital Costs for 50 MW gas firing Unit= 2.8·[50/28]^0.6

= 3.6 M€

The different investments costs proposed by ADEME, which are derived from French refineries [15] are detailed in the Excel sheet established. From these costs, the average investment is 2,000 k€ for fuel firing boiler and 1,900 k€ for gas firing boiler.

Table 2.4: Investments and Operating costs

Description	Investment (k€)		Fixed Operating costs (%/a)*	Variable Operating costs (k€/PJ/a)
	Source (1)	Source (15)		
Reference installation 1				
Low NO_x Burner	636	450	4	0
SNCR	920	920	4	32
SCR	4,150	2,000	4	55.7
Reference installation 2				
Low NO_x Burner	400	300	4	0
SNCR	700	700	4	15.6
SCR	3,850	1,900	4	44.2

*: The fixed Operating costs only depend on the capacity - or size - of the installation, i.e. on the investment, and they are expressed as a **percentage of the plant investment** [%/a]

Parameters needed to calculate Variable Operating costs

✓ SNCR

Electricity cost $\lambda^e \cdot c^e / 10^{-3}$ [k€/**PJ fuel input**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**PJ fuel input**]
- c^e: electricity price [€/kWh]

$\lambda^e = 5.56 \cdot 10^4$ kWh/**PJ** for a consumption of 10 kW [15] (see Excel sheet for more details) $c^e = 0.0569$ €/kWh (value for France)

Ammonia cost $\lambda^s \cdot c^s \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**PJ fuel input**]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/**PJ fuel input**]
- λ^s: specific ammonia demand [t/t pollutant removed]
- c^s: ammonia price [€/t]

- η: removal efficiency = $(1 - ef_{abated}/ef_{unabated})$

$\lambda^s = \lambda^m \cdot \lambda^M / \eta$
with:
λ^m: NH_3/ NO_x (mol/mol) ratio for NO_x emitted
λ^M: NH_3/ NO_x (mol weight/mol weight) ratio

$\lambda^s = 1.5/0.6 \cdot (17/46)$
$= 0.92$

$ef_{unabated} = 100.8\ t_{NOx}$/PJ for fuel firing $ef_{unabated} = 27\ t_{NOx}$/PJ for gas firing $\lambda^s = 0.92\ t_{NH3}$/t NO_x removed $c^s = 400$ €/t_{NH3} (ammonia pur) $\eta = 60$ %

Labour cost $(\lambda^l \cdot c^l) \cdot 10^6 / (3{,}6 \cdot pf)$ [k€/**PJ fuel input**]

- λ^l: labour demand [person-year/**MWth**] or [man -year/**GWth**]
- c^l: labour cost/wages [k€/ man -year]
- pf: plant factor [h/a]

The number of additional personnel required for the SNCR unit is taken here as 0.25

Thus, the annual personnel costs for the SNCR process are:

$AC_{PERS} = 0.25 \cdot c^l$

Thus $\lambda^l = (0.25)$/ Capacity

$= 0.25/50$

$= 5 \cdot 10^{-3}$ person-year/$\mathbf{MW_{th}}$

$\lambda^l = 5 \cdot 10^{-3}$ person-year/$\mathbf{MW_{th}}$ $c^l = 37{,}234$ k€/ person –year (value for France) pf= 8,000h

Table 2.5: Parameters needed to calculate variable Operating costs for SNCR

	$ef_{unabated}$ [g NO_x/GJ]	η	λ^s [t/t NO_x removed]	c^s [€/t]	λ^e [kWh/PJ]	c^e [€/kWh]	λ^l [person-year/MWth]	c^l [€/person-year]	pf [h/a]
Reference installation 1									
SNCR	100.6	60	0.92	400	$5.56 \cdot 10^4$	0.0569	0.005	37.234	8,000
Reference installation 2									
SNCR	27	60	0.92	400	$5.56 \cdot 10^4$	0.0569	0.005	37.234	8,000

✓ SCR

Electricity cost $\lambda^e \cdot c^e / 10^{-3}$ [k€/**PJ fuel input**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**PJ fuel input**]

- c^e: electricity price [€/kWh]

$\lambda^e = 3.33{\cdot}10^5$ kWh/**PJ** for a consumption of 60 kW [15] (see Excel sheet for more details) $c^e = 0.0569$ €/kWh (value for France)

Ammonia cost $\lambda^s \cdot c^s \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**PJ fuel input**]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/**PJ fuel input**]
- λ^s: specific ammonia demand [t/t pollutant removed]
- c^s: ammonia price [€/t]
- η: removal efficiency = $(1 - ef_{abated}/ef_{unabated})$

$\lambda^s = \lambda^m{\cdot}\lambda^M/\eta$
with:
λ^m: NH_3/ NO_x (mol/mol) ratio for NO_x emitted
λ^M: NH_3/ NO_x (mol weight/mol weight) ratio

$\lambda^s = 1.05/0.85{\cdot}\ (17/46)$
$= 0.46$

$ef_{unabated} =$ 100.8 t_{NOx}/PJ for fuel firing $ef_{unabated} =$ 27 t_{NOx}/PJ for gas firing $\lambda^s = 0.46$ t_{NH3}/t NO_x removed $c^s = 400$ €/t_{NH3} (ammonia pur) $\eta = 85$ %

Labour cost [person-year/**MWth**]: $(\lambda^l \cdot c^l) \cdot 10^6 / (3{,}6 \cdot pf)$ [k€/**PJ fuel input**]

- λ^l: labour demand [person-year/**MWth**] or [person -year/**GWth**]
- c^l: labour cost/wages [k€/ person -year]
- pf: plant factor [h/a]

The number of additional personnel required for the SCR unit is taken here as 0.25

Thus, the annual personnel costs for the SCR process are:

$AC_{PERS} = 0.25 \bullet c^l$

Thus $\lambda^l = (0.25)/$ Capacity

$= 0.25/50$

$= 5{\bullet}10^{-3}$ person-year/$\mathbf{MW_{th}}$

$\lambda^l = 5{\bullet}10^{-3}$ person-year/$\mathbf{MW_{th}}$ $c^l = 37{,}234$ k€/ person –year (value for France) pf= 8,000h

Catalyst cost $(\lambda^{cat} \cdot ci^{cat} / lt^{cat}) \cdot (10^3 /3.6)$ [k€/**PJ fuel input**]

- λ^{cat}: catalyst volume [$m^3/\mathbf{MW_{th}}$]
- ci^{cat}: unit costs of catalysts [k€/m^3]
- lt^{cat}: life time of catalyst [10^3 h]

and: $\boxed{[PJ] = [MW].\frac{3,6.[h]}{10^6}}$

In our case, the gas volume flow is around:
V = F_{conv}·(Capacity)
= 275·(50·10^{-3}·3600)
= 48,600 Nm³/h
Then according some statistics [15], the catalyst volume is around 7 m³.

ci^{cat} = 15 k€/m^3 λ^{cat} = 0,14 m^3/**MW_{th}** [15] (see Excel sheet for more details) lt^{cat} = 5 years = 40 · 10^3 h pf= 8,000 h

Table 2.6: Parameters needed to calculate variable Operating costs for SCR

	$ef_{unabated}$ [g NOx/GJ]	η	λ^s [t/t NOx removed]	c^s [€/t]	λ^e [kWh/PJ]	c^e [€/kWh]	λ^l [person-year/MWth]	c^l [k€/person-year]	pf [h/a]	λ^{cat} [m³/MWth]	ci^{cat} [k€/m^3]	lt^{cat} [10^3 h]
Reference installation 1												
SCR	101	85	0.46	400	3.33·10^5	0.0569	0.005	37.234	8,000	0.14	15	40
Reference installation 2												
SCR	27	85	0.46	400	3.33·10^5	0.0569	0.005	37.234	8,000	0.14	15	40

✓ <u>Conclusion</u>

In the petroleum industry as the SCR process is much more likely to be chosen than the SNCR process, the cost of secondary measures has been assessed taking into account the following shares :
99 % of SCR
01 % of SNCR.
According to this repartition, the different costs of the NO_x secondary measures are the following:

Table 2.7: Investments and Operating costs of the secondary measures

Description	**Lifetime** (a)	**Investment (k€)** Source (1)	Source (15)	**Fixed Operating costs** (%/a)	**Variable Operating costs** (k€/PJ)
Reference installation 1					
None	-	-		-	-
Secondary technology	10	4,120	2,000	4	55,7
Reference installation 2					
None	-	-		-	-
Secondary technology	10	3,820	1,900	4	44,2

Table 2.8: Parameters needed to calculate variable Operating costs for secondary measure

$ef_{unabated}$ [t NO_X/t]	η	λ^s [t/t NO_X removed]	c^s [€/t]	λ^e [kWh/t]	c^e [€/kWh]	λ^l [person-year/t]	c^l [k€/person-year]	λ^{cat} [m³/t]	ci^{cat} [k€/m^3]	lt^{cat} [10^3 hrs]
Reference installation 1										
1001	85	0.46	400	3.33·10^5	0.0569	0.005	37.234	0.14	15	8,000

Reference installation 2										
27	85	0.46	400	$3.33 \cdot 10^5$	0.0569	0.005	37.234	0.14	15	8,000

2.3.2.3 Methodology to calculate the application rate

To determine the application rate of the different abatement measures, the following methodology can be used.

Input parameter :

- $E_{cons\ gas:}$ Gas consumption (GJ)
- $E_{cons\ fuel}$:Liquid fuel consumption (GJ)
- E_{NOx}: Emission of NO_x in a country (t per year)

Considering the different emission factors determined in the last paragraph, it is possible to calculate an equivalent Emission level for a fuel mixture of gas and liquid fuel :
Equivalent Emission level = [(NO_x emission factor for *Reference installation 1*) x $E_{cons\ gas}$ + (NO_x emission factor for *Reference installation 2*) x $E_{cons\ fuel}$] / ($E_{cons\ gas}$ + $E_{cons\ fuel}$)

Table 2.9: Emission level for fuel mixture

Description	EF NO_x [g/GJ fuel input] for Gaseous fuel	EF NO_x [g/GJ fuel input] for Liquid fuel	Emission level [g/GJ fuel input] for fuel mixture
Uncontrolled	168	54	$(168 \cdot E_{cons\ gas} + 54 \cdot E_{cons\ fuel}) / (E_{cons\ gas} + E_{cons\ fuel})$
Low NO_x Burner	101	27	$(101 \cdot E_{cons\ gas} + 27 \cdot E_{cons\ fuel}) / (E_{cons\ gas} + E_{cons\ fuel})$
Low NO_x Burner + secondary measure	18	4	$(18 \cdot E_{cons\ gas} + 4 \cdot E_{cons\ fuel}) / (E_{cons\ gas} + E_{cons\ fuel})$

Then, the sector situation may be defined by:

$$F_{s\ a\ NOx} = E_{NOx} / (E_{cons\ gas} + E_{cons\ fuel})$$

According to this result, it is possible to calculate the different application rates :

$F_{S1NOx\ fuel\ mix}$: Uncontrolled NO_x emission level for fuel mixture
$F_{S2NOx\ fuel\ mix}$: NO_x emission level implementing the $DeNO_x$ stage 1 technical option (primary measures - PM) for fuel mixture
$F_{S3NOx\ fuel\ mix}$: NO_x emission level implementing the $DeNO_x$ stage 2 technical option (secondary measures - SM) for fuel mixture

- ✓ If $F_{S1NOx} > F_{s\ a\ NOx} > F_{S2NOx}$, it can be considered that some primary measure may still be implemented on a given percentage of the production capacity.

The virtual application rate of primary measures $T_{1,NOx}$ is obtained by:

$$T_{1,NOx} = (F_{s\ a\ NOx} - F_{S1NOx\ fuel\ mix})/(F_{S2NOx\ fuel\ mix} - F_{S1NOx\ fuel\ mix})$$

- ✓ If $F_{s\ a\ NOx} < F_{S2NOx}$ it may be considered that some secondary measures have already been implemented. In this case, it can be considered that the application rate concerning NO_x primary measures is 100%.

The virtual application rate of secondary measures $T_{2,NOx}$ is obtained by:

$$T_{2,NOx} = (F_{s\ a\ NOx} - F_{S2NOx\ fuel\ mix}) / (F_{S3NOx\ fuel\ mix} - F_{S2NOx\ fuel\ mix})$$

Table 2.10: Application rate and applicability for NO_x abatement measures

Description	**Application rate in 2000 [%]**	**Application rate in 2005 [%]**	**Applicability [%]**	**Application rate in 2010 [%]**	**Applicability [%]**	**Application rate in 2015 [%]**	**Applicability [%]**	**Application rate in 2020 [%]**	**Applicability [%]**
None									
Primary technologies			100		100		100		100
Secondary technologies			100		100		100		100

2.3.3 SO_x emissions

2.3.3.1 Abatement measures

- ✓ Fuel switch HF-GAS

The aim of the fuel switch is to change to a fuel leading to a less pollutant emissions. In the case of refinery a fuel switch from heavy fuel oil to gas is normally realized, lowering emission of NO_x, SO_2 and particulate matter.

- ✓ Wet scrubber

Table 2.11: SO_x abatement measures

Description	**EF SO_x [mg/Nm³] mean value**	**EF SO_x [t/PJ fuel input] mean value**
Reference Installation 01		
Uncontrolled	3,400*	950
Fuel switch HF-GAS	20	5.4
Scrubber (η=90 %)	340	95
Reference Installation 02		
Reference level	20	5.4

*: depending of the characteristics of the fuel. In this case, it is heavy fuel oil with 2% S content *(3 % O_2, dry)*.

2.3.3.2 Costs

Table 2.12: Investments and Operating costs

Description	**Investment (k€)**	**Fixed Operating costs** (%/a)	**Variable Operating costs** (k€/PJ)

Fuel switch HF-GAS	0	4	See table 2.13
Wet scrubber*	4,000	4	433

*This option is detailed in the following paragraph, although CONCAWE doesn't validate this abatement option.

Parameters needed to calculate Variable Operating costs

✓ Fuel switch HF-GAS [k€/**PJ fuel input**]

SUM [(new consump/prod)$_i$ · (new price)$_i$] – SUM [(old consump/prod)$_i$ · (old price)$_i$]

- Energy consumption (+)
- Energy production (-)
- Consumption [MJ/GJth input]
- Fuel price [€/GJ]

Table 2.13: Parameters needed to calculate variable Operating costs for fuel switch

(new consump/prod)$_I$ [MJ/GJth input]	**(new price)$_I$ [€/GJ]**	**(old consump/prod)$_I$ [MJ/GJth input]**	**(old price)$_I$ [€/GJ]**

✓ Wet scrubber

The different costs are the following:

Limestone cost: $\lambda^s \cdot c^s \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**PJ**]

- $ef_{unabated}$: unabated emission factor of pollutant [t pollutant/**PJ**]
- λ^s: specific limestone demand [ton/t pollutant removed]
- c^s: limestone price [€/t]
- η: removal efficiency (= 1 - $ef_{abated}/ef_{unabated}$)

with: $\lambda^s = \lambda^m \cdot \lambda^M$
λ^m: Ca/S (mol/mol) ratio
λ^M: $CaCO_3/SO_2$ (mol weight/mol weight) ratio

$ef_{unabated} = 950$ t $_{SO2}$ /**PJ**
$\eta = 90$ %
$\lambda^s = 1.59$ t/t$_{SO2\ removed}$
$c^s = 20$ €/t (value for France)

Waste disposal cost $\lambda^d \cdot c^d \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**PJ**]

- $ef_{unabated}$: unabated emission factor of pollutant [t pollutant/**PJ**]
- λ^d: demand for waste disposal [ton/ t pollutant removed]
- c^d: byproduct/waste disposal cost [€/ton]
- η: removal efficiency (= 1 - $ef_{abated}/ef_{unabated}$)

$ef_{unabated} = 950$ t $_{SO2}$ /**PJ**
$\eta = 90$ %

$\lambda^s = 2.6$ t/$t_{SO2\ removed}$ $c^s =$ €/t (value for France)

Labour cost $\lambda^l \cdot c^l$ [k€/**PJ**]

- λ^l: labour demand [person-year/MW_{th}]
- c^l: labour cost/wages [k€/person-year]

The number of additional personnel for the wet scrubber is taken here as 0.5 person-year.

Thus, the annual personnel costs are:

$AC_{PERS} = 0.5 \cdot c^l$

Thus $\lambda^l = (0.5)/$ Capacity

$= 0.5/50$

$= 0.01$ person-year/MW_{th}

$c^l = 37{,}234$ k€/ person-year (value for France) $\lambda^l = 0.01$ person-year/**t**

Electricity cost $\lambda^e \cdot c^e / 10^{-3}$ [k€/**PJ**]

- λ^e: additional electricity demand (= new total consumption – old total consumption) [kWh/PJ]
- c^e: electricity price [€/kWh]

$\lambda^e = 1.06 \cdot 10^6$ kWh/**PJ for 190 kW** $c^e = 0.0569$ €/kWh (value for France)

Table 2.14: Parameters needed to calculate variable Operating costs for Wet scrubber

	$ef_{unabated}$ [t SO_2/PJ]	**η**	**λ^s [t/t SO_2 removed]**	**c^s [€/t]**	**λ^d [t/t SO_2 removed]**	**c^d [€/ton]**	**λ^l [person-year/PJ]**	**c^l [k€/person-year]**	**λ^e [kWh/t]**	**c^e [€/kWh]**	**Variable Operating costs (k€/PJ)**
Wet scrubber	950	90	1.59	20	2.6		0.01	37,234	$1.06 \cdot 10^6$	0.0569	**433**

2.3.3.3 Methodology to calculate the application rate

To determine the application rate of the different abatement measure, the following methodology can be used.

Input parameter :

- $E_{cons\ fuel}$: Liquid fuel consumption (GJ)
- E_{SOx}: Emission of SO_x in a country (t per year) for liquid fuel firing

Then, the sector situation may be defined by:

$F_{s\ a\ SOx} = E_{SOx} / E_{cons\ fuel}$

According to this result, it is possible to calculate the different application rates :

$F_{S1SOx\ fuel}$: Uncontrolled SO_x emission level for liquid fuel
$F_{S2SOx\ fuel}$: SO_x emission level implementing the Wet scrubber

The virtual application rate of the wet scrubber $T_{2,SOx}$ is obtained by:

$$T_{2,SOx} = (F_{s\ a\ SOx} - F_{S1SOx\ fuel})/(F_{S2SOx\ fuel} - F_{S1SOx\ fuel})$$

Table 2.15: Application rate and applicability for SO_x abatement measures

Description	**Application rate in 2000 [%]**	**Application rate in 2005 [%]**	**Applicability [%]**	**Application rate in 2010 [%]**	**Applicability [%]**	**Application rate in 2015 [%]**	**Applicability [%]**	**Application rate in 2020 [%]**	**Applicability [%]**
None									
Fuel switch HF-GAS			100		100		100		100
Wet scrubber			100		100		100		100

2.4 Regulatory constraints introduced by the LCP Drective

2.4.1 SO_2 emissions

Concerning SO_2 emissions from boilers, it is important to distinguish SNAP codes :

- 01 03 01: Combustion plants >= 300 MW (boilers)
- 01 03 02: Combustion plants >= 50 and < 300 MW (boilers)
- 01 03 03: Combustion plants < 50 MW (boilers)

The refinery sector uses the *bubble* concept which refers to air emissions of SO_2. This concept is a regulatory tool applied in several EU countries. The bubble approach for emissions to air reflects "a virtual single stack" for the whole refinery. This concept is used for refineries because it is recognised that they meet some or all of their energy needs with a variety of gaseous and liquid fuels that are by-products of the various processes. [18]

In the revisions of the LCP Directive, the SO_2 emission limit values VEL for new and existing refineries are respectively 600 and 1000 mg/Nm³.
With 2 input parameters, it is possible to calculate how many emissions a country does abate in order to comply with LCP Directive.

Input Parameters :

- $E_{cons\ fuel}$: Liquid fuel consumption (GJ)
- E_{SOx}: Emission of SO_x in a country (t per year) for liquid fuel firing

Then, the sector situation may be defined by:

$$F_{s\ a\ SOx} = E_{SOx} / E_{cons\ fuel}$$

Taking into account the average conversion factor (F_{conv}) between concentrations of pollutants (in mg/Nm^3) and specific mass flows of pollutants (emission factor, in g per **GJ fuel input**) for liquid fuels :

$$F_{conv} = 280\ Nm^3/GJ\ (3\ \%\ O_2,\ dry)$$

The situation versus the LCP Directive then is :

$$S = \frac{E_{SO_x}}{E_{cons\ fuel}} \cdot \frac{1}{F_{conv}} \cdot 10^9 - VEL\ \ [mg/Nm^3]$$

If the result is positive, the country has to abate "S" mg/Nm³ to follow the LCP Directive. Otherwise the country has abated more than the Directive imposed.

2.4.2 NO_x and Dust emission

For NO_x and Dust emissions, the LCP Directive contains a lot of constraints, depending on the state of the installation, the capacity and the fuel used.

Examplary of Sweden

The Swedish Parliament decided in 1990 to introduce a tax to be paid for emissions of nitrogen oxides from boilers with a usable energy production of at least 50 gigawatt hours (GWh) per year. The NO_x charge is based on actual recorded emissions. The abatement cost was found to be between 3 and 84 SEK/ kg of NO_x reduced, *331 to 9,270 €/t of NO_x reduced* The charge is imposed irrespective of the fuel used and is levelled at a rate of SEK 40 per kg of emitted NO_x, *4412 €/t of emitted NO_x*. To avoid distorting the pattern of competition between those plants which are subject to the NO_x charge and those that are not (and possibly create incentives to replace existing equipment with inefficient smaller boilers that are not subject to the charge), the system is designed in a way that all revenue except the cost of administration is returned to the participating plants, in proportion to their final production of usable energy. [19]

The consequence of this charge in Sweden is that the average cost of measures to reduce emissions as a result of the charge on NO_x was SEK 7.5 per kg of NO_x reduced, about *900 €/t of NO_x reduced* (according to a 1996 study). [19]

Combustion in refinery
Summary list of parameters and data

	Parameter	Annotation	Unit	Type of data	Current proposal
1	Gas consumption 2000, 2005, 2010, 2015 and 2020	$E_{cons\ gas}$	GJ	Input	-
2	Liquid fuel consumption 2000, 2005, 2010, 2015 and 2020	$E_{cons\ fuel}$	GJ	Input	-
3	SO_x (as SO_2)	E_{SO2}	Tonnes per year	Input	-
4	NO_x (as NO_2)	E_{NOx}	Tonnes per year	Input	-
5	Dust	E_{Dust}	Tonnes per year	Input	-
6	Conversion factor between concentration and specific mass flow for liquid fuel	$F_{conv\ Lfuel}$	Nm^3/GJ	Fixed by the experts	280
7	Conversion factor between concentration and specific mass flow for gas	$F_{conv\ gas}$	Nm^3/GJ	Fixed by the experts	270
8	Uncontrolled dust emission level for liquid fuel firing	$F_{S\ Dust\ Lfuel}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	200-1000 56-280
9	Uncontrolled dust emission level for gas firing	$F_{S\ Dust\ gas}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	5 1.35
10	Uncontrolled NO_X emission level for liquid fuel firing	$F_{S1NOx\ Lfuel}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	600 168
11	NO_X emission level implementing the $DeNO_X$ stage 1 technical option (primary measures - PM) for liquid fuel firing	$F_{S2NOx\ Lfuel}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	420 101
12	NO_X emission level implementing the secondary measure for liquid fuel firing	$F_{S3NOx\ Lfuel}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	*65* *18*
13	Cost of the $DeNO_x$ stage 1 technical option (PM) per tonne of pollutant avoided	$C_{NOx\ 1\ Lfuel}$	Euro / tonne NO_x abated	Evaluated by the experts	1,650 (1) 1,012 (2)
14	Cost of the $DeNO_x$ secondary measure per tonne of pollutant avoided	$C_{NOx\ 2\ Lfuel}$	Euro / tonne NO_x abated	Evaluated by the experts	6,100 (1) 3,290 (2)
15	Uncontrolled NO_X emission level for gas firing	$F_{S1NOx\ gas}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	200 54
16	NO_X emission level implementing the $DeNO_X$ stage 1 technical option (primary measures - PM)	$F_{S2NOx\ gas}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	100 27
17	NO_X emission level implementing the secondary measure	$F_{S3NOx\ gas}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	15 4
18	Cost of the $DeNO_x$ stage 1 technical option (PM) per tonne of pollutant avoided	$C_{NOx\ 1\ gas}$	Euro / tonne NO_x abated	Evaluated by the experts	1,940 (1) 1,260 (2)
19	Cost of the $DeNO_x$ secondary measure per tonne of pollutant avoided	$C_{NOx\ 2\ gas}$	Euro / tonne NO_x abated	Evaluated by the experts	20,800 (1) 11,260 (2)
20	Uncontrolled SO_2 emission level for liquid fuel firing used for the economical assessment	$F_{S1\ SO2\ Lfuel}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	3,400 950
21	SO_2 emission level implementing the switch from liquid to gaseous fuels	$F_{S2\ SO2\ Lfuel}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	20 5.4
22	Applicability rate for the fuel switch	A_R	%	Input	-
23	SO_2 emission level implementing the wet scrubber technical option	$F_{S3\ SO2\ Lfuel}$	mg/Nm³ g/GJ fuel input	Fixed by the experts	340 95
24	Cost of the stage 1 $DeSO_2$ technical option per tonne of pollutant avoided for liquid fuel firing (switch to gaseous fuels)	$C_{SO2\ 1\ Lfuel}$	Euro / tonne SO_2 abated		Specific national data

25	Cost of the wet scrubber technical option per tonne of pollutant avoided for liquid fuel firing	$C_{SO2\ 2\ \ Lfuel}$	Euro / tonne SO_2 abated	Evaluated by the experts	1,038

(1): Data from Source (1)
(2): Data from Source (15)

3 Gas turbines in refinery

3.1 General information

SNAP CODE: 01 03 04 **NFR**: 1b
Sector activity unit: PJ fuel input

SO_2	NO_x	PM	VOC	NH_3
X	X	X	-	-

This sector covers emissions from gas turbines in refineries and will be treated in the draft "Combustion".

4 Stationary engines in refinery

4.1 General information

SNAP CODE: 01 03 05 **NFR**: 1b
Sector activity unit: PJ fuel input

SO_2	NO_x	PM	VOC	NH_3
X	X	X	-	-

This sector covers emissions from stationary engines in refineries.

This sector will be considered in the draft "Combustion".

5 Fluid Catalytic Cracking Unit

5.1 General information

SNAP CODE: 04 01 02 - **NFR** 4a
Sector activity unit: tonne oil throughput

SO_2	NO_x	PM	VOC	NH_3
x	x	x	-	-

Within a refining complex, one of the sources with major potential for atmospheric emissions is the catalytic cracking unit. Emissions from an FCC can be 20-30 % of total refinery SO_2 emissions, 15-30 % for NO_x and 30-40 % of particulates. [2]
This sector is part of the RAINS sector "Other industrial Processes – Petroleum Refining" (code: PR_REF)

5.2 Definition of reference installation/process

According statistics from CONCAWE (average capacity of FCC in European refineries = 40,331 bpsd), one Fluid Catalytic Cracking Units (FCC U) with a capacity of 2000 kt/a is proposed as reference installations for the activity of "processes in oil refining".
The flow sheets of a Heavy Oil and Residue Cracker (HORC) – or a Residue Catalytic Cracker (RCC)- are basically the same as for a FCC with the difference that it has a CO-Boiler and catalyst cooler. FCC can be retrofitted to RCC. This technique gives the possibility to upgrade heavier residues than with FCC.

Table 5.1: Reference installations

Reference Code	Technique	Capacity [kt/a] feed
01	Fluid Catalytic Cracking Unit (FCCU)	2,000

Data on emission factors from EPA and IPPC reports were exactly the same.[10] [12]

5.3 Emission abatement techniques and costs

This chapter considers the emissions abatement techniques for the Fluid Catalytic Cracking Unit in a refinery, the cost of installing and operating them and their performance. The most representative measures considered in the EU-countries are mentioned below.

5.3.1 NO_x emissions

5.3.1.1 Abatement measures

No primary measures are installed but the SCR and SNCR (in very few plants) technologies may be implemented.

Table 5.2: NO_x abatement measures for each reference installation

Description	Abatement	EF NO_x	EF NO_x

	efficiency [%]	[mg/Nm³]		(kg/t feed)	
		Source (1)	Source (15)	Source (1)	Source (15)
Uncontrolled	-	800	500	0.48	0.3
Secondary measures(SCR or SNCR)	80	160	100	0.096	0.06

Remark:
An average conversion factor (F_{conv}) between concentrations of pollutants (in mg/Nm^3) and specific mass flows of pollutants (emission factor, in g per **t feed**)
Concentration of pollutant emitted (in mg/Nm^3) x F_{conv} = Specific mass flow of pollutant emitted (in mg/t feed)

$$F_{conv} = 600\ Nm^3/t\ [1]\ (2\ \%\ O_2)\ [1]$$

5.3.1.2 Costs

The different investments costs proposed by ADEME, which are derived from French refineries [15] are detailed in the Excel sheet established. From these costs, the average investment is 1,300 k€ for SNCR and 5,000 k€ for SCR.

Table 5.3: Investments and Operating costs

Description	Investment (k€)		Fixed Operating costs * (%/a)	Variable Operating costs (€/t)	
	Source (1)	Source (15)		Source (1)	Source (15)
SNCR	5,400	1,300	4	0.117	0.0775
SCR	8,000	5,000	4	0.211	0.183

*: The fixed Operating costs only depend on the capacity – or size - of the installation, i.e. on the investment, and they are expressed as a **percentage of the plant investment** [%/a]

Variable Operating costs are defined as the costs depending on the level of production. Parameters for variable operating costs depend on the type of measure (technology) installed. The following tables show the common parameters and prices needed for the calculation of the variable costs.

In this case, to determine the operating cost, the SNCR and SCR technologies are considered. The different costs are the following:

✓ SNCR

Electricity cost $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (= new total consumption – old total consumption) [kWh/**t**]
- c^e: electricity price [€/kWh]

λ^e = 0.112 kWh/**t** for a consumption of 28 kW [15] (see the Excel sheet for more details) c^e = 0.0569 €/kWh (value for France)

Ammonia cost $\lambda^s \cdot c^s \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**t**]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/t]
- λ^s: specific sorbents demand (NH_3) [t/t pollutant removed]
- c^s: Ammonia price [€/t]
- η: removal efficiency = $(1 - ef_{abated}/ef_{unabated})$

with: $\lambda^s = \lambda^m \cdot \lambda^M/\eta$
λ^m: NH_3/NO_x (mol/mol) ratio for NO_x emitted
λ^M: NH_3/NO_x (mol weight/mol weight) ratio

$\lambda^s = 1.5 \cdot (17/46)/0.6$
$= 0.92$

$ef_{unabated} = 4.8 \cdot 10^{-4}$ t_{NOx}/t according [1]	$ef_{unabated} = 3 \cdot 10^{-4}$ t_{NOx}/t according [15]
$\lambda^s = 0.92$ t_{NH3}/t NO_x removed [15]	
$c^s = 400$ €/t_{NH3} (ammonia pur)	
$\eta = 60$ %	

Labour cost $(\lambda^l \cdot c^l)$ [k€/**t**]

- λ^l: labour demand [person -year/**t**]
- c^l: wages [k€/ person -year]

The number of additional personnel for the SNCR unit is taken as 0.25.

Thus, the annual personnel costs for the SNCR process are:

$AC_{PERS} = 0.25 \cdot c^l$

Thus $\lambda^l = (0.25)/$ Capacity

$= 0.25/(2{,}000{,}000)$

$= 1.25 \cdot 10^{-7}$ person-year/**t**

$\lambda^l = 1.25 \cdot 10^{-7}$ person-year/**t**
$c^l = 37.234$ k€/ person-year (value for France)

✓ SCR

Electricity cost $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**t**]
- c^e: electricity price [€/kWh]

$\lambda^e = 0.68$ kWh/**t** for a consumption of 170 kW [15] (see the Excel sheet for more details)
$c^e = 0.0569$ €/kWh (value for France)

Ammonia cost $\lambda^s \cdot c^s \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**t**]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/t]
- λ^s: specific sorbents demand (NH_3) [t/t pollutant removed]
- c^s: Ammonia price [€/t]

- η: removal efficiency (= 1 - $ef_{abated}/ef_{unabated}$)

with: $\lambda^s = \lambda^m \cdot \lambda^M/\eta$
λ^m: NH_3/NO_x (mol/mol) ratio for NO_x emitted
λ^M: NH_3/NO_x (mol weight/mol weight) ratio

$\lambda^s = 1.05 \cdot (17/46)/0.9$
$= 0.43$

$ef_{unabated} = 4.8 \cdot 10^{-4}$ t_{NOx}/t according [1] $ef_{unabated} = 3 \cdot 10^{-4}$ t_{NOx}/t according [15] $\lambda^s = 0.43$ t_{NH3}/t NO_x removed [15] $c^s = 400$ €/t_{NH3} (ammonia pur) $\eta = 80$ %

Catalyst cost $(\lambda^{cat} \cdot ci^{cat})/lt^{cat}$ [k€/**t**]

- λ^{cat}: catalyst volume [m^3/**t**]
- ci^{cat}: unit costs of catalysts [k€/m^3]
- lt^{cat}: life time of catalyst [a]

In our case, the gas volume flow is around:
$V = F_{conv} \cdot$Capacity per hour
$= 600 \cdot 2{,}000{,}000/8{,}000$
$= 150{,}000$ Nm^3/h
Then according some statistics [15], the catalyst volume is around 62 m³.

$ci^{cat} = 15$ k€/m^3 $\lambda^{cat} = 3.1 \cdot 10^{-5}$ m^3/**t** [15] (see the Excel sheet for more details) $lt^{cat} = 5$ years

Labour cost $(\lambda^l \cdot c^l)$ [k€/**t**]

- λ^l: labour demand [person -year/**t**]
- c^l: wages [k€/ person -year]

The number of additional personnel for the SCR unit is taken as 0.25.

Thus, the annual personnel costs for the SCR process are:

$AC_{PERS} = 0.25 \cdot c^l$

Thus $\lambda^l = (0.25)/$ Capacity

$= 0.25/(2{,}000{,}000)$

$= 1.25 \cdot 10^{-7}$ person-year/**t**

$\lambda^l = 1.25 \cdot 10^{-7}$ person-year/**t** $c^l = 37.234$ k€/ person-year (value for France)

Table 5.4: Parameters needed to calculate variable Operating costs for SNCR and SCR technologies.

	$ef_{unabated}$	η	λ^s [t/t NOx	c^s [€/t]	λ^e [kWh/t]	c^e [€/kWh]	λ^l [person-	c^l [k€/	λ^{cat} [m³/t]	ci^{cat} [k€/m³]	lt^{cat} [a]

	[t NOx/t]		removed]				year/t]	person -year]			
SNCR		60	0.92	400	0.112	0.0569	$1.25 \cdot 10^{-7}$	37.234			
SCR		90	0.43	400	0.68	0.0569	$1.25 \cdot 10^{-7}$	37.234	$3.1 \cdot 10^{-5}$	15	5

✓ **Conclusion**

In the petroleum industry for FCC unit, to obtain the cost of the secondary measures, the following shares are taken into account:
95 % of SCR
05 % of SNCR.
According to this repartition, the different costs of the NO_x secondary measures are the following:

Table 5.5: Investments and Operating costs of the secondary measures

Description	**Lifetime** (a)	**Investment (k€)** Source (1)	Source (15)	**Fixed Operating costs** (%/a)	**Variable Operating costs** (€/t) Source (1)	Source (15)
None	-	-	-	-	-	-
Secondary technology	10	7,870	4,815	4	0.206	0.177

Table 5.6: Parameters needed to calculate variable Operating costs for secondary measure

$ef_{unabated}$ [t NO_x/t]	**η**	**λ^s [t/t NO_x removed]**	**c^s [€/t]**	**λ^e [kWh/t]**	**c^e [€/kWh]**	**λ^l [person-year/t]**	**c^l [k€/person-year]**	**λ^{cat} [m³/t]**	**ci^{cat} [k€/m³]**	**lt^{cat} [a]**
	80	0.45	400	0.65	0.0569	$1.25 \cdot 10^{-7}$	37.234	$3.1 \cdot 10^{-5}$	15	5

5.3.1.3 Application rate and applicability

Respective percentage of reduction measures in 2000 for each reference installation as well as if possible, the percentage of use in 2005, 2010, 2015, 2020 and applicability according to the definition used in the RAINS model.

<u>NO_x abatement measures</u>

Table 5.7: Application rate and applicability for NO_x abatement measures

Description	**Application rate in 2000 [%]**	**Application rate in 2005 [%]**	**Applicability [%]**	**Application rate in 2010 [%]**	**Applicability [%]**	**Application rate in 2015 [%]**	**Applicability [%]**	**Application rate in 2020 [%]**	**Applicability [%]**
None									
Secondary technologies			Dust application rate		Dust application rate		Dust application rate		Dust application rate

- For helping to provide the information, use the following methodology.

<u>Methodology to calculate the different application rate:</u>

The different input parameter to determine the application rate are:

- ✓ E_{NOx}: Emission of NO_x in a country (t per year) for the different years
- ✓ *Na*: Activity level (t feed per year) for the different years.

Then, the sector situation may be defined by:

$$F_{s\,a\,NOx} = (E_{NOx}/N_a)$$

According to this result, it is possible to calculate the different application rates :

F_{S1NOx}: Uncontrolled NO_x emission level
F_{S2NOx}: NO_x emission level implementing the $DeNO_x$ secondary measure

The virtual application rate of secondary measures T_{NOx} is obtained by:

$$T_{NOx} = (F_{s\,a\,NOx} - F_{S1NOx})/(F_{S2NOx} - F_{S1NOx})$$

5.3.2 SO_x emissions

5.3.2.1 Abatement measures

For SO_x abatement techniques, the **$DeSO_x$ catalyst additive option** may be considered as a measure (efficiency of 40 to 50%).
The most performing options (Wet scrubbing,…) could be considered in the same category.

Table 5.8: Abatement Measure for SO_x

Abatement technique	Abatement efficiency [%]	SO_2 Emission factor (mg/Nm³)		SO_2 emission factor (kg/t feed)	
		Source (1)	Source (15)	Source (1)	Source (15)
Uncontrolled		4,000	3,500	0.0024	0.0021
$DeSO_x$ catalyst additive option	45	2,200	1,900	0.0013	0.0012
Wet scrubber	90	400	350	0.00024	0.00021

5.3.2.2 Costs

The different investments costs proposed by ADEME, which are derived from French refineries [15] are detailed in the Excel sheet established. From these costs, the average investment is 500 k€ for the $DeSO_x$ catalyst additive option and 8,000 k€ for Wet scrubber.

Table 5.9: Investments and Operating costs

Description	Investment (k€)		Lifetime (a)	Fixed Operating costs * (%/a)	Variable Operating costs (€/t/a)	
	Source (1)	Source (15)			Source (1)	Source (15)
$DeSO_x$ catalyst additive option	2,500	500	10	4	1.40	1.25
Wet scrubber	15,000	8,000	10	4	0.939	0.929

*: The fixed Operating costs only depend on the capacity – or size - of the installation, i.e. on the investment, and they are expressed as a **percentage of the plant investment** [%/a]

Variable Operating costs are defined as the costs depending on the level of production. Parameters for variable operating costs depend on the type of measure (technology) installed. The following tables show the common parameters and prices needed for the calculation of the variable costs.

<u>$DeSO_x$ catalyst additive option</u>

Labour cost $\lambda^l \cdot c^l$ [k€/**t**]

- λ^l: labour demand [person-year/t]
- c^l: labour cost/wages [k€/ person -year]

The number of additional personnel for the $DeSO_x$ additive catalyst unit is taken as 0.25.

Thus, the annual personnel costs for the process are:

$AC_{PERS} = 0.25 \cdot c^l$

Thus λ^l = (0.25)/ Capacity

= 0.25/(2,000,000)

= $1.25 \cdot 10^{-7}$ person-year/**t**

$\lambda^l = 1.25 \cdot 10^{-7}$ person-year/**t** c^l = 37.234 k€/ person-year (value for France)

Additive (zeolithe) cost: $\lambda^s \cdot c^s \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/t]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/**t**]
- λ^s: specific additive demand [t/t pollutant removed]
- c^s: additive price [€/t]
- η: removal efficiency = $(1 - ef_{abated}/ef_{unabated})$

$ef_{unabated} = 0.0024\ t_{SOx}/t$ according (1) $ef_{unabated} = 0.0021\ t_{SOx}/t$ according (15) $\lambda^s = 0.07\ t_{Zeolithe}/t\ SO_x$ removed [15] c^s = 18,300 €/$t_{Zeolithe}$ η = 45 %

Waste disposal cost [k€/**t**]

- Disposal cost = 152 [€/t of additive]

Table 5.10: Parameters needed to calculate variable Operating costs for $DeSO_x$ catalyst additive option

	$ef_{unabated}$ [t SOx/t]	**η**	**λ^s [t/t SO_2 removed]**	**c^s [€/t]**	**λ^l [person -year/t]**	**c^l [k€/ person - year]**	**Disposal cost [€/t of additive]**
$DeSO_x$ catalyst additive option	0.0021/ 0.0024	45	0.07	18,300	$1.25 \cdot 10^{-7}$	37.234	152

Wet scrubber :

Electricity cost $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**t**]
- c^e: electricity price [€/kWh]

λ^e = 2.13 kWh/**t** for a consumption of 534 kW [15]

c^e = 0.0569 €/kWh (value for France)

Limestone cost: $\lambda^s \cdot c^s \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**t**]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/**t**]
- λ^s: specific sorbents demand (e.g. NH_3) [ton/t pollutant removed]
- c^s: sorbents price [€/t]
- η: removal efficiency = $(1 - ef_{abated}/ef_{unabated})$

with: $\lambda^s = \lambda^m \cdot \lambda^M/\eta$
λ^m: Limestone/SO_x (mol/mol) ratio for SO_x emitted
λ^M: Limestone/SO_x (mol weight/mol weight) ratio
$\lambda^s = 1.05\cdot(100/34)$
$= 1.6$

$ef_{unabated}$ = 0.0024 t_{SOx}/t according (1) $ef_{unabated}$ = 0.0021 t_{SOx}/t according (15) λ^s = 2.34 $t_{Limestone}/t_{SOx\ removed}$ [15] c^s = 20 €/$t_{Sorbent}$ (ammonia pur) η = 90 %

Waste disposal cost

- ✓ Dc: Disposal cost = 152 [€/t of waste]
- ✓ Wa: Amount of waste produced = 1,56 [t/ tonne of limestone]

Labour cost $\lambda^l \cdot c^l$ [k€/**t**]

- λ^l: labour demand [man-year/t]
- c^l: labour cost/wages [k€/man-year]

The number of additional personnel for the wet scrubber unit is taken as 0.5.

Thus, the annual personnel costs for the process are:

$AC_{PERS} = 0.5 \cdot c^l$

Thus λ^l = (0.5)/ Capacity

= 0.55/(2,000,000)

= $2.5\cdot10^{-7}$ person-year/**t**

$\lambda^l = 2.5\cdot10^{-7}$ person-year/**t** c^l = 37.234 k€/ person-year (value for France)

Table 5.11: Parameters needed to calculate variable Operating costs for Wet scrubbber

	$ef_{unabated}$ [t SO_x/t]	**η**	**λ^s [t/t SO_x removed]**	**c^s [€/t]**	**λ^e [kWh/t]**	**c^e [€/kWh]**	**λ^l [person-year/t]**	**c^l [k€/ person-year]**	**Dc [€/t of waste]**	**Wa [t/ tonne of limestone]**
Wet scrubber	0.0021 0.0024	90	1.64	20	2.13	0.0569	$2.5\cdot10^{-7}$	37.234	152	1,56

5.3.2.3 Application rate and applicability

Respective percentage of reduction measures in 2000 for each reference installation as well as if possible, the percentage of use in 2005, 2010, 2015, 2020 and applicability according to the definition used in the RAINS model.

Table 5.12: Application rate and applicability for SO_x abatement measures

Description	**Application rate in 2000 [%]**	**Application rate in 2005 [%]**	**Applicability [%]**	**Application rate in 2010 [%]**	**Applicability [%]**	**Application rate in 2015 [%]**	**Applicability [%]**	**Application rate in 2020 [%]**	**Applicability [%]**
None	A								
$DeSO_x$ catalyst additive option	B								
Wet scrubber	C								

- To support provision of this information, you are invited to use the following methodology:

Methodology to calculate the different application rates:

In a refinery, either the $DeSO_x$ catalyst additive option or the wet scrubber can be installed, but nor simultaneously.

Thus A + B + C = 1 (first equation with 3 unknown parameters)

The different input parameters to determine the sector situation are:

- ✓ E_{SO2}: Emission of SO_2 in a country (t per year) for the different years
- ✓ N_a: Activity level (t of feed per year) for the different years

Then, the sector situation may be defined by:

$$F_{s\,a\,SO2} = (E_{SO2}/N_a)$$

Using this result, it is then possible to calculate the different application rate:

$F_{S1\ SO2}$: Uncontrolled SO_2 emission level
$F_{S2\ SO2}$: SO_2 emission level after implementing the $DeSO_x$ catalyst additive option
$F_{S3\ SO2}$: SO_2 emission level after implementing the Wet scrubber

$F_{s\,a\,SO2} = A \cdot F_{S1\ SO2} + B \cdot F_{S2\ SO2} + C \cdot F_{S3\ SO2}$ (second equation)

But a third equation is needed to solve the system. The only solution is to give the application rate for one technique and then the other could be easily calculated.

Consequently, the different input parameters to determine the application rate are:

- ✓ E_{SO2}: Emission of SO_2 in a country (t per year) for the different years
- ✓ N_a: Activity level (t of feed per year) for the different years
- ✓ Application rate of one abatement technique

5.3.3 Dust emissions

5.3.3.1 Abatement techniques

Concerning dust, different configurations of **cyclones** may be used. The performance range may be greatly variable but as average an efficiency of 80% could be taken.

The second option is an end of pipe technology like bag filters and ESP with much better performances. This option could be named “deduster”.

Table 5.13: Abatement Measure for dust

Description	PM abatement efficiency [%]	PM emission factor (mg/Nm³)	PM emission factor (kg/t feed)
None (two stage cyclone)	-	600	0.36
Higher stage cyclones	80	120	0.072
Deduster(EP and bag filter)	97.5	15	0.009

5.3.3.2 Costs

Table 5.14: Investments and Operating costs

Description	Efficiency (%)	Lifetime (a)	Investment (k€)	Fixed Operating costs * (%/a)	Variable Operating costs (k€/t/a)
None	-	-	-	-	-
Higher stage cyclones	80	10	2,000	4	0.039
Deduster(EP and bag filter)	95	10		4	See table 5.15

*: The fixed Operating costs only depend on the capacity – or size - of the installation, i.e. on the investment, and they are expressed as a **percentage of the plant investment** [%/a]

Variable Operating costs are defined as the costs depending on the level of production. Parameters for variable operating costs depend on the type of measure (technology) installed. The following tables show the common parameters and prices needed for the calculation of the variable costs.

✓ <u>Higher stage cyclone</u>

<u>Electricity cost</u> $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**t**]
- c^e: electricity price [€/kWh]

$\lambda^e = 0.6$ kWh/**t** for a consumption of 150 kW $c^e = 0.0569$ €/kWh (value for France)

<u>Labour cost</u> $\lambda^l \cdot c^l$ [k€/**t**]

- λ^l: labour demand [person-year/**t**]
- c^l: wages [k€/person-year]

$\lambda^l = 0$ person-year/**t** $c^l = 37.234$ k€/ person-year (value for France)

Dust disposal cost $\lambda^d \cdot c^d \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**t**]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/**t**]
- λ^d: demand for dust disposal [t/ t pollutant removed]
- c^d: specific dust disposal cost [€/t]
- η: removal efficiency (= 1 - $ef_{abated}/ef_{unabated}$)

For the considered technique and efficiency, there is **no dust disposal.**

$\lambda^d = 0$ t/ t TSP removed

✓ ESP

Electricity cost $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**t**]
- c^e: electricity price [€/kWh]

$\lambda^e = 0.6$ kWh/**t** for a consumption of 150 kW $c^e = 0.0569$ €/kWh (value for France)

Labour cost $\lambda^l \cdot c^l$ [k€/**t**]

- λ^l: labour demand [person-year/**t**]
- c^l: wages [k€/person-year]

$\lambda^l = 3.75 \cdot 10^{-7}$ person-year/**t** for a number of additional personnel of 0.75 person-year $c^l = 37.234$ k€/ person-year (value for France)

Dust disposal cost $\lambda^d \cdot c^d \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**t**]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/**t**]
- λ^d: demand for dust disposal [t/ t pollutant removed]
- c^d: specific dust disposal cost [€/t]
- η: removal efficiency (= 1 - $ef_{abated}/ef_{unabated}$)

For the considered technique and efficiency, there is **no dust disposal.**

$\lambda^d = 0$ t/ t TSP removed

✓ Fabric filter

Electricity cost $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**t**]

- c^e: electricity price [€/kWh]

λ^e = 2.2 kWh/**t** for a consumption of 550 kW c^e = 0.0569 €/kWh (value for France)

<u>Labour cost</u> $\lambda^l \cdot c^l$ [k€/**t**]

- λ^l: labour demand [person-year/**t**]
- c^l: wages [k€/person-year]

$\lambda^l = 3.75 \cdot 10^{-7}$ person-year/**t** for a number of additional personnel of 0.75 person-year c^l = 37.234 k€/ person-year (value for France)

<u>Dust disposal cost</u> $\lambda^d \cdot c^d \cdot ef_{unabated} \cdot \eta / 10^3$ [k€/**t**]

- $ef_{unabated:}$ unabated emission factor of pollutant [t pollutant/**t**]
- λ^d: demand for dust disposal [t/ t pollutant removed]
- c^d: specific dust disposal cost [€/t]
- η: removal efficiency (= 1 - $ef_{abated}/ef_{unabated}$)

For the considered technique and efficiency, there is **no dust disposal.**

λ^d = 0 t/ t TSP removed

Table 5.15: Parameters needed to calculate variable Operating costs for primary deduster

	$ef_{unabated}$ [t dust/t]	η	**λ^d [t/t dust removed]**	**λ^e [kWh/t]**	**c^e [€/kWh]**	**λ^l [person-year/t]**	**c^l [€/person-year]**
Cyclones	$3.6 \cdot 10^{-4}$	80	0	0.6	0.0569	$1.25 \cdot 10^{-7}$	37,234
Electrofilter	$3.6 \cdot 10^{-4}$	95	0	0.6	0.0569	$3.75 \cdot 10^{-7}$	37,234
Bag filter	$3.6 \cdot 10^{-4}$	95	0	2.2	0.0569	$3.75 \cdot 10^{-7}$	37,234

✓ **Conclusion**

In the petroleum industry for FFC unit, to obtain the cost of the deduster technology which comprises ESP and fabric filter, the following shares are taken into account:
50 % of ESP
50 % of fabric filter.
According to this repartition, the different costs of the deduster measure are the following:

Table 5.16: Investments and Operating costs of the deduster

Description	**Lifetime (a)**	**Investment (k€)**	**Fixed Operating costs** (%/a)	**Variable Operating costs** (€/t)
None	-	-	-	-
Deduster	30	3,500	4	0.094

Table 5.17: Parameters needed to calculate variable Operating costs for secondary measure

$ef_{unabated}$ [t dust/t]	η	**λ^d [t/t dust removed]**	**λ^e [kWh/t]**	**c^e [€/kWh]**	**λ^l [person-year/t]**	**c^l [€/person-year]**
$3.6 \cdot 10^{-4}$	95	0	1.4	0.0569	$3.75 \cdot 10^{-7}$	37,234

5.3.3.3 Application rate and applicability

Respective percentage of reduction measures in 2000 for each reference installation as well as if possible, the percentage of use in 2005, 2010, 2015, 2020 and applicability according to the definition used in the RAINS model.

Table 5.18: Application rate and applicability for Dust abatement measures

Description	**Application rate in 2000 [%]**	**Application rate in 2005 [%]**	**Applica bility [%]**	**Application rate in 2010 [%]**	**Applica bility [%]**	**Application rate in 2015 [%]**	**Applica bility [%]**	**Application rate in 2020 [%]**	**Applica bility [%]**
None									
Cyclones			100		100		100		100
Deduster			100		100		100		100

- To support provision of this information, you are invited to use the following methodology:

Methodology to calculate the different application rates:

The different input parameters to determine the application rates are:

- ✓ E_{dust}: Emission of Dust in a country (t per year) for the different years
- ✓ N_a: Activity level (t of feed per year) for the different years

Then, the sector situation may be defined by:

$$F_{s\ a\ Dust} = (E_{Dust} / N_a)$$

Using this result, it is then possible to calculate the different application rate:

$F_{S1\ Dust}$: Uncontrolled Dust emission level
$F_{S2\ Dust}$: Dust emission level implementing the Cyclone
$F_{S3\ Dust}$: Dust emission level implementing the Deduster

- ✓ If $F_{S1\ Dust} < F_{s\ a\ Dust} < F_{S2\ Dust}$, it can be considered that some cyclones may still be implemented to a given percentage of the production capacity.

The virtual application rate of primary measures $T_{1,\ Dust}$ is obtained by:

$$T_{1,\ Dust} = (F_{s\ a\ Dust} - F_{S1\ Dust})/(F_{S2\ Dust} - F_{S1\ Dust})$$

- ✓ If $F_{s\ a\ Dust} < F_{S2\ Dust}$ it may be considered that cyclones have already been implemented. In this case, it can be considered that the application rate concerning cyclones is 100%.

The virtual application rate of *deduster* $T_{2,\ Dust}$ is obtained by:

$$T_{2\ Dust} = (F_{s\ a\ Dust} - F_{S2\ Dust}) / (F_{S3\ Dust} - F_{S2\ Dust})$$

Petroleum industry: Fluid Catalytic Cracking Unit
Summary list of parameters and data

	Parameter	Annotation	Unit	Type of data	Current proposal
1	Activity level 2000, 2005, 2010, 2015 and 2020	N_a	Tonnes per year	Input	-
2	SO_x (as SO_2) 2000, 2005, 2010, 2015 and 2020	E_{SO2}	Tonnes per year	Input	-
3	NO_x (as NO_2) 2000, 2005, 2010, 2015 and 2020	E_{NOx}	Tonnes per year	Input	-
4	Dust 2000, 2005, 2010, 2015 and 2020	E_{Dust}	Tonnes per year	Input	-
5	Application rate of one DeSOx option	A_R	%	Input	-
6	Conversion factor between concentration [mg/Nm³] and specific mass flow [kg/tonne of feed]	F_{conv}	-	Fixed by the experts	600
7	Uncontrolled dust emission level	$F_{S1\ Dust}$	mg/Nm³ kg / tonne of feed	Fixed by the experts	600 0.36
8	Emission level after Higher stage cyclone	$F_{S2\ Dust}$	mg/Nm³ kg / tonne of feed	Fixed by the experts	120 0.072
9	Emission level after deduster	$F_{S3\ Dust}$	mg/Nm³ kg / tonne of feed	Fixed by the experts	15 0.009
10	Cost of the cyclone option per tonne of pollutant avoided	$C_{Dust\ 1}$	Euro / tonne of dust avoided	Evaluated by the experts	702
11	Cost of the deduster option per tonne of pollutant avoided	$C_{Dust\ 2}$	Euro / tonne of dust abated	Evaluated by the experts	6,000
12	Uncontrolled NO_X emission level	$F_{S1\ NOx}$	mg/Nm³ kg / tonne of feed	Fixed by the experts	800 (1) / 500 (2) 0.48 (1) / 0,3 (2)
13	NO_X emission level implementing the $DeNO_X$ technical option	$F_{S2\ NOx}$	mg/Nm³ kg / tonne of feed	Fixed by the experts	160 (1) / 100 (2) 0.096 (1) / 0,06 (2)
14	Cost of the DeNOx technical option (PM) per tonne of pollutant avoided	C_{NOx}	Euro / tonne NO_x abated	Evaluated by the experts	2210 (1) 2130 (2)
15	Uncontrolled SO_2 emission level	$F_{S1\ SO2}$	mg/Nm³ g / tonne of feed	Fixed by the experts	4,000 (1) /3,500(2) 2.4 (1) / 2.1 (2)
16	SO_2 emission level implementing the $DeSO_X$ catalyst additive option	$F_{S2\ SO2}$	mg/Nm³ g / tonne of feed	Fixed by the experts	2,200 (1) /1,900(2) 1.32 (1) / 1.2 (2)
17	SO_2 emission level implementing the wet scrubber option	$F_{S3\ SO2}$	mg/Nm³ g / tonne of feed	Fixed by the experts	400 (1) /350(2) 0.24 (1) / 0.21 (2)
18	Cost of the $DeSO_X$ catalyst additive option per tonne of pollutant avoided	$C_{1\ SO2}$	Euro / tonne SO_2 abated	Evaluated by the experts	1,485 (1) 1,366 (2)
19	Cost of the wet scrubber option per tonne of pollutant avoided	$C_{2\ SO2}$	Euro / tonne SO_2 abated	Evaluated by the experts	1,000 (1) 0,837 (2)

(1): Data from Source (1)
(2): Data from Source (15)

6 Sulphur recovery plants

6.1 General information

SNAP CODE 04 01 03 - **NFR** 4a
Sector activity unit: tonne of sulphur produced

SO_2	NO_x	PM	VOC	NH_3
x	-	-	-	-

This sector covers emissions from sulphur recovery plants (Claus plants) in refineries.

6.2 Definition of reference installation/process

Sulphur recovery refers to the conversion of hydrogen sulphide (H_2S) to elemental sulphur. Hydrogen sulphide is a byproduct of processing natural gas and refining high-sulphur crude oils.
In the widely used multistage Claus sulphur recovery process, a portion of the H_2S in the feed gas is oxidized to SO_2 and water in a reaction furnace with air or enriched oxygen. After quenching the hot gases to generate steam, the cooled gases are passed through a sulphur condenser to recover liquid sulphur and the gases are reheated. The remaining non-combusted fraction of the feed gas H_2S reacts with SO_2 in catalytic converters to form elementar sulphur, water and heat. The number of catalytic stages depends on the level of conversion desired. [1]

Table 6.1: Efficiencies of the Claus process [1]

Number of Claus reactors	Efficiency (%H_2S converted)
1	90
2	94-96
3	97-98

The tailgas, containing H_2S, sulphur vapour and traces of other sulphur compounds formed in the combustion section, escapes with the inert gases from the tail end of the plant. Thus, it is frequently necessary to follow the Claus unit with a tailgas cleanup unit to achieve higher recovery. Tailgas from a Claus sulphur recovery unit contains a variety of pollutants from direct process oxidation reactions including SO_2 and unreacted H_2S, other furnace side reaction products such as reduced sulphur compounds and small quantities of CO and VOC. [1]

Table 6.2: Reference installation

Reference Code	Technique	Plant size range [t /a]
01	Standard Claus Unit (one thermal and two catalytic steps)	33,333

6.3 Emission abatement techniques and costs

This chapter considers the emissions control techniques for the process SRU in a refinery, the cost of installing and operating them and their performance. Only the SO_2 abatement techniques are considered.

6.3.1 Abatement measures

The most common process is the Claus unit, which enables a recovery rate of sulphur amounting to 95-97%.
To bring sulphur recovery yield to 99% or more, a Claus Tail Gas Treating Process can be added to a Claus unit. Indeed gases through Claus plants still contain substantially sulphur compounds. There are different types of tail gas treatment units [13] :

- ✓ SULFREEN

This process is based on the Claus reaction. Here the sulphur produced is adsorbed on an active alumina based catalyst.

- ✓ CLAUSPOL

This process is based on the Claus reaction. The reaction takes place in a column with packed beds, with the gas entering from the bottom of the column while a solvent with catalyst is distributed in the top of the column.

- ✓ SCOT process

The Claus tail gas is selectively hydrogenated to H_2S, which is separated from the gas stream in an amine absorber.

- ✓ SUPERCLAUS

The tail gas is led through a reactor with a selective oxidation catalyst, which converts H_2S with excess oxygen to sulphur.[1]

- ✓ Others techniques

Some others techniques exist also.

All these techniques will be regrouped into three categories with different abatement efficiencies as described in the following table 6.3.

Table 6.3: SO_2 abatement techniques

Abatement technique	Techniques	Abatement efficiency [%]	Emission factor (kg/t sulphur)
Uncontrolled		96	80
Category 1	SuperClaus,..	99	20
Category 2	Clauspol, Sulfreen,..	99.5	10
Category 3	SCOT,..	99.9	2

6.3.2 Costs

Table 6.4: Investments and variable Operating costs

Measure Code	Description	Removal efficiency (%)	Investment (k€)		Fixed Operating costs (%/a)	Variable Operating costs (k€/t)
			Source (1)	Sources (16, 17)		
00	None	-	-	-	-	-
01	Category 1	99	3,000	2,000	4	3.86

02	Category 2	99.5	10,000	5,000	4	2.83
03	Category 3	99.9	15,000	10,000	4	5.11

Source: BAT to reduce emissions from refineries, May 1999.

<u>Variable Operating costs [16, 17]:</u>

To determine the different costs, according the different costs found in [16], an equivalent quantity of utilities has been taken into account.

✓ <u>Category 1</u>

<u>Catalyst replacement cost</u> $(\lambda^{cat} \cdot ci^{cat}) / lt^{cat}$ [k€/**t**]

- λ^{cat}: catalyst volume [m^3/**t**]
- ci^{cat}: unit costs of catalysts [k€/m^3]
- lt^{cat}: life time of catalyst [a]

ci^{cat} = 15 k€/m^3 $\lambda^{cat} = 9 \cdot 10^{-5}$ m^3/**t** for an equivalent catalyst volume of 3 m³ lt^{cat} = 1 year

<u>Labour cost</u> $\lambda^l \cdot c^l$ [€/**t**]

- λ^l: labour demand [person-year/t]
- c^l: labour cost/wages [k€/person-year]
-

$\lambda^l = 7.5 \cdot 10^{-6}$ person-year/**t** for a number of additional personnel of 0.25 per year c^l = 37.234 k€/ person-year (value for France)

<u>Electricity cost</u> $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**t**]
- c^e: electricity price [€/kWh]

λ^e = 39,1 kWh/**t** for a consumption of 163 kW c^e = 0.0569 €/kWh (value for France)

✓ <u>Category 2</u>

<u>Catalyst replacement cost</u> $(\lambda^{cat} \cdot ci^{cat}) / lt^{cat}$ [k€/**t**]

- λ^{cat}: catalyst volume [m^3/**t**]
- ci^{cat}: unit costs of catalysts [k€/m^3]
- lt^{cat}: life time of catalyst [a]

ci^{cat} = 15 k€/m^3 $\lambda^{cat} = 6 \cdot 10^{-5}$ m^3/**t** for an equivalent catalyst volume of 2 m³ lt^{cat} = 1 year

Labour cost $\lambda^l \cdot c^l$ [€/**t**]

- λ^l: labour demand [person-year/t]
- c^l: labour cost/wages [k€/person-year]
-

$\lambda^l = 1.5 \cdot 10^{-5}$ person-year/**t** for a number of additional personnel of 0.5 per year $c^l = 37.234$ k€/ person-year (value for France)

Electricity cost $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**t**]
- c^e: electricity price [€/kWh]

$\lambda^e = 24$ kWh/**t** for a consumption of 100 kW $c^e = 0.0569$ €/kWh (value for France)

✓ Category 3

Catalyst replacement cost $(\lambda^{cat} \cdot ci^{cat}) / lt^{cat}$ [k€/**t**]

- λ^{cat}: catalyst volume [m^3/**t**]
- ci^{cat}: unit costs of catalysts [k€/m^3]
- lt^{cat}: life time of catalyst [a]

$ci^{cat} = 15$ k€/m^3 $\lambda^{cat} = 3 \cdot 10^{-5}$ m^3/**t** for a catalyst volume of 1 m³ $lt^{cat} = 1$ year

Labour cost $\lambda^l \cdot c^l$ [€/**t**]

- λ^l: labour demand [person-year/t]
- c^l: labour cost/wages [k€/person-year]
-

$\lambda^l = 1.5 \cdot 10^{-5}$ person-year/**t** for a number of additional personnel of 0.5 per year $c^l = 37.234$ k€/ person-year (value for France)

Electricity cost $\lambda^e \cdot c^e / 10^3$ [k€/**t**]

- λ^e: additional electricity demand (=new total consumption – old total consumption) [kWh/**t**]
- c^e: electricity price [€/kWh]

$\lambda^e = 72$ kWh/**t** for a consumption of 300 kW $c^e = 0.0569$ €/kWh (value for France)

Table 6.5: Parameters needed to calculate variable Operating costs

	$ef_{unabated}$ [t SOx/t]	η	λ^e [kWh/t]	c^e [€/kWh]	λ^l [person-year/t]	c^l [k€/ person	λ^{cat} [m³/t]	ci^{cat} [k€/m^3]	lt^{cat} [a]

						-year]			
Category 1	0.08	99	11,7	0.0569	$7{,}5\cdot10^{-6}$	37.234	$9\cdot10^{-5}$	15	1
Category 2	0.08	99.5	24	0.0569	$1.5\cdot10^{-5}$	37.234	$6\cdot10^{-5}$	15	1
Category 3	0.08	99.9	72	0.0569	$1.5\cdot10^{-5}$	37.234	$3\cdot10^{-5}$	15	1

6.3.3 Application rate and applicability

Respective percentage of reduction measures in 2000 for each reference installation as well as if possible, the percentage of use in 2005, 2010, 2015, 2020 and applicability according to the definition used in the RAINS model.

Table 6.6: Application rate and applicability for SO_x abatement measures

Description	**Application rate in 2000 [%]**	**Application rate in 2005 [%]**	**Applicability [%]**	**Application rate in 2010 [%]**	**Applicability [%]**	**Application rate in 2015 [%]**	**Applicability [%]**	**Application rate in 2020 [%]**	**Applicability [%]**
None	A								
Category 1	B								
Category 2	C								
Category 3	D								

- To support provision of this information, you are invited to use the following methodology:

Methodology to calculate the different application rates:

In a refinery, all the different abatement measures are not installed together.

Thus A + B + C + D = 1 (first equation with 4 unknown parameters)

The different input parameters to determine the sector situation are:

- ✓ E_{SO2}: Emission of SO_2 in a country (t per year) for the different years
- ✓ N_a: Activity level (t of sulphur produced per year) for the different years

Then, the sector situation may be defined by:

$$F_{s\,a\,SO2} = (E_{SO2}/N_a)$$

Using this result, it is then possible to calculate the different application rate:

$F_{S1\,SO2}$: Uncontrolled SO_2 emission level
$F_{S2\,SO2}$: SO_2 emission level after implementing the category 1 option
$F_{S3\,SO2}$: SO_2 emission level after implementing the category 2 option
$F_{S4\,SO2}$: SO_2 emission level after implementing the category 3 option

$F_{s\,a\,SO2} = A\cdot F_{S1\,SO2}+B\cdot F_{S2\,SO2}+C\cdot F_{S3\,SO2}+D\cdot F_{S4\,SO2}$ (second equation)

But two equations are needed to solve the system. The only solution is to give the application rate for two technical options and then the other could be easily calculated.

Consequently, the different input parameters to determine the application rate are:

- ✓ E_{SO2}: Emission of SO_2 in a country (t per year) for the different years
- ✓ N_a: Activity level (t of sulphur produced per year) for the different years

Petroleum industry: Sulphur Recovery Unit
Summary list of parameters and data

	Parameter	Annotation	Unit	Type of data	Current proposal
1	Activity level 2000, 2005, 2010, 2015 and 2020	N_a	Tonnes of sulphur produced by the Claus unit per year	Input	-
2	SO_x (as SO_2) 2000, 2005, 2010, 2015 and 2020	E_{SO2}	Tonnes per year	Input	-
3	Application rate of one DeSOx option	A,B, C or D	%	Input	-
4	Application rate of a second DeSOx option	A,B, C or D	%	Input	-
6	Uncontrolled SO_x (as SO_2) emission level	$F_{S1\ SO2}$	kg / tonne of sulphur	Fixed by the experts	80
7	SO_x(as SO_2) emission level implementing the $DeSO_X$ category 1 option	$F_{S2\ SO2}$	kg / tonne of sulphur	Fixed by the experts	20
8	SO_x (as SO_2) emission level implementing the $DeSO_X$ category 2 option	$F_{S3\ SO2}$	kg / tonne of sulphur	Fixed by the experts	10
9	SO_x (as SO_2) emission level implementing the $DeSO_X$ category 3 option	$F_{S4\ SO2}$	kg / tonne of sulphur	Fixed by the experts	2
10	Cost of the $DeSO_X$ category 1 option per tonne of pollutant avoided	$C_{1\ SO2}$	Euro / tonne SO_2 abated	Evaluated by the experts	309 (1) 228 (2)
11	Cost of the $DeSO_X$ category 2 option per tonne of pollutant avoided	$C_{2\ SO2}$	Euro / tonne SO_2 abated	Evaluated by the experts	740 (1) 390 (2)
12	Cost of the $DeSO_X$ category 3 option per tonne of pollutant avoided	$C3_{\ SO2}$	Euro / tonne SO_2 abated	Evaluated by the experts	955 (1) 693 (2)

(1): Data from Source (1)
(2): Data from Source (15)

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