The hidden costs of electricity

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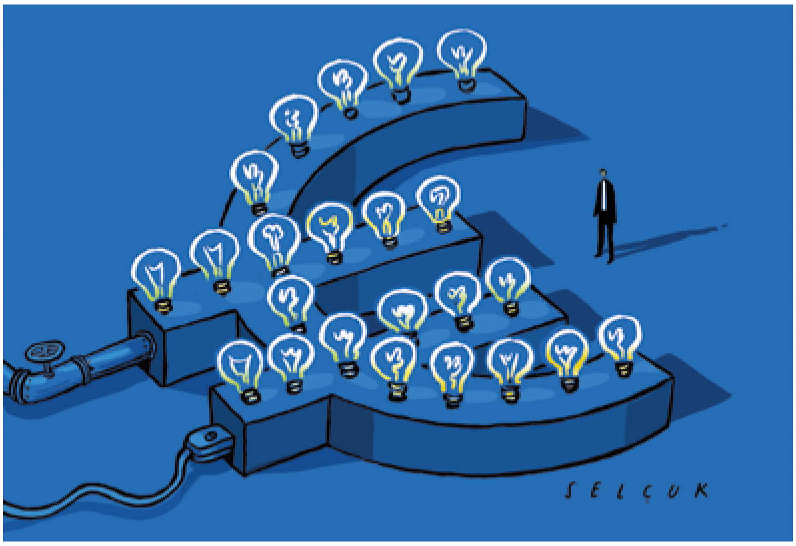
The price of electricity must take into account all the costs, both direct and induced, which are often hidden. This is true when calculating the average production cost per kWh at the power station. It is also true in the context of the operation of the wholesale electricity market based on the merit order, which leads to power stations being called on the basis of the marginal cost per kWh. Ignoring these hidden costs leads to distortions of competition and sub-optimal choices.



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In a market economy, prices must follow costs, while including a normal rate of return on invested capital. If they are much higher than costs, this generates rents. If they are lower, subsidies are required. These rents can be explained by scarcity or monopoly situations, and these subsidies can sometimes be justified on grounds of general interest. But the rule is that rents and subsidies should be eliminated as far as possible.

In the case of electricity, the price paid by an end consumer (a household, for example) in the European countries is the sum of three components:

- the cost of producing a kWh at the power station, which in France represents around 35% of the total cost, estimated at 19 euro cents on average in 2020 (i.e. €190/MWh);
- the cost of using the transmission (RTE) and distribution (Enedis) networks, which accounts for around 31% of the total cost;
- and the fiscal cost (taxes) which represents the balance, i.e. 34% of the price including VAT.

Taxes, like network access charges, escape the logic of the market, since they are set by the State for the former and by the Energy Regulation Commission (CRE) for the latter. Only the cost price of the kWh at the power station and the marketing costs set by the supplier are considered to be market prices. But the costs taken into account in the calculation ignore certain hidden costs and, moreover, the logic of market operation generates "system" costs that are not included in the cost price.

Calculation of the levelized cost of electricity

The levelized cost of electricity (LCOE) is the sum of four components:

1- the annualised cost of capital (ACC),
2- fixed operation & maintenance costs (FOMC),
3- variable operation & maintenance costs (VOMC),
4- fuel costs (CC).

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Energy	CF (%)	n (Years)	OC ($/kW)	FXC (%)	VOMC ($/MWh)	FC ($/GJ)	CE (GJ/MWh)	r (%)
Photovoltaic	15.0 %	20	1 153.00	1.10 %	-	-	-	3.0 %
Wind	25.0 %	20	1 692.00	2.60 %	-	-	-	3.0 %
Gas	85.0 %	25	917.00	1.70 %	3.25	7.50	6.60	3.0 %
Hydroelectricity	55.0 %	40	2 456.00	1.60 %	1.39	-	-	3.0 %
Coal	85,0 %	40	2 772.00	1.50 %	5.42	3.10	10.90	3.0 %
Nuclear	90,0 %	45	5 956.00	1.90 %	4.60	0.80	11.00	3.0 %

Table 1. **elements required to assess the discounted average cost of electricity (LCOE) in US$ [1].**
- CF: the plant capacity factor;
- n: the number of years the facility has been in operation;
- OC: Overnight construction cost;
- FXC: the annual fixed costs expressed in percentage of OC;
- VOMC: variable operation & maintenance costs;
- FC: the price of fuel as a function of energy capacity;
- CE: the efficiency of converting the energy released by the fuel into electricity;
- r: the return on capital.

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The facts needed to establish these four components are set out in Table 1.

The three other components of LCOE are :

$$ACC = OC \times CRF \times 1000 / (CF \times 24 \times 365)$$

with $CRF = [r(1+r)^n] / [(1+r)^n - 1]$;

$$FOMC = FXC * 1000 / (CF \times 24 \times 365);$$

$$CC = FC \times CE$$

CC is combustible cost

Based on an exchange rate of US$1 = €0.822, we obtain the values shown in Table 2.

Average cost and marginal cost

It is important to distinguish between two types of cost per kWh, excluding access charges and taxes: the average cost and the marginal cost. The average cost (LCOE for "levelized cost of electricity") is the cost price of a kWh (in present value) obtained by dividing the sum of the fixed and variable costs incurred during the economic life of the power plant by the total electricity production expected over the period. This requires an assumption to be made about the plant's availability rate during its economic life.

It is on the basis of this average cost that an investment program is decided: the plant with the lowest average cost is chosen. Three variables are therefore crucial to the calculation:
• the amount of expenditure over the lifetime of the plant,
• the volume of kWh produced over the period,
• the discount rate chosen.

The marginal cost is the only variable cost of operating the power plant (excluding fixed costs); this essentially covers the cost of fuel. It is on the basis of this marginal cost that power stations are called up to the grid (for a given fleet of power stations). Once the number of power stations is known, we start by calling up those that cost the least to run. As demand for electricity increases, we call on plants whose marginal cost increases. This is known as *merit order*. On the wholesale electricity market (known as the *day-ahead* market), the equilibrium price is aligned hour by hour with the marginal cost, which explains its volatility when marginal costs differ greatly from one plant to another.

When nuclear power is said to be marginal (at off-peak times, for example), the market price recovers only the variable costs of nuclear power. When nuclear power is infra-marginal, at peak times for example, the equilibrium market price is determined by the marginal cost of a gas-fired power station, which is higher because it is based on the variable cost of this power station (fuel cost). The difference between the market price and the marginal cost of nuclear power then enables

Énergie	ACC (€/MWh)	FOMC (€/MWh)	VOMC (€/MWh)	CC (€/MWh)	LCOE (€/MWh)
Photovoltaic	48.49	7.93	-	-	56.42
Wind	42.69	16.51	-	-	59.20
Gas	5.81	1.72	2.67	40.72	50.93
Hydro	18.13	6.70	1.14	-	25.98
Coal	13.24	4.59	4.46	27.80	50.09
Nuclear	25.33	11.80	3.78	7.24	48.15

Table 2. **Breakdown of the average cost (in €/MWh) for each energy source, updated according to [1].** LCOE = ACC + FOMC + VOMC + CC

the nuclear power plant to recover part of its fixed costs.

The logic of *merit order* means that, if the fleet is optimal, low variable cost plants will recover their fixed costs when their kWh is sold on the basis of the variable cost of a high marginal cost plant (generally at peak times). Only the marginal plant at peak will have difficulty recovering its fixed costs, which means that the price at peak will have to be slightly higher than the marginal cost.

But not all costs are necessarily taken into account when calculating average costs, and the "system" costs induced by this *merit order* logic are ignored, which explains certain distortions of competition and can lead to sub-optimal choices. In a recent study, P. Graham compared different methods for taking into account the costs induced by intermittent renewable electricity generation technologies [2].

This is why, since 2018, the International Energy Agency has tended to replace the LCOE with the VALCOE to calculate the "generalised" average cost of kWh in its publications such as the *World Energy Outlook*[3]. This means taking into account the potential value of kWh on the market (at peak times, for example), its capacity to be used as a reserve, but also the fact that it can be "controlled", i.e. adjusted in real time to electricity demand. This new calculation method tends to favour dispatchable energies such as nuclear or fossil-fired power, which have a lower relative cost, and to penalise electricity produced using intermittent energies.

The hidden costs of average cost

Carbon intensity

The quest for *carbon neutrality* by 2050 means that the **cost of the carbon** emitted in the production of a kWh must be accounted for. There is a European carbon market on which electric utilities are obliged to acquire the allowances they need for their activities. However, no account is taken of the carbon incorporated into imported equipment or materials, such as photovoltaic panels imported from China or electrical equipment manufactured abroad, whatever the energy in question. Direct CO_2 emissions should therefore not be confused with the carbon content per kWh calculated *using* a product life cycle analysis. This could, for example, justify the introduction of a carbon tax at the borders of the European Union.

Energy dependency

The **foreign currency cost** of the electricity produced is also ignored. Imported products (raw materials or finished products) are paid for in dollars, which weighs heavily on France's balance of trade. Admittedly, imports are sometimes the counterpart of export markets, but this is not always the case.

The **cost** of foreign **dependence**. This can be a dependency on certain fuels, such as gas or coal for power stations using fossil fuels. This is the case for imported uranium, which is why it is important to have a large volume of depleted uranium or reprocessed uranium available for use as fuel. This also justifies the use of Generation IV power plants if we want to avoid such dependency. But it also means dependency on rare minerals (such as cobalt) or rare earths (see the article by G. Bonhomme *et al.*, p. 144). This dependency can also be technological, which is more problematic. One example is the Arabelle turbine, considered to be the most efficient in the world, which was developed by the French company Alstom, which had come under foreign control (the American General Electric) and which EDF has just bought.

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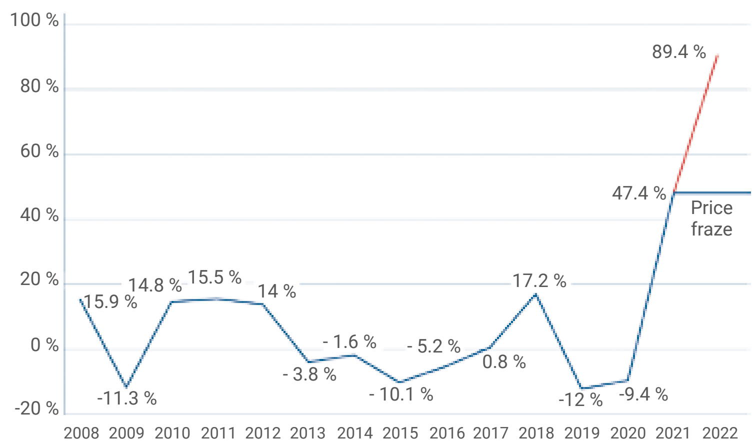
CHANGES IN GAS PRICES AND THEIR CONSEQUENCES

In 2020 and the first half of 2021, the price of gas was around €30/MWh on the European market (Rotterdam price). At the end of 2021, the price rose sharply as a result of the global economic recovery; in March 2022, it soared to over €300/MWh because of the war in Ukraine and the risk of shortages in Europe. It fell back to €80/MWh in June 2022. As the marginal cost (fuel) of the marginal (gas-fired) power plant rose sharply, the price of MWh of electricity also soared on the European wholesale market, exceeding €200/MWh on average in the first half of 2022. This situation has generated a very high infra-marginal rent for power plants other than gas-fired power plants. This explains why the government has frozen gas and electricity tariffs for domestic consumers in 2022. We are not taking into account this exceptional situation, which could certainly last for a few more months, but which does not alter the logic of the conclusions of this study.



Change in the regulated duty-free gas tariff in France from 2008 to 2022.
Source: Commission de régulation de l'énergie

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The cost of job destruction

Importing equipment that could be produced in France means destroying jobs and skills. France has lost a great deal of know-how since it sacrificed whole swathes of its industry to globalisation. Unfair competition from China, thanks to massive public subsidies, has destroyed the fledgling European industry in the photovoltaic and wind power sectors. Industry in general now accounts for just 14% of value added in France, compared with an average of 19% in the European Union and 25% in Germany. Energy accounts for little more than 2% of employment in France and 2% of GDP, even though it still accounts for 25% of industrial investment.

System costs linked to marginal cost logic

The logic of the *merit order* creates three types of distortion in the operation of the wholesale electricity market, and these so-called *external* costs or *system* costs are generally not taken into account.

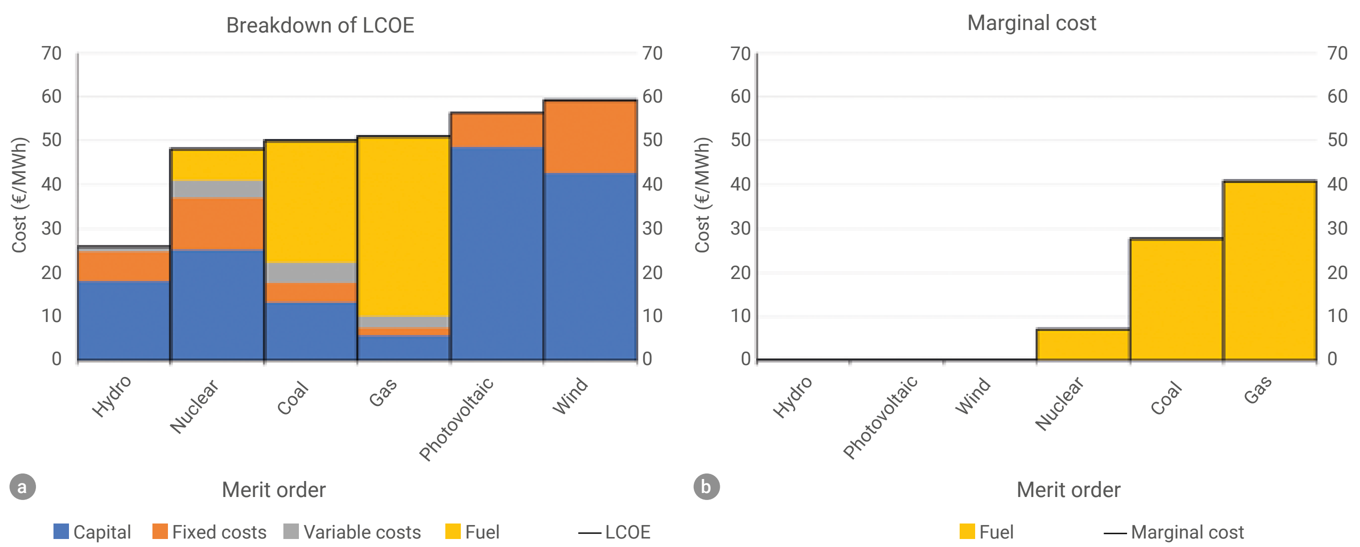
The cost of crowding-out effect

Firstly, it is the cost of displacing *dispatchable* power plants (nuclear power plants and power plants using fossil fuels) with a non-zero marginal cost by *non-dispatchable* power plants (wind and solar power plants) with a zero marginal cost. Giving priority to these intermittent *non-dispatchable* power plants increases the average production cost of *dispatchable* power plants, since it reduces the load factor of these plants. The problem is that *non-dispatchable* power plants are generally not available at peak times when market prices are remunerative, so they can only recover their fixed costs because they receive subsidies in the form of guaranteed purchase prices. The logic of calling up power stations in order of increasing marginal cost generates distortions of competition if some power stations are subsidised. Switching off *dispatchable* power plants with *non-dispatchable* power plants would be economically justified if the average cost (and not the marginal cost) of producing a kWh from *non-dispatchable* power plants were lower than the marginal cost of the kWh produced by the *dispatchable* power plants switched off.

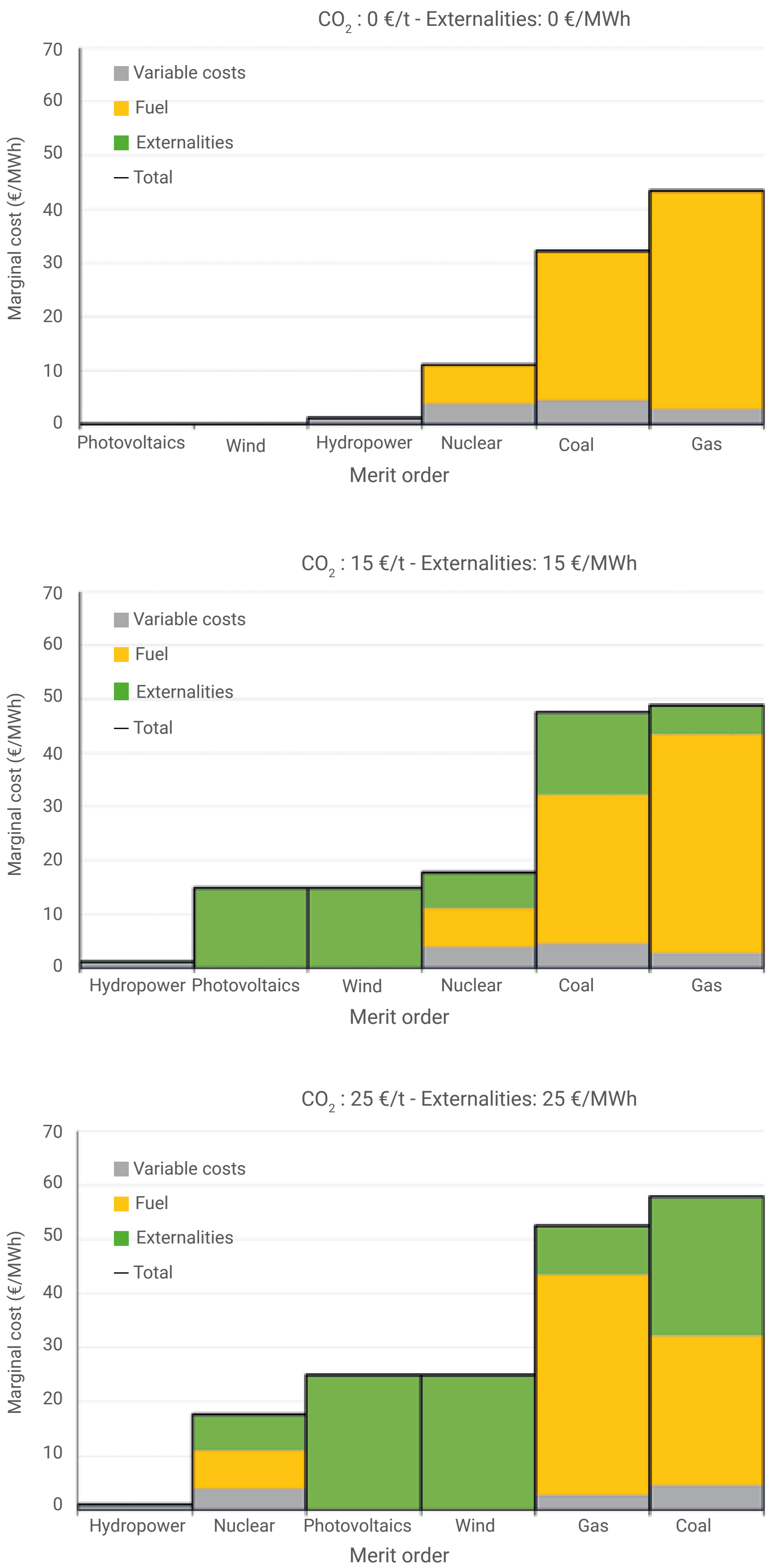
The *merit order* gives different results depending on whether the average cost or the marginal cost per kWh is used, as shown in Figure 1. If the average cost is used, then, according to recent data from the World Bank [1], power plants are called upon in ascending order of cost: hydro, nuclear, coal, gas, photovoltaic, wind. If we use the marginal cost, the order of demand by increasing cost becomes: hydro, photovoltaic, wind, nuclear, coal, gas. This is logical, since the marginal cost is essentially the cost of the fuel. This cost is zero for hydro, wind and solar, and low for nuclear.

It should be noted that the massive injection of wind and solar power, at zero variable cost, drives down the price on the wholesale electricity market (spot market). This results in a loss of income for all producers, and can even lead to negative prices in off-peak periods. It is the fatal nature of this electricity that is the main cause of these negative prices. Operators have to be paid to acquire electricity that has become cumbersome. The logical thing to do would be to interbreak off the injection of this electricity if demand is low and this risks leading to negative market prices.

In other words, the fixed cost per *non-dispatchable* kWh must be lower than the variable cost (fuel cost and carbon price) of the *dispatchable* kWh if distortions of competition are to be eliminated. The crowding out of *dispatchable* plants outside this case leads to *stranded costs*, which means that nuclear and fossil-fired operators cannot recover all their fixed costs. A study by Percebois and Pommeret published in *The Energy* Journal in 2018 estimated the loss of revenue for nuclear power due to stranded costs at several billion euros a year [4].



1. Influence of cost composition on the theoretical merit order :
(a) Average discounted electricity cost (adapted from [1]). (b) Fuel costs alone.



2. Influence of externalities on the order of merit order sources according to [6]. For *fossil fuels* the externality is CO_2 (xx €/t); for intermittent renewable energies, it is storage/destorage (Ext = yy €/MWh); for nuclear, it is waste and the cost of storage (6.7 €/MWh).

Note, as shown in Figure 1a, that the average costs of wind power and photovoltaics are higher than the marginal cost of kWh produced with coal (excluding CO_2) or gas.

The cost of *back-up*

Another ignored *system* cost is that of the *back-up* (reserve capacity) of *non-dispatchable* power plants. Power plants need to be set aside to cope with the unavailability of solar and wind power at the busiest times of the year. An alternative is to store electricity so that it can be released when needed. This could be *via* batteries in the short term, or *via methanation* in the short to medium term (electrolysis of water to produce hydrogen, which is then combined with CO_2 to produce methane for use in a gas power plant, for example).

The logic would therefore be to include the cost of storing and destoring intermittent electricity in the marginal cost of *non-dispatchable* power plants. The marginal cost of *dispatchable* power plants running on fossil fuels includes the cost of carbon (price of CO_2), which is logical since this is a negative externality that has a cost. To calculate CO_2 emissions from gas- and coal-fired power stations, we used the conversion factors of the Swiss Federal Office for the Environment (55 kg CO_2/GJ for gas and 94 kg CO_2/GJ for coal) [5]. For intermittent renewable energies, the cost of storage must be taken into account. The cost of managing nuclear waste, which is proportional to the volume of fuel processed, must also be included in the marginal cost of a nuclear kWh. A study [6] shows that the *merit order*, based on marginal costs (taking into account externalities such as carbon and waste management) for *dispatchable* power plants and based on marginal costs plus storage costs for *non-dispatchable* power plants, leads to a change in the merit order. Figure 2 illustrates the influence of externalities on the merit order 0 of energy sources.

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> The massive development of renewable energies means that we need to finance additional grid infrastructure"

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The merit order, based on marginal costs without and with externalities, remains unchanged as long as the cost of storage remains low (€15/MWh). As soon as this cost exceeds €20/MWh, nuclear power takes over from renewables. Similarly, gas-fired power stations are called upon before coal-fired power stations, not after them, as soon as the price of a tonne of CO_2 exceeds €20 to €25.

If externalities were not taken into account in the calculation, the result shown in Figure 1 would be the same, with the merit order increasing as follows: renewables, nuclear, coal and gas. Introducing these externalities puts nuclear ahead of renewables when the cost of storage is taken into account, and gas ahead of coal if the price of carbon is high. A kWh produced with coal emits almost three times more carbon than a kWh produced with gas. It should be noted that hydroelectric dam power is given special treatment in the merit order. Despite a zero marginal cost, the kWh produced by a hydroelectric dam power station is called last, since it is one of the few ways of storing electricity indirectly and on a large scale. In fact, the *value of* this hydro kWh is high, since it corresponds to the *avoided cost* of the kWh not produced in the event of a blackout, i.e. what is known as the *cost of failure*.

The cost of dependency

A third *system* cost to consider is the **growing dependency on transnational interconnections**. A study by Percebois and Pommeret [7] shows that the increase in the share of renewables in the electricity mix of European countries has generally been accompanied by a growing dependency on trade with neighbouring countries. The liberalisation of electricity within the European Union and the desire to build a single electricity market are inherently leading to an increase in trade between countries. But this increase seems to be more marked in countries with a high proportion of renewables, either because certain countries like Germany need to export their surplus electricity at off-peak times when the availability of wind and sun is high, or because other countries, such as Denmark, need to import electricity on a massive scale at peak times when availability is low.

The massive development of renewable energies means that additional grid infrastructure has to be financed, both to import electricity from neighbouring countries and to export electricity to these countries. This can constitute a negative *externality* for these neighbouring countries, which are obliged to absorb this electricity or facilitate its transit to other countries.

Smoothed electricity costs for society

Failure to include hidden costs in the economic calculation of the MWh and in the merit order mechanism leads to distortions and inconsistencies. A true-price policy first requires all the costs associated with electricity generation to be properly identified and accounted for. These externalities should also be taken into account at the level of the average cost (LCOE) of the MWh, which would show that the cost to the community ("social" LCOE) may differ from the average cost calculated by the producers when choosing the equipment to be built.

Figure 1 shows that, excluding externalities, electricity generated from gas is slightly cheaper than electricity generated from coal. The LCOE of gas is only slightly lower than that of coal, the relatively higher cost of gas compared with coal being more than offset by the higher unit cost of equipping a coal-fired power station compared with a gas-fired combined-cycle power station. The introduction of a carbon price will increase the cost differential between these two fossil fuels, since the carbon content of a MWh produced with coal is significantly higher than that of a MWh produced with gas.

It may be interesting to calculate the *pivotal carbon price* at which photovoltaic or wind-generated electricity has a lower LCOE than electricity from fossil fuels. The calculation can be carried out for increasing values of the cost of storing and destoring renewables,

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