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Analysis of the cost of electricity in a 100\% renewable energy system

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Abstract

Renewable generation is expected to grow in share in the following years as a result of growing climate concerns among others. Wind and solar energy will become the main generation technologies and their intermittency will result in important changes in the energy system. The question of the cost of such a transition is addressed. The measure of cost used in this paper is the system levelized cost of energy (LCOE) which includes both generation and integration costs. M. Jacobson et al. (2017) investigates a transition to 100% renewable energy along with the electrification of all energy sectors and developed a broad roadmap for 139 countries in the world. This work challenges some of their assumptions regarding generation, transmission, distribution and storage costs before estimating a corrected value of the system LCOE for Europe by 2050. Results indicate that it would lie between \$124.6/MWh and \$172.1/MWh and that the cost is not uniformly distributed across Europe. It is higher than the system LCOE projected by M. Jacobson et al. (2017) and the main difference lies in the storage costs.

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List of abbreviations

BAU	business as usual
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CSP	concentrated solar power
DOD	depth of discharge
EROI	energy return on investment
GtP	gas-to-power
HCLB	high cost, low benefits
HVDC	high voltage direct current
LCHB	low cost, high benefits
LCOE	levelized cost of electricity
LCOS	levelized cost of storage
OCGT	open cycle gas turbine
O&M	operation and maintenance
PCM	phase-changed material
PHS	pumped hydro storage
PtG	power-to-gas
PV	photovoltaic
RE	renewable energy
SNG	synthetic natural gas
STES	sensible energy storage
TES	thermal energy storage
TFC	total final consumption
T&D	transmission and distribution

USD	United States Dollar
UTES	underground thermal energy storage
VRE	variable renewable energy
VRF	vanadium redox flow
WWS	wind, water and sunlight

Contents

1 Introduction

Ever since the 19^{th} century and the first industrial revolution, energy has been a resource of primary importance, either in the industry or in the households day-to-day life. Energy is necessary for heating, cooling, transportation, etc. and is, today, one of the major challenges of both political and economical scenes.

Through the years, the needs in energy have never stopped growing and are expected to continue to do so. Today, Belgium consumes annually 491 TWh of final energy (IEA, 2017b) and a household in Wallonia has an average annual energy consumption of 22,152[1] kWh (SPW, 2017). As a matter of example, it takes 116 Wh to bring one liter of water from 0°C to 100°C (Benson, 2015), a large fridge has a consumption of 140 kWh per year[2] and watching the television for an hour consume 147 Wh[2].

The sources of energy have also seen an important evolution through the years, from animal traction to nuclear energy through coal, oil, natural gas, etc. Today, the world total final consumption (TFC) of energy is equal to 111,128 TWh and is distributed by fuel as follow: 41% oil, 19% electricity, 15% natural gas, 11% coal, 11% biofuels and waste and 3% other sources of energy. In Europe, the TFC reaches 14,310 TWh while the electricity consumption is equal to 3,397 TWh (IEA, 2017a).

The renewable energy share in electricity generation has seen an important growth in the last 15 years. While wind and solar generation only represented 0.6% of the total electricity generation in 2005, it now represents 5.2%. Renewable generation share in the world today is 22.2%, mostly driven by hydro generation. The share of the different fuels used in electricity generation in 2016 is summarized in figure 1 and the renewable share in electricity generation per European country is described in figure 2.

[1]Large numbers are written following the anglo-saxon convention, the comma being used as a thousands separator.

[2]The consumption is an average as it will depend on the device size, specifications and use.

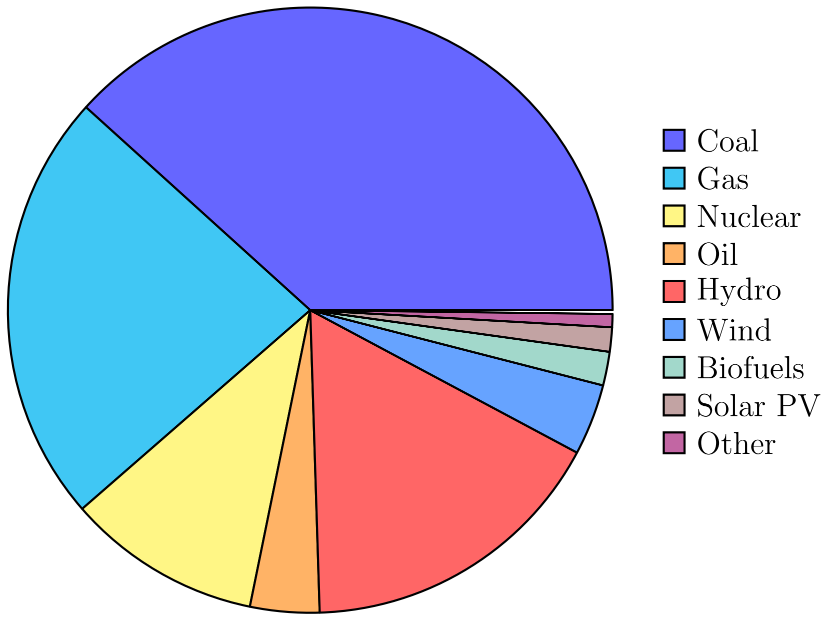

Figure 1: Share of electricity generation by fuel in the world in 2016 (IEA, 2017a).

In the years to come, the worldwide energy sector is expected to undergo an important transition, with variable renewable energy sources (i.e. solar, wind) growing in importance in the energy mix at the expense of conventional thermal generation as a result of growing climate concerns, increasing willingness to be self sufficient, fossil fuel reserves depletion, increasing fuel prices and decreasing cost of renewable generation among others.

In its World Energy Outlook, the International Energy Agency (IEA) developed three scenarios regarding the future: a "current policies scenarios" whereby no new measure is allowed, a "new policies scenario" whereby announced targets and intentions are taken into account, and a "450 scenario" whereby decisions are made as to respect the objective of restricting the rise in global temperature by 2100 to 2°C above pre-industrial era (IEA, 2016).

The IEA projects the TFC in 2040 to reach respectively 157,633 TWh in the "current policies scenario", 143,851 TWh in the "new policies scenario" and 125,965 TWh in the "450

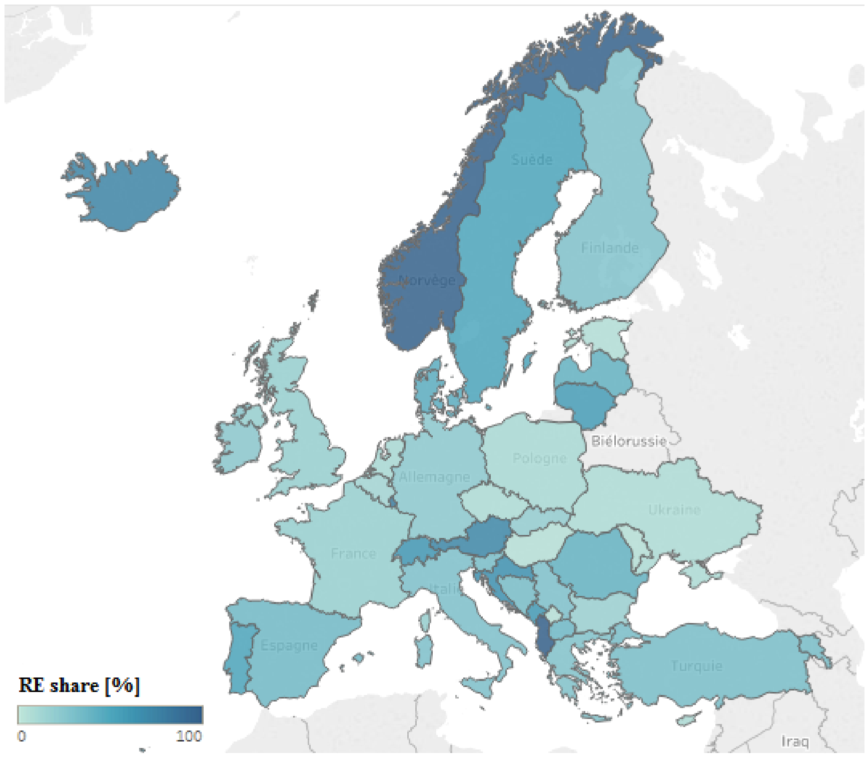

Figure 2: Renewable share in electricity generation in Europe (IEA, 2017b)

scenario" with a renewable share of respectively 13%, 16% and 26%. The renewable share of electricity generation is projected to be respectively 29%, 37% and 58% (IEA, 2016).

The Paris agreement, signed in 2015 by 195 countries with the aim to limit the global warming to 1.5°C regarding pre-industrial era, as well as the European Union ambition to reduce the greenhouse gas emissions by 80 to 100% by 2050 (Commission, n.d.) will probably enhance this trend towards a renewable-dominated energy mix.

However, a system dominated by wind and solar power will face new challenges to achieve a constant match between energy supply and demand, such as the natural intermittency of variable renewable energy. Energy storage and long-distance transmission seem to be promising potential solutions to mitigate these challenges.

In recent years, many authors have treated the question of the feasibility of a system entirely powered by renewable energy. Through the existing literature, there is no consensus and the opinions differ from one study to another. Some argue that 100% renewable is not achievable and that we will always need a part of conventional dispatchable generation[3], others claim that it would not only be feasible but also profitable. Most of the studies on the topic rely on complex models representing the electrical grid of a specific area, minimizing either the cost or the energy losses.

In 2017, M. Jacobson et al. (2017) suggested a roadmap for 139 countries around the world to reach a 100% renewable energy system based exclusively on wind, water and solar energy. This transition goes together with an electrification of all energy sectors. They built two scenarios, one business as usual (BAU) scenario and one wind, water and sunlight (WWS) scenario where the whole energy sector is powered by variable renewable energy. In their analysis, they evaluated that end-use energy is reduced by 42.5% in WWS scenario compared to BAU scenario[4] and that 24.3 million net full-time jobs are created. The projected energy mix is depicted in figure 3.

The question of the cost of such a transition needs to be addressed to determine if such transition is economically feasible, and a deep look at the cost of these technologies is thus of primary importance. This work will thus tackle the cost issue of a system in which the energy is exclusively generated from renewable sources.

In M. Jacobson et al. (2017), the authors project that this transition will come along with a slight decrease in the cost of electricity. When looking at the literature, we will see that these results vary from one study to another, some authors estimating that a transition to 100% renewable energy would come along with an important decrease in cost while others

[3]Generation that can be turned on or off or adjusted whenever needed depending on the current needs (e.g. coal, gas, nuclear, hydro dam) as opposed to variable renewable energy such as wind and solar.

[4]This reduction is mostly due to a higher efficiency of electricity with regards to fossil fuel. Also, more mining, fuel transporting or fuel processing is no longer required.

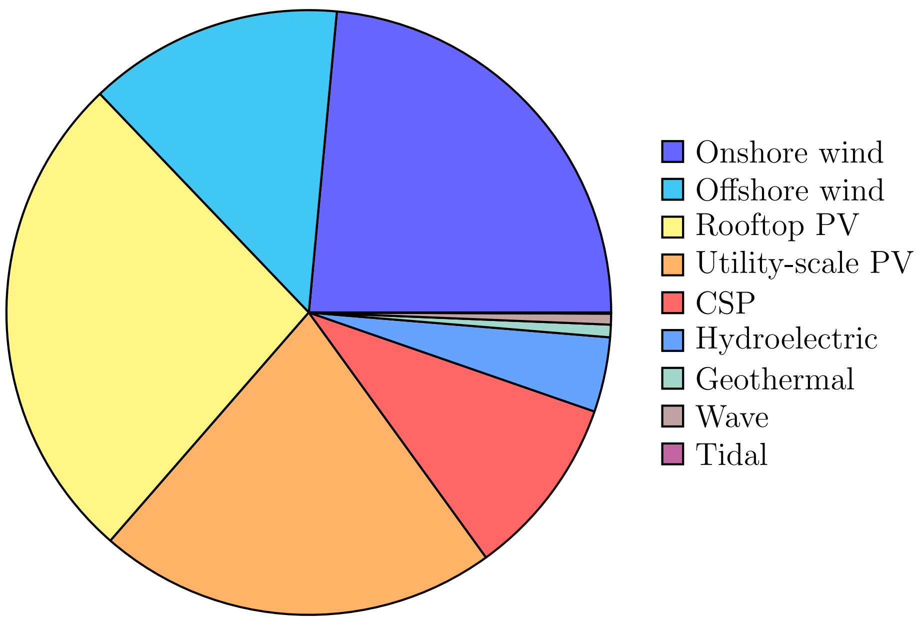

Figure 3: Projected share of electricity generation by fuel in the world in 2050 (M. Jacobson et al., 2017).

found that cost would double.

This work aims at challenging some assumptions made by M. Jacobson et al. (2017), comparing the results with those of other studies and finally recalculate the cost of the energy in a 100% renewable energy system. In this last section, we decided to focus on Europe as the documentation on that area is abundant. Furthermore, by covering an area too broad, we would not be able to take the specificities of the territory under scope into account while by covering an area too narrow, we would not be able to appreciate the big picture needed for such an analysis. The European territory thus seems appropriate for this study.

This work is structured as follow: first, a definition of the cost measure that will be used throughout the study. Secondly, several examples of roadmaps for Europe to achieve 100% renewable energy and the cost associated. Then, an analysis of the results and assumptions made by M. Jacobson et al. (2017) regarding generation, transmission, distribution and storage costs followed by a comparison with existing studies. Finally, a new evaluation of the cost of energy in a 100% renewable European energy system will be made.

2 Measure the cost of the energy system

2.1 The Levelized Cost of Electricity

The levelized cost of electricity (LCOE) is the most common measure to compare the cost-effectiveness of several power generation technologies and is often used as a benchmarking tool. The LCOE of a specific technology represents the break-even cost to generate the energy (Bruck et al., 2018).

By definition, LCOE is calculated by equalizing the income from power generation and its cost in present value (Ouyang & Lin, 2014), as in Eq. 1.

$$\sum_{t=0}^{T} E_t \frac{LCOE}{(1+r)^t} = \sum_{t=0}^{T} \frac{C_t}{(1+r)^t} \tag{1}$$

where E_t is the energy production in time period t, r is the discount rate, C_t is the net costs in time period t, including investments, operations and maintenance costs and fuel costs in case of thermal generation power and T is the lifetime of the power unit. If the project is debt financed, we could also include the interests payments in the net costs (Branker et al., 2011). Typical discount rates used in the literature range from 6 to 8%.

We can rearrange Eq. 1 to find the formula of LCOE:

$$LCOE = \frac{\sum_{t=0}^{T} C_t(1+r)^{-t}}{\sum_{t=0}^{T} E_t(1+r)^{-t}} \tag{2}$$

Or

$$LCOE = \frac{\sum_{t=0}^{T}(I_t + O_t + M_t + F_t)(1+r)^{-t}}{\sum_{t=0}^{T} E_t(1+r)^{-t}} \tag{3}$$

where I_t represents the investment in time period t, O_t represents the operation expenses in time period t, M_t represents the maintenance expenses in time period t and F_t represents the fuel expenses in time period t.

The LCOE of a generating technology can thus be defined as the life-cycle cost per unit of electricity (Ueckerdt et al., 2013) and is expressed in currency unit per Wh.

Please find in table 1 a review of current LCOE values for different generation technologies extracted from Bloomberg (n.d.).

Technology	**LCOE [2018-$/MWh]**
PV plant	80.0
Onshore wind	67.4
Offshore wind	124.0
Hydro	76.2
Tidal	442.3
Wave	498.5
Geothermal	63
Biomass	122.2
Biogas	128.0
Nuclear	174.0
Coal	68.2

Table 1: LCOE values (Bloomberg, n.d.).

2.2 Integration costs

But LCOE is often considered insufficient to evaluate variable renewable power generation since it does not take the integration costs into account (Ueckerdt et al., 2013). Although integration costs are negligible for conventional power generation technologies, variable renewable energy (VRE) generation implies considerable integration costs due to three characteristics of VRE supply: it is variable, uncertain until realization and location-specific (Hirth et al., 2015). A new metric including these integration costs is thus suggested to allow an economic comparison of VRE generation technologies: the System LCOE (Ueckerdt et al., 2013; Hirth et al., 2015).

We can thus define the System LCOE of a technology as the sum of generation costs (i.e. LCOE) and integration costs per unit of energy generated (Ueckerdt et al., 2013). Integration costs of VRE can be defined as "all additional costs in the non-VRE part of the power system when VRE are introduced" (Ueckerdt et al., 2013) or, more intuitively "the cost of substituting one MWh of thermal electricity with one MWh of VRE electricity at a given penetration level" (Reichenberg et al., 2018).

Integration costs are composed of three components: the profile costs resulting from temporal variability, the balancing costs resulting from uncertainty and forecast errors, and the grid-related costs resulting from the location of generation sites and transmission losses (Hirth et al., 2015).

Integration costs of VRE are positively correlated with their penetration rate. In a thermal system, the integration costs of wind at 30-40% share reach 35% of generation costs (Hirth et al., 2015).

The main component of integration costs are the profile costs, while balancing costs and grid-related costs are negligible (Ueckerdt et al., 2013). The term "cost" is sometimes used to qualify a discount on revenues (Hirth, 2013). The main driver of profile costs below 20% share is the full-load hours reduction of existing thermal plants, which and levels off at higher penetration levels. However, overproduction costs increase significantly with the penetration level and become the main driver of integration costs (Ueckerdt et al., 2013).

These costs are likely a barrier to the future development of VRE. However, integration costs could be mitigated by integration options. The adjustment of conventional generating technologies capacity (i.e. shift the residual thermal capacity mix to mid and peak load instead of base load) could have a huge impact on profile costs. However, this is not possible in a system where VRE has a 100% penetration level. Secondly, long-distance transmission allow to access better VRE generating area. A third option is to match the energy demand with VRE supply in time as much as possible. This can be achieved either by shifting the demand in time with demand-side management or by shifting the supply in time with electricity storage. Even though these options need an important investment at first, it may be overcompensated by the decrease of integration costs (Ueckerdt et al., 2013).

According to Ueckerdt et al. (2013), VRE thus need exogenous factors (e.g. high CO_2 price, important nuclear restrictions, improvement in integration options) to become cost-efficient and compensate the smaller integration costs of conventional generation. Hirth (2013) argues that high share of wind and solar power will only be competitive with fundamental technological breakthroughs, even though steep learning curves can be observed.

2.3 A pathway for Europe

In this section, we will describe several models and their results. Here, we will call a "short-term" model a model whereby the generation and transmission infrastructure is exogenous to the model, we will call a "mid-term" model a model whereby existing infrastructure is given and where (dis)investment decision are allowed and we will call a "long-term" model a model whereby a greenfield approach has been adopted (Hirth, 2013).

Reichenberg et al. (2018) aim at minimizing the marginal System LCOE for wind and solar PV penetration levels from 0 to 100% in Europe in a greenfield situation. The only exception to the greenfield approach is hydropower which is likely to remain at constant capacity since it is low-cost and CO_2 free, but also subject to environmental constraints keeping it from expansion. Trade between different areas is extremely important with increasing VRE shares and allows to smooth variability (Reichenberg et al., 2018). However, the impact of long-distance transmission is limited, particularly in regions where the weather variation from place to place is not significantly different.

The average system LCOE is around 40 €/MWh with VRE penetration level equal to 0%

and around 80 €/MWh at 99% penetration. The marginal system LCOE is approximately linear (6 €/MWh for each additional 10%) until 80% penetration, where it starts increasing sharply. In the optimal mix, wind generation predominates over solar generation. To smooth variability, trade is preferred to storage, which is not used below 80% penetration of VRE. This observation is in line with MacDonal et al. (2016) which stipulates that HVDC transmission mitigates the effect of VRE intermittency at lower cost than electrical storage. Curtailment[5] increases exponentially and reaches 20% of generated electricity when VRE share gets close to 100% (Reichenberg et al., 2018).

Pleßmann & Blechinger (2017) built a mid-term model that minimizes the average System LCOE in Europe while respecting the European Union greenhouse gas emissions targets for 2050, i.e. cutting down annual greenhouse gas emissions from 1300 to 24 Mt CO2eq by 2050. They introduced a "decision year" every 5 years where new investments decisions must be taken.

Th results of the model are the following: the average system LCOE increases from 67 €/MWh to 90 €/MWh while the share of renewable energy increases from 27.5% to 98.5%. Coal is not used from 2035 and, in 2050, natural gas is the only fossil fuel still used in power generation. Most of the gas turbine generation uses synthetic natural gas (SNG) as fuel. In 2050, the total installed capacity is equal to 2,896 GW and the total generation is equal to 5,968 TWh (Pleßmann & Blechinger, 2017). You will find the share of VRE technologies in table 2. Please note that the remaining installed capacity comes from old facilities not operating anymore.

In 2050, the total input power to energy storage is equal to 432 GW (power-to-gas: 84.95%, pumped hydro storage: 10%, batteries: 5.14%) and 19.5% of generation is lost

[5]"Curtailment is a reduction in the output of a generator from what it could otherwise produce given available resources" (Bird et al., 2014). This reduction can either be voluntary (e.g. limit the power output during low demand period) or involuntary (e.g. maintenance, transmission issue).

Technology	Installed capacity	Generation
Wind	51.3%	63.7%
Solar	31.4%	20.1%
Hydro	5.2%	9.0%
CCGT	8.4%	7.2%

Table 2: Projected share of generation technologies in Europe in 2050 (Pleßmann & Blechinger, 2017).

because of efficiency losses in transmission or storage or curtailed. Transmission capacity increases from 79.5 to 362 GW and the net energy transmission increases from 188 TWh to 977 TWh (Pleßmann & Blechinger, 2017).

Child et al. (2018) also modeled a transition to a 100% European energy system in a mid-term optimization model from 2015 to 2050. Unlike Reichenberg et al. (2018) and Pleßmann & Blechinger (2017), they concluded that such a transition would allow a decrease in the energy cost with a system LCOE falling from 69 €/MWh in 2015 to 51.1 €/MWh in 2050, distributed as in table 3. You will find the share of VRE technologies in table 4. Solar PV is the main generation technology, followed by wind turbines.

In the model, conventional generation plants are allowed to live their expected lifetime but no further investment will be made, which explains why the sum of installed capacities in table 4 is not equal to 100%. Child et al. (2018) investigate two scenarios for Europe: one scenario whereby the defined sub-regions are independent one to another and another whereby the defined sub-regions are strongly interconnected. The needs in energy storage and, consequently, the costs are lower in the latter scenario and we will thus focus on that one.

Seasonal intermittency is mostly balanced by gas storage, with synthetic natural gas (SNG) produced from Power-to-Gas (PtG), and dispatchable RE such as hydro and bio-

Category	Share of total LCOE
Generation	67.9%
Storage	24.4%
Curtailment	2.9%
Transmission	4.8%

Table 3: Projected composition of total LCOE in Europe in 2050 (Child et al., 2018).

Technology	Installed capacity	Generation
Wind	21.6%	36.6%
Solar PV	62%	41%
Hydro	7.7%	11.1%
Others (e.g. Biomass, Biogas, CCGT)	8.7%	11.3%

Table 4: Projected share of generation technologies in Europe in 2050 (Child et al., 2018).

gas while diurnal intermittency is balanced by batteries. However, the deployment of the transmission network across Europe will lower the need of long-term storage. This effect is limited though since the decrease of solar energy will take place everywhere at the same time. In the 100% renewable energy system with interconnections between the European sub-regions proposed by Child et al. (2018) by 2050, storage relative contribution represents 16% of electricity demand and 4.9% of energy is curtailed. Short-term storage is mostly ensured by batteries while long-term storage is ensured by gas storage (through PtG process). Pumped hydro storage (PHS), thermal energy storage (TES) and adiabatic compressed air energy storage (A-CAES) are also used to a significantly lower extent. The different energy storage technologies and their specifications will be explained in section 3.2.3. Regarding the transmission grid, the model projects an extension up to three times the current capacity (Child et al., 2018).

Bussar et al. (2014) built a model of the European energy system with a greenfield approach. Their analysis of a 100% renewable energy system in Europe for 2050 concluded that such a transition would imply a system LCOE of 68.7 €/MWh distributed as in table 5. Distribution costs are not taken into account in this calculation.

Category	**Share of total LCOE**
Generation	70.8%
Storage	20%
HVDC grid	9.2%

Table 5: Projected composition of total LCOE in a 100% renewable energy system (Bussar et al., 2014).

In the presented model, the authors assumed an annual demand of 4,122 TWh and load between 300 and 670 GW. The energy generation is exclusively based on wind turbines (1,090 GW) and solar PV (1,400 GW) and is supported by high voltage direct current (HVDC)[6] long-distance transmission lines and 530 GW of discharging rate of storage. The storage is ensured by a mix of hydrogen (through PtG), PHS and battery (Bussar et al., 2014).

In this section, we presented four different studies, all of them modeling a European energy system with high VRE share. While Child et al. (2018); Bussar et al. (2014) constrained the VRE share to 100% in 2050, Pleßmann & Blechinger (2017) constrained the greenhouse gas emissions to 24 Mt CO2eq in 2050 and thus allows for conventional generation. The resulting energy mix includes 83.8% of wind and solar generation that are supported by 9% of hydro generation and 7.2% of gas turbine generation fueled mostly by SNG. Reichenberg et al. (2018) calculated the LCOE as a function of VRE share.

[6]Emerging technology allowing the long-distance transmission of power. With regards to high voltage alternative current, HVDC technology has lower losses, lower cost and allows to set the transmitted power at each time (MacDonal et al., 2016).

In Reichenberg et al. (2018); Pleßmann & Blechinger (2017), the LCOE increases proportionally to the VRE share and dispatchable gas turbine generation is preferred to energy storage options because of its lower cost. The system LCOE increases respectively from 40 €/MWh to 80 €/MWh in Reichenberg et al. (2018) and from 67 €/MWh to 90 €/MWh in Pleßmann & Blechinger (2017). In Reichenberg et al. (2018), the LCOE increases linearly until a VRE share of 80% and then exponentially until 100%. By contrast, Child et al. (2018) project a reduction in the system LCOE with increasing VRE share up to 100%, from 69 €/MWh to 51.1 €/MWh. Bussar et al. (2014) project a system LCOE of 68.7 €/MWh in a 100% renewable energy system in Europe by 2050.

3 The analysis of M. Jacobson et al. (2017)

3.1 Introduction

M. Jacobson et al. (2017) developed a roadmap for 139 countries to switch to an energy system based on 100% wind, water and sunlight (WWS) supposing the electrification of the whole energy sector by 2050. Before going any further, let us review the main existing renewable generation technologies and their future perspectives.

Hydropower Hydropower turns the mechanical energy of water into electricity by activating a turbine. It can be classified in two types: run-of-river, where the turbine is activated by the water flow in a river (in the same way than a water mill), and hydro dams, where the water in stored in large reservoirs before flowing through the turbine when needed. The latter technology allows to decouple power generation from natural intermittency on the water flows, making hydroelectricity dispatchable IRENA (2012b).

Hydropower is the most widely spread renewable technology with 16.7% share of electricity generation in the world IEA (2017b). It is also the most flexible, as hydro plants are able to adapt to demand fluctuation in real time but also to store energy for long periods IRENA (2012b).

Hydropower has a relatively low cost thanks to a longer lifetime than most technologies and the absence of fuel costs. It is a mature technology with only small cost reduction potential in the future. The main barrier to its broader expansion is the specificity of favourable sites IRENA (2012b).

Wind power Wind power generation turns the kinetic energy of the wind into electricity. The generated energy is a cubic function of the wind speed which means that if the wind speed doubles, the output of the turbine increases by a factor of eight. Several factors, such as the hub height or the rotor dimension, have a direct influence on the power output IRENA (2012d).

The generation is only possible at specific wind speed, typically between 5 m/s and 25 m/s. When the wind speed is out of this range, the turbine is idle. The maximum power is typically achieved at wind speed of 15m/s. Wind generation is by nature intermittent IRENA (2012d).

Wind turbines can be placed both onshore and offshore. With regards to onshore wind, offshore wind benefits from higher wind speeds and allows larger rotor dimensions. Although offshore wind involves higher capital costs than onshore, it is often compensated by higher capacity factors IRENA (2012d).

Wind generation has grown drastically in the last twenty years, increasing by a factor of 100 between 1996 and 2016 IEA (2017b), and is projected to keep on growing in the years to come. Cost reduction is expected to be achieve in the following years as the result of design improvement, economies of scale, learning curves, etc. IRENA (2012d).

Solar PV Solar photovoltaic (PV) generation converts sunlight into electricity. It is the renewable technology with the fastest growth as PV generation has been multiplied by a factor of 1500 between 1996 and 2006 IEA (2017b). In the future, PV share is expected to grow significantly in the energy mix, mostly driven by decreasing costs and high availability. PV generation is possible either with direct or diffuse sunlight IRENA (2012c). Solar irradiation is extremely variable in time, with both daily fluctuations (day-night cycle) and seasonal fluctuations.

First-generation PV technology, based on crystalline silicon cells, is a mature technology but still expects cost reduction in the future. Recently, new lower-cost technologies have emerged, such as thin-film PV or organic PV, with significantly lower efficiency (between 4 and 8 % while the efficiency of first-generation modules lies between 14% and 19%) IRENA

(2012c).

The rapid growth of PV has allowed important cost reductions in the last years and this trend is projected to continue in the future due to high learning rate IRENA (2012c).

CSP Concentrating solar power (CSP) technology concentrates the sun's ray with mirrors or lenses to heat a fluid. The fluid then turns into steam which is used to activate a turbine and generate electricity as in conventional thermal power plants. A thermal storage system can be integrated to the CSP plant which allows to generate power when the sun is not shining IRENA (2012a).

As opposed to PV, CSP needs direct solar radiation to produce energy. That technology is not yet widely spread and is mainly deployed in regions with high solar irradiation (e.g. Spain, North Africa) and only some specific areas of the world are suitable for CSP IRENA (2012a).

Today, CSP generation has a higher cost than most conventional fossil fuel technologies but important cost reduction are expected from technology improvement and economies of scale due to large-scale commercial deployment IRENA (2012a). Further benefits are expected from local thermal storage.

Geothermal Geothermal generation transforms the heat of the planet into electricity. As opposed to wind and solar resources, geothermal generation is dispatchable and does not rely on specific conditions. Geothermal energy exploitation requires favourable sites, i.e hot water reservoirs or natural high-temperature steam which are only available in some areas of the world (e.g. in Iceland) Clauser & Ewert (2018).

In table 6, you will find the share of each generation technology in the 100% renewable energy based system projected in M. Jacobson et al. (2017).

The major part of the energy generated in this projection comes from wind and sunlight despite their variability, this prevalence being explained by their availability and the maturity

Technology	**139 countries**	**Europe**
Onshore wind	23.52%	27.13%
Offshore wind	13.62%	20.08%
Solar PV plant	21.36%	25.21%
Residential roof PV system	14.89%	9.17%
Commercial/gov/industrial roof PV system	11.58%	7.18%
CSP plant	9.72%	4.42%
Hydroelectric plant	4.00%	5.69%
Geothermal electric plant	0.67%	0.26%
Wave device	0.58%	0.62%
Tidal turbine	0.06%	0.23%
Total	100%	100%

Table 6: Projected share of total end-use demand in 2050 according to the WWS scenario.

of these technologies. Hydropower is a solution to mitigate the volatility issue due to the intermittent nature of wind and sunlight, but the scarcity of available sites makes it difficult to expand.

Even though geothermal generation benefits from stability and a capacity factor[7] close to one, the capacity installed remains low as a consequence of decreasing return on investment. Indeed, once the least-cost locations are exploited, the technology will need to develop into areas that are less profitable because of higher costs or lower performance. This implies an increasing cost through the years. One of the main limitation today for the growth of geothermal activity is the scarcity of favorable sites, i.e. natural high-temperature steam or hot water reservoirs. In order to overcome this limitation, substantial investments are

[7]Ratio of the actual energy produced to the energy that would be produced by running continuously at full rated power

required in the development of Engineered Geothermal Systems (EGS). Once matured, EGS and man-made reservoirs would allow most of the continental land mass to use geothermal energy (Clauser & Ewert, 2018). However, this technology is not mature yet and would require massive investment which explains the very low share of geothermal generation.

3.2 LCOE analysis

Please find in table 7 the projection of M. Jacobson et al. (2017) for both the BAU scenario and the WWS scenario in the world and, more specifically, in Europe. By taking the storage into account, the authors project a constant system LCOE from $96.8/MWh in 2013 to $96.5/MWh in 2050 in the WWS scenario while the LCOE reaches $97.8/MWh in the BAU scenario. In Europe, the LCOE is expected to decrease by 5% by 2050 in the WWs scenario. While costs in the current situation and in the BAU scenario are only related to electricity, the electrification of the entire energy system assumed in the WWS scenario implies that the LCOE becomes the cost of all energy generated. M. Jacobson et al. (2017) developed a low low, high benefits (LCHB) scenario (best case) and a high cost, low benefis (HCLB) scenario (worst case). Please note that, in this section, all costs are expressed in 2013-USD[8].

Region	**2013 [$/MWh]**	**2050-BAU [$/MWh]**	**2050-WWS [$/MWh]**
World (139 countries)	96.8	97.8	96.5
Europe	100.3	101.7	95.7

Table 7: LCOE in M. Jacobson et al. (2017)

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To find these results, M. Jacobson et al. (2017) calculate the LCOE for each generation technology, including generation, transmission, distribution and fuel costs, for both the WWS

[8]Currency conversion retrieved from https://fxtop.com/fr/convertisseur-devises.php

and the BAU scenario. Please find the LCOE values for the WWS case in table 8.

	Share		**LCOE [$/MWh]**	
Technology	**Generation**	**T&D**	**LCHB**	**HCLB**
Geothermal	56.2%	43.8%	81.0	117.6
Hydropower	33.7%	66.3%	53.5	77.7
Onshore wind	43.4%	56.6%	63.1	89.7
Offshore wind	63.4%	36.6%	93.4	171.1
CSP no storage	62.1%	37.9%	87.5	147.7
CSP with storage	43.3%	56.7%	60.9	93.8
PV utility crystalline tracking	37.8%	62.2%	59.0	79.0
PV utility crystalline fixed	40.6%	59.4%	60.6	84.6
PV utility thin-film tracking	37.2%	62.8%	58.7	78.0
PV utility thin-film fixed	40.4%	59.6%	60.2	84.6
PV commercial rooftop	52.9%	47.1%	69.4	104.6
PV residential rooftop	59.9%	40.1%	80.1	125.6
Wave power	65.2%	34.8%	89.3	178.5
Tidal power	55.1%	44.9%	67.9	143.5

Table 8: Projected LCOE per technology in the WWS scenario (M. Jacobson et al., 2017).

Then, based on the forecasted distribution of the actual power delivered to end users by 2050 and the cost multiplier for each country, they find the LCOE for each country individually. The LCOE calculation for a country c is summarized in Eq. 4.

$$LCOE_c = \sum_{i=0}^{I} LCOE_i * share_{i,c} * multiplier_{i,c}, \qquad \forall c \tag{4}$$

where $LCOE_i$ is the generic LCOE of the technology i, I is the number of different technologies, $share_{i,c}$ is the share of total end-use demand met by technology i in country c and

$multiplier_{i,c}$ is the cost multiplier for technology i in country c which is the ratio of the capacity factor in country c to the capacity factor used in the generic LCOE calculation.

Finally, the weighted average of these values gives the global LCOE. The storage costs are not taken into account in the former calculation, and the author estimates an additional $7.9/MWh for storage in the WWS case (M. Jacobson et al., 2015).

Now, let us analyse more deeply the LCOE calculation through its components, namely generation, T&D and storage.

3.2.1 Generation costs

The generation cost is composed of the initial capital cost, the fixed O&M cost and the variable O&M cost. For the RE under scope in this section, we will assume that variable O&M costs are zero. As a reminder, the formula to calculate the generation cost is described in Eq. 3.

For starters, we will compare the values obtained in M. Jacobson et al. (2017) with the values found in the existing literature. You will find a summary of the review in tables 9, 10 and 11 for the three main generation technology, i.e. onshore wind, offshore wind and solar PV. In the comparison, we focused on fixed PV crystalline technology. Since it is the most mature and broadly used technology, the literature about it is the most abundant.

The values from M. Jacobson et al. (2017) regarding the CAPEX, OPEX, capacity factor and lifetime for PV, onshore and offshore generation in 2050 are entirely consistent with the values found in the literature.

The LCOE of both onshore and offshore wind, projected to be respectively between $24/MWh and $43/MWh for onshore wind and between $54/MWh and $118/MWh for offshore wind (M. Jacobson et al., 2017), is aligned with OpenEI (n.d.), a database regrouping the results of existing studies on the topic, which gives LCOE between $30/MWh and $60/MWh for onshore wind and between $40/MWh and $90/MWh for offshore wind (first

Study	**CAPEX** [$/kW]	**Fixed O&M** [$/kW*year]	**Capacity factor** [%]	**Lifetime** [years]
Jacobson et al. (2017)	1,196-1,640	41-48	34-36	25-35
IEA (2010)	1,284-1,712	42	n.a.	n.a.
NREL (2016)	1,508	52	39	24.5
Mott Macdonald (2011)	1,357-1,443	15-16	n.a.	20
Zappa et al. (2019)	1,417	27	25	25
VITO (2013)	1,276	27	n.a.	20
Open EI	1,270-2,000	14-52	47-35	n.a.
Clauser & Ewert (2018)	1,525	35	15-31	20
Blumberga et al. (2016)	2,215	45	28	20
Carlsson et al. (2014)	1,461	25	45	25
Dai et al. (2016)	1,286-2,143	29	30	25
Pleßmann & Blechinger (2017)	1,169	39	n.a.	25
Reichenberg et al. (2018)	1399	44	n.a.	25
Child et al. (2019)	900	18	n.a.	25

Table 9: Literature review of the projected cost of onshore wind in 2050.

and third quartile).

The LCOE of PV estimated by M. Jacobson et al. (2017) is in line with the results of Vartiainen et al. (2015), which conducted a deep study of the evolution of the LCOE of PV generation in Europe to 2050 and reach to the conclusion that the LCOE of PV generation will drop between $17.75/MWh and $35.5/MWh while M. Jacobson et al. (2017) projected LCOE between $22/MWh and $38/MWh. The LCOE projections for PV, onshore and offshore wind is consistent with the projections of EIA (2018).

Study	**CAPEX** [$/kW]	**Fixed O&M** [$/kW*year]	**Capacity factor** [%]	**Lifetime** [years]
Jacobson et al. (2017)	2,552-4,515	71-119	40-44	25-35
IEA (2010)	2,247-2,782	73	n.a.	n.a.
NREL (2016)	3,920	n.a.	47	23
Mott Macdonald (2011)	1,776-2,323	46-60	45	20
Zappa et al. (2019)	2,801	78	38	25
VITO (2013)	2,347	101	n.a.	20
Open EI	2,560-4,000	45-73	44-53	n.a.
Clauser & Ewert (2018)	2,999	111-140	34-51	20
Blumberga et al. (2016)	3,748	45	39	20
Carlsson et al. (2014)	3,028	70	48	30
Reichenberg et al. (2018)	2800	100	n.a.	25

Table 10: Literature review of the projected cost of offshore wind in 2050.

3.2.2 Transmission and distribution costs

First, let us differentiate transmission and distribution through an analogy. The transmission network can be assimilated to the highway network, which allows a large amount of cars to move from one large city to another large city, while the distribution network can be assimilated to the regional road and street network. As the highway with cars, transmission delivers large quantity of electricity across long distances, e.g. from a generation site to a substation closer to end-users. Then, the distribution network will carry the electricity from this substation up to the end-user. The voltage is much higher in transmission lines and thus needs to be reduced before entering the distribution network.

By switching from a centralized system with large generation sites to a decentralized system where the generation is more distributed, the power requirement will switch from

Study	**CAPEX [$/kW]**	**Fixed O&M [$/kW*year]**	**Capacity factor [%]**	**Lifetime [years]**
Jacobson et al. (2017)	1,045-1,131	7-11	19-20	45-52
IEA (2010)	1,070-1,712	14	n.a.	n.a.
Mott Macdonald (2011)	512-712	1-2	10	20
Zappa et al. (2019)	644	0	15	25
Open EI	1,000-2,040	8-13	17-23	n.a.
Clauser & Ewert (2018)	1,611	48	10-23	25
Blumberga et al. (2016)	6,697	5	23	40
Carlsson et al. (2014)	690	12	17	25
Pleßmann & Blechinger (2017)	729	12	n.a.	25
Reichenberg et al. (2018)	600	19	n.a.	25
Child et al. (2019)	300	4.5	n.a.	40

Table 11: Literature review of the projected cost of a PV plant in 2050.

transmission to distribution since more generation units will be connected directly to the distribution network.

A distributed plant is a small decentralized generation unit connected directly to the distribution grid, as opposed to conventional large-scale central plants. An on-site plant is a generation unit located on the consumption site (e.g. residential PV). An on-site plant is thus distributed, while a distributed plant is not necessarily on-site.

First, to estimate the T&D costs, M. Jacobson et al. (2017) followed the projections of the Annual Energy Outlook 2014 (EIA, 2014) which assumed a slight increase in transmission costs, from $10.4/MWh in 2013 to $11.4/MWh in 2050, and a decrease in distribution costs, from $30/MWh to $25.5/MWh. However, in the Annual Energy Outlook 2019 (EIA, 2019), the EIA reviewed its forecasts, predicting an increase in both transmission (from $12.3/MWh in 2018 to \$14.4/MWh in 2050) and distribution (from \$26.5/MWh to \$32.9/MWh).

Then, M. Jacobson et al. (2017) estimated the transmission costs for distributed generation sites to be between \$10.5/MWh and \$11.4/MWh and the distribution costs for on-site (and thus distributed) generation sites to be between \$20.9/MWh and \$24/MWh.

Subsequently, for each technology, M. Jacobson et al. (2017) assume the share of distributed and on-site generation sites in 2050 and calculate the weighted cost of T&D.

Finally, they add a cost for HVDC transmission for both land-based and offshore transmission. They first calculate the cost per MWh out of the HVDC system, then they assumed the share of energy sent through the HVDC system. Finally, they were able to find a cost of HVDC transmission spread over all generated energy. Please find the resulting costs in table 12. The offshore costs account for offshore transmission only and need to be added to land-based transmission for offshore generation technologies.

Parameters	**Land-based**	**Offshore**
Cost per MWh out of the HVDC system [$/MWh]	3.8-14.8	1.6-8.2
Share of energy sent through the HVDC system [%]	40-60	60-75
Cost of HVDC transmission spread over all generated energy [$/MWh]	1.5-8.9	0.9-6.1

Table 12: Projected HVDC costs in 2050 (M. Jacobson et al., 2017)

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In M. Jacobson et al. (2017), T&D costs are calculated for the United States territory (M. Jacobson et al., 2015) and then applied to the rest of the world. Furthermore, both the average length of new HVDC lines and the proportion of total generation sent through these lines do not result from a least cost optimization of the combination of storage, transmission and over-capacity but from a judgment of the authors (M. Jacobson et al., 2015).

In their cost optimization model of the United States electrical grid, Clack et al. (2015) found an average utilization of the HVDC network of 30%. Regarding Europe, the 98.5%

renewable energy system from Pleßmann & Blechinger (2017) results that 16.4% of the energy generated is sent through the long-distance transmission network.

The total T&D costs from M. Jacobson et al. (2017) are provided in table 13.

Technology	**LCHB**	**HCLB**
Geothermal	39	46.5
Hydropower	39	46.5
Onshore wind	38.8	46.5
Offshore wind	39.7	52.7
CSP no storage	38.8	46.5
CSP with storage	38.8	46.5
PV utility crystalline tracking	38.7	46.5
PV utility crystalline fixed	38.7	46.5
PV utility thin-film tracking	38.7	46.5
PV utility thin-film fixed	38.7	46.5
PV commercial rooftop	35.2	45.4
PV residential rooftop	35.2	45.4
Wave power	39	46.5
Tidal power	39	46.5

Table 13: Projected levelized cost of T&D per technology in the WWS scenario [$/MWh] (M. Jacobson et al., 2017).

In the cost optimization models representing a 100% renewable European energy system from Child et al. (2018) and Bussar et al. (2014), the long-distance transmission costs represent respectively $2.95/MWh and $8.59/MWh.

3.2.3 Storage costs

Energy storage is one of the main integration options to deal with the intermittency of VRE. It is used to shift the supply in time in order to fit the demand by charging whenever there is an energy surplus (e.g. in low demand periods) in the system and discharging whenever there is an energy deficit (e.g. in high demand periods). First, let us start with a short review of the most commonly used storage technologies.

PHS Pumped hydro storage (PHS) is a mechanical energy storage system that needs two connected water reservoirs located at different height. In charge, the energy is stored by pumping water from the lower to the upper reservoir while in discharge the water flows through a turbine from the upper to the lower reservoir, restoring the stored energy. It is today the most mature and widely expanded energy storage technology (Gallo et al., 2016; Zhao et al., 2015; Luo et al., 2015).

The storage capacity of a PHS plant is proportional to the reservoirs' volume and the height difference between both reservoirs. Typically, PHS facilities have an energy-to-power[9] ratio of several hours and are able to store energy for long time periods thanks to a small self discharge rate. PHS benefits from long lifetime (30-60 years), fast response time and efficiency[10] between 65% and 85%. The main limitation to its further expansion is the scarcity of suitable sites (Gallo et al., 2016).

CAES Compressed air energy storage (CAES) systems compress air with a compressor when charging, the obtained compressed air being then stored in either underground or above ground reservoirs. When discharging, the resulting compressed air is heated and then expanded in a turbine to generate electricity (Gallo et al., 2016; Zhao et al., 2015; Luo et al.,

[9]Ratio of the energy capacity (MWh) of a storage technology to its power rating (MW).

[10]The efficiency of a storage technology is ratio of the energy output to the energy input. An efficiency of 80% thus means that 20% of the energy put in the system is lost.

2015).

Compared to PHS, CAES technology benefits from lower capital costs but suffers from lower efficiency (40-60%), shorter lifetime (20-40 years), longer response time and higher operational costs. While the conventional diabatic CAES (D-CAES) needs the use of additional fuel to heat the compressed air when discharging, adiabatic CAES (A-CAES) preserves the heat generated during compression to use it during the discharge process by including thermal storage (Gallo et al., 2016).

Battery A battery is an electrochemical energy storage technology composed of three parts: an electrolyte, a positive and a negative electrode. "The two electrodes are compounded by materials having different electrochemical potentials that spontaneously induces a redox reaction generating an external electrical current when the circuit is closed for discharge cycle" (Gallo et al., 2016). The cycle life (measure of the lifetime) of a battery is a function of the depth of discharge (DOD), i.e. the degree of discharge allowed before charging the battery (e.g. at 0% DOD, the battery is full while at 100% DOD the battery is empty). For most battery technologies, the cycle life is negatively correlated to the DOD.

There is different types of batteries and each has its own specifications. For example, lead-acid battery is a mature technology benefiting from low cost, low self-discharge rate and efficiency between 70% and 80% and suffering from low cycle life, environmental issues and frequent maintenance needs (Gallo et al., 2016).

Lithium-ion (Li-ion) battery shows interesting characteristics, such as an efficiency between 85% and 90%, a low self-discharge rate and longer life-cycle than lead-acid battery (Gallo et al., 2016).

Redox flow batteries have the particularity to allow to increase the storage capacity simply by enlarging the volume of electrolyte. Another particularity is that the DOD has no influence on their cycle life. Among them, vanadium redox flow (VRF) battery is the most advanced

EES Technology		Power rating (MW)	Storage capacity		Response time	Self-discharge rate (%/day)	Suitable storage duration	Efficiency (%)	Lifetime	
			Energy rating (MWh)	Discharge time					(years)	(cycles @80% DOD)
PHS	Conventional (Upgrading)	100–5000+	1000+	1–24+ h	~3 min	0.005–0.02	h-month	65–85	30–60	N/A
	Underground shaft & piston	200–1000	8.5–200	0.3–4 h	< 1 min	Very small	h-month	75–80	30	N/A
CAES	D-CAES	5–300+	1000+	1–24+ h	~ 10 min	0.003–0.03	h-month	40–60	20–40	N/A
	A-CAES	0.1–10 small 100+ large	1–10 small 100+ large	1–12 h small 1–24+ h large	min	0.5–1	h-month	75–95	20–30	N/A
	I-CAES	0.1–10	1–10	1–12 h	< 1 min	Very small	h-month	75–95	20–30	N/A
	UW-CAES	1–1000+	1–1000+	1–24+ h	< 1 min	Very small	h-month	75–95	20–30	N/A
Flywheel		0.1–10	0.01–5	s-min	ms-s	55–100	s-min	75–95	15–20	20,000–100,000
LAES		10–100+	10–1000+	1–12+ h	5–10 min	Very small	h-month	40–85	20–40	N/A
PTES		0.5–10+	0.5–60+	1–6+ h	< 1 min	1	h-month	70–80	25	N/A
Conv. Batteries	Lead-acid	0.001–50	0.1–100	s-h	ms	0.033–0.3	min-day	70–90	5–15	400–1500
	Ni-Cd	0.01–40	$10^{-5}-1.5$	s-h	ms	0.067–0.6	min-day	60–73	10–20	1000–1500
	Ni-MH	0.01–1	$10^{-5}-0.5$	h	ms	0.4–1.2	min-day	70–75	5–10	800–1200
	Li-ion	0.1–50	$10^{-5}-100$	min-h	ms	0.1–0.3	min-day	85–95	5–15	2000–5000+
HT Batteries	NaS	0.05–50	6–600	s-h	ms	0.05–20	s-h	70–90	10–15	4000–4500
	Na-$NiCl_2$	0.001–1	0.12–5	min-h	ms	15	s-h	85–90	15	4000–4500
Flow Batteries	VRB	0.005–7	0.01–10	s-10 h	ms	0.2	h-month	60–85	5–15	10,000–13,000
	ZBB	0.025–2	0.05–4	s-10 h	ms	0.24	h-month	60–75	5–10	5000–10,000
	PSB	1–15	0.01–10+	s-10 h	ms	Very small	h-month	57–85	10–15	2000–2500
Supercapacitors		0.001–10	$10^{-6}-10^{-2}$	ms-h	ms	20–40	s-h	85–95	10–20	> 100,000
SMES		0.01–10	$10^{-4}-0.1$	ms-min	ms	10–15	min-h	80–90	15–20	> 100,000
PtG+ Storage +GtP	Hydrogen	0.1–1000+	100–1000+	1–24+ h	s-min	Very small	h-month	30–50	20–30	N/A
	Methane	0.1–1000+	100–1000+	1–24+ h	min	Very small	h-month	25–35	30	N/A

Figure 4: Summary of energy storage technologies characteristics (Gallo et al., 2016).

technology and has an efficiency between 60% and 85% (Gallo et al., 2016).

TES The term thermal energy storage (TES) regroups the storage technologies in which the energy output is thermal, i.e. heat or cold. The energy sources are the solar thermal energy, waste heat or cold or excess electricity (Gallo et al., 2016).

Sensible thermal energy storage (STES) is the most widely spread and the cheapest TES technology. The energy is stored by increasing or decreasing the temperature of a medium, typically water even though the use of molten salt is growing for higher temperature levels. When the storage medium is underground, one may talk about underground thermal energy storage (UTES) (Gallo et al., 2016; IEA & IRENA, 2013).

STES benefits from extremely low costs but suffers from variable discharging temperature and low energy density. These drawbacks can be overcome with another TES technology using phase-change materials (PCM) given that the change of phase occurs at constant temperature and has a significantly higher energy density (Gallo et al., 2016; IEA & IRENA, 2013).

PtG In a power-to-gas (PtG) process, the excess electricity is turned into hydrogen through electrolysis, which can be stored with insignificant losses for long periods of time. When needed, hydrogen can either be used as a fuel or turned back into electricity through gas turbines or in fuel cells (GtP). The whole power-to-power process efficiency is between 30% and 50% which is the major drawback of such technology. Hydrogen can also be converted in methane through a methanation process which involves lower efficiency (25-35%) in power-to-power applications but allows the use of methane as a fuel, which is more energy dense than hydrogen (Gallo et al., 2016). The characteristics of energy storage technologies are summarized in figure 4.

In a 100% renewable energy system, the generation needs to be supported by both long- and short-term storage. Long-term storage technologies have high energy-to-power ratio (days, months) and compensate mainly for the seasonal variability of both wind and solar energies. Typically, long-term storage will be allocated to PtG or TES technologies (Bussar et al., 2014).

Short-term storage technologies have low energy-to-power ratio (minutes, hours) and compensate mainly for the diurnal variability of solar energy. Typically, short-term storage will be allocated to battery technologies (Bussar et al., 2014). PHS acts as a medium-term storage technology (Bussar et al., 2014) and is used for both long- and short-term energy storage (Hirth, 2013; Child et al., 2018).

Cebulla et al. (2018) propose a synthesis of the existing literature on the need of energy storage capacities in Europe as a function of the VRE share in the generation mix. The authors found that storage power capacity increases linearly with VRE share while storage energy capacity increases exponentially as a consequence of the switch in the main role of energy storage, from buffering small fluctuations to the smoothing of VRE intermittency.

In M. Jacobson et al. (2017), the authors account a constant $7.9/MWh for storage costs, whatever the energy mix in the country under scope. However, one may suppose that Norway, with 44.5% of energy generated in dispatchable hydroelectric plants, would need lower investment in storage technologies than Belgium, where the energy is exclusively extracted from wind and sunlight.

Cebulla et al. (2018) emphasize the importance of the energy mix in the storage needs calculation. At an identical share of VRE, a wind-dominated mix will require less storage capacity than a solar-dominated mix. This finding is due to the higher correlation with consumption in time over a specific area of solar resource compared to wind. Even with increased transmission, there is no sunlight from sunset until sunrise. Spatial flexibility is thus not sufficient (Cebulla et al., 2018).

The storage capacity in M. Jacobson et al. (2017) is chosen so that the energy supply is able to match the demand at all time while on the same time no energy is curtailed, and is based on a six year simulation.

To balance supply and demand, they found that over-capacity could be less costly than energy storage only in the HCLB scenario under strong assumptions. They thus reasonably assume that the cost of balancing supply and demand is given by the storage costs as it is expected to be the most cost-effective option (M. Jacobson et al., 2017).

As for the transmission costs, M. Jacobson et al. (2017) calculate the storage needs and costs for the U.S. energy system (M. Jacobson et al., 2015) and then assume that they are identical in each of the 139 countries studied. Furthermore, these storage capacities and assumptions are not the results of any least cost optimization model (M. Jacobson et al., 2015).

The share of each storage technology in M. Z. Jacobson et al. (2015) is described in table 14, these technologies representing a Levelized Cost of Storage (LCOS) of \$3.3/MWh. The total storage capacity represents 4.7% of the planned annual end-use power delivered in the U.S. in 2050 in the WWS scenario. In addition, the authors assume that 11.46% of delivered power will be sent through the PtG process, resulting in an additional cost of \$4.6/MWh. The resulting total LCOS is thus \$7.9/MWh.

Technology	**Storage capacity [GWh]**
PHS	808
STES	350
PCM-ice	525
PCM-CSP	11,610
UTES	528,300
Total	541,593

Table 14: Projected reservoir capacity per storage technology in the U.S. in 2050 (M. Z. Jacobson et al., 2015; M. Jacobson et al., 2017).

In the cost optimization model representing a 100% renewable European energy system from Child et al. (2018), storage capacity represents 3.3% of the total end-use demand and storage output represents 15.7%. The distribution is described in table 15. The resulting LCOS is \$13.9/MWh. Please notice that that ratio of output to capacity is much lower for hydrogen storage than for other technologies. This observation is explained by the fact that hydrogen is used for long-term storage and thus runs only a few cycles per year. This also explains the significantly larger capacity of hydrogen storage.

In the cost optimization model representing a 100% renewable European energy system from Bussar et al. (2014), storage capacity represents 6% of the total end-use demand. The distribution is described in table 16. The resulting LCOS is \$18/MWh.

Technology	**Capacity [GWh]**	**Output [TWh]**
Battery	2,878	746.24
PHS	388	83.25
TES	23	3.17
A-CAES	16	0.38
Hydrogen (PtG)	170,638	392.42
Total	173,942	1,225.46

Table 15: Projected storage capacity and output per technology in Europe in 2050 (Child et al., 2018).

Technology	**Capacity [GWh]**
PtG	245,000
PHS	2,300
Battery (NaS)	300
Total	247,600

Table 16: Projected reservoir capacity per storage technology in Europe in 2050 (Bussar et al., 2014).

4 System LCOE in a 100% renewable energy system: The case of Europe

In this section, we will calculate a new evaluation of the system LCOE in a 100% renewable energy system in Europe in 2050. To do so, we will rely on studies mentioned above.

4.1 Parameters

Generation costs For the generation costs, we will use the values from M. Jacobson et al. (2017) since that study is the only one that differentiate the generation costs per technology per country as a function of the capacity factor. Furthermore, the generation costs prediction for 2050 in M. Jacobson et al. (2017) are in line with the rest of the literature (IEA, 2015; OpenEI, n.d.) and rely on plausible assumptions (e.g. evolution of CAPEX, OPEX, capacity factors).

However, regarding PV technologies, while M. Jacobson et al. (2017) assume 65% crystalline and 35% thin film by 2050, we assume in this work that the entire PV generation will come from crystalline PV panels. This assumption is based on several characteristics of both technologies. First, crystalline PV panels are made out of silicon, the most abundant resource on earth, which facilitates its growing share (IRENA, 2012c). Then, it is a mature technology which still expects cost reduction in the following years (IRENA, 2012c). Finally, crystalline technology has higher efficiency than thin-film technology, and therefore remains cost-competitive with regards to emerging PV technologies (IRENA, 2012c).

Please find the generation costs per country in table 20.

T&D costs Regarding the T&D costs, we will apply the same approach as in M. Jacobson et al. (2017) with updated parameters. To do so, the parameters extracted from EIA (2014) are replaced by those extracted from EIA (2019) and the T&D costs for both distributed and on-site generation are then re-calculated following the same methodology. Please find the values from M. Jacobson et al. (2017) as well as the corrected values in table 17.

Parameters	**Cost in M. Jacobson et al. (2017) [$/MWh]**	**Corrected cost [$/MWh]**
Transmission	11.4	14.4
Distribution	25.5	32.9
Transmission (distributed generation)	10.5-11.4	13.2-14.3
Distribution (on-site generation)	20.9-24	27-30.9

Table 17: T&D costs

Given that the specifications of the HVDC grid for long-distance transmission in M. Jacobson et al. (2017) does not result from any optimization model and that these specifications have been calculated for the U.S. territory and then applied to the rest of the world, the additional cost implied by HVDC transmission does not seem to be reliable. Instead, the HVDC grid provided by Bussar et al. (2014) in their cost optimization model of the European electricity system represents a better picture of the true long-distance transmission connections in Europe in 2050. The HVDC costs estimated in Bussar et al. (2014) will thus be used in the final calculation and $8.59/MWh will be added. The total T&D costs per country are expressed in table 20.

Storage costs Regarding storage, the proportion of final consumption that transits through a storage system per country is given by the ratio of output per storage technology to the total final consumption, both provided by the optimization model of Child et al. (2018, 2019). This particular study has been chosen because a cost-optimization model of the European system is built with the constraint of 100% renewable generation by 2050. The ratios for the whole Europe are represented in table 18.

Technology	Output/TFC
Battery	14.59%
PHS	1.63%
TES	0.06%
A-CAES	0.01%
Gas (PtG)	7.67%
Total	23.95%

Table 18: Ratio of storage output to TFC per technology in Europe in 2050 (Child et al., 2018).

The cost of each MWh-out-of-storage per technology is described in table 19. The cost associated to battery, PHS, A-CAES and gas storage (through PtG and GtP process) comes from Jülch (2016). This particular study has been chosen because it aims at presenting a detailed analysis of the current LCOS of several storage technologies as well as expected trends in LCOS for the future. Furthermore, the results are aligned with existing documentation on the matter (EPRI, 2010; Obi et al., 2017).

Regarding battery technology, we decided to use exclusively VRF batteries because of their interesting characteristics. First, it is expected to become the cheapest battery technology by 2050 (Jülch, 2016; Zhao et al., 2015). Second, VRF batteries have a much longer lifetime expectancy than other battery technologies (Gallo et al., 2016; Luo et al., 2015), i.e. potentially unlimited (Cunha et al., 2019). Then, VRF batteries have a longer storage duration than conventional batteries (Gallo et al., 2016; Luo et al., 2015). Finally, the ability to expand the storage capacity by enlarging the electrolyte reservoir with no limit is necessary since the storage capacity needed in a 100% renewable energy system is consequent. It is thus the most appropriate technology for utility-scale battery storage. VRF batteries are particularly well-suited to support wind and solar generation (Cunha et al., 2019). For all the reasons explained here above, we make the assumption that VRF battery technology will overcome conventional battery technologies for large-scale installation in the following years (Zhao et al., 2015; Luo et al., 2015). Although this assumption is simplistic, it will allow us to give a fair estimation of the storage costs. In reality, it is more plausible that a mix of existing and emerging battery technologies will support the energy generation.

The cost of TES chosen follows the projections of González-Portillo et al. (2017) because that study proposes a parametric model based on reliable assumptions to find the optimal LCOS of TES. Also, the results are aligned with IEA projections (IEA & IRENA, 2013).

	LCOS [$/MWh]	
Technology	LCHB	HCLB
Battery	94.5	126
PHS	52.5	94.5
TES	140	140
A-CAES	73.5	115.5
Gas (PtG)	273	451.5

Table 19: LCOS per technology (Jülch, 2016; González-Portillo et al., 2017)

The cost of storage per MWh consumed is finally calculated by weighting the LCOS by the proportion of energy transiting by each storage technology. The resulting cost is given in table 20.

Energy mix The energy mix chosen in this study is extracted from M. Jacobson et al. (2017) as they are the only one to assume the electrification of the whole energy system. The energy mix in M. Jacobson et al. (2017) is consistent with the energy mix in Child et al. (2018) and we thus assume that the storage mix estimated in Child et al. (2018) is consistent for the aim of this study.

To estimate the storage needs, the most important parameter is the share of wind and solar generation as their intermittency will determine the needs (Cebulla et al., 2018). The share of PV generation in Europe is equal to 41% in both case and the share of wind generation is equal to respectively 47% in M. Jacobson et al. (2017) and 37% in Child et al. (2018). Child et al. (2018) allow 11% of other dispatchable RE (e.g. biogas, biomass) while M. Jacobson et al. (2017) do not.

4.2 Results

The system LCOE per country and its composition is given in table 20. As in section 3, the costs are all expressed in 2013-USD to allow a fair comparison.

	Generation		**T&D**		**Storage**		**System LCOE**	
Country	LCHB	HCLB	LCHB	HCLB	LCHB	HCLB	LCHB	HCLB
Albania	29.68	51.68	54.02	55.33	21.10	30.18	104.80	137.18
Austria	24.44	40.30	54.98	55.63	39.89	63.42	119.30	159.35
Belgium	25.19	45.62	55.45	55.78	55.61	88.29	136.25	189.69
Bosnia and Herzegovina	30.89	54.06	54.06	55.34	21.10	30.18	106.06	139.58
Bulgaria	30.10	49.80	54.42	55.46	51.05	77.85	135.57	183.11
Croatia	27.33	46.53	54.39	55.45	21.10	30.18	102.83	132.16
Cyprus	42.64	74.40	53.60	55.22	26.89	36.81	123.13	166.42
Czech Republic	24.53	39.84	55.05	55.66	40.26	63.25	119.84	158.75
Denmark	37.88	71.71	55.34	55.75	54.81	87.12	148.03	214.57
Estonia	33.14	59.67	55.23	55.71	79.04	122.02	167.41	237.40

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	Generation		T&D		Storage		System LCOE	
Country	LCHB	HCLB	LCHB	HCLB	LCHB	HCLB	LCHB	HCLB
Finland	35.24	66.30	55.42	55.77	27.68	42.64	118.34	164.71
France	39.50	73.46	54.81	55.58	33.74	52.74	128.06	181.78
Germany	31.43	57.07	55.08	55.67	30.00	45.84	116.51	158.58
Greece	35.24	59.65	54.27	55.41	51.05	77.85	140.56	192.91
Hungary	24.06	38.72	54.54	55.51	39.89	63.42	118.49	157.65
Iceland	33.25	60.59	55.73	55.83	1.74	2.43	90.72	118.85
Ireland	40.96	77.42	54.89	55.60	38.87	61.70	134.72	194.72
Italy	30.30	51.42	54.62	55.52	54.36	83.03	139.28	189.98
Kosovo	38.68	60.84	54.57	55.49	21.10	30.18	114.35	146.50
Latvia	30.63	55.43	55.13	55.67	79.04	122.02	164.80	233.12
Lithuania	35.27	62.81	54.72	55.56	79.04	122.02	169.03	240.39
Luxembourg	17.04	27.41	55.44	55.78	55.61	88.29	128.09	171.48
Macedonia	30.59	50.75	53.69	55.24	21.10	30.18	105.38	136.17
Malta	25.98	44.56	55.28	55.73	54.36	83.03	135.61	183.32
Moldova	32.86	53.95	54.44	55.47	21.02	30.24	108.32	139.66
Montenegro	30.87	56.00	54.27	55.40	21.10	30.18	106.25	141.58
Netherlands	38.51	75.30	55.51	55.80	55.61	88.29	149.63	219.38
Norway	28.37	55.91	55.52	55.77	6.74	9.56	90.63	121.25
Poland	35.46	62.54	54.57	55.51	73.91	119.14	163.94	237.19
Portugal	40.32	74.38	54.11	55.36	40.90	62.00	135.32	191.73
Romania	36.97	67.26	54.63	55.52	51.05	77.85	142.65	200.64
Serbia	25.74	42.29	54.19	55.40	21.10	30.18	101.03	127.86

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	Generation		T&D		Storage		System LCOE	
Country	LCHB	HCLB	LCHB	HCLB	LCHB	HCLB	LCHB	HCLB
Slovak Republic	28.78	47.27	54.86	55.60	40.26	63.25	123.91	166.12
Slovenia	29.16	49.30	54.59	55.51	21.10	30.18	104.85	134.98
Spain	37.62	67.77	54.48	55.48	40.90	62.00	133.00	185.24
Sweden	33.41	63.56	55.40	55.75	9.33	13.62	98.14	132.93
Switzerland	22.48	38.43	54.74	55.55	15.77	23.60	92.99	117.58
Turkey	35.18	59.89	53.73	55.25	26.89	36.81	115.79	151.95
Ukraine	40.46	75.67	55.11	55.67	21.02	30.24	116.59	161.58
United Kingdom	36.02	69.76	55.32	55.74	38.87	61.70	130.20	187.20
Europe	34.04	61.86	54.88	55.60	35.67	54.64	124.59	172.11

Table 20: System LCOE and components per country in a 100% renewable energy system in 2050.

The resulting system LCOE in a 100% renewable energy in Europe in 2050 lies between \$124.59/MWh and \$172.11/MWh. The cost is well balanced between generation, T&D and storage since they account on average respectively for 32%, 37% and 31% of the system LCOE.

In M. Jacobson et al. (2017), the system LCOE in 2050 was expected to lie between \$80.23/MWh and \$109.65/MWh with generation, T&D and storage respectively accounting for 50%, 42% and 8% of the total cost.

4.3 Discrepancies across Europe: deeper analysis

It can be seen from table 20 that each country in Europe faces different costs. In this section, we will analyse more deeply the extreme values, i.e. the three countries with the most expensive energy and the three countries with the least-cost energy. Unfortunately, the methodology to calculate the cost of T&D in M. Jacobson et al. (2017), which is followed in the present study, does not allow to significantly differentiate the different countries with regards to the T&D cost. We will thus mainly focus on generation and storage costs.

4.3.1 Low cost energy

Iceland The projected system LCOE in Iceland is 30% below the average system LCOE in Europe which is mostly explained by the significantly low cost of storage (95% below the average), both the generation cost and the T&D cost being in the average range. The projected energy mix in Iceland is described in figure 5.

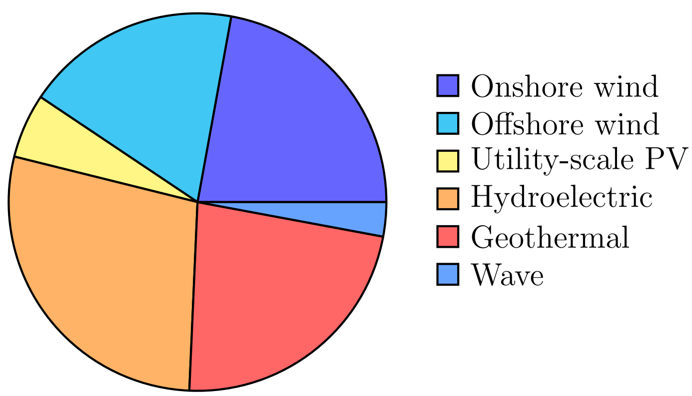

Figure 5: Projected energy mix in Iceland in 2050.

Iceland benefits from a favourable geology and an abundant hydrography, allowing for a particularly large share of geothermal and hydroelectric energy, which together represent 50% of the projected energy mix. Today, already, the totality of the electricity generated in Iceland is provided by those two sources (IEA, 2017b).

Such a high share of dispatchable generation gives to the country the opportunity to mitigate the effect of intermittent generation and allows to match the energy supply and demand at all time with only a small storage capacity.

Furthermore, beside the high share of dispatchable generation, wind share is far higher than solar share (ratio of 8:1) which implies lower needs in storage to support the generation Cebulla et al. (2018). In total, only 1.42% of the demand is filled by stored energy.

Switzerland The projected system LCOE in Switzerland is also 30% below the average system LCOE in Europe which is explained by both the low cost of generation (37% below the average) and the significantly low cost of storage (56% below the average). The projected energy mix in Switzerland is described in figure 6.

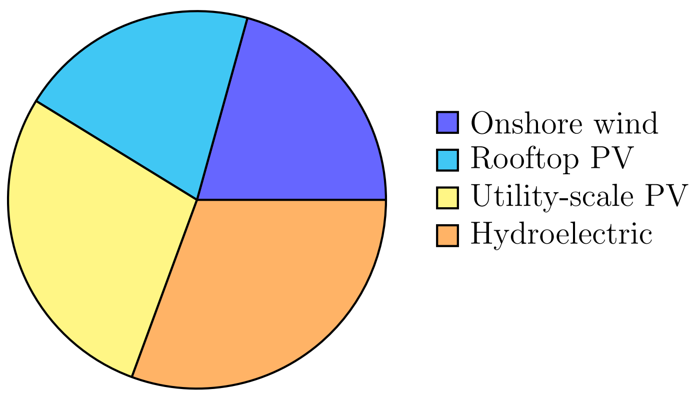

Figure 6: Projected energy mix in Switzerland in 2050.

The mountainous landscape of Switzerland offers a large amount of favourable sites for both hydroelectric generation and PHS.

The significantly lower generation cost results from the high share of hydroelectric and utility-scale PV generation, which are projected to become the two least expensive technologies. Moreover, the remaining generation is provided by onshore wind, which is also one of the cheapest technologies.

The storage cost reflects the high share of dispatchable hydroelectric generation which mitigate the negative effect of the intermittency of both wind and solar generation. However, the difference is less pronounced than in Iceland because of the high share of solar energy which requires more storage capacity. In total, 16.74% of the demand is filled by stored energy. Furthermore, the proportion of PHS is almost four times the average and PHS is the least cost storage technology.

Norway The projected system LCOE in Norway is 29% below the average system LCOE in Europe which is mostly explained by the significantly low cost of storage (82% below the average) but also by the low cost of generation (12% below the average). The projected energy mix in Norway is described in figure 7.

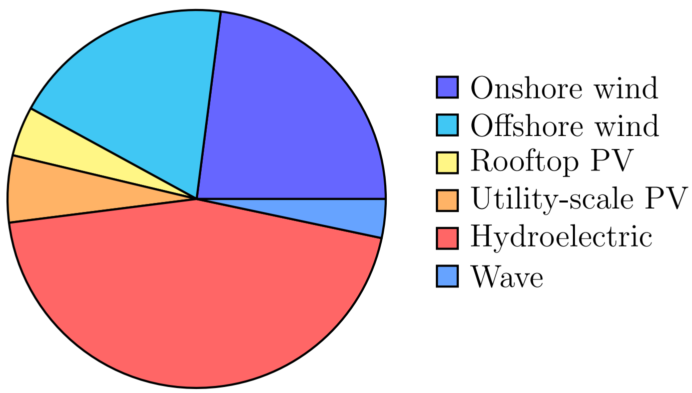

Figure 7: Projected energy mix in Norway in 2050.

The low generation cost is explained by the large share of hydroelectric energy, which is the least expensive generation technology. Hydroelectric generation already accounts for 96% of the current electricity generation mix in Norway (IEA, 2017b) and the country is today the first hydroelectric energy producer in Europe. However, the hydropower resources are not sufficient to support the electrification of all energy sectors and the country will need to develop other RE generation technologies such as wind. Furthermore, Norway benefits from an above average capacity factor in offshore wing generation which decrease the LCOE.

As in the case of Iceland, the significantly low storage cost is the result of both a high share of dispatchable hydro energy and a high share of wind energy. Annually, only 7.05%

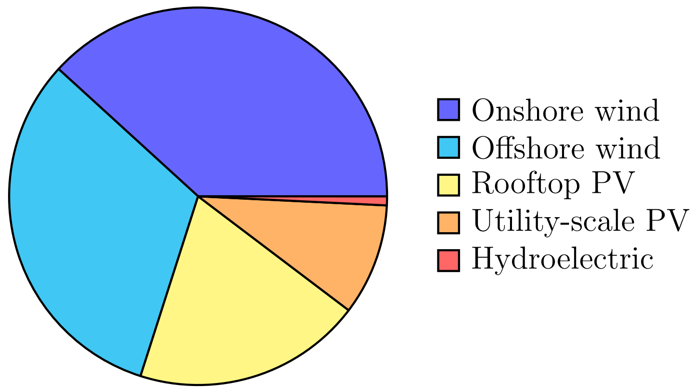

Figure 8: Projected energy mix in Lithuania in 2050.

of the demand is filled by stored energy.

4.3.2 High cost energy

Lithuania The projected system LCOE in Lithuania is 38% above the average system LCOE in Europe which is mostly explained by the significantly higher cost of storage (123% above the average). The projected energy mix in Lithuania is described in figure 8.

This particularly heavy cost of storage results from the absence of dispatchable RE, the generation relying thus entirely on wind and solar energy. In total, 47.69% of the demand is filled by stored energy. Battery storage represents 60% of the storage technologies.

Nowadays, only 40% of the Lithuanian electricity demand is filled by domestic generation plants and the remaining electricity is imported. In their analysis of the future of the Lithuanian energy system, Norvaisa & Arvydas (2016) found that an increase in the domestic generation can only be achieved by increasing the number of fossil fuel power plants, renewable potential being limited. By constraining the generation to 100% renewable in the present study, the cost is thus expected to be high.

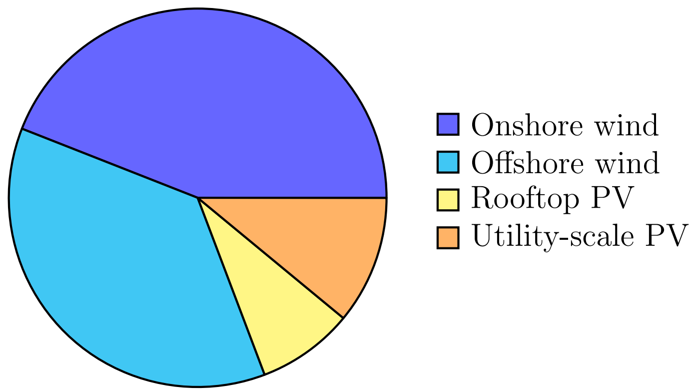

Figure 9: Projected energy mix in Estonia in 2050.

Estonia The projected system LCOE in Estonia is 36% above the average system LCOE in Europe which is explained by the significantly higher cost of storage (126% above the average). Is is interesting to notice that the cost of generation is slightly lower than average. The projected energy mix in Estonia is described in figure 9.

As for Lithuania, the high cost of storage is explained by the fact that generation relies entirely on wind and solar energy with no dispatchable generation to mitigate the effect of their intermittency. The energy mix is not diversified (it accounts 80% wind generation) which is another cause of the high storage needs. The country must thus rely on storage to compensate. Annually, 47.69% of the demand is filled by stored energy.

The flat topography of Estonia does not allow for large-scale PHS installation and the country must thus rely on more expensive storage technologies such as batteries and PtG. Moreover, the climate conditions in the Baltic region is not favourable for solar generation. Nowadays, 84% of electricity demand is generated in coal plants IEA (2017b).

Poland The projected system LCOE in Poland is 35% above the average system LCOE in Europe which is mostly explained by the significantly higher cost of storage (114% above the average). The projected energy mix in Poland is described in figure 10.

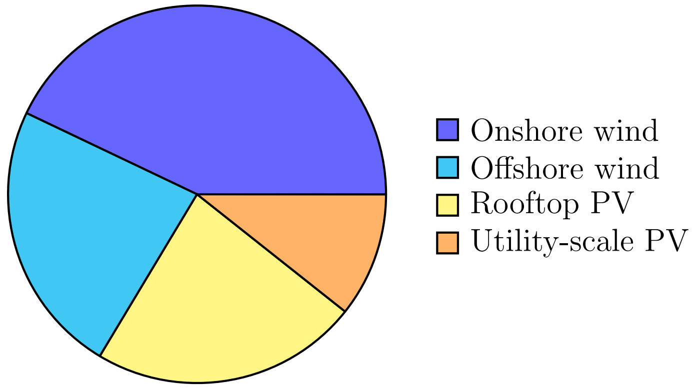

Figure 10: Projected energy mix in Poland in 2050.

As for both Lithuania and Estonia, the substantial cost of storage is explained by the exclusively intermittent nature of the energy mix. In total, 34.95% of the demand is filled by stored energy.

In their analysis of the RE potential in Poland, Paska et al. (2009) explain that the construction of new large-scale hydropower stations is not possible without seriously harming the environment. However, they are confident about the wind potential of the country, which is one of the greatest in Europe. Today, coal generation has a 80% share in the energy mix of the country IEA (2017b).

5 Conclusion

Although the transition to a renewable-dominated energy system is today the ambition of most industrialized countries, the shape of such a system is still to be determined. While it seems inevitable that wind and solar generation will become the main drivers of the power sector of tomorrow, the best way to manage their intermittent nature remains uncertain. Indeed, both the storage system and the transmission and distribution network are currently not fit for a significantly high share of variable renewable energy (VRE).

The economical feasibility of such a transition is of prime importance, as a 100% renewable energy system can only be achievable if the costs associated are acceptable. Although the cost of wind and solar generation is relatively low compared to other conventional sources and is still expected to decrease in the future, their intermittency involves challenges and the cost of the mitigation options needs to be taken into account when estimating the levelized cost of energy (LCOE).

In a system exclusively powered by renewable sources, storage plays an important role as it allows to mitigate the intermittency of VRE by shifting the energy supply in time. In our analysis of a European 100% renewable energy system in 2050, we found that 24% of the electricity demand would be filled by storage solutions among which the highest share is dedicated to batteries for short-term storage and the third is filled by gas storage (through PtG and GtP process) for long-term and seasonal storage. PHS, the most widely spread storage technology today, is still present but the installed capacity becomes marginal as its expansion is limited by the favourable sites availability.

Beside storage, long-distance interconnections between remote regions is another solution the mitigate the intermittency of VRE as it allows the shift of energy supply in space. According to most studies, the improvement of interconnections is the most cost-effective option for the integration of VRE. Long-distance transmission allows to take advantage of the complementarity between wind and solar energy.

The aim of this study was to challenge the assumptions made in M. Jacobson et al. (2017), to compare their results with the existing literature and finally to calculate a fair estimation of the LCOE in a 100% renewable energy system in Europe by 2050.

Although the generation costs in M. Jacobson et al. (2017) are consistent and relying on plausible assumptions, the assumptions regarding transmission and distribution (T&D) and storage costs are more debatable. Neither the high-voltage direct current (HVDC) grid or the storage needs were the result of any least-cost optimization model. Instead, they used fair guesses in their calculation. Moreover, these two parameters have been calculated for the U.S. territory and then applied to all of the 139 countries under scope with no distinction.

To compute our own estimation, we thus decided to take the parameters regarding HVDC long-distance transmission and storage from studies whereby a least-cost optimization model has been applied to the European territory. We also updated the parameters regarding T&D costs. The result is depicted in figure 11.

From figure 11, one can see that the projected LCOE from the present study is approximately 50% higher than the LCOE projected in M. Jacobson et al. (2017). While the T&D costs are slightly superior, the main difference relies in the storage costs which are more than seven times higher. This contrast can be explained by several factors, such as the different storage needs in the U.S. with regards to Europe or the storage mix chosen by the authors, which e.g. excludes every battery technology.

The present study has its own limitation. In our calculation, we have used numbers from different studies and combined them all together, as e.g. regarding the energy mix, the HVDC network and the storage mix. Although we made the assumption that the sources of information were consistent with one another, the construction of an optimization model would be optimal to determine the energetic needs of each country. Such a work is beyond the scope of this study and would constitute an interesting path for further researches.

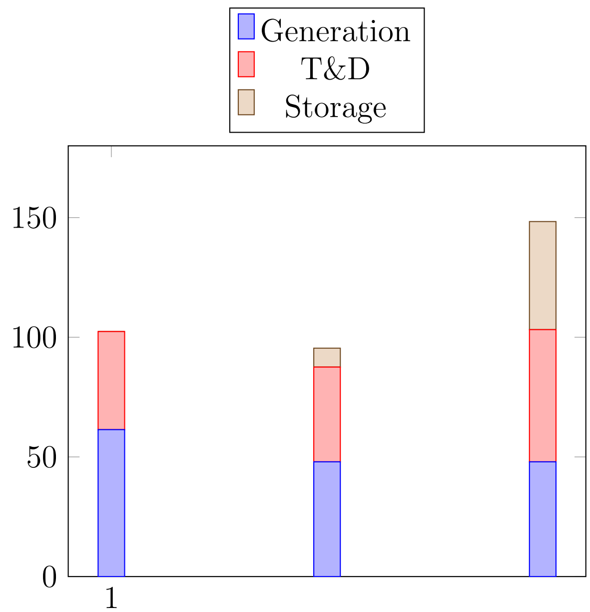

Figure 11: Current system LCOE in M. Jacobson et al. (2017) (left), average system LCOE projected in Europe in 2050 according to M. Jacobson et al. (2017) (middle) and the present study (right). in 2013-$/MWh.

As we have seen in this study, a 100% renewable energy system does not automatically rhyme with economically feasible and integration options to mitigate the negative effect of the intermittency of VRE is of primary importance. In our analysis, we found an increasing average system LCOE in Europe, but this result is to be tempered. Indeed, the effect of the transition to 100% renewable energy on the system LCOE is extremely different from one country to another, which is depicted in figure 12.

While some countries suffer a drastic increase in costs, sometimes up to the double, others show an almost constant LCOE. This difference is mostly explained by the generation mix; the countries that are able to rely on dispatchable generation, such as geothermal or hydroelectric, have much lower storage needs than the countries relying exclusively on wind and solar generation, implying significantly lower costs.

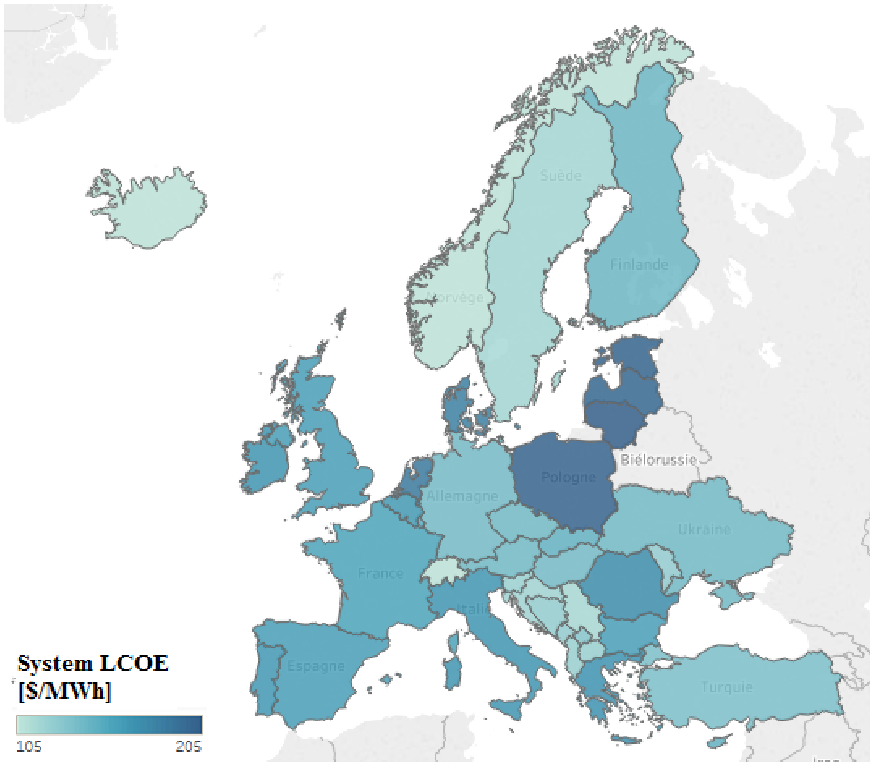

Figure 12: System LCOE per country

As it is explained in Reichenberg et al. (2018), the system LCOE as a function of the VRE share increases sharply from 80% wind and solar energy share. As a cause, the increasing need in expensive storage solutions to mitigate the effect of the intermittency of VRE generation when the dispatchable thermal generation (e.g. gas turbine) is not sufficient (or not existent in the case of 100% renewable energy) to compensate during peak-load.

While a 100% renewable energy system would hardly be economically profitable by 2050, a system dominated by renewable generation, e.g. 80% VRE share, allowing a certain percentage of conventional generation might turn out to be more feasible. In this case, gas turbines can be used to meet peak-load demand, decreasing drastically the needs in short-term storage (e.g. batteries) which is the most expensive.

Future work including a cost-optimization model in Europe is required in order to give a better approximation of the actual energy needs after the electrification of all energy sectors. It will be interesting to analyse the evolution of the system LCOE for VRE generation share between 80% and 100% to find the best compromise between economical and ecological considerations.

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