# What caused the drop in European electricity prices?

## A factor decomposition analysis

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*Abstract* – European wholesale electricity prices have dropped by nearly two thirds since their all-time high around 2008. Different factors have been blamed, or praised, for causing the price slump: the expansion of renewable energy; the near-collapse of the European emission trading scheme; over-optimistic power plant investments; a decline in final electricity consumption; and cheap coal and natural gas. This paper is an *ex-post* study of European spot markets in electricity from 2008 to 2015. We use a fundamental electricity market model to quantify the impact of these and other factors on day-ahead prices using a *ceteris paribus* approach. In the two countries we study in detail, Germany and Sweden, different factors were important drivers of the price drop: fuel and $CO_2$ prices in Germany, electricity demand in Sweden. In both countries, however, the single largest factor contributing to the fall in wholesale prices was the expansion of renewable energy.

*Keywords* – electricity price; ex-post analysis; utility crisis

*JEL* – Q42, C61

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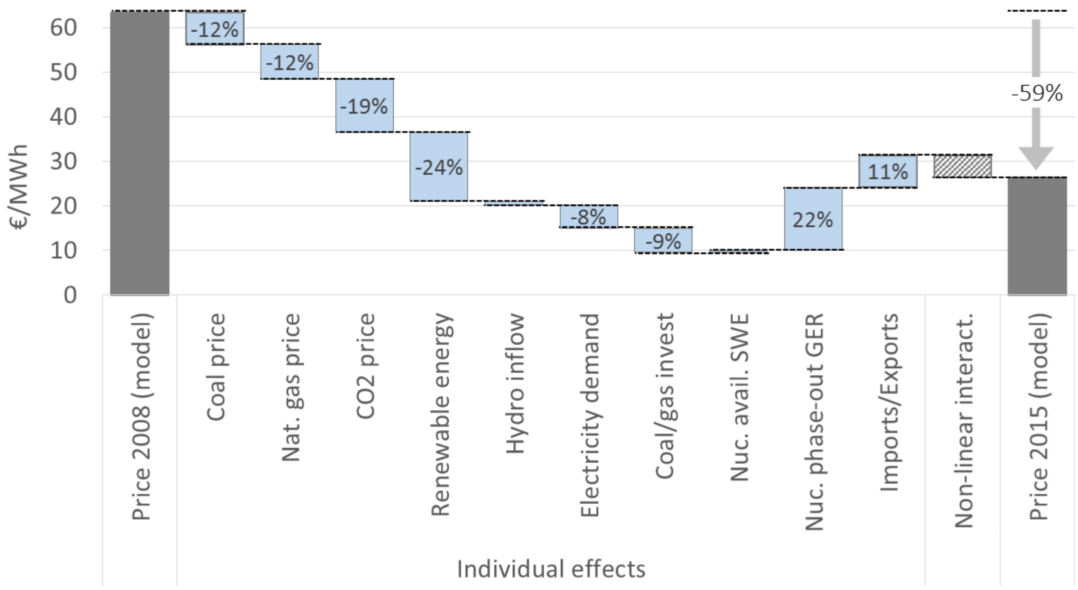


*Graphical abstract* – The change in German spot prices from 2008 to 2015, showing the contribution of ten individual factors. Numbers indicate the price impact of an individual factor relative to 2008 prices. For example, the decline of coal prices on its own would have caused an electricity price drop of 12%. In contrast, the nuclear phase-out alone would have increased prices by 22% from 2008 levels. Overall, electricity prices fell by 59%.

*Highlights*

- This *ex-post* study disentangles the factors that caused European wholesale electricity prices to decline.
- A fundamental power market model is used to replicate historical prices.
- Ten individual factors that impacted prices are quantified.
- The largest price driver in Germany and Sweden was renewable energy investment.
- Electricity demand, fuel prices, and the $CO_2$ price also contributed significantly to the fall.

# 1. Introduction: the dramatic drop in European power prices

Wholesale prices for electricity in Europe have witnessed a dramatic decline during recent years. For example, in Germany and Sweden prices peaked in 2008-10 and have fallen by nearly two thirds since then (Figure 1, Figure 2).

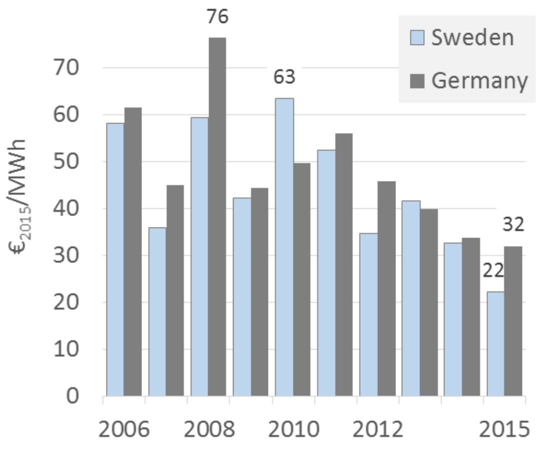


Figure 1. Inflation-adjusted yearly average day-ahead spot prices in Germany and Sweden.

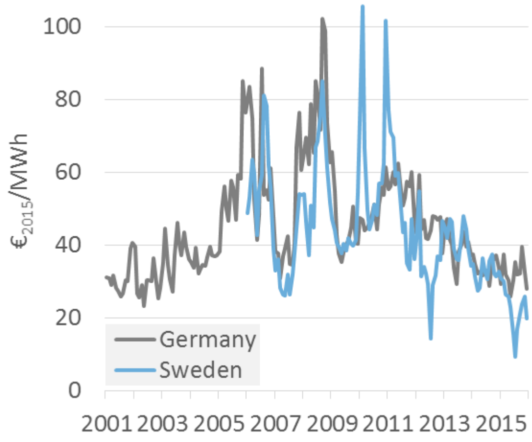


Figure 2. Inflation-adjusted monthly average day-ahead spot prices in Germany and Sweden.

Different factors have been blamed – or praised – for the price slump: the expansion of renewable energy, the collapse of the European emission trading scheme (EU ETS) certificate price, over-optimistic power plant investments, a decline in final electricity consumption and the decline in fuel prices. In particular, the EU ETS price collapse has been traced back to policy interventions, lack of credibility, and the macroeconomic recession. The reduction of electricity consumption has been attributed to energy efficiency policy, the macroeconomic recession, carbon leakage, and structural change in the European industry. Figure 3 illustrates how different shocks impact electricity prices in a "merit-order" or "supply stack" model.

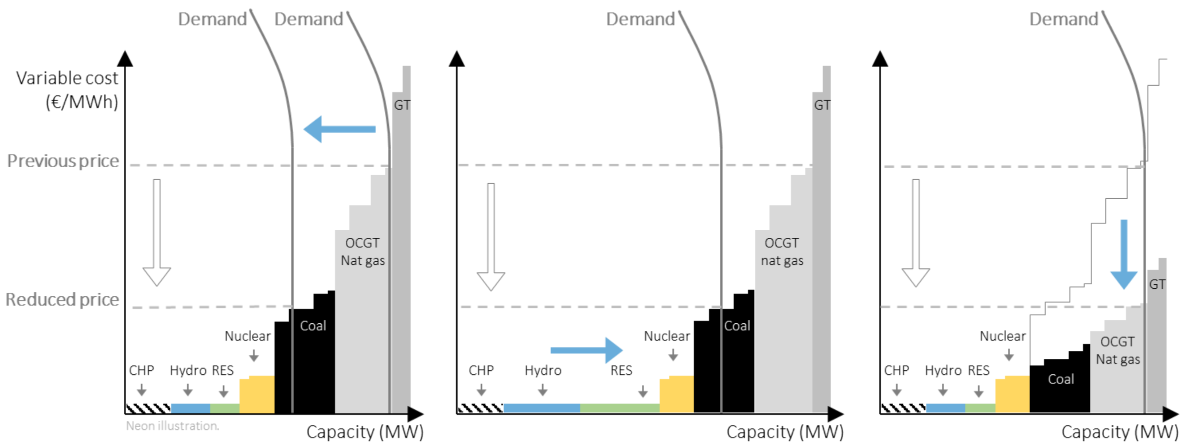


Figure 3. The impact of reduced electricity demand (left), increased low-variable-cost supply (middle) and reduced variable cost (right) on the electricity price. Each shock (blue arrow) leads to a price decline (white arrow).

This paper is an *ex-post* study of European day-ahead spot prices from 2008 to 2015. The fundamental electricity market model EMMA is used to quantify the impact of these factors. Initially we use the model to replicate historical prices, using input parameters from the relevant year. Then individual input parameters are substituted with their 2015 value. The change in modeled electricity prices is interpreted as the impact of this parameter.

A large branch of the energy economics literature discusses the price-depressing effects of increasing penetration of renewable energy – the so-called "merit-order effect" (Olsina et al. 2007, Rathmann 2007, Sáenz de Miera et al. 2008, Munksgaard & Morthorst 2008, MacCormack et al. 2010, Mount et al. 2010, O'Mahoney & Denny 2011, Gil et al. 2012). However, while these studies estimate the price impact of *one* important parameter, they do not attempt to quantify all the other variables that determine electricity prices.

Recently, two papers have been published that investigate the reasons for the erosion of German power prices. Kallabis et al. (2016) study the plunge in electricity futures, with delivery in 2014, as traded between 2008 and 2013; they investigate the change in the *expectations* of the market actors. Kallabis et al. find that nearly half of the price decline can be explained by the – unexpected – drop in $CO_2$ certificates. In contrast, the aim of our study is to assess the change in market fundamentals, rather than expectations. Hence we study spot, rather than financial, markets (see section 2.2). Everts et al. (2016) study German spot markets. Our paper differs from Everts et al. by adopting a broader geographic coverage – modeling the whole of Northwest Europe – and addresses a richer set of factors. Another contribution of this paper is that it explicitly addresses a number of methodological challenges of the factor decomposition employed in all three papers (including ours).

Understanding what caused the price slump is important for a number of reasons. Obviously, understanding past price patterns helps in forecasting future price development, which is of interest for producers and consumers alike. However, understanding the recent history of European power price development is also important for public policy discussion. A number of policy interventions have affected prices – $CO_2$ trading, subsidies for renewable energy, and Germany's nuclear phase-out, to name some prominent examples. These policies affect electricity prices and hence redistribute economic wealth between producers and consumers and across different kinds of producers (Hirth & Ueckerdt 2013). Some of these implications might be intended, while others might be side-effects of pursuing other policy objectives. In both cases, understanding the price impacts of past policy action can affect the design of future policies.

In this study, ten factors are explicitly modeled. Six of them are found to have contributed to the price decline while three have mitigated it; one is ambiguous in the direction of its effect. Detailed results are reported for Sweden and Germany, being two quite distinct European markets. In Germany, the largest contributors to the decline of the power price since its peak have been the expansion of renewable energy and the $CO_2$ price decline. In Sweden, the major factors have been renewable energy, the decline in final electricity demand, and larger volumes of water inflow into hydro reservoirs. The major factors that mitigated the price erosion were the nuclear phase-out in Germany and the increase in net exports, particularly in Sweden.

# 2. Methodology

This study is an *ex-post* evaluation of spot prices using a fundamental electricity market model. The properties of spot prices are discussed in the following paragraph, before the model is introduced. Finally, some caveats of a factor decomposition, like the one used here, are discussed.

## 2.1. Different types of power prices: spot vs. financial markets

Electricity is traded on a range of wholesale markets that can be ordered along the time span between trading and delivery. In Europe, on *financial markets,* futures and forwards are traded between a few days and several years ahead. Futures and forwards are usually traded for delivery periods (durations) of between one day and one year. *Spot markets* can be split into two segments: day-ahead markets which trade in electricity with next day delivery; and intra-day markets, where trade takes place until gate closure of 15 to 60 minutes before delivery. Spot market contracts have a duration of between 15 minutes and one day. Real-time, or balancing markets trade until delivery and products might be shorter than 15 minutes.

Spot market prices reflect *market fundamentals*. If market power is absent, settlement prices on spot markets reflect the marginal costs of electricity generation and the marginal willingness to pay for electricity consumption.

Financial markets reflect the *expectations* of market actors concerning future market fundamentals. A change in a future price implies that market actors have changed their view concerning some period in the future. Kallabis et al. (2016) study the plunge in electricity base futures with delivery in 2014 (the so-called "Cal14 base future") as traded between 2008 and 2013. Hence they investigate the change in *expectations* of the market actors for 2014 as time unfolded.

This paper studies spot prices between 2008 and 2014. More precisely we investigate the yearly average of hourly contracts on day-ahead auctions. This should be interpreted as a change in market fundamentals. Such change in fundamentals might be or might not be anticipated, and hence can come with constant or changing future prices.

## 2.2. The fundamental power market model EMMA

The open-source Electricity Market Model EMMA is a techno-economic model of the integrated Northwestern European power system. It models both dispatch of and investment in power plants, minimizing total costs with respect to investment, production and trade decisions subject to a large set of technical constraints. For this study, no endogenous investment was modeled and installed generation capacity was taken from statistical sources. In economic terms, EMMA is a partial equilibrium model of the wholesale electricity market with a focus on the supply side. It was used to calculate the short-term optimum (equilibrium) and to estimate the corresponding hourly prices, generation, and cross-border trade for each market area. Technically, EMMA is a linear program with six million non-zero variables. EMMA has been used for eight peer-reviewed publications to address a range of research questions.[2] It is also open-source: the model code as well as all input parameters and its documentation are freely available to the public under the Creative Commons BY-SA 3.0 license and can be downloaded from http://neon-energie.de/EMM.

**Objective function and decision variables.** For a given hourly electricity demand, EMMA minimizes total system cost, i.e. the sum of capital costs, fuel and $CO_2$ costs, and other fixed and variable costs of generation, transmission, and storage assets. Investment and generation are jointly optimized for one representative year. Decision variables comprise the hourly production of each generation technology including storage, hourly electricity trade between regions, and annualized investment and disinvestment in each technology, including wind and solar power. The important constraints relate to

[2] Hirth (2016), Hirth & Steckel (2016), Hirth & Müller (2016), Hirth (2015a), Hirth (2015b), Hirth & Ueckerdt (2013), Hirth (2013).

energy balance, capacity limitations, and the provision of district heat and ancillary services. For this study, investment was disabled such that EMMA worked as a pure dispatch model.

**Generation technologies.** Generation is modeled as twelve discrete technologies with continuous capacity: (i) Two variable renewable energy sources with zero marginal costs – wind and solar power. Hourly wind and solar generation is limited by exogenous generation profiles, but can be curtailed at zero cost. (ii) Six thermal technologies with economic dispatch – nuclear power, two types of coal-fired power plants (lignite and hard coal), two types of natural gas-fired power plants (combined cycle gas turbines, CCGT, and open cycle gas turbines, OCGT), and lignite-fired carbon capture and storage plants (CCS). Dispatchable plants produce whenever the price is above their variable costs. (iii) A generic "load shedding" technology. Load is shed if prices reach its opportunity cost. (iv) Three hydro power technologies: run-off-the-river hydro power, hydro reservoir power, and pumped hydro storage; run-off-the-river hydro power is exogenous, while the other hydro technologies are optimized endogenously under turbine, pumping, inventory, inflow, and minimum generation constraints.

**Spot price.** The hourly zonal electricity price is the shadow price of demand, which can be interpreted as the prices of an energy-only market with scarcity pricing. In the electric engineering power system literature, the marginal costs of power generation is often labeled "system lambda", because they are derived from the shadow price of one of the constraints of an optimization model.

**Demand elasticity.** Demand is exogenous and assumed to be perfectly price inelastic at all prices but the very highest, when load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short timescales.

**Power system constraints.** EMMA accounts for a large number of power system constraints. Two important classes of constraints concern combined heat and power generation and the provision of system services. Combined heat and power (CHP) generation is modeled as must-run generation. A certain share of the co-generating technologies lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of these technologies can be freely optimized. System service provision is modeled as a must-run constraint for dispatchable generators that is a function of peak load and VRE capacity. Hirth (2015c) and Hirth & Ziegenhagen (2015) provide background on the calibration procedure.

**Trade.** Cross-border trade is endogenous and limited by available transfer capacities. Endogenous investments in interconnector capacity have been disabled for this study. Within regions, transmission capacity is assumed to be non-binding.

**Cycling costs.** The model is linear and does not feature integer constraints. Thus, it is not a unit commitment model and cannot explicitly model start-up cost or minimum load. However, start-up costs are parameterized to achieve a realistic dispatch behavior. An electricity price is bid below the variable costs of assigned base load plants in order to avoid ramping and start-ups.

**Deterministic.** The model is fully deterministic. Long-term uncertainty surrounding fuel prices, investment costs, and demand development are not modeled. Short-term uncertainty concerning VRE generation (day-ahead forecast errors) is approximated by imposing a reserve requirement via the system service constraint, and by charging VRE generators balancing costs.

**Geographical scope.** EMMA is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, France, Sweden, and Norway. Due to space constraints, results are only presented for Germany and Sweden, as they are representatives of quite distinct power systems: a system with mostly fossil power plants (Germany), and a nuclear-hydro dominated system (Sweden).

### 2.3. Input data

Electricity demand, as well as electricity generation, of zero-variable-cost renewable energy (wind, solar, hydroelectricity) was taken from the International Energy Agency's Monthly electricity statistics. Net exports outside the mode region was taken from ENTSO-E Statistical factsheets. Table 1 summarizes these assumptions for different years, together with their sources.

Table 1: Important volumetric input parameters and data sources

| Parameter | 2008 | 2010 | 2015 | Data source |
|---|---|---|---|---|
| Electricity demand | 1705 TWh | 1723 TWh | 1647 TWh | IEA Monthly electricity statistic |
| Wind + solar generation | 60 TWh | 75 TWh | 193 TWh | IEA Monthly electricity statistic |
| Hydroelectricity output | 276 TWh | 282 TWh | 302 TWh | IEA Monthly electricity statistic |
| Net exports of model region | -38 TWh | 38 TWh | 90 TWh | ENTSO-E Statistical factsheet |
| Net demand | 1331 TWh | 1404 TWh | 1246 TWh | Own calculation |

Numbers are shown for the entire model region (Sweden, Norway, Germany, France, Poland, Belgium, The Netherlands). For 2015, electricity consumption and wind/solar generation is estimated based on November data, because December data are not yet published.

Both German and Swedish 2015 prices are compared to their respective price peaks in 2008 and 2010. Figure 4 shows the volume shocks that hit the model region between 2010 and 2015. Net electricity demand, defined as demand minus wind, solar, and hydro power generation as well as net exports, dropped by 11%. The expansion of wind and solar energy, as well as the decline in final electricity demand, played a large role. Hydroelectricity generation had a small impact. Net exports increased, compensating for a quarter of the volume reduction. The change in net demand between 2008 and 2010 was positive, such that the difference between 2008 and 2015 is only about half of the difference of 2010-15.

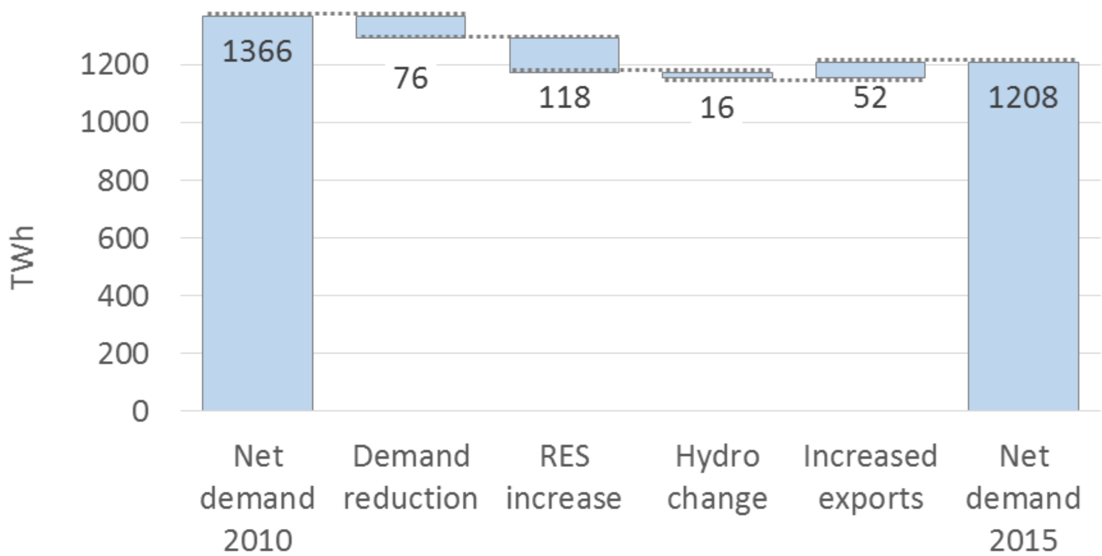

Figure 4. The change in model-region net demand (demand to be served from thermal power plants) from 2010 to 2015.

Price data are as important as volumetric input data. Hard coal prices are the Northwest Europe Marker Prices provided by HIS McCloskey. Natural gas prices are German border import prices as reported by the International Monetary Fund (IMF). The carbon price is the price of EU ETS allowances (EUAs). Dollar-denominated prices were converted into Euro using exchange rate data from the European Central Bank. Figure 2 summarizes price assumptions for different years as well as their sources. While volume shocks on net demand are greater in the 2010-15 period than the 2008-15 period, the opposite is true for price shocks.

Table 2: Important price input parameters and data sources

| Parameter | 2008 | 2010 | 2015 | Data source |
|---|---|---|---|---|
| Coal price | 150 $/t<br>12 €/MWh | 92 $/t<br>8.4 €/MWh | 59 $/t<br>6.4 €/MWh | IHS McCloskey Northwest Europe Marker Price |
| Natural gas price | 30 €/MWh | 21 €/MWh | 22 €/MWh | IMF German border import price |
| $CO_2$ price | 25 €/MWh | 16 €/t | 6 €/t | EUA price |

All prices are nominal values (not inflation-adjusted). Dollar-denominated prices were converted into Euro using exchange rate data from the ECB.

## *2.4. Factor decomposition: some remarks*

We wanted to estimate the individual effect of each of these parameter changes on electricity prices, holding everything else fixed (*ceteris paribus*). This was done by first replicating the base year (2008 or 2010) and the target year (2015). Taking the base year input dataset, one single parameter was substituted with its 2015 value, leaving all other parameters unchanged. The change in the modeled electricity price was interpreted as the price impact of these parameters.

This straightforward procedure is less innocent than it looks at first glance. There are four caveats as follows.

Firstly, the sum of the individual effects does not necessarily equal the joint effect, which is the effect of changing all parameters at once. In a non-linear system such as power markets, this is generally the case. The following extreme example clarifies the energy economics behind this phenomenon: an increase in coal prices raises the electricity price, as does an increase in $CO_2$ prices; however an increase in both prices might not cause an increase in the electricity price, if all coal plants are driven out of the money.

Secondly, alternative base years, or benchmarks, exist. Particularly, the two following questions are not identical: "What would be the reduction of the electricity price if all parameters are set at 2010 levels, and only the RES supply is increased to 2015 levels?" (2010 benchmark) and "What would be the increase of the electricity price if all parameters are set at the 2015 level, and only the RES supply is decreased to 2010 levels?" (2015 benchmark). Any other year could be chosen as benchmark as well.

Thirdly, individual effects are not identical to cumulative effects. We test factors individually, always starting with the base year parameter set. In other words, we test each effect individually (separately), holding all other parameters at 2010 levels. A different approach would be to add changes on top of each other (cumulative). The impact of a given change of renewable energy expansion is different at 2008 or 2015 coal prices. In a cumulative procedure, there is no interaction effect.

Finally, if effects are added (cumulative), the order of the changes matters. For example, if we started with an increase in renewable energy supply, and then decreased the demand, the result would be different to that obtained by decreasing the demand first, and then increasing the renewable energy supply. This is the reason we do not follow such an approach.

# 3. Results

First, historical prices were replicated. Then the parameters were individually substituted with those of 2015. First we present German and then Swedish results.

## *3.1. Replication of historical prices*

Figure 5 and Figure 6 compare historical price patterns to modeled shadow prices. Figure 7 contrasts the historical generation mix with the modeled mix. Both prices and quantities are replicated fairly well. These model runs serve as the basis to change individual factors in the following subsection.

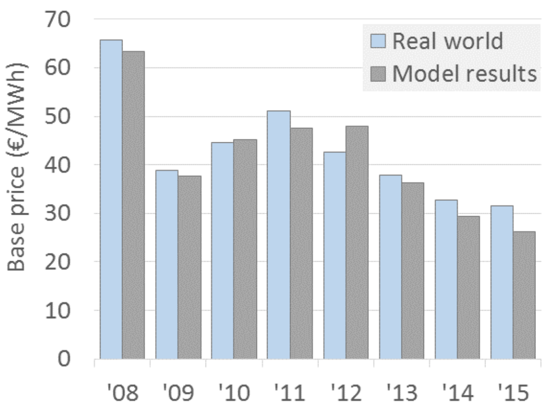


Figure 5. Yearly German base prices as observed and modeled.

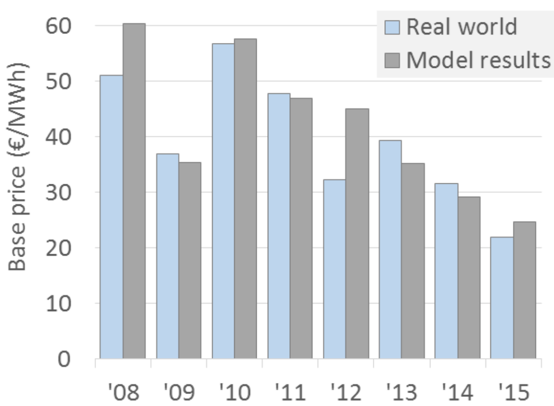


Figure 6. Yearly Swedish base prices as observed and modeled.

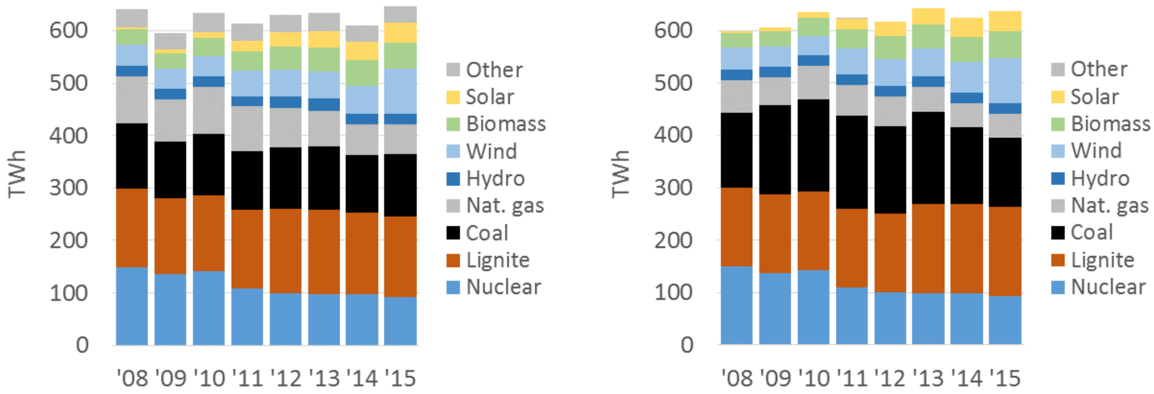


Figure 7. German electricity generation mix as observed (left) and modeled (right). Generation patterns are well replicated.

### *3.2. Germany: impact factors on electricity prices 2008-15*

German power prices peaked in 2008. Between that year and 2015, they declined by nearly two thirds. Figure 8 summarizes the modeled impact of all input parameters. The single largest contributing factor to the price erosion was the expansion of renewable energy (wind and solar power as well as bioenergy). In almost all European countries renewable energy has grown strongly during this time period; in Germany its output increased by two-and-a-half. This rise has been caused by declining generation costs and implicit and explicit subsidies. According to our model runs the expansion of renewable energy alone would have decreased German spot prices by 24%.

The fall in fuel prices has also been important. Hard coal and natural gas prices contributed 12% each to the price drop. Even more important than this has been the collapse of the EU ETS price, adding another 19%. The decline of power prices and investments in conventional plants has had a moderate impact of 8-9%, while international trade has compensated for the price drop. *Ceteris paribus*, the increase in net exports would have increased the power price by 11%. The largest price-increasing element, however, was the German nuclear phase-out. After the Fukushima Daiichi nuclear disaster in 2011, eight nuclear reactors were immediately shut down. On its own, this policy intervention would have increased the power price by 22%. Hence, if one defines the *Energiewende* as the combination of two policies, being the support of renewable energy and the phase-out of nuclear power, its net effect during the period under consideration has been negligible.

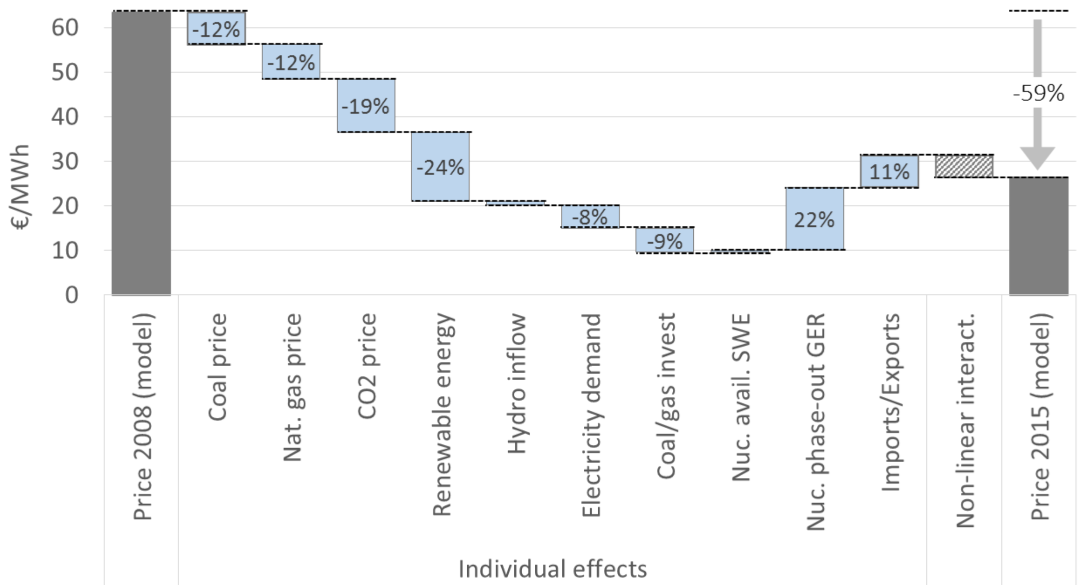


Figure 8. The change of German spot prices from 2008 to 2015 showing the contribution of ten individual factors. Numbers indicate the price impact of an individual factor relative to 2008 prices. For example, the effect of declining coal prices, holding everything else fixed, would have been a price decline of 12%. Overall, prices declined by 59%.

### *3.3. Sweden: impact factors on electricity prices 2010-15*

Sweden experienced a similar drop in spot prices, although prices peaked in 2010. The same factors contributed to the drop, with the exception of natural gas prices that declined and hence reduced electricity prices in the period 2008-15. These, however, increased and hence supported electricity prices during the 2010-15 period.

The quantitative role that individual factors have played however, is dramatically different from the German case (Figure 9). The reason for the difference lies both in the different time frames under consideration, and the distinctions between the two power systems. Fuel and $CO_2$ prices played an insignificant role in the erosion of Swedish prices, both because there are fewer fossil fuel plants in the Nordic power system and because the decline in fuel prices over 2010-15 was lower than in the period 2008-15. Three quantity shocks – the increase in renewable electricity generation, the additional hydroelectricity supply during the wet year of 2015, and the decline in final electricity demand – strongly depressed Swedish prices. The main reason these volume shocks had a greater effect than in Germany lies in the nature of the Nordic power system; most electricity is supplied from power stations with zero or very low short-term marginal costs, such as nuclear power, hydroelectricity, and combined heat and power plants. Such a power system is always at the tip of a balance between demand and supply. This is reflected in significant year-to-year variations of the base price. Accordingly, the positive volume shock of increased net exports had an overwhelming role in stabilizing the price.

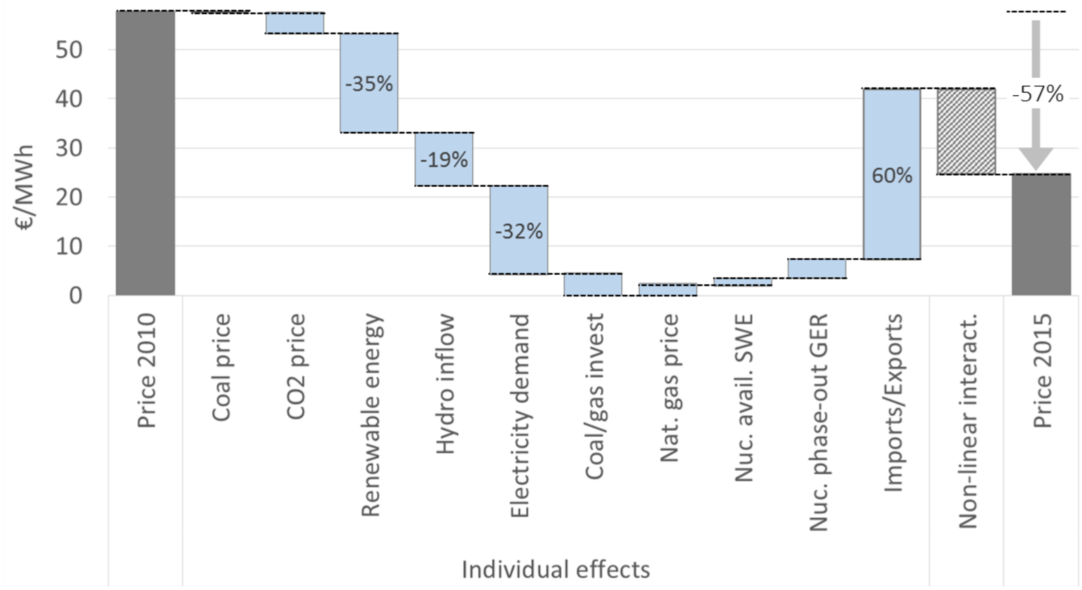


Figure 9. The change of Swedish spot prices from 2010 to 2015 showing the contribution of ten individual factors. Numbers indicate the price impact of an individual factor relative to 2010 prices.

A note of caution: the non-linear interaction term in Sweden is much greater than in Germany. This is not surprising given the very large effects of individual factors. The large interaction effect makes the interpretation of individual contributions more difficult. For example, the role of increased net exports is likely to be smaller if previous price-reducing effects are taken into account (recall that each factor is modeled as a *ceteris paribus* assessment starting from the base year parameters).

### *3.4. Discussion and further research*

The model used for this study is confined to the power sector of Northwestern Europe. It would be worthwhile further exploring the reasons for the price drop with a model that allows the sectoral and geographical scope to be increased. Endogenizing the carbon market and fossil fuel markets would be a particularly promising line of further research.

# 4. Conclusions

Understanding the past is interesting in itself, but it can also have implications for the present. Several conclusions can be drawn from our findings. First, this study shows that the biggest decline of wholesale electricity prices in Europe, in the liberalized era, was the result of the coincidence of several strong price and volume shocks. However, it was not a "perfect storm"; the price decline was mitigated by several shocks, including policy interventions (the German nuclear phase-out) and market responses (trade flows responding to changes in relative prices). Second, the study also shows that two much-debated pillars of Germany's *Energiewende*, the support of renewable energy and the nuclear phase-out, have balanced each other out in terms of impacts on the power market. Those who demand compensation for low prices caused by politicians (bearing in mind the market entrance of renewables) should be warned that a similar argument could be used to call for compensation for the price-increasing effect of the nuclear shutdown. Finally, the study shows that electricity generation is a risky business. Prices are volatile and hard to predict. Moreover, future annual volatility is likely to increase for three reasons: political interventions are likely to become ever more important, there are year-to-year fluctuations in the availability of energy from renewable energy-based power systems, and the price response of power systems with large numbers of generators with low short-term marginal costs tend to be more sensitive to volume shocks.

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