UNECE Convention on Long-range Transboundary Air Pollution

EGTEI Methodology
Work to update costs for LCP

SO_2, NO_x and PM abatement techniques

Second meeting
31 January 2012

Agenda

- Information Gothenburg Protocol revision, NEC directive revision, LCP BREF process
- Outcomes of the kick off meeting – objectives
- General hypothesis
- Co-firing of biomass
- Investments and operating costs for SO_2 reduction techniques
- Investments and operating costs for NOx reduction techniques
- Investments and operating costs for PM reduction techniques
- Collection of investments covering the techniques considered by the group and thermal capacities > 50 MWth
- Other issues

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Gothenburg Protocol

- Negotiations could be finalised in April 2012, if not in September 2012
- Introduction of PM2.5
- Set of ELVs which could be based on option 2 (for combustion installation, similar to IED)
- No absolute ceilings but percentage of reduction of emissions, with 2005 as reference year
- Flexibility mechanisms introduced to enable the addition of new sources, unexpected changes in emission factors, average emissions over 3 years,
- Reductions announced

% / 2005	EU	USA	CH
SO2	-55	-58	-20
NOx	-40	-47	-49
NH3	-5		-13
VOC	-35	-24	-32
PM	-20	-24	-26

Revision of the NEC Directive

◈ NEC directive in revision

◈ Directive project expected in 2013

◈ 2025 or 2030 as target year possible

◈ Work programme for the determination of emissions in 2020 - 2030

• February:

– Report and on-line access to Final EC4MACS baseline emission scenario (GAINS/IIASA

• March-September:

– Bilateral consultations MS experts / IIASA on GAINS emission calculations (but not on energy scenarios!) to improve the EC4MACS Final Assessment

– Submission of national energy/agricultural scenarios to IIASA for implementation in GAINS. GAINS data templates with PRIMES data will be provided by IIASA.

Revision of the NEC directive

◈ Work programme for the determination of emissions in 2020 – 2030

• March-September:

– New PRIMES 2012 baseline, with consultations of DG-ENER/PRIMES with MS energy experts

• June:

– Draft TSAP baseline (including first MS comments) presented to ESG

– Further feedbacks to IIASA up to September

• December 2012:

– Final TSAP baseline(s)

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Main conclusions from the kick off meeting

Consider:

- Combustion plants > 50 MWth : investment functions to be developed for different ranges of size

(50 – 100 MW; 100 – 300 MW (or 500) – > 300 MW (or 500))

- Hard coal (HC), brown coal (BC), HFO and natural gas + **biomass wood** in co-firing up to 20 % with coal (non commercial gases and blast furnaces not covered)
- Different load factors (included in the cost function)
- Boilers and gas turbines (not yet stationary engines)
- Retrofit factor for existing plants : different retrofit factor according to different techniques

Derive:

- Yearly costs provided but also cost effectiveness (€/t pollutant eliminated), cost per MWth and or MWe as well as costs per MWh for different load factors

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Fuels considered

Fuels :

- BC: Brown coal – Low calorific value between 15 to 20 GJ/t; S ?
- HC1: Hard coal grade 1 – Low calorific value between 26 to 32 GJ/t, S > 1% w/w
- HC2: Hard coal grade 2 – Low calorific value between 26 to 32 GJ/t, S : 0.6 to 0.8 % w/w
- HC3: Hard coal grade 3 – Low calorific value between 26 to 32 GJ/t, S < 0.6 % w/w
- HF1: Heavy fuel oil grade 1 - Low calorific value between 38 to 42 GJ/t, S > 1 % w/w
- HF2: Heavy fuel oil grade 2 - Low calorific value between 38 to 42 GJ/t, S : 0.5% to 1 % w/w
- HF3: Heavy fuel oil grade 3 - Low calorific value between 38 to 42 GJ/t, S < 0.5% w/w
- Gas: HHV: 30-47 MJ/Nm³ (L-Gas / H-Gas), S : 0.00012 to 0.0013 % w/w
- OS1: Wood - Low calorific value between 13 to 18 GJ/t, S # 0% w/w

Dry waste gas flow rates per unit of energy considered

Boilers :

- For solid fuels (coals): $F_{ref} = 350\ Nm^3/GJ\ (6\ \%\ O_2,\ dry)$
- For liquid fuels: $F_{ref} = 280\ Nm^3/GJ\ (3\ \%\ O_2,\ dry)$
- For gaseous fuels: $F_{ref} = 270\ Nm^3/GJ\ (3\ \%\ O_2,\ dry)$
- What factor for wood ?

To be checked by experts

Other data to be used ? data from the CEN standard in elaboration to be used?

Gas Turbines:

- Conversion of 270 Nm^3/GJ (3% O_2) to 810 Nm^3/GJ (15% O_2)

Real condition waste gas flow rates per unit of energy (useful to use some references)

- For solid fuels (coals): F_{real} = ? Nm^3/GJ (% O_2 real condition, humid)
- For liquid fuels: F_{real} = ? Nm^3/GJ ((% O_2 real condition, humid)
- For gaseous fuels: F_{real} = ? Nm^3/GJ ((% O_2 real condition, humid)
- For biomass wood: F_{real} = ? Nm^3/GJ (% O_2 real condition, humid)

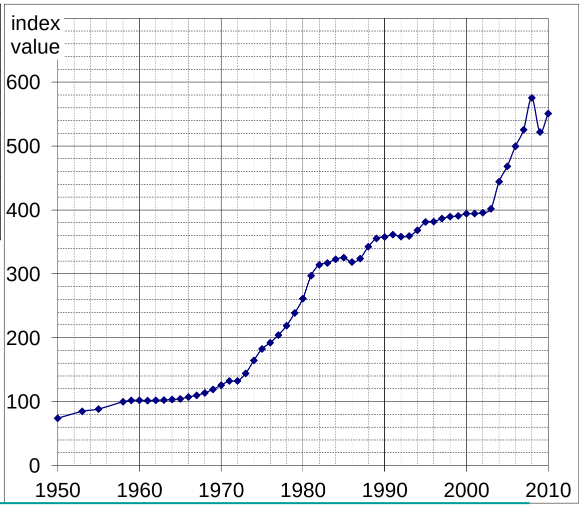
Boiler	**% O2 real**	**Temp K**	**H real %**	**P real Pa**
HC				
BC				
HFO				
Natural gas				
Wood				

Chemical Engineering Plant Cost Index

Year	CEPCI
1990	357.6
1989	355.4
1988	342.5
1987	323.8
1986	318.4
1985	325.3
1984	322.7
1983	316.9
1982	314
1981	297
1980	261.2

Year	CEPCI
2000	394.1
1999	390.6
1998	389.5
1997	386.5
1996	381.7
1995	381.1
1994	368.1
1993	359.2
1992	358.2
1991	361.3

Year	CEPCI
2010	550.8
2009	521.9
2008	575.4
2007	525.4
2006	499.6
2005	468.2
2004	444.2
2003	401.7
2002	395.6
2001	394.3



$$I_b = I_{act} \times (p_b/p_{act})$$

I_b = Investment (€ base year)
I_{act} = Investment (€ actual year)
p_i = CEPCI price level for year i

Exchange Rates USD / EUR

1990-2011

Year	Annual Average DEM/USD	Min	Max
2001	0,458	0,429	0,488
2000	0,472	0,422	0,531
1999	0,545	0,512	0,603
1998	0,568	0,538	0,615
1997	0,579	0,532	0,651
1996	0,674	0,641	0,717
1995	0,707	0,642	0,742
1994	0,619	0,568	0,675
1993	0,606	0,576	0,637
1992	0,643	0,596	0,721
1991	0,604	0,545	0,685
1990	0,619	0,582	0,679

Year	Annual Average ECU/USD	Min	Max
2001	0,896	0,838	0,955
2000	0,924	0,825	1,039
1999	1,066	1,002	1,179
1998	1,121	1,070	1,212
1997	1,135	1,049	1,258
1996	1,270	1,238	1,318
1995	1,308	1,222	1,357
1994	1,189	1,104	1,284
1993	1,172	1,113	1,244
1992	1,297	1,207	1,458
1991	1,240	1,120	1,408
1990	1,273	1,185	1,395

Year	Annual Average EUR/USD	Min	Max
2011	1,392	1,289	1,488
2010	1,327	1,194	1,456
2009	1,394	1,256	1,512
2008	1,471	1,246	1,599
2007	1,371	1,289	1,487
2006	1,256	1,180	1,333
2005	1,245	1,167	1,362
2004	1,243	1,180	1,363
2003	1,131	1,038	1,263
2002	0,946	0,858	1,049

Exchange Rates GBP / EUR

1990-2011

Year	Annual Average DEM/GBP	Min	Max
2001	0,318	0,305	0,328
2000	0,312	0,292	0,327
1999	0,337	0,318	0,364
1998	0,343	0,321	0,363
1997	0,354	0,326	0,384
1996	0,432	0,382	0,462
1995	0,448	0,411	0,468
1994	0,404	0,382	0,422
1993	0,403	0,387	0,429
1992	0,366	0,340	0,423
1991	0,342	0,334	0,353
1990	0,347	0,329	0,368

Year	Annual Average ECU/GBP	Min	Max
2001	0,622	0,597	0,641
2000	0,609	0,571	0,640
1999	0,659	0,622	0,712
1998	0,676	0,639	0,714
1997	0,693	0,646	0,742
1996	0,814	0,737	0,850
1995	0,829	0,784	0,857
1994	0,776	0,743	0,802
1993	0,780	0,751	0,829
1992	0,737	0,698	0,820
1991	0,701	0,689	0,716
1990	0,714	0,682	0,750

Year	Annual Average EUR/GBP	Min	Max
2011	0,868	0,832	0,905
2010	0,858	0,810	0,911
2009	0,891	0,843	0,961
2008	0,797	0,733	0,979
2007	0,685	0,655	0,735
2006	0,682	0,668	0,701
2005	0,684	0,662	0,707
2004	0,679	0,656	0,709
2003	0,692	0,650	0,724
2002	0,629	0,609	0,651

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How can we include Biomass (Wood) Co-Firing?

- Limit type of co-firing to hard coal PC units with discrete amount of co-firing shares (i. e. 5%, 10%, 20%).
- Effect Calculation:

a) Define 100% biomass-only numbers (derive from e.g. Swedish data) and calculate co-firing cases by taking the weighted average

or

b) Take values from existing Co-Firing cases (if accessible)

To be done for: emissions at equipment inlet / outlet, equipment abatement efficiency, equipment lifetime (if applicable)

Effects of Biomass (Wood) Co-Firing – SO_2

S-content of wood: 0% => Reduction of SO_2 emissions by amount of co-firing percentage

Effects of Biomass (Wood) Co-Firing – PM

Different ash behaviour in boiler and in ESP, different fouling in ESP etc.

Effects of Biomass (Wood) Co-Firing - NOx

- Reduction of pre-SCR NO_x emissions due to lower combustion temperature. This effect will decrease for newer LNBs.
- Higher catalyst deactivation rates => Shorter operating cycles between regeneration.
- Effect on possible no. of regenerations not known.
- Experiences: Mainly in DK and NL, in SE with biomass-only plants.

SO2 reduction techniques considered

Wet Flue Gas Desuphurisation with limestone (LSFO : limestone forced oxidation, and LSNO : limestone natural oxidation)

Wet Flue Gas Desuphurisation with lime?

Dry flue gas desulphurisation for small installation with lime

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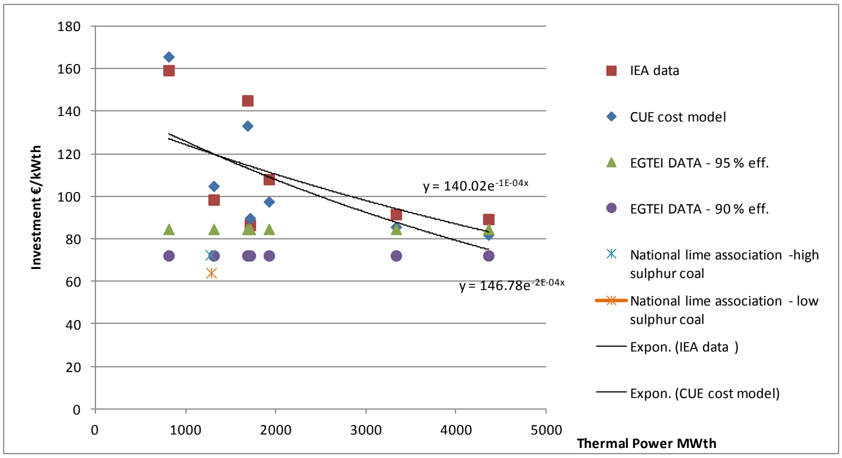
Investments for DeSOx - LSFO



Investments

Collect investments from real cases to cover the whole range of power – See the last slides and the list of parameters

Variable operating costs : limestone

Limestone demand current EGTEI data:

Efficiency of SO_2 removal η	t $CaCO_3$/t SO_2	Ratio Ca/S
85.0%	1.41	0.90
90.0%	1.48	0.95
95.0%	1.59	1.02

Purity of limestone less than 100 %, reactivity less than 100 %.

Efficiency of SO_2 removal η	t $CaCO_3$/t SO_2	Ratio Ca/S
85.0%	1.48	0.95
90.0%	1.56	1.00
95.0%	1.67	1.07

λ^s : specific limestone demand in ton $CaCO_3$/ton SO_2 removed to be checked by experts; Other data expected to derive the correct demand of $CaCO_3$ for different efficiencies of reduction

Variable operating costs : lime

Lime demand :

λ^s : specific lime demand in ton CaO/ton SO_2 removed to be provided ; Other data expected to derive the correct demand of CaO for different efficiencies of reduction

Variable operating costs : reagent prices

Limestone prices : between 30 to 40 € / t in France. Other data?

Lime prices : ?

Variable operating costs : water consumption

Limestone slurry:

Solid concentration from 15 – 20 % ? 30 % ?

Validate the concentration to be taken into account in case of LSFO and LSNO

Lime slurry:

Solid concentration ?

Validate the concentration to be taken into account in case of LSFO and LSNO

Water losses and purges to be compensated : 10 % of water demand

To be validated

Variable operating costs : byproducts

With LSNO

$I^{bp} = I^{s}$ x 136/100 in case of byproduct ($CaSO_3$) produced

With LSFO:

$I^{bp} = I^{s}$ x 151/100 in case of gypsum produced

Prices of waste disposal ? €/t

Prices of gypsum sold ? €/t ? Depend on the quality?

Variable operating costs : electricity consumption

Electricity demand to overcome the pressure drop and auxiliairy equipemeent such as mist eliminator…

Data from the literature :

Coal with 1.3% S, efficiency 98% : 5.46 MW for equipment for an installation of 500 We or 1.1% of the net electricity production

LSFO : coal 1% S : 1.1 % of gross electrical output

coal 2.25 % S : 1.5 %

LSNO : coal 2.25 % S : 1.0 % of gross electrical output

LSFO 90 % efficiency :10 to 12 MW for a unit of 600 MWe

Obtain data to derive a function according to the sulphur content of coal or liquid fuel and the efficiency of desulphurisation required (LSFO and LSNO). Differences between LSFO and LSNO to be taken into account.

Variable operating costs : wages

Wages

Data from the literature :

12 operators (40 hours/week) for an existing 500 MWe and 8 for a new,

10 operators for a 600 MWe

λ^{wage} : specific demand in human resource for control of the FGD and its operation as well as maintenance operation in number of operators.
Function according to the size to be determined from examples provided by experts for LSFO and LSNO.
Is the factor constant according to the size?

Fixed operating costs

Fixed operating costs depend on the capacity or size of the installation, i.e. on the investment and are expressed as a percentage of the unit investment.

They include costs of maintenance and repair, insurance, administrative overhead, etc. Taxes are not included in order to be coherent with GAINS.

According to one reference , fixed operating costs are 2.5 % of investment for an existing plant and 3.3 % for a new installation.
EGTEI considered 4 % of the investment.

Percentage to be validated: 4 % of the investment or another factor. Is the factor lower for LSFO than for LSNO?

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DeNOx equipment

- Primary Measures:
  - Low NOx Burner (LNB) for all types of LCP
  - FGR possibly for gas furnaces
  - Water / Steam Injection for Gas Turbines
- Secondary Measures:
  - SCR for all types of LCP
  - SNCR (for certain cases only – which?)

Typical / Reported NO_x Emissions [Heinze 1999, Rentz 2002]

NO_x Emissions (mg/Nm³)	HC-PC	BC-PC	CFB-HC	CFB-BC
Baseload (w/o LNB)	800-1,300⁽¹⁾	500-800	< 200	< 200
LNB (pre-1999)	300-500	140-175	-	-
LNB+SCR	90-200	-	-	-

NO_x Emissions (mg/Nm³)	Oil-HSFO	CCGT-HEL	CCGT-Gas
„Primary Measures“	-	-	40-120
Water Injection	-	260	-
LNB+SCR	120-130	-	-

(1): Lower End of Range for Tangentially Fired Boiler, Upper End of Range for Wall Fired Boiler

Suggested Default Emission Levels

NOx Boiler Outlet Emissions in mg/Nm³ at corrected O_2-Level	Baseload	1°/LNB 1st Generation	1°/LNB 2nd Generation	1°/LNB 3rd Generation
Lignite	650	300	200	150
Hard Coal (Bit) – Tang.	800	500	400	300
Hard Coal (Bit) – Wall.	*1,100*	*700*	*550*	*400*
Heavy Fuel Oil	1,000			
GAS – GT		50	25	
GAS – Furnace				

Current SCR Benchmark for Coal Fired Power Plants [Heiting 2011]

- NO_x conversion: 90%
- Minimum NO_x outlet concentration at plants with new generation LNBs: 35-40 mg/Nm^3
- NH_3 slip < 1 ppmv
- Catalyst regeneration each 1-3 years (low end for biomass co-firing)
- SCR setup in general 3 catalyst layers, sometimes up to 5 layer

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NO_x Emissions at SCR Outlet:

- NO_x emissions at existing HC-fired PC-plants:

  1st and 2nd generation LNB + (3+1) SCR:

  130-180 mg/Nm^3

- ELVs of Dutch installations of 2005 and later[1]:

  CCGT: 20 mg/Nm^3 (15% O_2)
  Gas Furnace: 25 mg/Nm^3 (3% O_2)
  Coal/Biomass: 50-65 mg/Nm^3 (6% O_2)

(1) Data on NL permits provided by Infomil

Next Steps for NO$_x$ (I)

- Validation / Comments on presented data to fill out the following table:

	HC-PC	HC-CFB	BC-PC	BC-CFB	Oil - B	GAS – B	GAS - CCGT
Baseline							
1st Gen. PM							
2nd Gen. PM							
3rd Gen. PM							
SCR	**Only, if calculating with an average / individual abatement efficiency is not suitable**						
(SNCR)							

Next Steps for NO$_x$ (II)

Suggestion for SCR default values (derived from HC cases):

- average abatement efficiency (3+1 layer): 85%
- average NH_3 consumption: 0.3 t NH_3/t NO$_x$ abated
  (SR: 0.85)
- Power consumption: 0.3% of gross electrical output
- Total catalyst lifetime: 75,000 hrs
- Catalyst regeneration: every 15,000 hrs (fossil fuel-only)
- Specific amount of catalyst needed: 0.32 m^3/MW_{th}

Next Steps for NOx (III)

- Agree on SCR catalyst data (lifetime, spec. catalyst volume, regeneration cycles, etc.)
- Decide, whether to include SNCR/FGR or not
- Decide, how to proceed with different size classes (do technical numbers change?)
- Decide on how to modify catalyst lifetime when co-firing biomass (which numbers, e. g. 1/3 of fossil-fuel only?)

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PM reduction techniques

	10 mg/Nm3	**20 mg/Nm3**	**30 mg/Nm3**	**50 mg/Nm3**
FF	y	y	y	y
2 fields ESP	n	n	With FGD?	With FGD?
3 fields ESP	n	With FGD?	y	y
4 fields ESP	?	y	y	y
6 fields ESP	y	y	y	y

From Simon Schulte – determination of costs for activities of annexes IV, V and VII for boilers and process heaters

PM reduction techniques

- Provide information on wage demand for FF and ESP

- Provide information on electricity consumption :
  - Pressure drop for ESP and FF
  - Power needed for electrodes and pulse jet cleaning

	FF		**ESP**	
	Pressure drop mbar	Power for pulse jet cleaning	Pressure drop mbar	Power for electrodes
5 mg/Nm3	10 to 12	1360 kW for a 800 MWe burning coal	3 to 4	1060 kW for a 800 MWe burning coal
10 mg/Nm3	?	?	?	?
20 mg/Nm3	?	?	?	?

PM reduction techniques

- Bag lifetime : 20000 to 30000 hours ?
- What is done with dust recovered (waste disposal, recovery) ?
- Prices of waste disposal or dust sold?

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Collection of investments

Questionnaire

List of parameters to be collected to characterise the installation for which investments will be provided:

◈ Age of the installation, thermal capacity MWth,

◈ Short description of the installation (number of boilers linked to the FGD, type of boiler) – new or existing installation when the reduction technique was installed?

◈ Fuels used : type, low calorific value, % S, ash content (HC1 to 3; BC; HF, NG, wood),

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Collection of investments

List of parameters to be collected to characterise the installation for which investments will be provided:

For each process considered : LSFO, LSNO, SCR, SNCR, ESP, FF, LNB, other techniques if necessary

❖ information on the reduction technique,

❖ Inlet concentration of SO2, NOx or PM to be abated (according to the technique),

❖ Outlet average SO2, NOx or PM concentrations obtained (according to the technique) - Efficiency

❖ Year of the investment, investment for each technique

❖ Components of the costs included in the investments provided (detail the components taken into account for comparison reason)

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- ◈ Other issues