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System LCOE: applying a whole-energy system model to estimate the integration costs of photovoltaic

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Abstract:

On the road to a carbon-neutral continent, Europe will have to implement major changes to its energy system. The following transformations are needed: massive integration of renewable energies, from which intermittent ones; electrification of the heat and mobility sectors; use of renewable fuels (e.g. biogas and hydrogen); and use of storage technologies. As a result, the energy system of tomorrow will be very different from that of today. Recently, technologies based on intermittent renewable announced cheaper production costs than their equivalent fossils. However, these announced costs usually do not account for the adaptation of the energy system to implement back-up technologies or reinforce the grid.

The levelised costs of electricity (LCOE), a common metric to compare electricity generation technologies, is extended in this work to compare dispatchable technologies with intermittent ones. By applying an energy model (EnergyScope TD) that optimises the system design and operation, it computes the integration costs of photovoltaic energy and therefore its system LCOE. We find that accounting for the integration costs almost double the system LCOE of the photovoltaic compared to a LCOE calculated on the technology only. Another key finding is the importance of the electrification among sectors, which facilitates the integration of additional intermittent renewables and at a cheaper cost.

Keywords:

Energy transition, LCOE, Energy system, EnergyScope

1. Introduction

A key to the transition is the massive deployment of renewable energies. Solar and wind potentials are greater than our energy needs [1-2]. The transformation of the energy system from fossil fuels to solar and wind energies brings several challenges, including the management of the intermittency. Surely, everyone has already heard: how will the intermittent renewables be balanced? And what will be the cost for balancing these technologies? These questions point at a complex issue: the difficulty of defining strategies to integrate intermittent renewable energies.

Academics and industrialists use a common metric for estimating and comparing the costs of electricity generating technologies: the levelised cost of electricity (LCOE) [3-5]. Sometimes, the term levelised cost of energy is also used when considering energy systems. In the following, the metric will be applied for electricity production technologies exclusively, thus the term 'electricity' is suitable. LCOE includes the full life-cycle costs (fixed and variable) of an electricity producing technology per unit of electricity produced. This metric allows comparing the generation costs of dispatchable plants with intermittent ones, like wind and solar photovoltaic (PV), despite their different cost structures. Recently, the LCOE estimates for wind and photovoltaic energy have become lower than those of fossil fuels. As an example, the European Commission has published its LCOE estimates for different technologies in 2030: hydro (€43/MWh), wind (€73/MWh), solid-fired (€79/MWh), solar (€85/MWh), and gas-fired (€94/MWh) [5]. The International Energy Agency estimates that in 2020, the production costs of solar and onshore wind energy were lower than those of gas-fired power plants in Europe [6]. Moreover, the investment costs of these technologies continue to decrease which makes them more and more profitable.

However, the LCOE metric only includes the cost of installing and using the technology without considering the cost of integrating it within the energy system. For example, a system solely based on intermittent energy sources requires supplementary storage capacities to meet the demand during low production periods. Ueckerdt et al. have developed a methodology for calculating the costs of integration of these renewable energies for photovoltaic and wind energy [7]. They applied their methods to the results of different studies where different rates of integration of renewable energies have been implemented. They estimated that having 40% of the electricity produced from wind power implies an integration cost similar to its LCOE. The same is true with 25% of the electricity produced from photovoltaic. This study was focused on the electrical system only, without considering the interactions that may exist between the different sectors of consumption and the benefits of a deep electrification. Energy systems generally focus on a single energy vector, usually electricity. As an illustration, in their review, Connolly et al. [8] counted 11 models considering all the vectors out of 37. Yet, a whole-energy system approach can lead to solutions with reduced integration costs [9].

In this work, the cost of integrating intermittent renewable energies into a whole-energy system is analysed. To achieve this, the EnergyScope TD model is exploited [10]. It allows to optimise the integration of renewable energy in the system by minimising the total cost. The model is applied to the case of Belgium, a country where the renewable potential is lower than the energy demand. To overcome this limitation, the deployment of solar energy is unconstrained to estimate its integration costs also at high penetration rates. The integration costs of PV are estimated for different greenhouse gas emission targets, up to carbon neutrality. They are compared with the costs obtained when only the electrical system is considered.

At first, the energy model and the case study are described (Section 2). Then, the method for calculating the LCOE of a technology and the estimation of its integration costs is developed (Section 3). This methodology is applied to the electricity sector alone (Section 4) and all sectors (Section 5). Finally, the results are discussed highlighting the key role of electrification (Section 6).

2. Model and case study

In this paper, the results are obtained with a linear programming open-source energy model, EnergyScope TD [10]. It represents with the same level of detail the heating, mobility and electricity sectors. Its main features are: (i) satisfying the system end-use demand, accounting for electricity, heat and transport; (ii) optimizing both the design of the system and the operation by minimising its overall cost; (iii) an hourly resolution which makes the model suitable to analyse the integration of intermittent REs; (v) a low computational cost thanks to a method resorting on typical days (TDs). Hereafter, both the energy model and the case study are described.

2.1. Energy system modelling

As shown in Figure 1, the model is based on a series of parameters - imposed a priori - including the cost and availability of the resources, the technical and economic characteristics of the technologies, the demands of the different sectors and their hourly time series. From these inputs, the model minimises the total annualised cost of the system, i.e. the annualised investment costs of the technologies plus their maintenance costs and the prices of the resources used. The optimised variables are the capacities of the installed technologies and their hourly operation over a year. The system is constrained by a set of equations, for example to balance each of the energy carriers at every hour, or to reinforce the electricity network when intermittent renewable is deployed, or to limit the greenhouse gas emissions. The main constraint of the problem is to satisfy the nine different energy demands (electricity, high-temperature heat, public passenger mobility...) which are imposed exogenously. By optimising the problem, the solution gives the optimal design of the system and its hourly operation over one year.

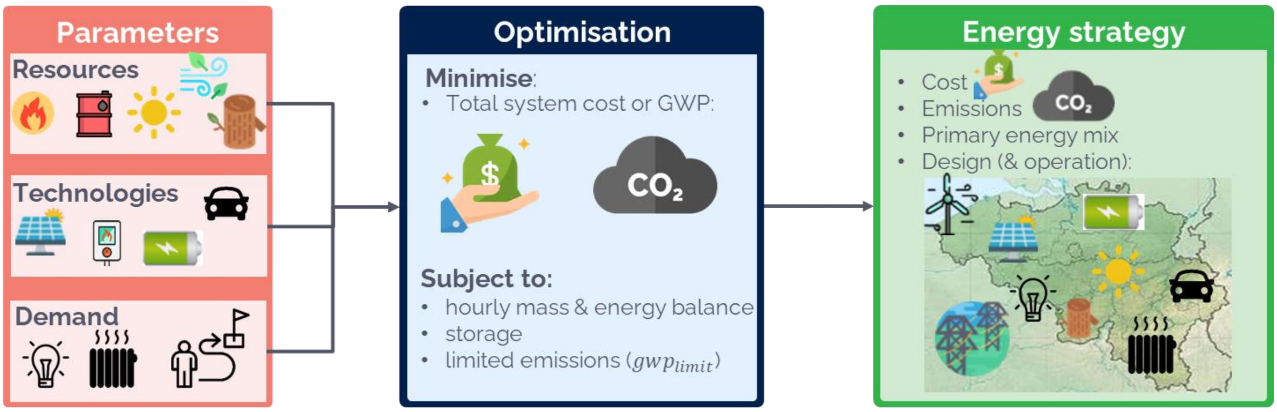

Fig. 1. Overview of EnergyScope TD.

2.2. Case study

The case study must meet certain criteria to be used with the model. The territory has homogeneous weather conditions, a high energy demand and a strong dependence on fossil fuels. Belgium, among others, perfectly suits these criteria. The case study has been previously presented and analysed in [11] where different strategies have been evaluated to reach carbon neutrality. In that study, the most realistic scenario is based on the import of electricity and renewable fuels from abroad. In the that scenario, the full potential of renewable in Belgium is deployed (160 TWh) and covers half of the primary energy demand. To underline the difficulty of integrating intermittent renewables, no import of electricity and renewable fuels is allowed. The system accounts for 104 technologies (e.g. combined cycle gas turbine, gasoline car, gas storage, electrolyser, etc.), 13 resources (e.g. diesel, wood, natural gas, atmospheric CO_2, etc.) and 9 end-use demands (private mobility, freight mobility, industrial heat, electricity, etc.). Compared to the case study presented in [11], the solar potential has been unconstrained. In addition, some technologies and resources have been removed: nuclear, geothermal and the integrated gasification combined cycle for coal. Nuclear and geothermal could facilitate the integration of intermittent renewables at an affordable cost (as shown later in Figure 2). However, Belgium plans to phase out Nuclear in 2025 and the geothermal potential is today unproven. Finally, Belgium does not plan to build new coal power plants.

3. Levelised cost of electricity

The levelised cost of electricity (LCOE) is a common metric to compare different electricity production technologies. It measures the net present cost of electricity generation by one technology or by a whole system during its lifetime. This metric relies on a financial assumption that accounts for a technology lifetime and a discount rate. The LCOE is defined as the ratio between the cost and the expected electricity produced. In the following, all costs are expressed in $€_{2015}$.

3.1. Technology LCOE

For a technology, the LCOE can be computed *a posteriori* based on the real data. However, it is generally estimated *a priori* to assess the profitability of an investment without accounting for the system integration costs. In this case, assumptions are made on the production. The expected production is calculated based on the lifetime (*lifetime*) and the expected capacity factor ($c_{p,expected}$), which is different for each production unit: Nuclear (85%), coal (70%) and geothermal (85%) are expected to be used as base loads, whereas combined cycle gas turbine (CCGT) has a lower load factor (50%) and non-dispatchable renewables are constrained by their resources resulting in lower estimated capacity for solar (11.8%), onshore wind (24.3%) and offshore wind (41.2%) (data for RE from real production in 2015 for the country, data collected by the transmission system operator).

In the model, the LCOE for each technology for electricity production (TECH_ELEC) can be calculated as the sum of the contribution related to, on the one hand, the capital expenditure ($lcoe_{capex}$), Eq. (1), and on the other hand, the contribution related to operating expenditure ($lcoe_{opex}$), Eq. (2). For each technology, the capital recovered is the product of the investment cost (c_{inv}) and the capital recovery factor (crf), Eq. (1). The latter is defined in Eq. (3) and can be expressed in terms of the interest rate (i_{rate}) and the lifetime. The contribution of the operational expenditure to the LCOE accounts for the operating expenses (c_{op}), and the yearly maintenance cost (c_{maint}), Eq. (2). The operating expenses account for the purchase of the resources; it is calculated based on the resource costs and the technology efficiency, Eq. (2). The technical and economic data for the technologies are summarised in Table 1.

$$lcoe_{capex}(i) = \frac{c_{inv}(i) \cdot crf(i)}{c_{p,expected} \cdot 8760} \qquad \forall i \in TECH\_ELEC \qquad (1)$$

$$lcoe_{opex}(i) = c_{op}(res) \cdot \eta(i,res) + \frac{c_{maint}(i)}{c_{p,expected} \cdot 8760} \qquad \forall i \in TECH\_ELEC, \forall res \in RESOURCES \qquad (2)$$

$$crf(i) = i_{rate} \cdot \frac{(1+i_{rate})^{lifetime(i)}}{(1+i_{rate})^{lifetime(i)-1}} \qquad \forall i \in TECH\_ELEC \qquad (3)$$

Table 1. Technical and economic characteristics of electricity production technologies. Data from [11]. The maximum installable capacity is given (max). Even if not allowed, nuclear and geothermal are given for comparison. For the latter, the potential proposed in [11] is used.

Technologies	c_{inv} [M€/GW]	c_{maint} [M€/GW/y]	η [-]	$c_{p,expected}$ [-]	max [GW]	$lcoe_{capex}$ [€/MWh]	$lcoe_{opex}$ [€/MWh]	**lcoe [€/MWh]**
Photovoltaic	870	9.9	- [c]	11.8%	60-∞[a]	34.8	14	**48.8**
Wind on.	1040	2.8	- [c]	24.3%	10	23.6	1.3	**24.9**
Wind off.	4974	9.6	- [c]	41.2%	3.5	66.5	2.7	**69.2**
Geothermal	7488	139	- [c]	95%	2	41.9	19.1	**61.0**
Hydro	5044	50.4	- [c]	48.8%	0.2	39.8	11.9	**51.7**
Nuclear	4845	102.9	36.7%	85%	2	16.5	24.3	**40.8**
CCGT	771	19.6	63.0%	50%[b]	∞	8.5	74.7	**83.2**
Coal	2516	29.4	49.0%	70%	∞	15.2	40.8	**56.0**

[a] the solar potential in [11] is estimated at 60 GW. In this work, there is no limit (∞).

[b] the LCOE is driven by the OPEX part, changing $c_{p,expected}$ has little influence on the LCOE.

[c] Renewable potential is generally expressed in terms of electrical output. Thus no efficiency is given.

By combining the estimated production costs and the potential of each technology, it is possible to reconstruct a curve of production costs as a function of the amount of electricity produced by each of the technologies, see Figure 2.

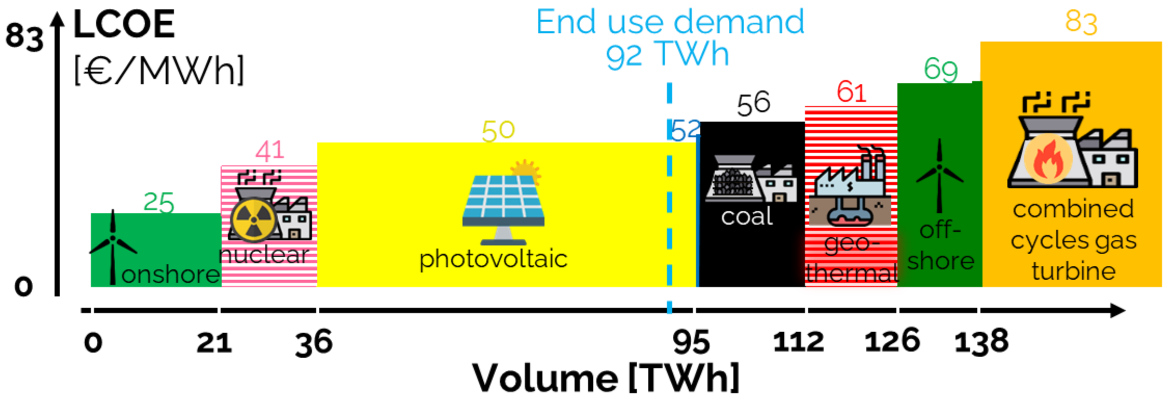

Fig. 2. Yearly volume of electricity production sorted by their LCOE. Stripes blocks represent technologies not allowed (nuclear and geothermal) in this study. The Blue dashed line represents indicatively the annual electricity end-use demand. The LCOE value is given on top of each bar. The hydro potential (in blue) is around 0.5 TWh.

3.2. System LCOE

The system LCOE accounts for the costs of the technologies and of their integration. This metric is deemed a more relevant LCOE for intermittent technologies, which are in this case, solar and wind. As proposed by Ueckerdt et al [7], integration costs can be estimated by varying the installed capacity of a technology. By comparing the new costs with a reference solution, the extra cost of the system can be related to this technology. The extra cost reflects the means used to integrate the technology, i.e. : (i) the reinforcement of the electricity grid; (ii) the deployment of storage capacities (e.g. electrical, thermal, etc.); (iii) the deployment of production capacity for synthetic fuels, such as hydrogen or methanol, which can be stored over the longer term but also used in other sectors; or (iv) the loss of production due to the curtailment of a part of the production.

In the model, the cost to reinforce the network (i) is assumed proportional to the intermittent renewable capacity deployed. On the basis of the estimated reinforcement of the Swiss and Belgian grids, the cost of integrating 1GW into the network ($c_{grid,extra}$) is estimated at 358M€. By annualising this cost ($\tau(GRID)$) and multiplying by the installed capacity of each technology ($\mathbf{F}$), the annualised cost of reinforcing the network ($\mathbf{C_{grid,reinforce}}$) is estimated, Eq (4). The annualisation depends on the technology lifetime (*lifetime*), Eq. (5).

$$\mathbf{C_{grid,reinforce}} = c_{grid,extra} \cdot \tau(GRID) \cdot \Big(\mathbf{F}(Wind_{onshore}) + \mathbf{F}\big(Wind_{offshore}\big) + \mathbf{F}(PV)\Big) \tag{4}$$

$$\tau(i) = \frac{i_{rate}(1+i_{rate})^{lifetime(i)}}{(1+i_{rate})^{lifetime(i)}-1} \quad \forall i \in \text{TECHNOLOGIES} \tag{5}$$

The deployment cost for storage technologies (ii) or those producing synthetic fuels (iii) is equal to the sum of the annualised investment costs plus their annual maintenance costs. Eqs. (6) and (7) define the costs for storage technologies ($\mathbf{C_{sto}}$) and synthetic fuel production technologies ($\mathbf{C_{syn.fuels}}$), respectively.

$$\mathbf{C_{sto}} = \sum_{i\ in\ STORAGE} \left(\mathbf{F}(i) \cdot c_{inv}(i) \cdot \tau(i) + c_{maint}(i)\right) \tag{6}$$

$$\mathbf{C}_{syn,fuels} = \sum_{i\ in\ SYN.FUELS} \left(\mathbf{F}(i) \cdot c_{inv}(i) \cdot \tau(i) + c_{maint}(i)\right) \tag{7}$$

There are two options to calculate the integration costs related to the curtailment: the expected capacity factor can be reduced to the real production or the curtailed production can be assimilated to an equivalent installed capacity. For sake of simplicity, the second option has been implemented. Eq. (8) calculates the load curtailed as the cost of installed and unused technologies for onshore wind power, offshore wind power and photovoltaics. For each one of these technologies, the equivalent unused capacity is equal to the installed capacity multiplied by the curtailed fraction. The latter is defined as the ratio between the maximum production ($\mathbf{Prod_{max}}$) minus the effective production ($\mathbf{Prod}$), and the effective production ($\mathbf{Prod}$).

$$\mathbf{C_{over,prod}} = \sum_{i \in \{Wind_{onshore}, Wind_{offshore}, PV\}} \left(\mathbf{F}(i) \cdot c_{inv}(i) \cdot \tau(i) \cdot \frac{\mathbf{Prod_{max}}(i) - \mathbf{Prod}(i)}{\mathbf{Prod}(i)}\right) \tag{8}$$

Finally, for the PV technology, the system LCOE is calculated as the LCOE related to the technology (non integrated) plus the integration costs, i.e. the ratio of the extra costs divided by the expected production, Eq. (9). Beforehand, a reference cost ($\mathbf{C_{ref}}$) must be deducted from the extra costs. The latter is defined as the sum of the extra costs for the reference scenario.

$$\mathbf{LCOE_{system}}(PV) = lcoe_{capex}(PV) + lcoe_{opex}(PV) + \frac{\left(\mathbf{C_{grid,reinforce}} + \mathbf{C_{sto}} + \mathbf{C}_{syn,fuels} + \mathbf{C_{over,prod}} - \boldsymbol{C_{ref}}\right)}{c_{p,expected} \cdot 8760} \tag{9}$$

4. Integration costs in an electricity system

This paper focuses on the analysis of the integration costs of intermittent renewable energies and the importance of electrification in their integration. In this first section on the results, the electrical system is analysed independently of the other sectors. In this case, only the end use demand in electricity will be considered (≈92TWh/y) and the other sector demands are omitted. A priori, the electric system can satisfy its demand with 33 TWh of wind and 60 TWh of solar (synthetic gas produced from biomass cannot be used).

4.1. PV integration costs

The reference scenario is defined at 20 $MtCO_2$/y for the power system. The electricity mix is based on cheap intermittent renewables and gas burned in flexible CCGTs. This results in a need for 46 TWh of flexible electricity production. With lower emissions, the system has no choice but to install more PV.

Figure 3 shows the technology and integration costs for the four categories detailed in Section 3. With emissions below 20 $MtCO_2$, the solar capacity exceeds 15 GW of installed capacity. In this case, the peak output is higher than the demand and the system uses different strategies to absorb these excesses. From 15 $MtCO_2$, the system curtails about 10% of the production and 387 GWh of batteries are installed. When emissions are further reduced, the same proportion of photovoltaics is curtailed. This amount (10%) represents the summer peaks that are not needed to be stored in the short term and are too expensive to be stored in the long term.

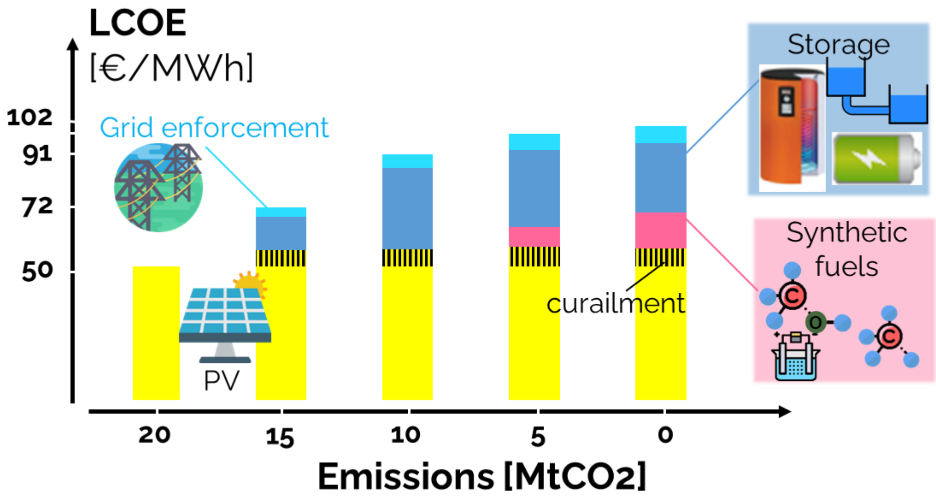

Fig. 3. The system LCOE for the integration of photovoltaic in an energy system accounting for the electricity sector only.

To understand this phenomenon, let's focus on one of the typical summer days, see Figure 4. It shows that the photovoltaic peak covers more than the end use demand (around 11 GW) plus the use of electrolysis and battery charging during the day. Batteries are used to supply the demand during the night. Reducing curtailment would be tantamount to deploying under-utilised technologies that would therefore not be cost-effective. This amount of curtailment appears to be a trade-off between the deployment of more PV and its integration.

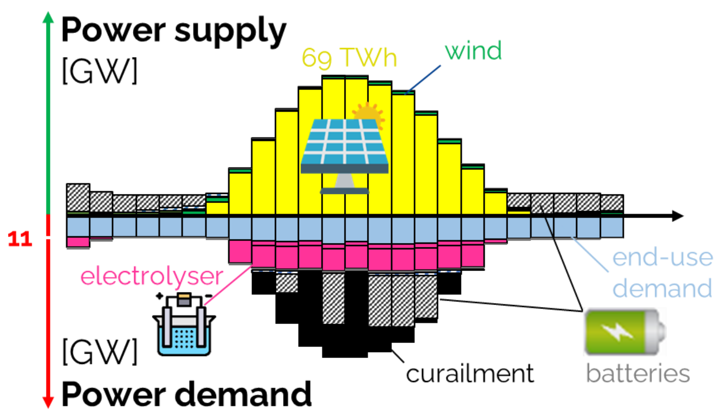

Fig. 4. Power balance in a carbon-neutral energy system for a typical summer day. The excess of electricity is used to provide electricity during the night and produce hydrogen. Additionally, a significant part is also curtailed.

4.2. Focus on the carbon neutral case

In the carbon neutral case, to integrate solar energy on a massive scale, it is necessary to shift part of the production from day to night via batteries and part from summer to winter via power to gas to power. This long-term storage method has a round trip efficiency of around 38%. In addition, part of the PV production cannot be absorbed at low cost and is curtailed. In this scenario, the average cost of electricity production is around 102€/MWh.

The annual electricity balance is shown in Figure 5. It can be seen that the curtailment is mainly on solar rather than wind power. A quarter of the electricity demand is covered by batteries and 10% by power to gas to power. Indeed, in summer, the surplus of renewable electricity is converted into hydrogen and then into methane for long-term storage. To create this molecule, the technology needs CO_2 capture. To do this, 3.4 TWh of electricity are used to drive the direct air capture of CO_2. The methane is mainly stored seasonally. In addition, half of the hydrogen is stored. This storage smoothens the hydrogen supply for methanation that run at base-load during sunny days.

Fig. 5. Yearly electricity balance for the carbon neutral electricity system. The gas produced (bottom right), is used in the system (bottom left).

5. Integration costs in a whole-energy system

The previous results were obtained by focusing on the electricity sector satisfying a demand of 92 TWh/year. In this second section on the results, the entire energy system is taken into account. The annual demand also includes heat (212 TWh) and mobility requirements (194 Gpass-km and 98 Gt-km, i.e. in the order of magnitude of 118 TWh if exclusively supplemented by diesel). Compared to the previous results, the electric system can produce excesses that are used to electrify the other sectors. This has several advantages such as enabling technologies that bridge the electricity sector with other sectors. They are generally more efficient than their fuel equivalent. We deem a technology 'more efficient' if it consumes less primary energy for a similar or improved service than another technology. For example, a heat pump is more efficient than a gas boiler and an electric vehicle (truck, bus or car) is more efficient than one based on internal combustion engine in terms of distance travelled (assuming electricity produced with RE or CCGT).

5.1. PV integration costs

Similar to Figure 3, Figure 6 shows the integration costs relatively to the CO_2 emissions allowed. Considering emissions from the heat and mobility sectors, which are highly dependent on fossil fuels, increases strongly the reference solution emissions up to 75 $MtCO_2$/y. In this scenario, wind onshore and offshore are already fully deployed at the highest emissions. Compared to the previous results, the trends are similar, except for a lower curtailment, an earlier use of synthetic fuels and a reduced cost of storage.

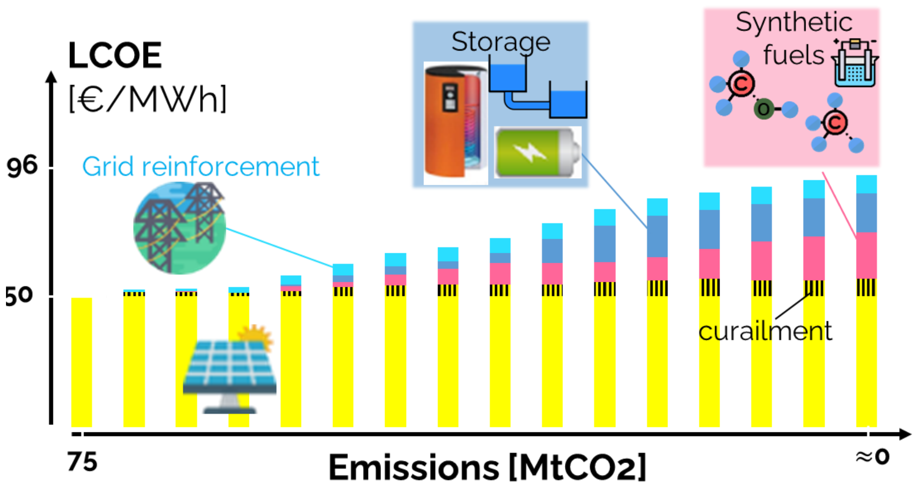

Fig. 6. System LCOE for the integration of photovoltaic in an energy system accounting for all sectors.

When lower emissions are imposed and only solar energy can increase, the system massively deploys PV. From the start, a small part (2-3%) is curtailed. However, this is well below the 10% obtained previously. Indeed, even during peaks in solar energy production, the system will be able to rely on the electrification of mobility and heat to absorb the excess of sun-produced electricity and, above all, the use of heat pumps coupled with thermal storage. In dwellings, heat pumps provide a small amount of sanitary hot water in summer. But on the scale of a heat network, seasonal storage enables the production of heat in summer – through heat pumps – which is consumed in winter.

4.3. Focus on the carbon neutral case

In the carbon neutral case, 181 TWh of electricity are consumed for electricity (92 TWh), heat (84 TWh) and mobility (5 TWh). In addition, 79 TWh are used to produce synthetic fuels.

Figure 7 shows the seasonally stored energy for the carbon-neutral case. The system installs 25.6 TWh of seasonal thermal storage at a cost of 666 millions of euros. As a comparison, the 0.11 TWh of batteries installed cost 2 446 millions of euros. In spite of the heat losses (7 TWh), the thermal storage shifts a part of the heat pumps consumption from winter to summer. In addition, there is a gas storage (37.1 TWh) which is used to store the gas produced by methanation. It will be used to balance the electricity needs but also to satisfy mobility needs.

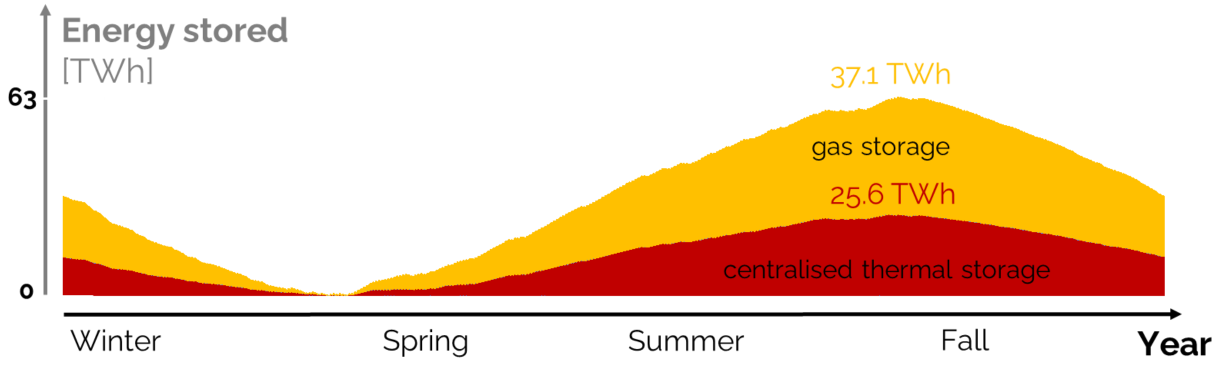

Fig. 7. Seasonal storages for the carbon neutral energy system. The gas and thermal storage are used on a yearly cycle, charging mainly during summer from solar energy.

The most economical powertrains for cars and trucks are fuel cells. These vehicles consume hydrogen produced from the electrolyser when there is excess electricity and from methane reforming during deficits. Thus, 50% of the gas stored seasonally is used in these vehicles.

Electric vehicles have a major opportunity for the integration of renewable energy since they contain batteries that can shift production and demand. However, their deployment implies an increased demand for electricity which is only of benefit to the system if a large proportion of the cars remain connected to the grid. It seems surprising that the electric car is not used. Indeed, this technology consumes 35% less energy than a fuel cell car and 49 to 68% less than a car with a combustion engine. This version of the model considers a 4-hour charging and discharging time of the car batteries and that only 20% of them could be recharged simultaneously. With these hypotheses, the system does not implement the technology because, with its daily demand of up to 46 GWh of electricity, it stresses the electricity network too much on days when there is not enough renewable energy. By increasing the availability to 100%, i.e. allowing all the electric vehicles (EVs) to be connected to the grid at the same time, this technology replaces the fuel cells. Despite the fact that they stress the grid, electric cars are used to absorb solar peaks by smart charging (15.8 TWh/y) and support the grid with vehicle-to-grid (9.6 TWh/y). In addition to daily storage cycles, EVs are used over several days to balance weeks when there is not enough renewable energy.

6. Electrification as a key to reach low emission energy system

Comparing the integration costs of PV between an electrical-only system and a whole-energy system highlights the benefits of electrification. It appears to be a key to the transition on several aspects: (i) it facilitates the massive integration of intermittent renewables by providing flexible consumers, (ii) it facilitates the deployment of efficient technologies, (iii) it allows more renewable energy to be used in the heat and mobility sectors.

6.1. Electrification, the cheap option to integrate massively renewables

Figure 8 shows the integration costs of solar energy as a function of the installed capacity (based on the results shown in Figures 4 and 6). It can be seen that the integration costs for an electrical system are much higher for relatively small capacities. As a comparison, the electrical system can integrate 16 GW without extra integration costs. In the case of the energy system, up to 22 GW can be installed. In both cases, flexibility will be provided by CCGTs using gas. Moreover, in the energy system, heat pumps coupled to storage are used to absorb the additional 6 GW.

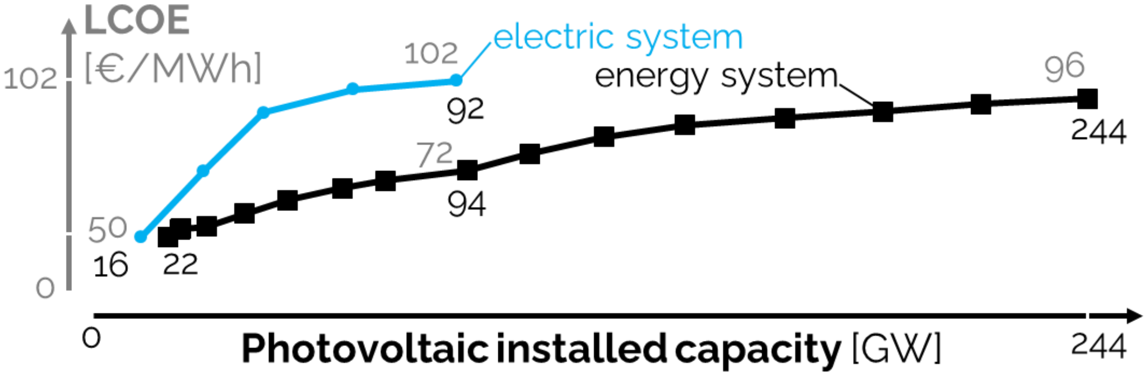

Fig. 8. Integration cost of Photovoltaic (PV) for different installed capacity. Integrating PV in an energy system is cheaper and allows more deployment. Numerical values for capacity and LCOE are given in black and grey, respectively.

The electrical system can deploy up to 92 GW of PV at a cost of 102€/MWh. To deploy a similar amount in an energy system, the system LCOE is only 72€/MWh. In addition, the energy system can integrate three times as much solar energy as the electrical system and at a lower cost.

6.2. Electrification enables the deployment of efficient technologies

For the electricity sector, electrification is beneficial; however, ones could wonder if for the other sectors, this electrification is more expensive than other options. By way of comparison, using gas to produce heat costs €44/MWh via a boiler (efficiency close to 93%), i.e. half the cost of electricity from integrated PV. However, the use of electricity makes it possible to use more efficient technologies, such as heat pumps that can produce up to 4 units of heat with 1 unit of electricity. In this case, it is necessary to spend 32€/MWh of heat produced, which is less than with gas in a boiler. The same applies to mobility. Freight and public transports make maximum use of the railway infrastructure, metros and trams. These technologies use less energy per km travelled and can generally carry more passengers or tons of goods than their fuel-based equivalents today, i.e. trucks and buses.

However, totally electrifying sectors might not be appropriate, such as high-temperature heat (where heat pumps cannot be used efficiently). Other technologies such as gas-fired boilers or cogeneration will have to be retained.

6.3. Electrification enables the use of more renewable energies

Three of the main sources of renewable energy are wind, solar and hydropower. These sources produce electricity, although solar energy can also produce heat. In the other sectors, renewable sources are biomass and geothermal energy for heat, and the conversion of biomass into fuels for mobility. The potential of these resources is more limited than the first three. Therefore, electrification can also bring more renewable energy into the mobility and heat sectors.

However, the solar potential is actually limited by the surface it covers. Devogelaer estimates that by using all roofs with the right orientation, a total of 60GW could be installed in Belgium [12]. This is well below the 244 GW required for the energy system. Importing energy and reducing our consumption will be the two keys to achieve carbon neutrality. Therefore, countries with a surplus potential will benefit from an important export demand from densely populated countries like Belgium. They will be able to sell their surplus in the form of electricity or synthetic fuels. In these countries, the integration of intermittent energies will have to be done by thinking on a system-wide scale and by thinking of producing surpluses for export.

7. Conclusion

In this work, a method for calculating the LCOE of the energy system was proposed. This method makes it possible to distinguish between the LCOE of a non-integrated technology which can be calculated 'a priori' and the LCOE of the system which considers the integration costs of this technology, calculated 'a posteriori'. This definition makes it possible to compare non-dispatchable technologies with dispatchable ones.

By applying a model which optimises the design and operation of a whole-energy system we identified the benefits of electrification in the integration of intermittent renewable energies. The approach was applied to a country with limited renewable potential where only the solar resource - highly intermittent - is considered unlimited. By comparing two scenarios, one including just the electrical system, and another including the entire energy system, the cost of integrating solar energy has been estimated for several greenhouse gas reduction targets.

The levelised cost of electricity (LCOE) of the photovoltaic (PV) technology is estimated at 50 €/MWh in 2035, which is consistent with the literature [5,13]. However, when its integration costs are considered, i.e. additional investments for storage capacity, grid reinforcement, production of synthetic fuels (i.e. hydrogen) and the curtailment of part of the production, the LCOE of the system can up to double.

Focusing only on the electricity sector only increases strongly the integration costs, for example, integrating 92 GW of photovoltaics into the electricity sector induces a system LCOE of €102/MWh, compared to €72/MWh in an integrated system. The electrification of different sectors is beneficial to the electricity sector by reducing the cost of integrating intermittent energy, but also allowing other sectors to deploy more efficient technologies and take advantage of abundant renewable energy sources: solar and wind.

In conclusion, the integration of intermittent energy in the electricity sector should not be seen as a single sector problem. On the contrary, the electrification of other sectors will bring flexible consumers who will adapt - partially - to the production peak. To satisfy this additional demand, the amount of renewable energy will have to be oversized compared to the end-use demand for electricity. As a result, the times when there will not be enough energy to meet the electricity needs will be reduced. Thinking that PV and wind have to cover only the electricity demand will imply extra costs. Thus, facilitating the integration of intermittent renewables, i.e. limiting the system LCOE, requires an important electrification and benefit of the demand-side management enabled by the heat and mobility sectors.

Nomenclature:

Abbreviations:

CRF		Capital recovery factor
EV		Electric vehicles
LCOE		Levelised cost of electricity
PV		Photovoltaic

Sets

$TECHNOLOGIES\ (TECH)$		Technologies
$TECH\_ELEC \in TECH$		Technologies with electricity as main output
$RESOURCES$		Resources

Parameters

$c_{inv}(TECH)$	[M€/GW]	Technology specific investment cost
$c_{maint}(TECH)$	[M€/GW/y]	Technology specific yearly maintenance cost
$c_{p,expected}(TECH)$	[-]	Expected yearly capacity factor
$c_{grid,extra}$	[M€/GW]	Cost to reinforce the grid per GW of intermittent renewable
$c_{op}(RESOURCES)$	[M€/GWh]	Specific cost of resources
$crf(TECH)$	[-]	Capital recovery factor
i_{rate}	[-]	Real discount rate
$lcoe_{capex}(TECH)$	[M€/GWh]	LCOE related to the capital expenditure
$lcoe_{opex}(TECH)$	[M€/GWh]	LCOE related to the operating expenditure
$lifetime(TECH)$	[y]	Technology lifetime
$\tau(TECH)$	[-]	Investment cost annualization factor

Variables

$\mathbf{C}_{grid,reinforce}$	[M€/y]	Yearly cost to reinforce the network
$\mathbf{C}_{over,prod}$	[M€/y]	Yearly cost of curtailment
$\mathbf{C}_{ref}$	[M€/y]	Yearly cost of the reference scenario
$\mathbf{C}_{sto}$	[M€/y]	Yearly cost for storage technologies
$\mathbf{C}_{syn,fuels}$	[M€/y]	Yearly cost for synthetic fuels production technologies
$\mathbf{F}(TECH)$	[GW] (or [GWh])	Installed capacity with respect to the main output [GW] (for storage: installed capacity [GWh])
$\boldsymbol{Prod}\ (TECH)$	[GWh]	Effective yearly production of a technology
$\boldsymbol{Prod}_{max}(TECH)$	[GWh]	Maximum yearly production of a technology

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