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Applying European Emissions Trading and Renewable Energy Support Mechanisms in the Greek Electricity Sector – ETRES (LIFE03 ENV/GR/000219)

Report on Task 4: Impact of ET & alternative RE support mechanisms in the Greek electricity sector

Modelling the impact of emissions trading in Greek Electricity Sector

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The current report describes simulations of a climate change policy to the Kyoto horizon. In addition to the reference case (without explicit climate policy), four preliminary exercises involving permit trade were examined, in which it was assumed that:

- The permit price will be 10Euro00/tn of CO_2,

- a perfect permit market will be established and,

- the grandfathering principle (free permit allocation) will be adopted.

In contrast to the scenarios that have been already produced by ELMAS before (June 2004), in the above climate policy scenarios the wholesale spot electricity price is reported instead of the electricity price to the final consumer.

Simulating climate change policy to the Kyoto horizon

The emissions trading directive 2003/87/EC became European law on 25th October 2003. However its finalisation is experiencing considerable delays in two major fields: the role of "flexibility" instruments (JI, CDM) and the National Allocation Plans (NAPs).

Concerning the flexibility instruments major uncertainties persist on:

- Joint Implementation use with non-EU Annex B countries (possible constraints on this option and the utilisation of so called "hot air")
- The eventual scope of Clean Development Mechanisms namely any restrictions on its use as well as an appropriate "baseline" against which CDM credits will be measured.

Concerning NAPs the whole process of submission is running behind schedule and finalisation is not expected before mid 2005. Furthermore from submissions today it appears to be a clear tendency towards generous endowments for energy intensive sectors casting doubts on whether sufficient CO_2 constraints will result in order to enable the creation of the market (possibility that overall constraint for energy intensive sectors exceeds the emissions that result without any specific action being undertaken).

Given the above it was therefore decided at this stage of ETRES project to simulate a climate change policy using a given carbon value. In view of uncertainties still surrounding the implementation of the Kyoto policies, this method is currently practised in most analyses undertaken (for example CAFE, in which the permit price is around 12Euro/tn of CO_2 in 2010). For the purposes of ETRES project we have assumed a carbon value of 10Euro/tn of CO_2 in 2010. In addition, the preliminary permit trade exercise assumes that there are no transaction costs and there is free permit allocation according to grandfathering scheme.

For the assessment of the climate policy, four different cases were examined with different assumptions on capacity structure. All results are discussed for the year 2010:

- Reference scenario; no explicit climate policy (code: REF)
- 10 Euro00/tn of CO_2 permit price without changes in capacity structures (code: CV-10)
- 10 Euro00/tn of CO_2 permit price while cancelling planned investment of 330MW supercritical lignite (in Florina, Greece) and replacing it with an additional 400 MW GTCC (code: SPCR-G)
- 10 Euro00/tn of CO_2 permit price while cancelling planned investment of 330MW supercritical lignite and replacing it with 1400MW wind turbines (code: SPCR-W)
- 10 Euro00/tn of CO_2 permit price while cancelling planned investment of a 400MW Gas Turbine Combined Cycle (GTCC) and replacing it with 1400MW wind turbines (code: GTCC-W)

The first scenario (CV-10) examines the consequences of the climate policy in the case where planned additions to capacity remain unchanged.

The other three scenarios assume that the power production companies are aware of the presence of a climate policy and they modify their investments plans accordingly. In the context of the current set of exercises, the changes in the capacity structure were made exogenously and they are not PRIMES results. This has been assumed for two reasons: a) a PRIMES run for such a short horizon, in which investments have been already decided, may produce inappropriate results simulating capacity additions at variance with announced plans, and b) PRIMES may suggest the substitution of “fractional” instead of “whole” stations.

It is important in all cases where thermal power stations are substituted by wind turbines, to maintain the productive capacity comparable to that pertaining in the reference case, in order to avoid bias in the analysis. It has been calculated in the reference scenario that the productive capacity of 330MW supercritical lignite is equal to the productive capacity of a 400MW GTCC unit, and in turn, equal to 1400MW wind, assuming that the average availability of wind turbines remains unchanged in all cases of higher wind penetration (i.e. there is no saturation in the available wind sites).

Finally in all cases it was assumed that the support to the wind power is continuing as in the reference case and it is passed to the final consumer through the electricity spot price.

1. The reference scenario

The assumptions underlying the reference scenario as well as the demand projections have been already described in the 6 months report of task T4 and will not be reproduced in this section. However, since the climate policy scenarios are focusing in the wholesale market price instead of the price to the final consumer, a short report on the whole electricity spot prices and the electricity production structure will be presented in the next paragraphs.

1.1. Electricity production and electricity spot price in 2010

1.1.1. Electricity production

Table 1-1 shows that the large lignite-based producers play the role of the “price leaders” by utilising their plants around 62%. On the other the GTCC-based producers are the “price takers” and they are utilising their plants almost 74% of their capacity. As a result, the production from GTCC units is the 46% of the total domestic electricity production. The intermittent sources hydro and wind have utilisation rates around 16.1% and 26.3% respectively and wind turbines cover only 4.3% of total domestic production. Finally, imports are expected to cover about 4.7% of total electricity supply and the utilisation rate of the international transmission line will be nearly 50%.

	PRODUCTION		UTIL. RATE
	TWh	%	%
HYDRO	4.2	6.5	16.1
LIGNITE	27.6	42.7	61.7
GTCC	29.9	46.2	73.9
GAS OC	0.2	0.3	7.2
OIL	0.0	0.0	0.1
WIND	2.8	4.3	26.3
DOMESTIC PRODUCTION	64.7	100.0	49.1
IMPORTS	3.2	-	49.1
TOTAL PRODUCTION	**68.0**	-	-

Table 1-1: A general view of the electricity production in 2010 under the reference scenario.

1.1.2. Electricity spot price

The electricity spot price considered in the present analysis is the wholesale price and not the consumer price, which had been reported in the ELMAS exercises in June 2004. Similar to the electricity price to consumer, the wholesale market electricity price is considerably higher in summer than in winter, especially during peak hours, because of the importance of air-conditioning. The lowest prices are observed mainly in May and October, when little air-cooling or electric heating takes place.

Figure 1-1 presents the distribution of electricity spot price over the sample in 2010. The distribution is multi-modal with a mean value of about 60 Euro00/MWh and a standard deviation of 19 Euro/MWh. There are two main "hills" in the distribution. The first corresponds to base load spot prices and lies in the range between 35 and 60 Euro/MWh, while the second corresponds to peak load spot prices and lies in the range between 70 and 100 Euro/MWh. The rest of the values are either extreme base load and peak load values or spot prices that correspond to intermediate hours.

As shown in the cumulative distribution graph, 5% of the electricity prices are below 33.3Euro/MWh and another 5% above 83.05 Euro/MWh. In extreme high price cases, it is evident that the projected demand is higher than the available power generation capacity.

July has proved to be the month with the higher electricity spot prices. As Figure 1-2 shows, the probability that the electricity spot price in the peak hours in July (12-15 & 21-23 hours) will exceed the level of 100 Euro/MWh is nearly 10%.

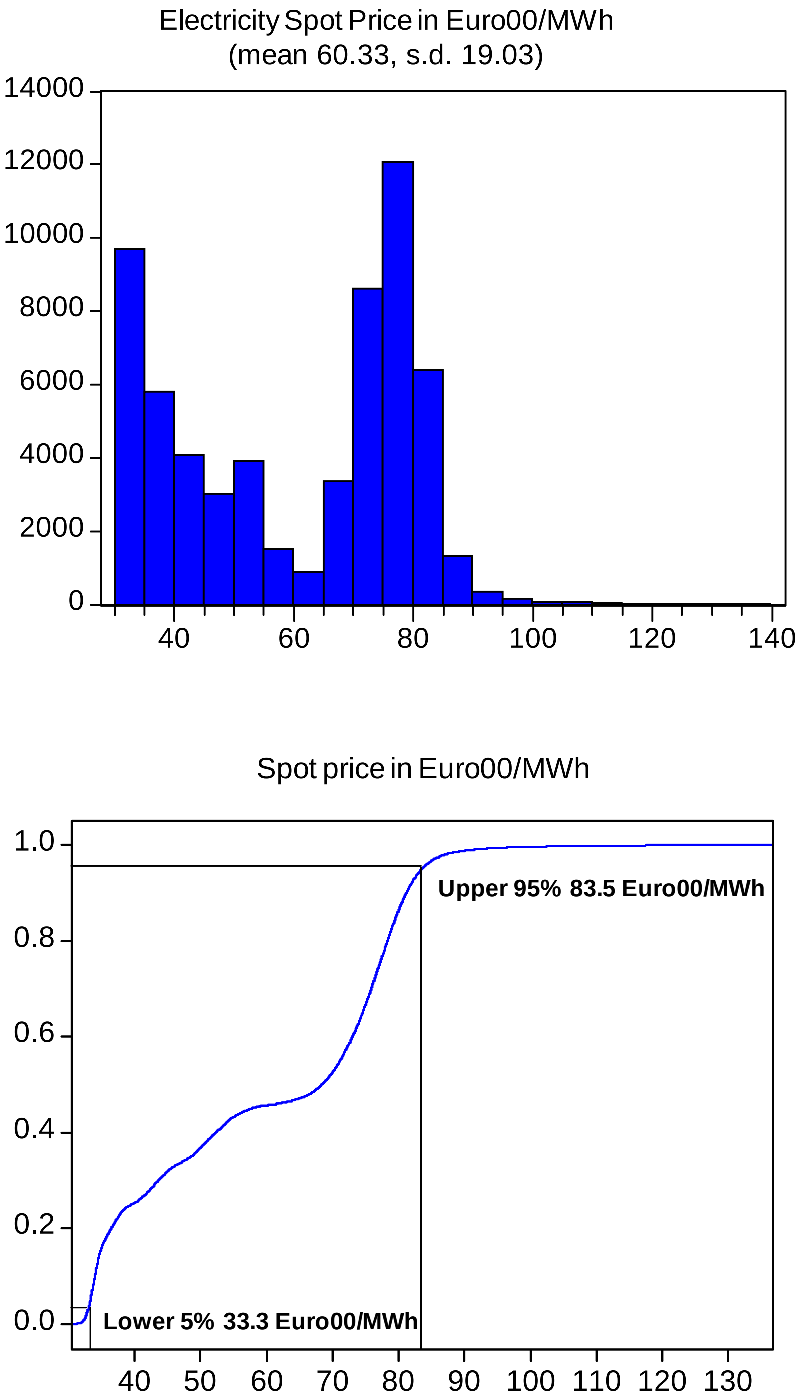

Figure 1-1: Electricity spot price distribution and cumulative distribution in 2010.

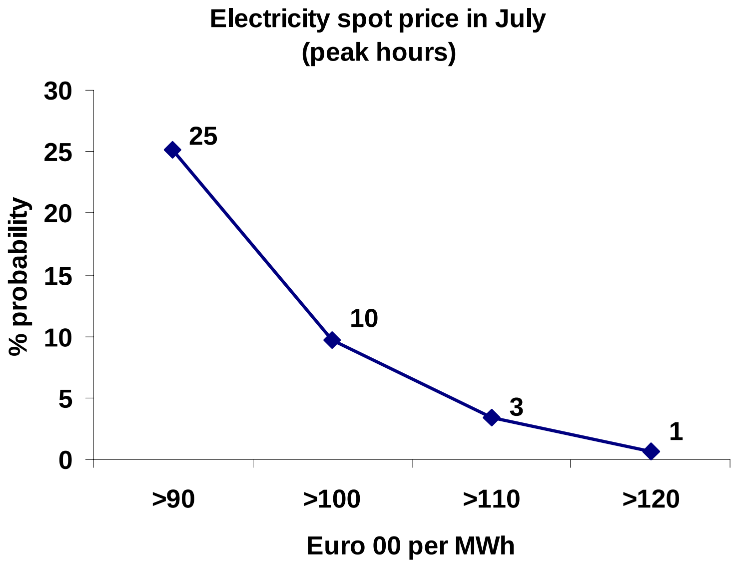

Figure 1-2: Probability that the electricity spot price will exceed a certain level in July peak hours.

Figure 1-3, presents the average spot price in each hour and the lower and upper 5% quantiles. The small price variation that is observed in base load is due both to lower seasonality in base load demand but also to easier supply conditions (smaller vulnerabilities to extreme events). On the other hand in peak hours the price variation is higher. This is due both to seasonal effects and to random situations that can occur.

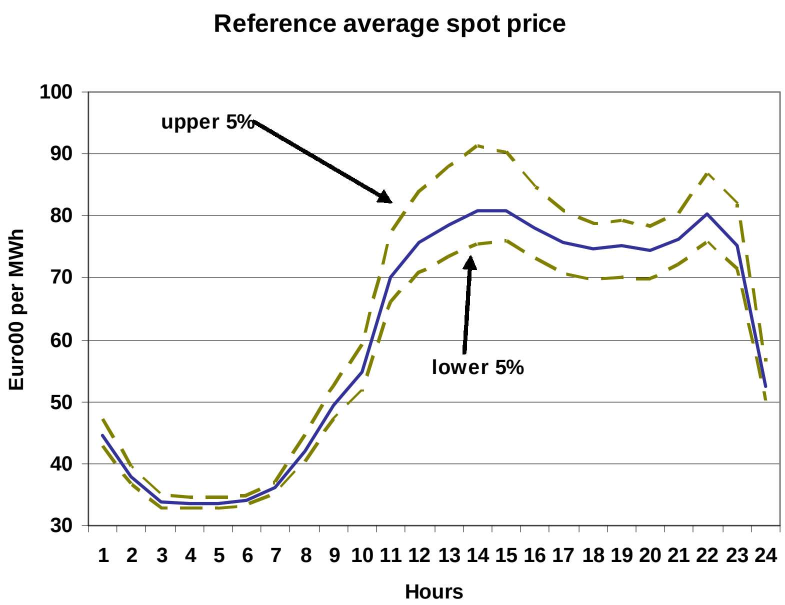

Figure 1-3: Average electricity spot price in 2010 by hour.

The following figures present the average electricity spot prices in typical days, which illustrate the seasonality effects. The figures also present the 5% lower and upper quantiles. The graphs clearly show that the price volatility in July is higher than in December, reflecting the increased demand in summer. In intermediate hours (19-21) spot prices in July tend to fall while they are maintained at high levels in December due to load considerations (lighting, electric heating).

On the other hand, the electricity spot price variation is small in a typical Sunday in May Sunday, reflecting the narrow variation of electricity demand.

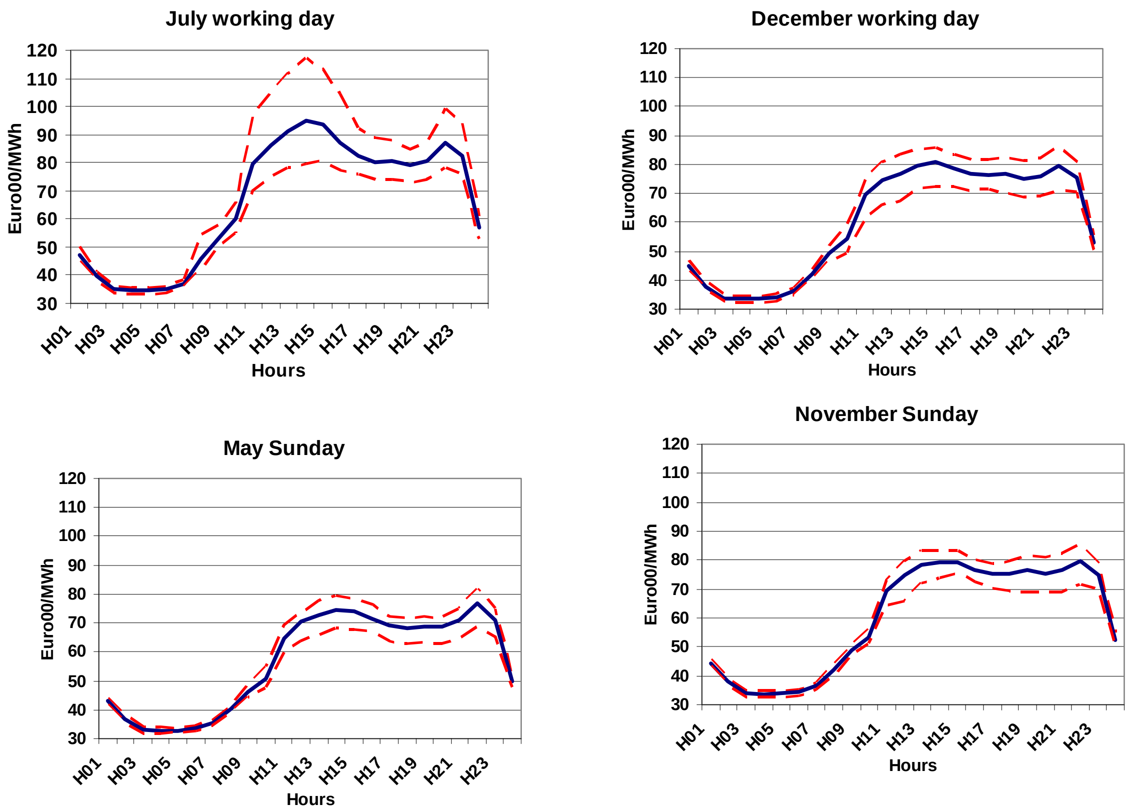

Figure 1-4: Average electricity spot price in typical days (2010).

2. Climate policy cases – comparison and conclusions

Table 2-1 presents a summary comparison of demand, imports, exports, electricity price and emissions between the four scenarios and the reference. A general view of the table shows that the electricity price increases 11-13% , because of the CO_2 permit price, which leads to a decrease in the final demand in the range of 2.9-3.6% (depending on the scenario). In all scenarios imports show an increase due to imports from countries which do not participate in the permit trade market (Greece's northern neighbours). Such an increase in imports could lead to carbon leakage to the extent that exporters' generation involves carbon emissions. Exports in all scenarios display a decrease; this decrease is mainly attributed to the reduced exports to Italy, which participates in the emissions permit trade market.

The table also shows that the largest emission reduction is achieved by substituting GTCC with wind turbines and not by substituting lignite with wind as it might be expected. This implies that the substitution of new lignite thermal plants leads to a situation in which the most cost-effective option for base load electricity production is the dispatching of older (and less efficient) lignite plants instead of the more expensive to run GTCC plants. The latter are used mainly in the medium load electricity production.

		Changes from REF			
		CV-10	SPCR-G	SPCR-W	GTCC-W
Final Demand	(%)	-2.9	-2.9	-3.4	-3.6
Imports	(GWh)	766	745	617	595
Exports	(GWh)	-171	-166	-124	-141
Mean Electricity price	(Euro/MWh)	6.6	6.4	7.1	7.9
CO2 emissions	(Mtn)	-4.9	-5.8	-5.7	-6.9

Table 2-1: Overview of the results

Figure 2-1 presents the decomposition of emissions reduction. In all scenarios the reduced electricity demand leads to a CO_2 abatement of around 2Mtn. Even in the case where no change in capacity structure is assumed, shifts in plant dispatching bring in another 3Mtn of CO_2 emission reduction.

By substituting the new lignite plant with wind turbines or GTCC, reduces the CO_2 emissions by 3.7 - 3.9Mtn, additionally to the 2Mtn due to the reduced demand. However, the most substantial CO_2 emissions reduction occurs in the case of substituting GTCC with wind turbines (around 4.8Mtn). This also implies that in the case of substituting new lignite plants, the most cost-effective option for base load electricity production is the dispatching of older (less efficient) lignite plants.

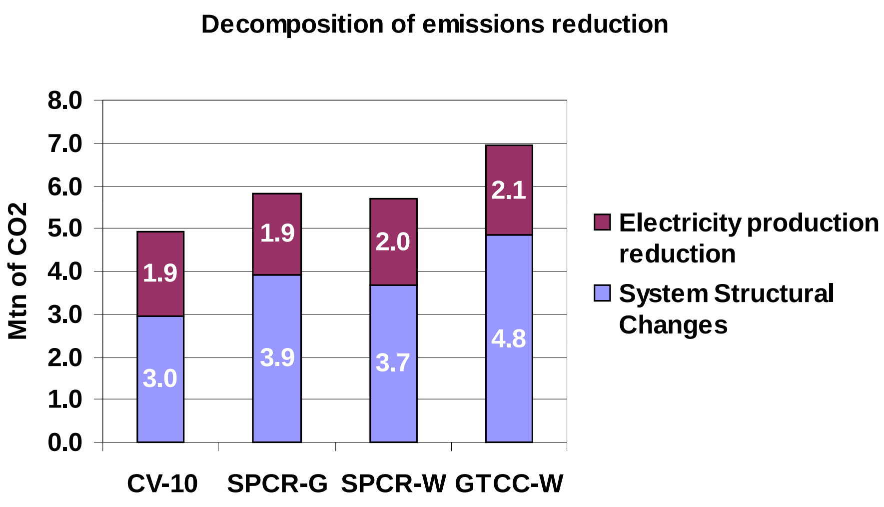

Figure 2-1: Decomposition of emissions reduction

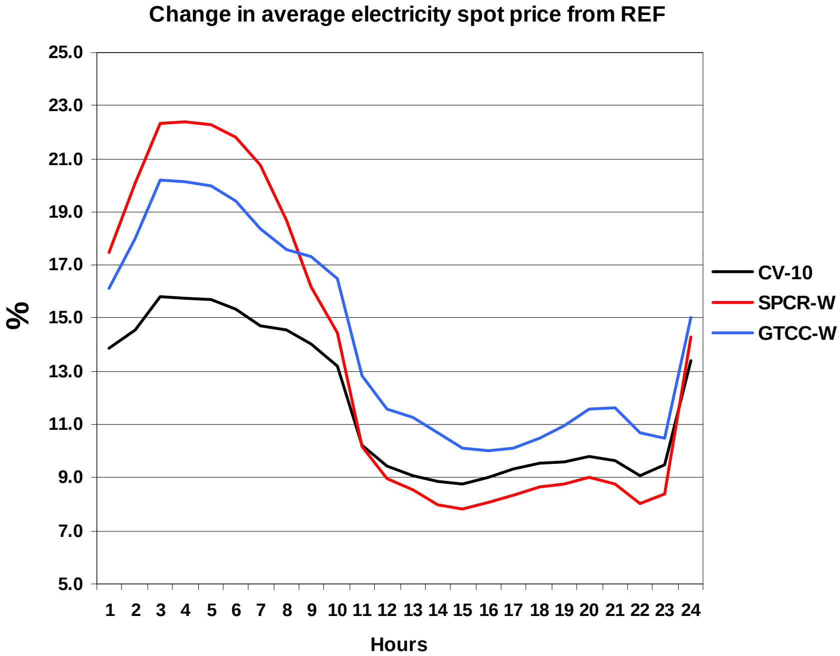

Figure 2-2: Comparison of the wholesale market electricity spot price.

A comparison in the electricity spot prices (Figure 2-2) shows a considerable increase in the base load price in all abatement scenarios. This is attributed to the significant role of lignite in base load electricity production, which is affected by the climate policy more than the other fuels used. Thus, the largest increase occurs in the case of supercritical lignite substitution, where more expensive options have to be considered (i.e. older lignite powered, GTCC) for base load production.

The substitution of thermal plants with wind turbines has beneficial effects on peak electricity prices; the increase in spot electricity price is less than in the case of no capacity changes. This is due to the higher availability of the wind power in the afternoon and early evening hours, when wind blows faster especially during the crucial summer months.

The wind variability tends to introduce additional variability in spot prices because of the increase reliance on wind power. When some of the highest demand loads occur, a combination of high dependence on wind capacity and atmospheric calm accentuates some of the most extreme spot price events. The opposite effect however is also possible (for example April afternoon hours).

Table 2-2 presents the probability that the spot electricity price will be lower or higher than certain thresholds in April and summer respectively.

	April (13h-18h)			Summer (11h-23h)	
	SPCR-G	GTCC-W		SPCR-G	GTCC-W
<70	3	9	>90	31	50
<75	26	31	>100	4	7

Table 2-2: Probability of exceeding certain thresholds in spot electricity price.

Figure 2-3 presents the average production cost and the abatement cost index (or cost effectiveness). As shown in the graphs, the substitution with wind turbines provides greater possibilities for emission reduction than the substitution with GTCC, but these reductions come at a higher cost. For marginal reductions the substitution of lignite plants with GTCC can be considered as a low-cost option.

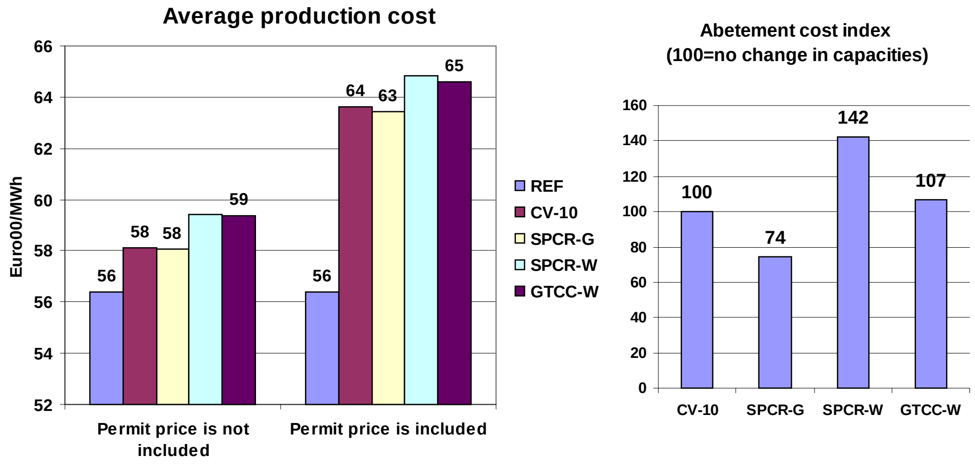

Figure 2-3: Change in system costs.