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Process Integration as a Decision-making Tool for Cost-effective Greenhouse Gas Reduction in Industry

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Abstract
The combustion of fuel for heat and/or power production is in most cases the largest contributor of greenhouse gas emissions from a process industry. Efforts to reduce the greenhouse gas emissions shall therefore preferably be concentrated on the industry's energy system. A method based on process integration for calculating costs and greenhouse gas emissions for different CO_2 reduction retrofitting measures in an industry has been developed in earlier work, and further developed in the present project. This paper discusses how the method can be used as a support tool for decision-making concerning retrofitting of a plant's energy system. Graphs of CO_2 emission reduction as a function of the cost-effectiveness of different options and of the total costs as a function of CO_2 tax are useful tools for decision-makers. Application of the method and tools to an example taken from the process industry shows potential for substantial cost-effective reduction of CO_2 emissions. The example also suggests that the Swedish CO_2 taxation system is not effective as a tool for directing industry towards sustainable biofuel usage as the primary source of process heat.

1. Introduction
Improvements in the energy system and fuel switching are the only economically feasible retrofit techniques for reducing the CO_2 emissions from a process industry. In the future, more effort must concentrate on new processes that are more energy efficient. With process integration methods and tools, attractive retrofit measures for energy cost savings in process industries can be identified [1, 2]. In an existing

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industrial energy system such savings can be accomplished through, in principle, four types of retrofit measures:

- Reduction of hot and cold utility by improved heat exchanging;
- Efficient heating by integration of combined heat and power (CHP) plants;
- Heat recovery by integration of a heat pump;
- Process modifications.

To reach a given emission target at the lowest possible cost would normally demand a combination of these measures. Each measure is dependent on the others, and the links between them are complex. A method accounting for the complex interplay between different measures has been developed in previous work in our department [3, 4]. The method calculates lowest total cost and associated emissions for different mixes of measures (improved heat exchanging, integration of CHP, integration of HP, and fuel switching). Process modifications are not considered; however the proposed methodology can easily be extended to include this measure as well. When all possible mixes of measures have been considered, it is possible to identify the optimal economic solution for different levels of greenhouse gas emissions reduction.
Results from the method can then be used as input for decision-making support tools concerning cost-effective ways to reach emission targets. The discussion is also focused on how to handle uncertainties in future CO_2 taxation so that a "least regrets" decision can be made. The developed decision-making tools are illustrated with an example taken from the chemical industry.

2. Aim

In order to be acceptable to industry, it is important that the reduction of greenhouse gas emissions be undertaken in the most cost-effective way available. For such cost-effective measures to be identified, support tools must be developed. The aim of this work is to propose decision-making tools concerning cost-effectiveness and robustness of retrofit measures for decreasing CO_2 emissions in industry. The proposed method and tools are applied to an example from the process industry, and the results are discussed.

3. Method

The retrofit measures considered for reducing CO_2 emissions include enhanced heat exchanging, integration of CHP, integration of heat pumping, and fuel switching. As discussed earlier, process modifications are not considered in this work. The procedure for finding the cost-optimal combination of these measures is outlined below. For a complete discussion of the methodology, the reader is referred to previous work by Axelsson [3, 4].

1. First consider increased heat exchanging within the plant by retrofitting of the heat exchanger network, and find the cost-optimal solution at various energy-saving levels. This gives the capital cost and increased operating cost due to any degree of heat recovery. The calculations are performed with a process integration tool (Matrix method) specially developed for plant retrofit analysis [5].
2. Investigate opportunities for CHP at various degrees of enhanced heat recovery. This is performed using novel composite curves developed for retrofit situations [6]. Start with the current system, i.e. without enhanced heat recovery. Repeat at various degrees of heat recovery. This gives efficiency and installation costs of the CHP plant as a function of the degree of heat recovery by heat exchanging.
3. Judge the opportunities for heat pumping at various degrees of enhanced heat recovery. A computational tool for identifying cost-effective opportunities for heat pump integration in industrial energy systems has been developed in previous work at our department by Wallin [7]. Start with the current system (no enhanced heat recovery). Repeat at various degrees of enhanced heat recovery. This gives heat recovery, COP and installation cost of the heat pump as functions of the degree of heat recovery by heat exchanging.
4. Calculate the total efficiency that a CHP plant can attain if a heat pump is also integrated. Repeat at various degrees of heat recovery by heat exchanging. This gives efficiency and capital cost of the CHP plant when it is combined with integration of a heat pump, as functions of the degree of heat recovery by enhanced heat exchanging.
5. Calculate the emissions and annual heating costs for current (boiler) and new heating facilities (boiler + HP, CHP, CHP + HP) at varying levels of heat recovery by enhanced heat exchanging. Repeat the calculations with different fuels in the boiler and CHP plant.
6. Identify the optimal solution, i.e. the mixture of measures that gives the lowest annual heating cost.
7. Identify the mixture of measures that has the lowest extra cost at different emission reduction levels, compared to the optimal solution.
8. Perform sensitivity analysis. Previous work by Axelsson [4] has shown that two important parameters that greatly affect the results are the electricity-to-fuel price ratio and the reference emissions from the national electricity grid. The above procedure should therefore be repeated to assess the sensitivity of the results to the values of these parameters.

4. Application of the methodology

The methodology described above is now applied to an example from the process industry, namely a urea plant. The plant's energy system is described in detail

in [8]. The process consists of 12 process streams that must be cooled, and 7 process streams that must be heated. In its original configuration, the plant is moderately integrated, with around 5 MW transferred in the existing heat exchangers. The present hot and cold utility consumptions are 26 MW and 47 MW, respectively. With maximum possible process integration the utility loads can be reduced by 8 MW. The utility system is assumed to consist of a heat-only boiler fuelled with heavy oil. This is a deliberate choice, since such a starting system (base case) is not biased in favour of one of the proposed CO_2 reduction measures. Furthermore, many small and intermediate process industries in Sweden current meet their heat demand by fuelling oil in a boiler. For the urea plant considered, the greenhouse gas emissions from the plant's existing energy system are just over 70,000 tons CO_2 equivalent emissions per year. The heating cost is about $US 5.2 million per year. The example is calculated for Swedish conditions where carbon dioxide tax is paid only for heat production (i.e. for CHP applications, the carbon tax is only levied on that fraction of the fuel that is used to produce heat, whereas the fraction used to produce electricity is not taxed).

Previous work by Axelsson [4] has shown that the influence of the greenhouse gas emissions from the reference electricity system have a great impact on the reduction potential for measures that produce or use electricity. In this example it is assumed that electricity to be replaced (or used in a heat pump) is produced in a natural gas fired combined cycle (NGCC). Coal fired steam condensing plants are the marginal technique today in the Nordic electricity system, but those plants will probably be phased out in 5-10 years. Thus, to avoid crediting industrial CHP plants with a too optimistic emission reduction potential, calculations are made with the next supposed marginal technique, which is NGCC.

The greenhouse gas reduction measures considered in this study include the following:

- Enhanced heat recovery by heat exchanging
- Switching from oil to a fuel with lower greenhouse gas emissions. The fuels considered are natural gas and biofuels
- Integration of an industrial heat pump
- Integration of CHP. For each fuel, we consider the most efficient available CHP technology. Thus, for natural gas, we consider gas turbine CHP systems, whereas for biofuel we consider backpressure steam turbine CHP systems. In the future, biomass gasification will enable biofuels to be used in gas turbine based industrial CHP systems. However, this technology is currently in the demonstration phase, and is therefore not considered in this study.

4.1 Improved heat exchanging

The first step in the method is to calculate CO_2 emissions and annual heating cost for different levels of heat recovery by heat exchanging. In Fig. 1 the relation between emissions and annualised total heating costs (i.e. annualised investment costs for retrofitting are included) is shown. Each point on the curve means a certain level of heat exchanging. With maximum heat recovery, a conventional pinch analysis shows that the heat load can be reduced to 18.3 MW. The figure shows that it is however not cost-effective to reduce the heat load below the optimum value, equal to 4030 k$/year in this case.

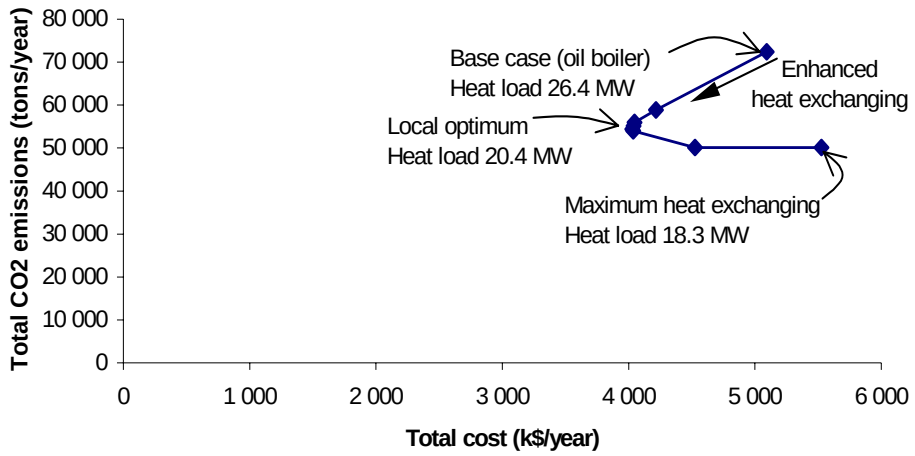

Figure 1. Total cost and CO_2 emissions at different levels of enhanced heat recovery by heat exchanging. Each point on the curve corresponds to an energy saving level.

4.2 Mix of measures

In Fig. 2 CO_2 emissions and annual heating costs are shown for all considered measures, namely enhanced heat exchanging in combination with one or more other measures. Each point on a curve corresponds to a level of energy saving due to heat exchanging. For example, the curve "Boiler biofuel + HP" refers to improved heat exchanging, switching to a biofuel boiler and integration of a heat pump into the process. The oil boiler curve is the same as shown in Fig. 1. Fig. 2 allows the global economic optimum point to be identified. In this example the lowest annual heating cost is achieved if the original oil boiler is retained, about 6 MW is saved by heat exchanging and an industrial heat pump is integrated to the process. Note that by choosing the economic best solution the emissions are reduced to 65 % of the emissions in the base case. The only way to modify the energy system if substantial CO_2 emission reduction is to be achieved is to retire the oil boiler and invest in biofuel based techniques (boiler or CHP). More than

100 % reduction is possible with the bio fuelled CHP in this example. This is due to the electricity output from such device. The “clean” electricity replaces “dirty” electricity produced by a NGCC in the reference energy system.

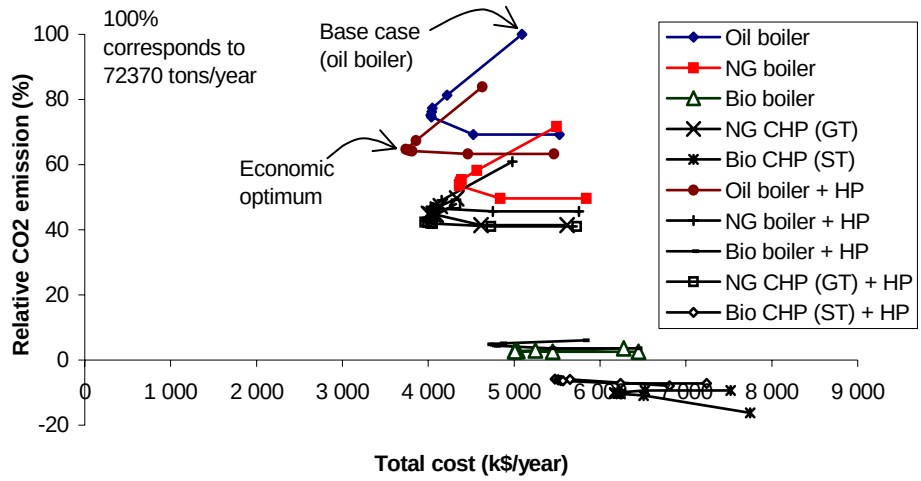

Figure 2. Total cost and CO_2 emissions for different heating techniques and fuels at various levels of heat recovery by heat exchanging.

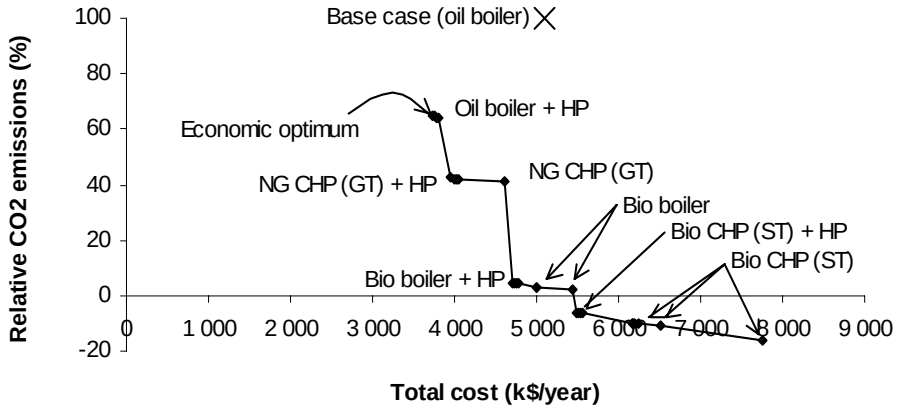

Figure 3. The minimum cost curve. Lowest extra cost to obtain a further reduction of CO_2 emissions compared to the economic optimal solution.

4.3 The minimum cost curve

The minimum cost curve, as shown in Fig. 3, consists of all the optimal points for each of the options considered from Fig. 2. For both Fig. 2 and Fig. 3 the same

axes are used. In Fig. 3 the starting system (base case) is marked with a cross. The minimum cost curve describes the lowest extra cost (compared to the economical optimal solution) to obtain a further reduction of CO_2 emissions. It can for example be seen that going from the optimum point (65 % on the y-axis) down to 95 % reduction (5 % on the y-axis) would infer an extra cost of about 900 k$/year. The corresponding mix of measures would be: biofuel boiler, enhanced internal heat exchanging and integration of an industrial heat pump.

5. Support tools for decision-making – presentation and discussion

Two graphic support tools for decision-making have been developed in this project. The first tool enables the cost-effectiveness of various CO_2 reduction measures to be compared. The second tool examines the sensitivity of the various measures to changes in CO_2 taxation. The motivation to develop such tools stems from the current will to add *external* costs to fuel costs, thus including the costs of e.g. environmental effects of fuel usage in the costs borne by the end-user. CO_2 taxation and trading of CO_2 emission permits are two examples of ways in which this may be accomplished with respect to external effects related to the greenhouse effect, which is the focus of this paper. This paper focuses on CO_2 taxes, as currently implemented in Sweden. The level of such taxation is subject to revision, as the country must meet increasingly stringent CO_2 emissions targets. To know the cost-effectiveness of CO_2 reduction measures is therefore essential for players in energy-intensive process industries. Of equal importance is the sensitivity of a given mix of CO_2 emission reduction measures to future changes in CO_2 tax levels, particularly given the long lifetime of the equipment involved.

5.1 Cost-effectiveness of CO_2 reduction measures

The slope of the minimum cost curve (Fig. 3) gives an indication of the cost-effectiveness, defined as the extra cost per unit reduction of CO_2 emissions. As a result of this definition, the reference point must be chosen with care. This is illustrated in Figs. 4 and 5, where the cost-effectiveness is plotted against relative CO_2 emissions. For the results in Fig. 4 the original boiler system (base case) is used as the reference point. The economic optimum mix of measures (see Fig. 3), reduces the emissions by 35 % with a cost-effectiveness of –53 US$/ton saved CO_2-emissions. It can also be seen that more ambitious CO_2-reduction targets will not be more cost-effective.

It is also important to calculate the cost-effectiveness of further CO_2 emission reductions compared to the economic optimal solution since this indicates the economic value of different mixes of measures with respect to CO_2 emission reduction goals. The results for cost-effectiveness calculated in this manner are shown in Fig. 5.

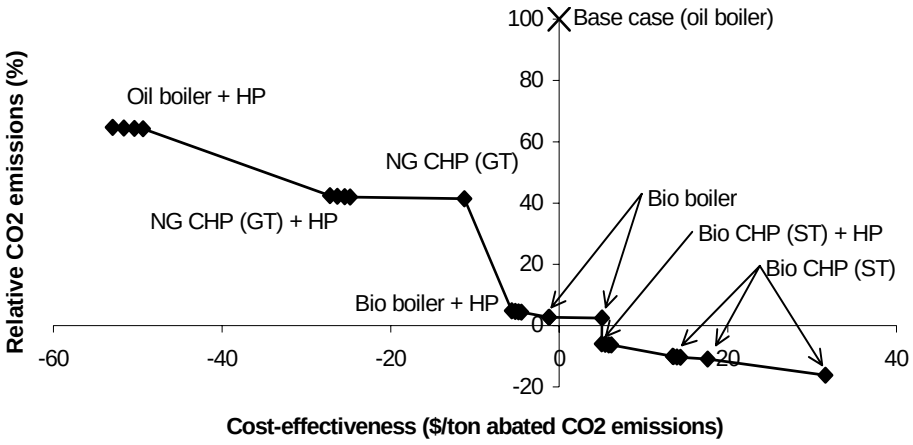

Figure 4. Cost-effectiveness of CO_2 emission reduction compared to the base case.

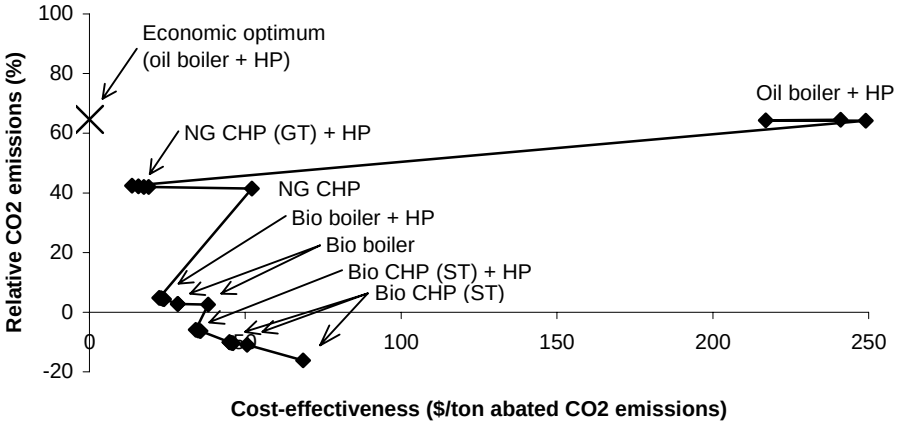

Figure 5. Cost-effectiveness of CO_2 emission reduction compared to the economic optimum mix of measures.

The figure (Fig 5.) shows that to go from the economic optimum (65 % emissions compared to the starting system) to measures that reduce the emissions to 43 % of the starting system (heat exchanging, integration of a gas turbine and integration of a heat pump) will cause an extra cost of approximately 13 US$/ton abated CO_2 emissions. A 95 % emission reduction would just cost a little more, 20 US$/ton saved CO2 emissions. The corresponding mix of measures is however biofuel based, and thus much less sensitive to future increases in CO_2 taxes. Investment in

such a system thereby constitutes a form of "insurance" against future CO_2 tax increases. In order to make such a decision it is clearly necessary to evaluate how sensitive the different retrofit measures considered are to future changes in CO_2 tax levels. This question is addressed in the following section.

5.2 Sensitivity to changes in CO_2 tax levels

As discussed above, it is of interest to evaluate how sensitive different mixes of measures under consideration are to changes in CO_2 tax levels. Fig. 6 shows total annual heating cost versus CO_2 tax levels for different mixes of measures. Remember that CO_2 tax is paid only for heat production and not for electricity generation. Changes in CO_2 tax have no effect on biofuel-based systems since these techniques are assumed to have zero net-emissions. The lines shown correspond to the local optimum for five different mixes of measures, except for the starting system (base case) that has no enhanced heat exchanging. The cheapest solution (economic optimum) for different taxation levels is the one furthest down in the figure. With today's taxation the economic optimum mix of measures is (as also seen in Fig. 2) to retain the oil boiler, enhance heat exchanging by 6 MW, and integrate a heat pump. It is remarkable to observe that the same set of measures would also have been the economic optimal solution if no CO_2 tax had to be paid. It is equally remarkable that the same set of measures is still economically most attractive when the CO_2 tax is doubled! Mixes involving biofuels become attractive beyond this point. From this discussion, a decision-maker would conclude that the optimal mix of measures identified for current CO_2 taxation levels is relatively robust to changes in the CO_2 tax level, and is probably a good investment.

Fig. 7 helps to understand the environmental consequences of the discussion above. The CO_2 emissions are plotted versus CO_2 taxation levels. Two curves are shown, the base case (oil boiler) and the economic optimal solution. Assuming that decision-makers in industry make rational decisions, the CO_2 tax will not lead to any CO_2 emission reduction at all in the case considered. Sweden has ambitious goals concerning the development of a sustainable energy system based on renewable biomass fuels. Biofuel based energy systems (heat-only and CHP) are expected to play a significant role in such a system, both in industry and in the district heating sector. The example considered in this paper suggests that high CO_2 taxes must be levied in industry if industry is to build up such an energy system on a "voluntary" basis. Alternatively, changes in the CO_2 taxation such as taxation of fuel for all purposes (heat and power) and/or implementation of emissions trading schemes may achieve the same effect by favouring the emergence of biofuel based CHP systems in industry.

This chapter is concentrated on the external parameter CO_2 tax. Note that the same analysis may be applicable for any external parameter (e.g. electricity price).

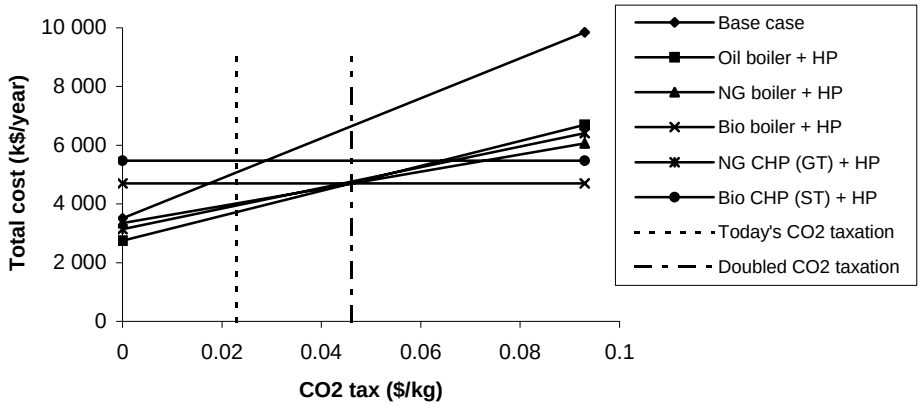

Figure 6. Cost-sensitivity to changes in CO_2 tax levels for different local optimum mix of measures (and for the base case).

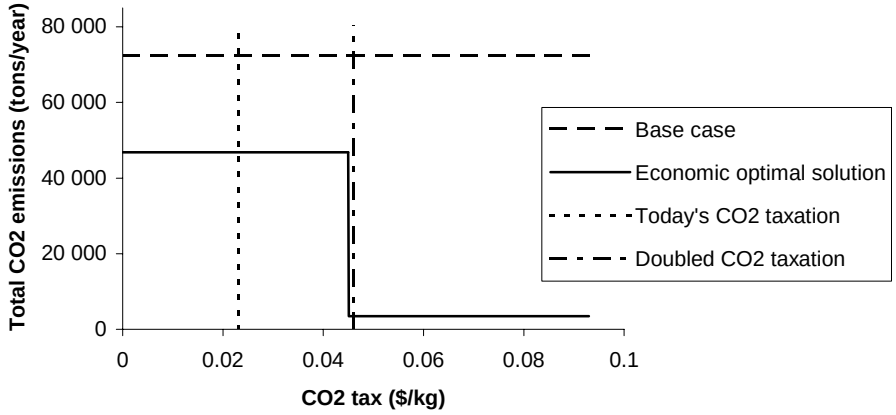

Figure 7. CO_2 emissions for the economic optimal mix of measures (and for the base case) as a result of changes in CO_2 tax levels.

6. Conclusions

In this study a systematic methodology for identifying attractive retrofit measures for reduction of CO_2 emissions in the process industries was described and applied to an example, namely a urea plant. Different mixes of measures were discussed, and the results evaluated in terms of cost-effectiveness of the proposed reductions measures, and the sensitivity of the proposed measures to changes in CO_2 taxation levels. Three important conclusions were drawn from the example:

- Substantial CO_2 reduction can be achieved in a cost-effective way. Almost the same cost-effectiveness is obtained for 95 % CO_2-reduction as for 60 %.
- The economic optimal solution (fossil fuel based) is robust with respect to changes in CO_2 tax levels.
- For the example considered, a major increase in CO_2 tax levels or a change in the tax structure is necessary in order to favour retrofitting the plant's energy system in an environmentally sustainable way.

7. Acknowledgements
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Appendix

Input data for the example where the heat demand in the starting system (base case) is supplied by a heat producing heavy oil fuelled boiler. The heat recovery is low in the base case.

General			
Operating time		8000 hours	
Annuity factor		0.2	
Carbon dioxide tax (only heat prod.)		23 $/ton CO2	
Electricity price		37.5 $/MWh	
Oil (heavy) price (excl. CO2 taxes)		13.5 $/MWh	
Natural gas price (excl. CO2 taxes)		14.0 $/MWh	
Biofuel price (excl. CO2 taxes)		13.8 $/MWh	
Capital costs:			
Heat exchanger (new)		40,000+400*Area(m2) $	
Heat exchanger (extended)		10,000+400*Area(m2) $	
Oil boiler		0.00 $	
Natural gas boiler		291,000*heat demand (MW)^0.86 $	
Biofuel boiler		721,000*heat demand (MW)^0.87 $	
Gas turbine (simple) fuelled with natural gas		1,290,000*elec. output (MW)^0.76 $	
High pressure biofuel boiler + steam turbine		1, 084,000*elec.output (MW)^0.90 $	
Heat pump (MVR)		1.0-1.3 M$. From Annex 21 programme	
Maintenance costs:			
Oil boiler		1.00 $/MWh fuel	
Natural gas boiler		0.63 $/MWh fuel	
Biofuel boiler		1.50 $/MWh fuel	
Gas turbine (simple) fuelled with natural gas		1.25 $/MWh fuel	
High pressure biofuel boiler + steam turbine		2.25 $/MWh fuel	
Heat pump (MVR)		11-30 k$/year. From Annex 21 programme	
Technical data:			
Oil boiler.	Heat efficiency	0.87	
Natural gas boiler.	Heat efficiency	0.90	
Biofuel boiler.	Heat efficiency	0.80*heat demand (MW)^0.018	
Gas turbine (simple)	Elec. efficiency	0.36	
	Exhaust gas temp	516 °C	
	Spec exh gas flow	1.14 kg/MJ fuel	
	Conversion losses	3%	
Biofuelled steam turbine	Admission state	70 bar, 480 °C	
Heat pump (MVR)	ΔTmin in evaporator	5°C	
	and condenser	5°C	
CO2-emissions from the reference electricity system:			
Natural gas fired combined cycle		380 kg/MWh el	
Net CO2-emissions from fuel combustion		*Combustion values*	*LCA-values*
Oil		282 kg/MWh	298 kg/MWh
Natural gas		202 kg/MWh	286 kg/MWh
Biofuel		0.00 kg/MWh	10.5 kg/MWh