1 Analysis of the Efficiency of RES-E Support Measures in Greece

1.1 General

When excluding from the analysis the equipment manufactures and distributers, as well as the aspects of job creation and security of energy supply improvement, the major monetary flows within the Greek wholesale electricity market are identified in Figure 1.1.1 *The major monetary flows within the Greek wholesale electricity market*.

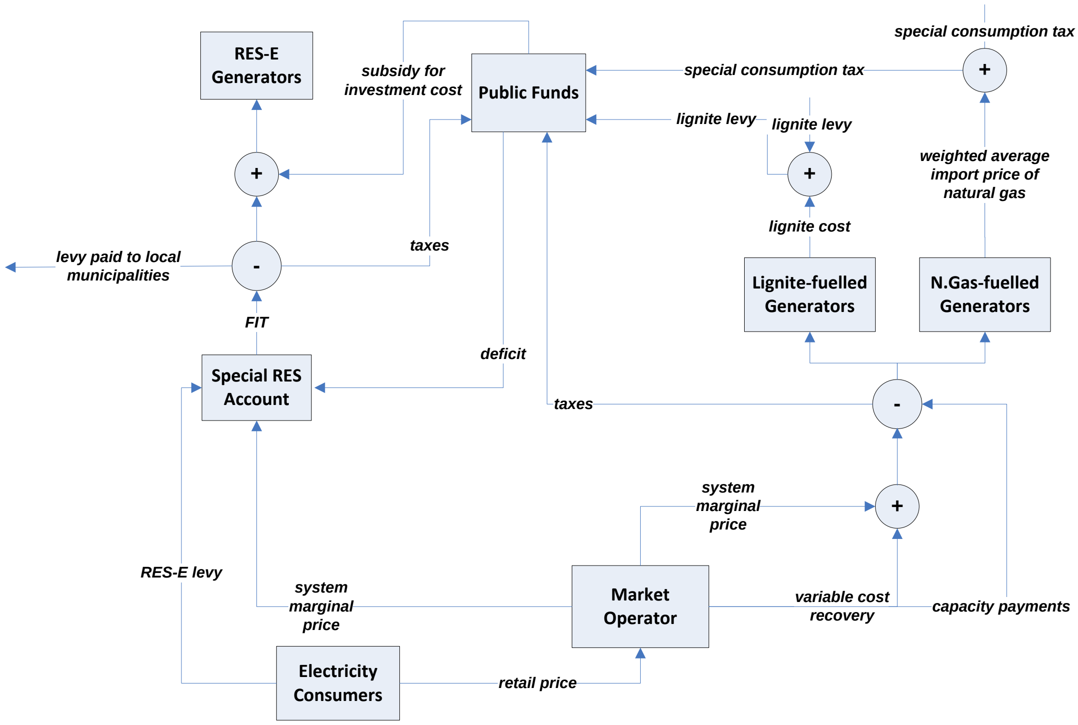

Figure 1.1.1 The major monetary flows within the Greek wholesale electricity market

The larger part of the compensation for power produced from non RES-E generators takes place at the System Marginal Price (SMP), which is the outcome of the Day-Ahead Scheduling (DAS) process. Offers made for day-ahead scheduling are firm, and if they are not fulfilled they expose the generator making the offer to a penalty payment for non-delivery in the form of the ex-post imbalance price. The Independent Power Transmission Operator[1] (ADMIE) determines an ex-post System Imbalances Marginal Price (SIMP) on an hourly basis by executing the ex-post imbalance pricing procedure after the dispatch day. This procedure is similar to the DAS procedure except that it uses the actual system demand, the actual availability of the units and the RES-E generation. The generators' deviations are divided into instructed and uninstructed. The instructed deviations are the real-time deviations of the actual production of a generating unit from the scheduled production by the DAS, due to a dispatch instruction by ADMIE. Positive instructed deviations are paid the relevant

[1] http://www.admie.gr/

SIMP, whereas positive uninstructed deviations are not paid. Negative instructed deviations are charged as bid, whereas negative uninstructed deviations are charged the relevant SIMP. Load deviations are settled at the SIMP.

Additionally, the Variable Cost Recovery Mechanism, in effect from 01/05/2008, provides additional payments so that a generation unit ends up with a profit equal to 10% of its variable cost, in case this profit is not reached through the market revenues for energy. The mechanism works in conjunction with the fact that non RES-E generators can offer up to 30% of their available capacity at prices lower than their variable cost, as long as the quantity-weighted average of their offer price is larger than or equal to their average variable cost.

The Greek Capacity Adequacy Mechanism provided capacity payments through which the non RES-E generation units are able to recover part of their fixed costs. Each producer issues for the next five Reliability Years, a number of Capacity Availability Tickets, each Ticket being valid for one Reliability Year. The total number of Tickets issued for each unit equals its net capacity. Every Reliability Year the ADMIE estimates the available capacity of each unit, based on its Demand Equivalent Forced Outage Rate (EFORd), and allocates it equivalently among the Tickets. Thus, every Ticket has an available capacity value equal to 1 - EFORd. Each producer can conclude a contract with ADMIE, receiving an amount equal to the available capacity of the Ticket multiplied by a non-compliance penalty value P^{NCP} for the hours that the unit is declared available in the day-ahead market. The non-compliance penalty value was equal to 35,000 €/MW-year until 31/10/2010 and to 45,000 €/MW-year from 1/11/2010 onwards.

An approximation for the payment received by a unit j is (Sakellaris, 2009):

$$P^{NCP} \cdot \left(1 - EFORd_j\right)^2$$

RES-E remuneration (through FITs) is paid to the RES producers through the Special RES Account which has been established by article 40 of Law 2773/1999 and is managed by the Greek Market Operator (LAGIE). The outflows of the Account are the RES-E FIT payments, whereas its main inflows are:

1) The amounts paid to the RES-E suppliers for each MWh fed in the system at the System Marginal Price (SMP).

2) The RES-E levy which covers the remaining needed amount and is paid directly by the final consumers. The RES-E levy is practically the difference of FITs minus the SMP or the difference between FITs and the average variable cost in the case of the islands[2]. Since FITs are generally higher than the SMP, LAGIE faces a deficit that must be paid by the electricity consumers through the RES-E levy. The annual deficit is equal to:

[2] A specificity of the Greek electricity system is the fact that 8.9% of its consumption takes place in the non-interconnected island electricity networks, which cover more than 90% of their demand through oil-fuelled units.

$$\sum_{t=1}^{n}\sum_{h=1}^{8760}(SMP_h - FIT_t) * RES_h^t$$

where:

SMP_h is the system marginal price during the hour h,

FIT_t is the feed-in tariff for the technology t,

RES_h^t is the RES-E production (MW) during hour h by technology t.

The deficit is covered through the RES-E levy, the level of which is determined by an administration act of the Greek Ministry of Development. The following table presents the evolution of the RES-E levy from 2002 to date.

RES-E levy (€/MWh)	Period in force
0.45	10/2002 – 12/2002
0.60	01/2003 – 10/2004
0.80	11/2004 – 09/2006
0.30	10/2006 – 05/2010
0.30 for residential customers 5.57 otherwise	06/2010 – 12/2010
1.04 for high voltage customers 0.74 for medium voltage agriculture customers 1.69 for others medium voltage 0.90 for low voltage agriculture customers 1.95 for low voltage residential customers 2.49 for others low voltage	01/2011 – 12/2011
2.96 for high voltage customers 2.29 for medium voltage agriculture customers 5.35 for others medium voltage 2.96 for low voltage agriculture customers 5.99 for low voltage residential customers 7.38 for others low voltage	01/2012 - 07/2012
4.58 for high voltage customers 4.35 for medium voltage agriculture customers 7.17 for others medium voltage 5.61 for low voltage agriculture customers 8.74 for low voltage residential customers 9.53 for others low voltage	08/2012 – 06/2013

Table 1.1.1 The evolution of the RES-E levy from 2002 to date

According to the current regulatory framework, all production from RES-E must be fed into the electricity grid. Conventional generation units (i.e. lignite, natural gas and large hydropower) cover the remaining (hereafter residual) load. As a result, RES-E generation can be regarded as a negative demand that affects the residual load's levels and profile. One way to understand the generation substitution by RES-E is to use the marginal cost concept, according to which generators are ordered in a production stack (the so-called merit order), ranging from lowest to highest marginal cost. The production stack is then the market level supply function and is used for determining the operating level (i.e. quantity of power produced) of each generator for any given level of demand. The higher the load the more to the right the intersection of the demand with the supply curve is shifted. In the following diagram, the supply curve of the Greek wholesale electricity market is depicted.

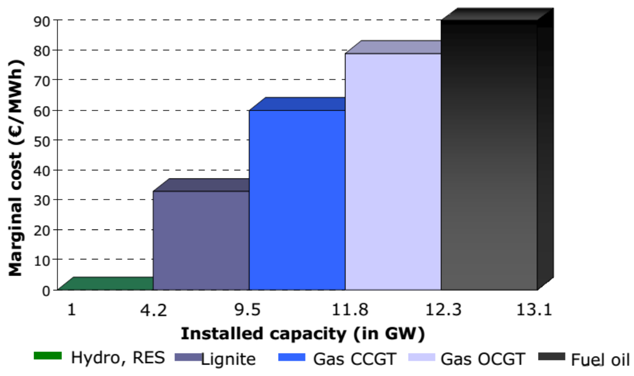

Figure 1.1.2 The supply curve of the Greek electricity market

The levy is calculated as the difference between FITs and the SMP; however, RES-E reduces the SMP via the merit order effect and lower prices lead to an increase of the required levy and, in practice, the RES Account deficit. This has caused the design of the RES-E levy mechanism to be brought into question. It also means that the RES Account deficit should not be a part of an efficiency analysis, since a) it merely reflects the question on who should pay for the FIT remuneration and b) it is not representative of the actual cost of the RES-E generation; the SMP may decrease or increase due to reasons that are not caused/affected by RES-E.

On the other hand, the displacement of conventional generation by RES-E is a real RES-E benefit, although a choice must be made on whether this benefit should be measured by the induced reduction in the SMP or in the fossil fuel usage. In order to avoid including transfer payments, the focus should be on whether or not there is consumption or savings of real resources with economic value (such as the fossil fuels), as well as on the net impact on public finances.

The annual emissions avoided due to the operation of a RES-E project may be estimated as:

$$\Delta E_t^p = G_t^{RES} \cdot \varepsilon_t^p$$

where:

G_t^{RES} is the energy production of the RES-E project (expressed in kWhe) during year t,

ε_t^p is the pollutant p emission coefficient of the displaced fossil-fuelled generation (expressed in kg of p per kWhe avoided) during year t.

In order, then, to calculate the emissions avoided, one must estimate the mix of the fossil-fuelled plants that were offset by the RES-E generation.

For the purposes of the current analysis, the major costs and benefits attributed to RES-E were chosen as follows:

- Costs

  The costs of RES-E will include the FIT support. Taxes are not considered in the analysis, as well as the levy paid by RES-E producers to the local municipalities, since it has only a distributional effect.

- Benefits

  Assuming that the reductions in the SMP, caused by the displacement of the fossil-fuelled plants by RES-E production, are counterbalanced by the variable cost recovery mechanism, a better proxy for the economic benefit from the displacement of the fossil-fuelled plants is the reduction in fuel use. Consequently, the avoided cost of natural gas imports and lignite use – before taxes – will be regarded as a benefit, as well as the avoided CO_2, NO_x and SO_2 emissions, due to RES-E offsetting fossil-fuelled power generation.

  IEA WIND R&D Task 25 on "Design and Operation of Power Systems with Large Amounts of Wind Power"[3] has collected and analysed a series of case studies that address different aspects of power system operation and design when integrating high volumes of RES-E: reserve requirements, balancing and generation efficiency, capacity credit of wind power, efficient use of existing transmission capacity and requirements for new network investments, bottlenecks, cross-border trade and system stability issues. For the current analysis, balancing costs due to the uncertainties in short-term forecasting of RES-E production will be excluded. Conversely, the reduction in capacity payments due to the capacity value of RES-E plants will be included in the benefits.

Such an analysis requires the following analytical steps:

1) Estimation of the fossil-fuelled power generation offset by RES-E, so that the avoided cost of natural gas imports and lignite, as well as the avoided emissions use can be quantified.

2) Estimation of the capacity value (or capacity credit) of RES-E, which is defined as the amount of conventional resources that could be replaced by RES-E production while maintaining the power system's designated level of reliability.

1.2 Fossil-fuelled generation offset by RES-E in the Greek electricity market

The quantity of electricity generated must be always equal to the quantity demanded plus total losses. Therefore, controlling for changes in the system load, an increase in RES-E generation must result in an equal decrease in non-RES-E generation.

[3] http://www.ieawind.org/task_25.html

Furthermore, the impact of a MWh_e of RES-E generation during an hour of high demand will differ from the impact during an hour of lower demand, since the generation avoided by an increase in RES-E generation varies with the marginal dispatchable generator. Based on the aforementioned, the estimation approach used in this section exploits the randomness and exogeneity of RES-E generation patterns to identify the average reduction in output for each generator in the Greek market due to RES-E.

A widely used econometric approach for modelling the interaction between the different variables that govern a power market is to implement cointegration analysis and vector error-correction modelling (VECM). The rationale behind the cointegration analysis is that if a relationship between two or more variables is proven to be stable over a sufficiently long time period, causal interactions between the variables can be inferred and, under the assumption that these interactions will stay in effect in the future, a scenario-based forecasting can take place. In most cases in literature, cointegration analysis is used for modelling the wholesale spot (i.e. day-ahead) electricity price as a function of its fundamental underlying drivers. The set of the fundamental parameters that drive the wholesale spot electricity prices includes:

- The demand for electricity consumption. The higher the load the more to the right the intersection of the demand with the supply curve is shifted; as the intersection of the load with the supply curve is shifted to the right, the marginal cost of serving the demand increases.

- The RES-E production. RES-E generation can be regarded as a negative demand that affects the residual load's levels and profile.

- The fuel prices since they define the variable costs of the generators. Coal prices are less influential that the natural gas ones, because: a) they are generally less volatile than natural gas and b) they primarily impact the lower, usually flatter part of the supply curve.

- The capacity available. The unavailability of pure base load technologies, such as lignite or nuclear, shifts the whole supply curve to the left. In terms of its effects on the spot electricity price, shifting the supply curve to the left is equivalent to keeping the curve as a reference and increasing the load by the same amount. On the other hand, the unavailability of technologies that serve peak load or both base and peak load, such as natural gas, is reflected mainly on the capacity margin of the market. The capacity margin is calculated as load – adjusted for base load unavailability – divided by total available capacity.

In a market where average load is constant, it is expected that a stable relationship between electricity and fuel prices can be discovered. Jong and Schneider (2009) study the Title Transfer Facility (TTF), the Zeebrugge and the National Balancing Point (NBP) natural gas spot markets in relation to the Amsterdam Power Exchange spot market, since these markets are strongly connected in terms of physical transportation. They develop a cointegrating multi-market model framework that shows the natural gas and electricity prices being cointegrated at long-term forward price levels. Bosco et al. (2010) examine the interdependencies existing in wholesale electricity prices in six major European countries. The results of their analysis reveal the presence of four highly integrated central European markets (France, Germany, the Netherlands and Austria). The trend shared by these four electricity markets appears to be common also to natural gas prices. Ferkingstad et al. (2010) also find that natural gas prices have strong instantaneous and lagged causal effects on electricity prices, while coal and oil prices are less important. Furió and Chuliá (2012) use a VECM to investigate the causal linkages between the Spanish electricity, Brent crude oil and Zeebrugge natural gas one month ahead forward prices. Their findings reveal that Brent crude oil and Zeebrugge natural gas forward prices play a prominent role in the Spanish electricity price formation process. Furthermore, causation, both in price and volatility, runs from Brent crude oil and natural gas forward markets to the Spanish electricity forward market.

In this section, cointegration analysis will be employed for the estimation of the fossil-fuelled generation offset by RES-E in the Greek electricity market. In order to model the relationships under study, one needs to decide on the explanatory variables that will be employed. This entails that a set of variables is identified such that:

1) The variables are exogenous in the sense that there is no reverse causation from the dependent variable to one or more of the explanatory ones.

2) No relevant variables are omitted, since in this case the model's error term will include the omitted factors needed to explain the variation of the dependent variable; this would lead to a correlation between the regressors and the error term and, thus, false results.

3) Unnecessary explanatory variables that will add noise to the estimation are excluded. Furthermore, the inclusion of multiple significantly correlated variables in the model will make the individual coefficients to be falsly and unstably[4] estimated.

Based on domain knowledge, the causal relationships one expects to be valid for the Greek electricity market are presented in Figure 1.2.1 *Causal relationships in the Greek electricity market*. The solid line arrows represent causation relationships that are practically certain, whereas the dashed ones represent relationships that are plausible to exist, but must be verified, if necessary. The term 'causal relationship' is not used for describing actual causation effects, but only as a way to indicate that:

> if Z_t includes a set of carefully chosen explanatory variables, we have a prediction of Y_{t+1} based on lagged values of Y_t and Z_t and we can improve the prediction by including the lagged values of W_t (i.e. W_t seems to contain certain unique information for predicting Y_{t+1}), then there is a (Garger) 'causal relationship' from W_t to Y_t ($W_t \rightarrow Y_t$).

[4] Coefficients may change erratically in response to small changes in the model or the data.

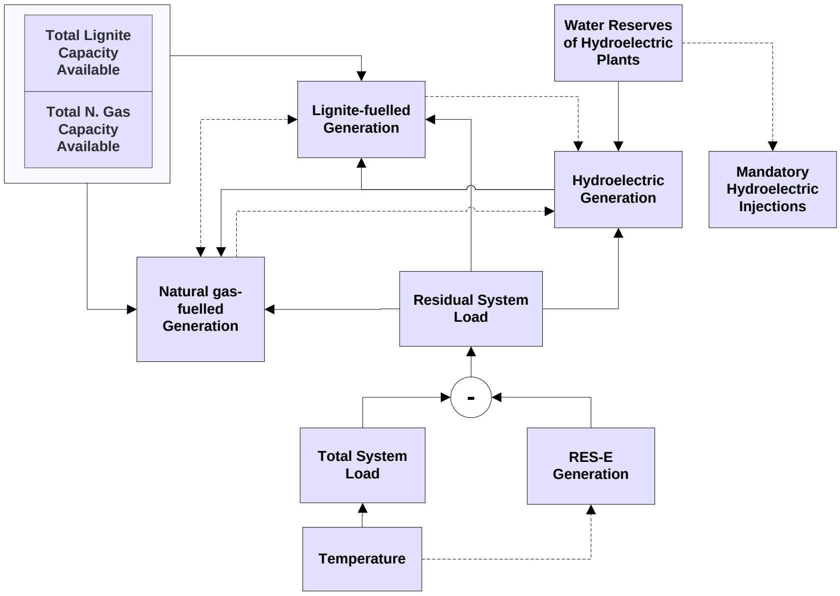

Figure 1.2.1 Causal relationships in the Greek electricity market

One should expect that the (Granger) causal flow between the quantities produced and the RES-E production, total load and total available capacity, has such a direction that the latter three variables can be considered as exogenous. Especially with regard to the load, Greek residential and commercial consumers do not respond directly to wholesale price signals, since they purchase electricity at fixed prices which change only after a number of years. Consequently, for periods where consumers face a constant price for electricity, changes in demand are driven by exogenous forces, that do not include the wholesale price or factors affecting it such as quantities of power production per fuel type. On the other hand, the causal relationship between the natural gas and the lignite-fuelled generation, as well as between them and the hydroelectric generation should be considered in more detail.

It is expected that the residual load (i.e. total load minus the RES-E generation) drives the quantities generated by the dispatchable generators of lignite, natural gas and large hydroelectric plants. Furthermore, temperature affects the total load; according to Giannakopoulos and Psiloglou (2006) seasonal variations of energy demand in the Greater Athens area are controlled by prevailing weather fluctuations[5]; energy demand in the Greater Athens area is non-linearly related to temperature, with an optimum ambient temperature for low levels of energy demand of 22 degrees C and with demand being more sensitive to air temperature in the cold period than in the warm one (Figure 1.2.2 *Scatter plot of daily energy consumption versus daily mean air temperature, 1993-2001*).

[5] As well as factors unrelated to weather such as weekend and holidays effects; weekends and public holidays always appear to have much lower values of energy demand than weekdays.

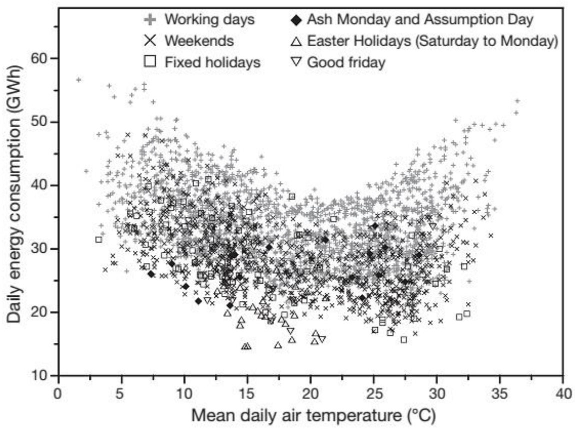

Figure 1.2.2 Scatter plot of daily energy consumption versus daily mean air temperature, 1993-2001

Due to the unavailability of high frequency data for PV RES-E generation, the analysis will focus on wind generation data only. This is possible since the published actual load data is adjusted by the ex post PV RES-E output. The following diagram depicts the hourly actual wind power generation for the time period from March 2009 to November 2013.

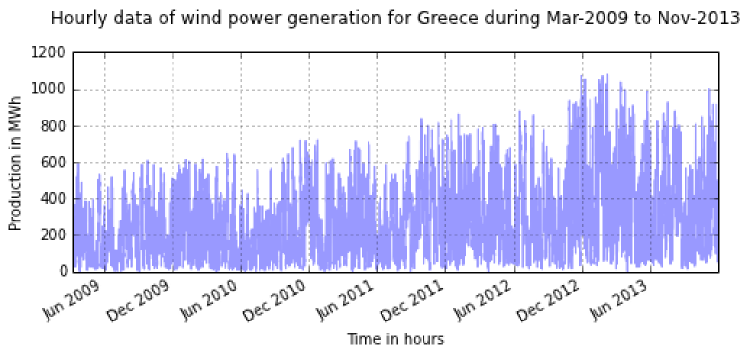

Figure 1.2.3 Hourly data of wind power production for Greece

We want to assess the correlation between load and wind generation. Since there is no meaning in calculating the correlation between two variables that are nonstationary, either due to a deterministic or due to a stochastic trend, the trend was removed from the load time series and the wind capacity factor was used instead of the wind generation (Figure 1.2.4). By construction, the capacity factor is bounded and, hence, stationary: $CF_t \in [0,1]$.

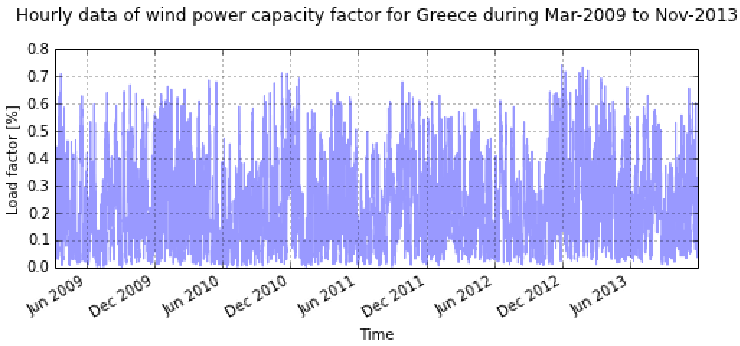

Figure 1.2.4 Hourly data of wind capacity factor for Greece

The correlation between the detrended load and the wind capacity factor has a mean value of -0.05 and presents no distinct patterns (Figure 1.2.5 *Rolling correlation between wind power capacity factor and the detrended load*) throughout time, so we can regard the assumption of load and wind power production being uncorrelated as valid.

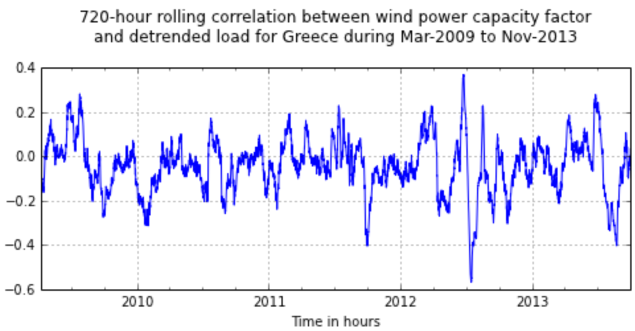

Figure 1.2.5 Rolling correlation between wind power capacity factor and the detrended load

Figure 1.2.6 presents the time evolution of the actual daily generation from lignite and natural gas plants from March 2009 to September 2013. The fact that until early 2012 the daily generation from natural gas-fuelled plants is increasing – rather than decreasing due to the merit order effect – should be attributed to the combined impact of the significant capacity additions during this period and the variable cost recovery mechanism, already in place from 01/05/2008.

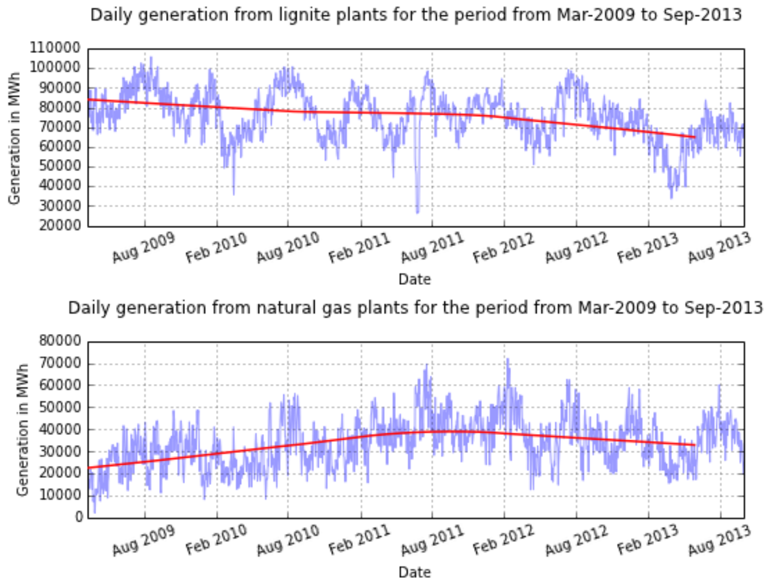

Figure 1.2.6 Daily generation from lignite and natural gas plants

The total available capacity for lignite-fuelled generators dictates the potential for the actual lignite-fuelled output, so for the same residual load levels, a decrease in the available capacity should cause a decrease in the output. The same is true for the relationship between the total available capacity and the actual output of the natural gas-fuelled generators. At the same time, for the same residual load levels, a decrease in the available lignite (natural gas) capacity should cause an increase in the actual output of the natural gas-fuelled (lignite-fuelled) generators.

Figure 1.2.7 *Monthly hydro and natural gas fuelled generation in Greece* presents the time evolution of the natural gas fuelled and the hydroelectric generation quantities. A first observation is that periods with high hydro generation are also periods with lower natural gas fuelled one.

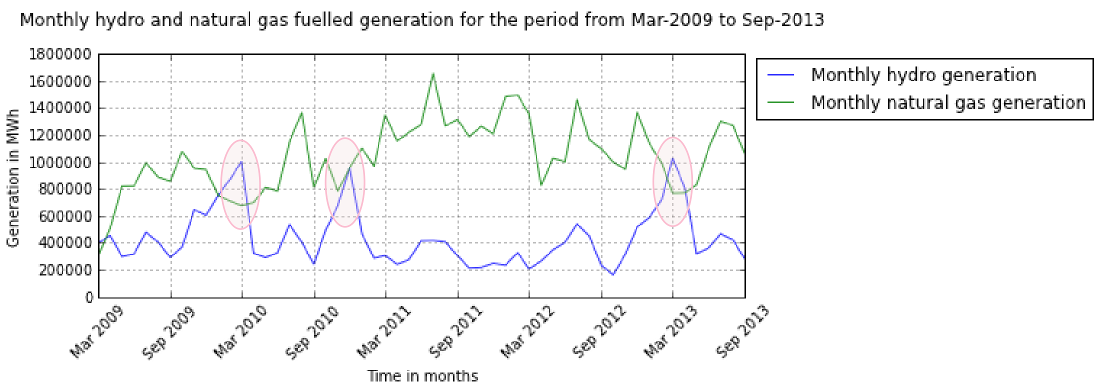

Figure 1.2.7 Monthly hydro and natural gas fuelled generation in Greece

The hydroelectric generation is dependent on the marginal water value (MWV) compared to the expected system marginal price (SMP) for the same time period. The value of water is associated with the expected profits of storing the water for later use (i.e. the water's opportunity cost). Expected future profits that can be obtained by storing water for later usage depend on the (stochastic) future hydro inflow, future electricity prices and the current reservoir levels.

While the MWV curve changes substantially over the year, its general shape is quite consistent (Tipping et al, 2004). When storage is low, the MWV is high, and vice versa, with the curve being relatively flat for most levels of storage, falling to zero at the upper bound, but rising much more steeply as storage decreases towards its lower bound. This reflects the fact that the system is able to cope with a wide variation of inflows, and hence storage levels, at moderate cost, unless storage reaches fairly extreme levels, in which case water becomes very valuable as a means of averting a significant probability of shortage.

Based on the way that the hydroelectric generators calculate their marginal cost in the Greek electricity market, the value of the water can be assumed to have two components: one ($C_{1,d,m}$) that concerns the value (i.e. impact on SMP) of the thermal generation that would be displaced if the hydroelectric generator would produce and one ($C_{2,d,m}$) that reflects the current reservoir levels, where d is a day and m is a month index (Figure 1.2.8 *Determinants of hydroelectric production*).

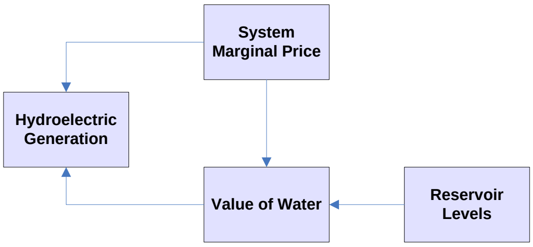

Figure 1.2.8 Determinants of hydroelectric production

The $C_{1,d,m}$ component can be calculated on a daily basis according to the following formula:

$$C_{1,d,m} = \left(1 + \sigma_{d,m}\right) \cdot C_{TH,m}$$

where:

$\sigma_{d,m}$ is an adjustment factor that encapsulates changes in the fuel prices;

$C_{TH,m}$ is the reference value of the the thermal generation that would be displaced if the hydroelectric generator would produce.

The reference value $C_{TH,m}$ is calculated as the three-year rolling average of the SMP during month m, adjusted by the corresponding hydroelectric generation during the same period:

$$C_{TH,m} = \frac{1}{3}\sum_{y-3}^{y-1}\left(\frac{\sum_h \left(SMP_{m(y),h} \cdot G_{m(y),h}^{hydro}\right)}{\sum_h G_{m(y),h}^{hydro}}\right)$$

The adjustment factor $\sigma_{d,m}$ is calculated daily and is the sum of the price change of the different fuels ($\Delta P_{fuel,m,d-1}$) multiplied by their contribution in the generation output ($a_{fuel,m}$):

$$\sigma_{d,m} = \sum_{fuel}\left(a_{fuel,m} \cdot \Delta P_{fuel,m,d-1}\right)$$

The price change of a given fuel is taken as the difference between the previous day and the average price of the same month for the last three (3) years:

$$\Delta P_{fuel,m,d-1} = \frac{P_{fuel,d-1}}{\frac{1}{3}\sum_{y-3}^{y-1} P_{fuel,m(y)}} - 1$$

Finally, the contribution of a given fuel in the generation output is the average contribution in the total fossil-fuelled generation for the last three (3) years:

$$a_{fuel,m} = \frac{1}{3}\sum_{y-3}^{y-1} \frac{G_{fuel,m(y)}}{G_{fossil,m(y)}}$$

Furtherempore, the hydroelectric generation is usually scheduled according to the Peal Shaving method which is based on the heuristic idea that the generation should be allocated in the higher part of the system load curve which corresponds to the system peak loads. In this way, the total available energy of the hydro plants, which is limited for a specific time period because of the resource constraints, can be economically dispatched through the considered scheduling horizon, resulting in a significant reduction of the total operating cost of the remaing thermal system. Based on the aforementioned, the hydroelectric generation is regarded in the Greek electricity market as an exogenous variable to the both the output of the remaining dispatchable generators and the SMP.

Regarding the relationship between lignite and natural gas-fuelled generators, we make the assumption that the continuous bidding 'game' between generators has reached an equilibrium such that for same levels of total system load, a generator will attain the same market share or equivalently will produce the same output, unless there is a change in the available thermal capacity. Furthermore, RES-E and hydroelectric production influence both lignite and natural gas-fuelled generation in such a way so that including the RES-E and hydroelectric production data in a model for lignite (natural gas) generation leads to natural gas (lignite) generation data providing no additional predictive power.

A vector autoregressive (VAR) model of the natural gas-fuelled generation, the total load, the RES-E output, the hydroelectric generation and the fossil-fuelled available capacities was formulated. Choosing the lags to be equal to 7, the partial autocorrelation diagram of the equation for the natural gas-fuelled generation suggests that the natural gas-fuelled generation during hour t is correlated with the generation realized during the same hour of the previous days (Figure 1.2.9 *Autocorrelation plot for natural gas-fuelled generation*).

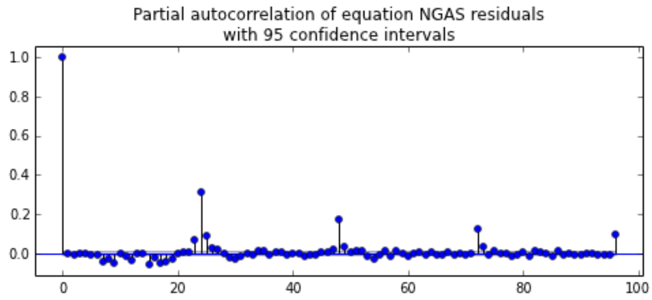

Figure 1.2.9 Autocorrelation plot for natural gas-fuelled generation

Motivated by this observation, it was decided that the modelling procedure will take place for each hour of the day, separately. Such a decision brings also the flexibility to assess the impact of electricity load curve changes that may result from future efficiency improvements. For example, load peaks could shift from midday hours to early evening hours, load growth could take place in evening hours (e.g. due to heat pump use) and load ramp rates could rise further.

The autoregressive distributed lag (ARDL) / Bounds Testing methodology of Pesaran and Shin (1999) and Pesaran et al. (2001) was utilized. The ARDL formulation implies that the natural gas-fuelled (lignite-fuelled) generation during time t is a function of past natural gas-fuelled lignite-fuelled) generation as modified by new information on the state of the electricity market that is incorporated into the total load, RES-E, hydroelectric generation and fossil-fuelled available capacity variables.

For the natural gas-fuelled generation, the corresponding ARDL model has the following structure:

$$q_{t,d}^{ng} = \sum_{i=1}^{p} a_i q_{t,d-i}^{ng} + \sum_{j=1}^{n} \beta_j X_{t,d-j} + \varepsilon_{t,d}$$

where:

$q_{t,d}^{ng}$ is the actual quantity produced by natural gas-fuelled generators during hour t and day d;

$X_{t,d} = \left[L_{t,d}, res_{t,d}, hydro_{t,d}, cap_{t,d}^{ng}, cap_{t,d}^{lig}\right]'$;

$L_{t,d}$ is the system load during hour t and day d;

$res_{t,d}$ is the actual RES-E production during hour t and day d;

$hydro_{t,d}$ is the hydroelectric production during hour t and day d;

$cap_{t,d}^{ng}, cap_{t,d}^{lig}$ are the total available capacities during hour t and day d for natural gas-fuelled and lignite-fuelled generators, respectively.

During the first step of the methodology, we formulate an unrestricted error-correction model (ECM) for the relationship between the actual quantity produced and its explanatory variables, choose the lag structure and assure that the model is well defined (practically that the errors of the model are serially independent). The coefficients for the unrestricted ECM for hour 00:00 and with number of lags equal to 2 are presented in the next table.

Results: OLS

Model:	OLS	AIC:	21217.4836
Dependent Variable:	diff(ngas)	BIC:	21346.0190
No. Observations:	1565	Log-Likelihood:	-10585.
Df Model:	23	F-statistic:	70.18
Df Residuals:	1541	Prob (F-statistic):	2.64e-220
R-squared:	0.512	Scale:	44552.
Adj. R-squared:	0.504		

	Coef.	Std.Err.	t	P>|t|	[0.025	0.975]
const	-70.2991	68.8041	-1.0217	0.3071	-205.2587	64.6606
L1.ngas	-0.2276	0.0200	-11.3680	0.0000	-0.2669	-0.1883
L1.load	0.0695	0.0102	6.7959	0.0000	0.0494	0.0895
L1.res	-0.0520	0.0384	-1.3569	0.1750	-0.1273	0.0232
L1.hydro	-0.0961	0.0175	-5.4984	0.0000	-0.1304	-0.0618
L1.lignite avail	-0.0525	0.0165	-3.1914	0.0014	-0.0848	-0.0202
L1.ngas avail	0.0811	0.0112	7.2465	0.0000	0.0592	0.1031
diff(load)	0.3626	0.0139	26.1010	0.0000	0.3353	0.3898
diff(res)	-0.4262	0.0305	-13.9603	0.0000	-0.4860	-0.3663
diff(hydro)	-0.3718	0.0236	-15.7492	0.0000	-0.4181	-0.3255
diff(lignite avail)	-0.0979	0.0156	-6.2835	0.0000	-0.1285	-0.0673
diff(ngas avail)	0.1178	0.0207	5.6865	0.0000	0.0771	0.1584
L1.diff(load)	0.1192	0.0181	6.5870	0.0000	0.0837	0.1548
L1.diff(res)	-0.1016	0.0361	-2.8175	0.0049	-0.1724	-0.0309
L1.diff(hydro)	-0.0127	0.0286	-0.4460	0.6557	-0.0688	0.0433
L1.diff(lignite avail)	-0.0721	0.0171	-4.2286	0.0000	-0.1055	-0.0387
L1.diff(ngas avail)	0.0506	0.0233	2.1695	0.0302	0.0049	0.0964
L1.diff(ngas)	-0.1970	0.0272	-7.2506	0.0000	-0.2503	-0.1437
L2.diff(load)	0.0507	0.0164	3.0843	0.0021	0.0185	0.0830
L2.diff(res)	-0.0528	0.0325	-1.6252	0.1043	-0.1164	0.0109
L2.diff(hydro)	0.0146	0.0254	0.5756	0.5650	-0.0352	0.0645
L2.diff(lignite avail)	-0.0171	0.0161	-1.0658	0.2867	-0.0486	0.0144
L2.diff(ngas avail)	-0.0007	0.0210	-0.0346	0.9724	-0.0418	0.0404
L2.diff(ngas)	-0.0653	0.0251	-2.5968	0.0095	-0.1146	-0.0160

Omnibus:	46.774	Durbin-Watson:	2.024
Prob(Omnibus):	0.000	Jarque-Bera (JB):	92.237
Skew:	0.188	Prob(JB):	0.000
Kurtosis:	4.128	Condition No.:	99643

Table 1.2.1 Coefficients for the unrestricted ECM for hour 00:00

Next, we perform an F-test of the hypothesis that the coefficients of the lagged values of the explanatory variables (i.e. `L1.ngas`, `L1.load`, `L1.res`, `L1.hydro`, `L1.lignite avail`, `L1.ngas avail`) are jointly equal to zero, which is equivalent to testing for the absence of a long-run equilibrium relationship between the variables. There is a practical difficulty that has to be addressed when we conduct the F-test. The distribution of the test statistic is totally non-standard and exact critical values for the F-test aren't available for an arbitrary mix of I(0) and I(1) variables.

However, Pesaran et al. (2001) supply bounds on the critical values for the asymptotic distribution of the F-statistic. If the computed F-statistic exceeds the upper bound, we conclude that we have cointegration, and if the F-statistic falls between the bounds, the test is inconclusive. The F-statistic was found to be 21.73, which exceeds by far the upper bound and, thus, implies that the coefficients are not equal to zero and the null hypothesis of no long-run equilibrium relationship should be rejected. Since the bounds test leads to the conclusion of cointegration, we can meaningfully estimate the long-run equilibrium relationship between the variables:

```
                                Results: OLS
===========================================================================
Model:                  OLS          AIC:                      22453.3982
Dependent Variable:     ngas         BIC:                      22485.5436
No. Observations:       1568         Log-Likelihood:           -11221.
Df Model:               5            F-statistic:              465.1
Df Residuals:           1562         Prob (F-statistic):       4.14e-306
R-squared:              0.598        Scale:                    96575.
Adj. R-squared:         0.597
---------------------------------------------------------------------------
                 Coef.    Std.Err.     t     P>|t|     [0.025     0.975]
---------------------------------------------------------------------------
const          -406.4450   85.9341   -4.7297 0.0000 -575.0032 -237.8867
load              0.3226    0.0102   31.5526 0.0000    0.3026    0.3427
res              -0.3723    0.0386   -9.6433 0.0000   -0.4480   -0.2966
hydro            -0.4386    0.0193  -22.6832 0.0000   -0.4765   -0.4007
lignite avail    -0.2190    0.0172  -12.6977 0.0000   -0.2529   -0.1852
ngas avail        0.3558    0.0113   31.5874 0.0000    0.3337    0.3779
----------------------------------------------------------------------------
Omnibus:               6.508          Durbin-Watson:             0.659
Prob(Omnibus):         0.039          Jarque-Bera (JB):          6.657
Skew:                  0.122          Prob(JB):                  0.036
Kurtosis:              3.205          Condition No.:             83351
============================================================================
```

Table 1.2.2 Coefficients for the long-run equilibrium relationship for hour 00:00

Although a VECM can be specified, the analysis is based on the premise that the long-run equilibrium relationship is the important aspect of the effect of RES-E generation on the fossil-fuelled generation. The coefficients of the long-run equilibrium relationship for natural gas-fuelled generation and for all 24 hours of the day are presented in *Table 1.2.3* (red numbers are negative). Since no distinct pattern is visible, one can infer that one (1) MWh of wind RES-E displaces on average 0.37 MWh of natural gas-fuelled generation.

The same procedure is followed for lignite-fuelled generation. However, only four representative hours were used for calculations, the results of which are presented in Table 1.2.4. One can infer that one (1) MWh of wind RES-E displaces on average 0.29 MWh of lignite-fuelled generation.

	Hour of day																							
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
load	0.32	0.33	0.29	0.28	0.28	0.27	0.28	0.33	0.36	0.37	0.41	0.42	0.42	0.41	0.40	0.39	0.38	0.39	0.41	0.43	0.46	0.47	0.37	0.35
res	0.37	0.38	0.30	0.27	0.25	0.23	0.23	0.22	0.32	0.37	0.42	0.43	0.43	0.43	0.42	0.42	0.40	0.41	0.42	0.44	0.43	0.42	0.50	0.45
hydro	0.44	0.40	0.36	0.39	0.44	0.47	0.5	0.43	0.39	0.35	0.37	0.38	0.38	0.39	0.39	0.38	0.35	0.35	0.32	0.29	0.28	0.28	0.47	0.48
ngas avail	0.36	0.34	0.31	0.30	0.28	0.28	0.27	0.28	0.32	0.31	0.30	0.29	0.29	0.28	0.27	0.26	0.28	0.30	0.31	0.31	0.30	0.31	0.32	0.33
lignite avail	0.22	0.20	0.15	0.14	0.14	0.14	0.15	0.17	0.20	0.23	0.25	0.26	0.25	0.24	0.23	0.24	0.24	0.23	0.24	0.24	0.24	0.25	0.24	0.23

Table 1.2.3 The coefficients of the long-run equilibrium relationship for natural gas-fuelled generation

	Hour of day			
	0	**10**	**16**	**20**
load	0.41	0.35	0.37	0.34
res	0.31	0.27	0.33	0.25
hydro	0.53	0.46	0.49	0.40
ngas avail	0.12	0.10	0.11	0.08
lignite avail	0.31	0.37	0.37	0.38

Table 1.2.4 The coefficients of the long-run equilibrium relationship for lignite-fuelled generation

1.3 Economic and emissions savings from RES-E generation in the Greek electricity market

The fuel cost – excluding the consumption tax and the tariffs of the Greek natural gas transmission system – of the natural gas-fuelled plants is calculated as the natural gas price divided by their efficiency. The efficiency was taken as the capacity-weighted average, which is 0.51. The evolution of the monthly weighted average import price of natural gas in Greece is depicted in the next diagram.

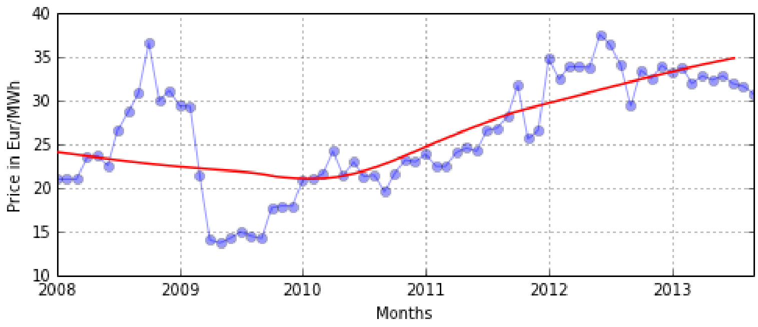

Figure 1.3.1 Evolution of the monthly weighted average import price of natural gas in Greece

Figure 1.3.2 presents the time evolution of the economic benefit from natural gas imports avoided due to wind RES-E generation offsetting the natural gas-fuelled one.

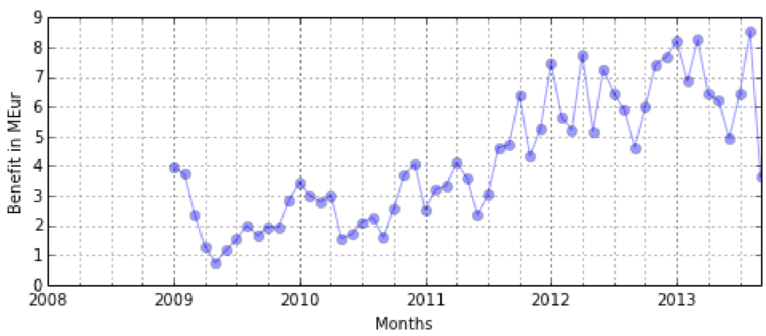

Figure 1.3.2 Economic benefit in million Euros from natural gas imports avoided by wind RES-E

Kaldellis and Kapsali (2013), combined historical data for CO_2, SO_2, NO_x and PM (mixture of solid and liquid particles suspended in the air) emissions from the Greek major lignite thermal power stations with data for their electricity generation, so as to estimate the emission contribution (i.e. the emission factor) from each. A table of the emission factors in kg/MWhe for 2011, per emission type and major lignite thermal power station was derived (Table 1.3.1).

CO_2		SO_2		NO_X		PM	
Plant	**Value**	**Plant**	**Value**	**Plant**	**Value**	**Plant**	**Value**
Megalopolis A	1652	Megalopolis A	8.70	Ag. Dimitrios	2.16	Ptolemaida	2.78
Ptolemaida	1577	Amyntaio	8.65	Kardia	2.08	Kardia	0.68
Kardia	1500	Ag. Dimitrios	3.11	Amyntaio	1.37	Megalopolis A	0.42
Ag. Dimitrios	1435	Ptolemaida	2.73	Ptolemaida	1.36	Amyntaio	0.18
Amyntaio	1349	Florina	2.29	Megalopolis B	1.15	Megalopolis B	0.12
Megalopolis B	1340	Kardia	1.73	Megalopolis A	1.09	Ag. Dimitrios	0.10
Florina	1210	Megalopolis B	0.69	Florina	0.82	Florina	0.02

Table 1.3.1 Lignite-based thermal power stations sorted by their emission factors

Gouw et al. (2014) use data from continuous emissions monitoring systems (CEMS), which measure emissions at the stack of U.S. natural gas-fuelled power generation units, to investigate the emission factors of CO_2, NO_X and SO_2. According to their results, per unit of energy produced, natural gas power plants equipped with combined cycle technology emit on average 44% the CO2, 40% the NOx and 44% the SO2 of the coal-fuelled ones. These numbers will be assumed valid for the Greek electricity market also.

The benefits from CO_2 emissions avoided due to lignite-fuelled and natural gas-fuelled generation offset by wind RES-E are depicted in the following plots.

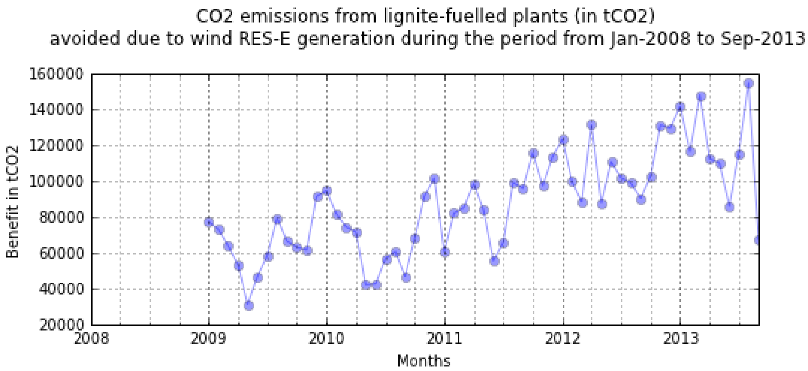

Figure 1.3.3 CO_2 emissions avoided due to lignite-fuelled generation offset by wind RES-E

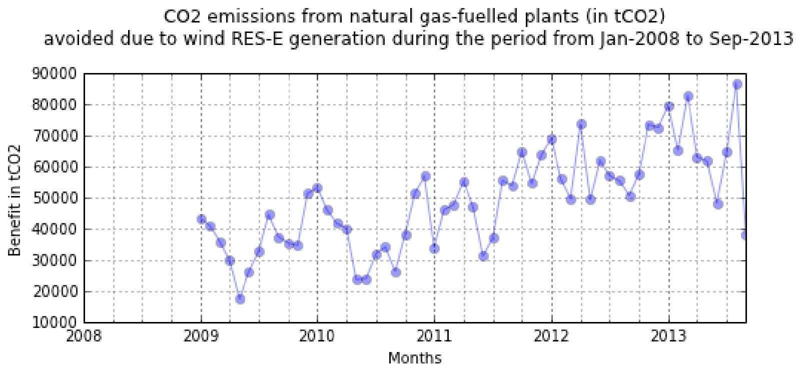

Figure 1.3.4 CO2 emissions avoided due to natural gas-fuelled generation offset by wind RES-E