A Response to Dominique Finon about our two recent articles:

"How sensitive are optimal fully renewable power systems to technology cost uncertainties"

&

"Low-carbon options for the French power sector"

By Behrang Shirizadeh (doctorant au Cired)
and Philippe Quirion (directeur de recherche au CNRS, Cired)

Dominique Finon has recently written and sent widely via unsolicited emails a text criticizing two of our journal articles. Besides the demeaning tone of these emails, we consider that that this critique is unfounded. It contains several important misunderstandings, unsubstantiated claims, as well as biased selection from the scientific literature.

This note responds in detail to the criticisms made by Dominique Finon. It sets the stage by recalling basic elements about our papers, before addressing each of Dominique Finon's point in turn.

Clarification about the scope of each paper

a) The 100% renewable paper (hereafter S/P/Q) aims at addressing two main shortcomings of the existing literature on 100% renewable energy systems:

1. Understanding the robustness of the simulations to differences in weather years (This point is ignored by most studies, ADEME goes up to 4 years, which is not enough): we study 18 consecutive weather years.

2. Understanding how the extent to which cost uncertainties for a prospective energy planning based on fully renewable electricity production, induce extra system costs.

b) The relative role of low-carbon options study (hereafter S/Q) aims at comparing low-carbon options: renewables, nuclear power, fossil with CCS (positive residual emissions since carbon capture and storage does not have 100% capture rate) and BECCS (negative emission as we use biogas and carbon capture and storage). We take into account several cost scenarios; several availability scenarios and we decentralize the optimum through simplified electricity and carbon markets to give an insight about the investment motivations depending on the social cost of carbon.

Contrary to what Dominique Finon wrote, we do not consider any cap or emission limit, instead we introduce a social cost of carbon. Thus, there is no emission constraint but several SCC scenarios (from 0 to 500€/tCO_2). Emission is an output based on utilization of CO_2-emitting plants, and we observe CO_2 emissions based on different SCC values.

The technologies in EOLES_elecRES and EOLES_elec models

Dominique Finon describes several technologies of our model erroneously. Here we highlight the existing technologies in each model and then clarify their utility by categorizing them.

EOLES_elecRES consists of six supply technologies: offshore wind power, onshore wind power, solar PV, hydro-generated lake (dams), run-of-river and biogas (which is sent to open-cycled gas turbines). It also consists of three storage options: Li-Ion batteries, pumped hydro storage (PHS) and methanation[1] (power-to-gas) whose produced synthetic methane is also sent to the open-cycled gas turbines (shared with biogas). Biogas is limited to 15TWh$_e$/year, hydro-electricity supply technologies are both fixed to their actual installed capacities, and we assume a doubling of the PHS capacity based on ADEME (2015).

EOLES_elec consists of the same technologies, moreover, fossil gas and nuclear power are added to supply options. By adding a second thermal power plant which is a combined-cycled gas turbine equipped with carbon capture and storage, we enable low CO_2 emitting natural gas, negative CO_2 emitting biogas and negative CO_2 emitting methanation.

Figure 1 shows the models EOLES_elecRES and EOLES_elec, the technologies added in EOLES_elec (S/Q) to the EOLES_elecRES model (S/P/Q) are surrounded by blue rectangles.

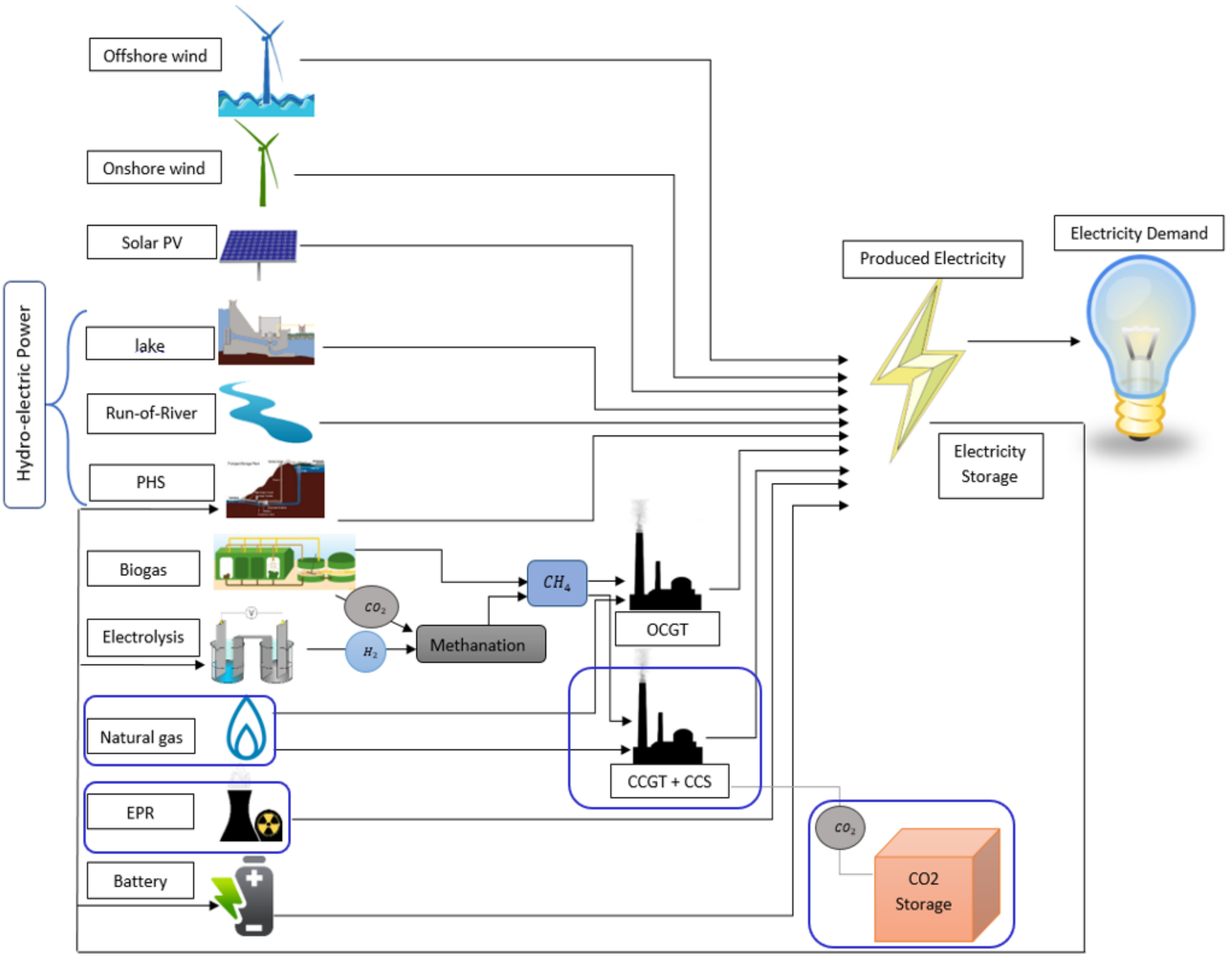

Figure 1. Graphical description of EOLES_elecRES and EOLES_elec models

Let's make the definitions clear

1. VRE (variable renewable electricity) = Offshore and onshore wind, solar and run-of-river

[1] First from water electrolysis by excess renewable power generation, we produce hydrogen. Then we send this hydrogen to methanation reactors (containing biogenic CO_2) where we produce synthetic methane by Sabatier reaction between hydrogen and biogenic CO_2.

2. Dispatchable RES (renewable energy source) = lake-generated hydro (dams) and thermal power plants with bio-energies (biogas in the EOLES_elecRES and EOLES_elec models).

Let's clarify storage categories

1. Short-term storage to manage the short-term variability of VRE => batteries with capex of 100€/kWh+140€/kW (for 2050), the recent utility scale projects in Australia and California are already at the GWh level.

2. Mid-term storage => PHS and Hydrogen (for our study PHS with very limited increase). We also did a variant case study by limited PHS to the existing capacity and classing them into two groups since they don't all have the same discharge time, and we added Hydrogen as a power-to-gas option, the results are in my GitHub.

3. Long-term storage, to account for seasonal variability of VRE technologies => Power-to-Methane. It is not an invention, it already exists, there are around 10 European pilot projects (at least), the French one is Jupiter 1000. Both PEM and Alkaline electrolyzers are relatively mature technologies, used widely (especially Alkaline). Methanation reactors have existed for a long time (since the 1960s). By itself, combination with electrolysis is the only uncertainty in large deployment of this storage option. Otherwise a couple of GW of electrolysis and methanation reactors are more than feasible.

Each of the storage options are representative, we can count several other alternatives for each of these three types of storage, the important is to have at least one technology representing each storage category.

The classification above is not a technical one, since all are technically dispatchable and they have very high ramp rates, the classification is economic, based on two investment cost components: power capacity related capex (in €/kW: inverters and power electronics for batteries, pumps and turbines for PHS etc.) and energy capacity related capex (in €/kWh: all the storage volume costs – electrolyte and cell costs for battery, reservoir cost for PHS etc.). The energy losses also vary across technologies and matter, of course.

The dispatchable technologies

Dominique Finon mentions several times the term "sans pilotable" (without dispatchable options in French). However, it is not the case for our studies. In the fully renewable power system model (S/P/Q) for fully renewable power system we have several dispatchable options: reservoir-based hydro (dams), with 13GW of installed capacity, around 30GW of open-cycled gas turbines (fueled with either biogas or synthetic methane), battery storage and pumped hydro storage (PHS) options (all together nearly 80GW of available dispatchable capacity). For the second article (S/Q) on top of these options, we added combined-cycled gas turbines with carbon capture and storage and nuclear power plants. Of course, the optimal capacities change since it is subject to optimization, but it doesn't change the fact that we have included several options to manage the variability of electricity demand and VRE production.

Let's make the modelling concept clear

Our model, as the ones that Dominique Finon mention, is not really a complex model. These are bottom-up sectorial optimization (cost minimization) models, subject to some technical and adequacy constraints. Anyone who has a system understanding can develop this kind of model, and there are a lot of open source available ones. Behrang, personally, studied EMMA (by Lion Hirth), DIFLEXIO (by Manuel Villavicencio), FLORE (by Quentin Perrier), ELMOD (by Alexander Zerrahn), DIETER (by Wolf-Peter Schill and Alexander Zerrahn), PyPSA (by Tom Brown) and TIMES, and by identifying the missing or extra elements, we developed the EOLES family of models (so far three of them: EOLES_elecRES, EOLES_elec and EOLES_mv).

Neither modelling, nor the used solvers are complicated. They are nearly all based on linear optimization in GAMS (except PyPSA: non-linear optimization in Python), using the CPLEX solver (that already exists in packages, no one writes the algorithm but only sets the solver). So please, let's not exaggerate the complexity of these models, IAMs and operational unit commitment models are much more complicated.

Some of these models are dynamic, showing the transition of the existing system (such as TIMES and FLORE) but most of them are static models, which show only an optimal end-point for a chosen horizon considering the coherent hypothesis (such as ELMOD, DIETER, PyPSA and EOLES). Nevertheless, static models are useful in providing energy policy insights, since in 2050 nearly none of the existing power plants will still be in operation (except hydroelectric power plants and a few historical nuclear power plants if we retrofit them for 20 years).

We actually compare our findings with the existing literature

Dominique Finon claims that we do not compare our results with other relevant literature. This is wrong. In each of the mentioned papers, the first part of the discussion section (Section 4.1 in both) is dedicated to comparison with existing studies. We highlight the findings of Villavicencio (2017), Krakowski et al. (2016), Petitet et al. (2016) and Brouwer et al. (2016) as contradictory studies (because they are the only ones we find published in peer-reviewed journals). Then we also compare our findings with the studies that have similar conclusions: both studies of ADEME (2015 and 2018) and Schlachtberger et al. (2018).

We also explain the reasons why the findings of our studies are different from these previous studies. For instance, in explaining why our findings diverge from the ones by Krakowski et al. (2016) we wrote:

These results contrast with those of Krakowski et al. (2016), where the least costly scenario for France is presented as being "business as usual", and increasing the proportion of RES gradually increases the annualized cost of the power system by approximately 20% for an electricity mix with 80% of RES (€40bn/year). The main reasons for this difference in the results (20.5 to €22.3bn/year depending on the availability of technology and on the SCC scenario) are (i) lower VRE capacity potentials (70GW for wind and 65GW for solar power vs. 140GW for wind and 218GW for solar power in the current study) which results in very high power import costs, (ii) very low storage availability, and furthermore only short-term, very low-efficiency storage and (iii) the assumption of perfect correlation between offshore and onshore wind power, which leads to a lower complementarity between these technologies.

For the difference with Villavicencio (2017) we wrote:

Villavicencio (2017) finds even higher annualized cost: more than €180 bn/yr. for 100% renewables, i.e. more than 8 times our result. Several factors may explain this huge difference. First, he takes a real discount rate of 7%/yr. This is much higher than ours, which corresponds to the rate recommended for socio-economic analysis in France (4.5%). Second, his investment cost for PV is much higher than ours: €3.6/W, while the current investment cost at utility scale is around $1/W

(Lazard, 2019). This explains why PV does not appear in his reference scenario (F1) with 100% renewables. Third, total annual demand is higher than ours (512TWh vs. 422TWh).

For the difference with Brouwer et al. (2016) we wrote:

According to another European-wide study (Brouwer et al., 2016), increasing the proportion of renewables in the final electricity mix from40% to 80% raises the total system cost, even in the presence of demand response. The average system cost (average LCOE) is approximately €91/MWhe for the case of 80% RES. This big difference in results can be explained by (i) the difference in the chosen future cost projections, where they use IEA's world energy investment outlook study (IEA, 2014), carried out in 2012, and projected for 2035, while since 2012we have seen a very big cost decrease in solar PV and storage technologies, (ii) the non-negligible higher annual power demand (547TWh/year vs. 423TWh/year), (iii) a low calculated capacity factor for wind power (25% vs. 32.5%) which is also weakly correlated with the historical data (86% correlation), (iv) the choice of 2013 as the weather data year without studying the importance of this choice (in the current article the chosen representative weather year is 2006, which results from a correlation study with a 19-yearweather data simulation), and finally (v) the methodological difference in the calculation, where they use a two-stage procedure, first optimizing the installed capacity before optimizing the dispatch, while the EOLES_elec model optimizes dispatch and investment simultaneously.

There are several other studies that we do not compare with our papers because that have very similar conclusions to ours. We cite some of them in the introduction section of each paper, and we do not cite some others: Brown et al. (2018), Victoria et al. (2019), Zhu et al. (2020), Zeyringer et al. (2018), Kan et al. (2020), Tröndle et al. (2020), Daggash and Mac Dowell (2019), Zerrahn et al. (2018), Bloess et al. (2018), Linares et al. (2013), Olauson et al. (2016) and many others.

Some of the misinterpretations when other studies are compared to ours

Dominique Finon claims that comparable studies yield LCOEs two to three times higher than ours. While this would not in itself disqualify our study, it turns out that of the two studies he compares our results with (ADEME 2015 and ADEME 2018) are misinterpreted, and another (Sepulveda et al. 2018) does not include important renewable sources which we include in our models (offshore wind power, biogas and hydro-electricity). We explain one by one briefly below:

Dominique Finon quotes costs between 100 and 120€/MWh from ADEME (2015). This figure, however, includes both the generation cost and network cost, the latter being at least 1/3 of the total (exogenous addition of around €14bn/year) – while our papers report only generation costs. Once network costs are excluded, the price of supply and storage and other flexibility options is around €70/MWh, much closer to our findings. ADEME (2018) finds 91€/MWh (and not 178€/MWh, as Dominique Finon writes), and out of these 91€/MWh, 62€/MWh is the wholesale market price (based on micro-economic theory it should be higher than the average energy production cost or equal to it) and 26€/MWh network cost. Again, this is much closer to our findings.

Sepulveda et al. (2018), which Dominique Finon calls the "MIT study",[2] do not include biomass and biogas in their scenario without firm low-carbon technologies (they call all the dispatchable low-

[2] It is not correct to call a study by researchers from research center X "the X study". Our papers are not "CIRED papers" either. In fact, a very recent study by researchers from the same MIT (Brown and Botterud, 2020), [not published yet at the time we wrote our article] published in the same journal (Joule) models the US electricity system and among other conclusions, it finds that (1) "Nuclear, if available, plays a smaller role than renewables at central cost projections" and a "100% US power system" including the cost of required

carbon options firm low-carbon options), and once nuclear, fossil (with or without CCS) and bio-energies are eliminated (and they do not include hydro-electricity, nor pumped hydro storage options), the only flexible option remaining is battery storage (fixed to 2-hour or 4-hour discharge times). This study is thus not comparable with ours, since our scenarios include either all renewable (including dispatchable ones and storage options) or all low-carbon.

The same Jesse Jenkins released another study in December 2020 (Princeton study) and in all scenarios studied (six scenarios) nuclear power has less than 5% share in the primary energy mix in 2050, except one scenario (high electrification, constrained RES), where it is around 33%. Renewables vary from 25% to 100% depending on the scenario.

About our hypotheses

1. *Demand scenario*

We considered ADEME's 2050 demand prediction, which has an annual electricity demand level of 422.3TWh/year (vs. currently ~450-480TWh/year), in an hourly temporal resolution. This demand scenario is the EFF scenario in the French public debate on energy transition. The mentioned two issues are the "low power demand" and "smoothened profile" arguments.

Low power demand: the existing demand profile already takes into account several factors increasing the power demand (more than 10 million electric vehicles and electrification of at least 1/3 of heat demand). However, there are also several efficiency measures that will decrease the electricity demand: replacement of resistive heaters by heat pumps, replacement of incandescent light bulbs by LEDs, and increased thermal isolation of buildings.

Smoothened demand profile: that is completely wrong. The peak demand in ADEME's 2050 demand scenario is 96GW, and the minimum demand is 17GW. This variability is higher than any observed year. For instance, for the year 2016 (one of the years with the highest observed electricity demand), the peak demand was 88GW, and the lowest demand was 30GW. The standard deviation of ADEME's demand is 13.5GW, while that of historical demand for 2016 is 11.5GW.

Regarding our study, we studied two other alternative demand scenarios for the second paper (S/Q). The SOB and DIV scenarios in public debate. On top of that, for the first article (S/P/Q), we also studied a variant case with the electricity demand profile of 2016, the results are on GitHub. The conclusion: the unit cost of a fully renewable electricity system is even cheaper with historical demand thanks to lower variability of the profile (50.65€/MWh for 2016 vs. 51.65€/MWh for ADEME's scenario).

If we consider a massive electrification, one should consider "sector-coupling" (a multi-vector fully endogenous optimization between different energy sources, carriers, conversion and storage options). Sector-coupling enables optimal allocation of different energy sources, carriers and storage options to satisfy the main end-use demands by allowing an endogenous choice of energy carrier and conversion options for different end-uses (Lund et al, 2017). We also studied it in another paper, submitted but not published in a journal yet, but available in the IEEE proceedings (since we presented it in several conferences), and in the SSRN working papers series (Shirizadeh, 2020). The conclusions remain at the same strength, exclusion of nuclear energy from the supply side doesn't change anything regarding the cost and emissions.

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transmission expansion costs "$73/MWh". Very similar conclusions to our findings in both papers (S/P/Q and S/Q).

2. Stability of power system frequency

In our model, we only consider secondary reserve requirements (the main reserve contribution for the voltage and frequency stability), with an hourly available dispatchable power capacity. The equation is based on the ENTSO-E's codes regarding the integration of renewables, and this equation is a function of hourly power demand and installed VRE capacity. Some statistical constants based on historical variability of hourly demand and VRE production are also introduced. Therefore, from an hourly available power capacity point of view, the model considers everything correctly. However, an AC power network requires frequency stability, which is normally ignored by the modelers because there is no parameter or variable in these models that is based on frequency. But the question is: is it important to model the frequency? The answer is of course no. First of all, there will be gas power plants in a fully (or highly) renewable power systems, fueled by either biogas from methanization or synthetic methane from methanation (power-to-gas). But let's consider that it is not enough. The hourly reserve capacity requirement (defined based on the equation of ENTSO-E), even for a fully renewable power system in the highest demand hour does not exceed 6GW. Let's say that we have underestimated the real requirement and take 10GW. A simple back-of-envelop calculation with no optimization is what we need here. Several frequency stability options exist, flywheels, synchronous condensers and even more recent solutions: synthetic inertia. Let's take only flywheels, since in the power network of New York, a big proportion of this stability is provided by them, for a cost of 700€/kW (actual cost). Let's see how much it will cost per unit of power consumed:

10GW×700€/kW/(422TWh×15years) = 1.1€/MWh

Therefore, if without any optimization we choose only flywheels, this is the additional cost of frequency stability. Note that other options are even cheaper, and this equation can also be divided in two parts, one for frequency and one for power capacity, thus, the frequency requirement will be less (and capacity options are much cheaper than flywheels). Thus, 1€/MWh is an upper bound, and it is much smaller than the average electricity unit cost of ~52€/MWh. To sum up, all these capacity related costs are of very minor importance compared to supply and energy adequacy costs. An interesting illustration for a simplified model can be found in this article of Robin Girard (researcher at the École des Mines de Paris).

3. Optimism in storage options and invention of power-to-gas

Two main storage technologies are criticized by Dominique Finon: pumped hydro storage (PHS) and power-to-gas (in our case methanation). The social acceptability of extension of PHS capacity is debatable, we agree. To that end, we also studied 3 variant cases all with existing PHS capacity in France. We first divided PHS capacities in two categories, big PHS and small PHS stations. In each of the three variant cases, we made a difference: one more power-to-gas option of hydrogen from electrolysis (we will call power-to-hydrogen). For the first case, we considered only onsite storage of hydrogen, thus no hydrogen network and the electrolysis take place on the storage site. For the second case, we considered a hydrogen network, and for the third case We just banned hydrogen but the methanation option remains available. The results are on GitHub, the conclusion is still the same: no difference in the cost, the model installs a bit more batteries if hydrogen is not available, otherwise hydrogen replaces both extra PHS requirements and methanation. In the worst case (no availability of hydrogen, no possible capacity extension for PHS), the cost difference is below 3%.

To answer to the criticism of Dominic Finon about the technology "invention" for methanation, first we need to understand how the storage technologies are categorized regarding their periodicity. In the beginning of this document, we explained it partially. From a storage period/temporality point of view, the classification has nothing to do with technical constraints, but economical ones. For instance, a technology like battery storage is considered a good short-term storage option because of its high volume cost and low power cost. Thus, a small quantity of volume with high power capacity will be chosen and emptied very fast in daily cycles. Vice-versa, a technology such as power-to-gas is the opposite, it has nearly null volume cost, but a very high power capacity cost (electrolyzers and methanation reactors for charging and thermal gas power plants for the discharge). Thus, the installed capacity will be small for charging but the volume will be big, and in case we separate the charge and the discharge costs (as in our papers), the storage will be with a small power capacity, the discharge (thermal power plant) will have a higher installed capacity, and the volume will be immense. In such a combination (resulting from a fully endogenous optimization), the model will choose to charge during a long period with small capacity, and discharge whenever it is economical (because of the high cost of this storage, it mainly chooses to use it in the winter, especially the periods with low wind and sun). There is no flexibility issue in any of the storage options: batteries have a subsecond response time, pumped hydro storage options are charged and discharged by pumps and turbines, opening and closing valves, and pipe flow, their flexibility is in seconds level. Electrolysis is an instantaneous process in stand-by (few seconds), and in matter of minutes in cold start-up, and methanation is a process that happens in few minutes (ENEA, 2016). Similarly, gas turbines have very high flexibility, either open-cycled or combined-cycled, with or without CCS, they can reach to their maximal power in less than an hour (Mac Dowell and Staffel, 2016). Thus, flexibility of all these three options are the same in an hourly model: 100%.

On top of all that, Dominique Finon misinterprets the discharge time of storage options, by mixing it with periodicity. Discharge time of a technology is the ratio of energy volume over the power capacity of that storage technology. It is defined in time unit (for example hours). Typically, the discharge time of batteries is between two to four hours, pumped hydro storage between two to 40 hours, and long-term storage options in order of ~1000 hours. It doesn't mean that they will do cycles over these periods, it means that in full discharge (charge) capacity, these technologies can function as long as their discharge (charge) time in case if they were initially full (empty). Although charge and discharge capacity of batteries are the same, pumped hydro storage technologies and power-to-gas technologies have different charging and discharging powers. The functioning of methanation regarding its charging and discharging periodicity is not 2000-hour cycles, it is charged during summer when there is excessive renewable power production, and it is discharged during the periods when there is less VRE production but high energy demand, it is based on merit-order effect, in case the electricity price is high enough.

Do we invent this technology? Of course not, already existing pilot and operational projects are proof for this. Even our cost assumptions are based on the cost of existing equipment, PEM electrolyzers and catalytic methanation reactors and open-cycled or combined-cycled gas turbines. As mentioned previously, there must be a long-term storage option. If we agree that methanation is not an option, we can think about hydrogen (with its dedicated network or with direct on-site electrolysis), and in fact, it becomes even cheaper to replace methanation with power-to-hydrogen (cf. results from modelling in GitHub).

About the communication we made after the second article (S/Q)

First, Dominique Finon interprets what "availability" means when he cites our abstract, and again, a mistake. When we say availability, we refer to the availability scenarios of the article, where we do not authorize some technologies to participate in the optimization and then we evaluate the relative role of each of those technologies. Unfortunately, Dominique Finon interprets this "availability" as capacity factor (a measure of utilization of the power plants), which has nothing to do with what we wrote.

Are we too optimist about the cost of renewables and storage?

The values in Table 1 show the cost projections of or references, the latest noted costs (2019 or 2020) and the other projection values.

Table 1. Comparison of taken cost input data and other sources

	Offshore wind	Onshore wind	Solar PV	Battery Storage	Biogas	Nuclear power
Our hypothesis for 2050	2330€/kW	1130€/kW	425€/kW	100€/kWh+ 140€/kW = 150€/kWh[3]	2510€/kW	3750€/kW
source	JRC (2017)	JRC (2017)	JRC (2017)	Schmidt et al (2019)	JRC (2017)	JRC (2014)
The current cost by end of 2020	3130€/kW (IRENA, 2020)	1216€/kW (IRENA, 2020)	820€/kW (IRENA, 2020)	190€/kWh (Neoen bid for 2021 NSW)	2141€/kW (IRENA, 2020)	7515.15€/kW (Flamanville 3[4])
Cost reduction in %	25%	7%	48%	21%	pessimist	50%
EIA (2020) for 2050	1957€/kW	725€/kW	501€/kW	-	-	-
IEA (2020) for 2040	1904€/kW	-	-	-	-	-
BNEF (2020)	-	-	-	50€/kWh	-	-

The comparison of our reference cost scenario (JRC, 2017) for 2050 is pessimist regarding both offshore and onshore wind power technologies in comparison with other projections. Battery storage is nearly reaching our projected cost by the end of 2020, and biogas is already more expensive than the current cost. However, JRC's 2050 cost development scenario is optimistic regarding solar PV (48% reduction) and nuclear power (50% reduction). Therefore, the optimism is mainly on the side of nuclear energy but not renewables, nor battery storage.

Considering the construction time of projects, according to IEA (2019), the construction time of renewables is less than 2 years (what matters here is the time between the start of the construction and the operation, not the studies and impact assessments). Therefore a one-year construction time assumption for 2050 does not seem very optimistic once we compare with our construction time assumption for nuclear power (10 years in 2050), which is currently more than 20 years in Europe looking at three European projects (Flamanville 3, Hinkley Point C and Olkliuoto 3).

To sum up, neither in cost hypotheses, nor in construction time, we don't see any optimism in our input data regarding renewables.

Our papers have been presented to many researchers and peer-reviewed several times

In the following we first highlight the conferences, seminars and workshops in which we presented at least one of these two articles, and later we show the number of reviews for each paper (on top of the conference submission reviews).

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[3] To present in one single form of €/kWh, the battery storage technologies' energy related capex must be summed by its power related capex divided by its typical discharge time:
overall capex = energy_capex (€/kWh) + power_capex (€/kW)/discharge_time (h)
[4] Cours des Comptes report: €12.4bn excluding the financial costs.

1. The conferences in which these papers were presented

International Energy Workshop 2019 (organized by IEA), French Association of Environmental and Resource Economists annual conference 2019 (FAERE), European Association of environmental and Resource Economics 2020 (EAERE), European Energy Markets 2020 (organized by IEEE), Sustainable Development of Energy, Water and Environment Systems south-east Europe annual conference 2020 (SDEWES – SEE), French Association of Environmental and Resource Economists 2020 (FAERE) and many other accepted conferences (IAEE 2020, IEW 2020, SDEWES 2020, GHGT-15 etc.) that we either chose other papers to present (Shirizadeh, 2020) or they were cancelled or postponed because of COVID pandemic.

2. The seminars and workshops in which these papers were presented

Risk Day 2019 (Cambridge, UK), annual doctoral students seminar of MPDD chair (2019), CEMES (2019), debate session CIRED-Associations (2018), French Association for Energy Economists annual PhD seminar (2019), Community in Economics and Management of the Energy Shift (CEMES) seminar (2018), and many others.

3. The industrials/labs/teams to which the papers were presented (with feed-back)

RTE R&D, ADEME, EDF R&D, EDF Strategic committee, LMD, E4C, The Shift Project, TOTAL Strategy, GRTgaz prospective R&D, EconomiX (economics laboratory of university of Nanterre), LEMNA (Economics laboratory of university of Nantes) etc.

Table 2. Number of journal and working paper series reviews for each article (excluding conference reviews)

Paper	**Journal**	**FAERE**	**USAEE/IAEE**	**Total reviews**
S/P/Q	4	1	2	7
S/Q	3	1	2	6

Conclusions

Scientific papers such try to expand existing knowledge at a given point in time. They are subject to intense peer review and intense debate, prior to, during and after the publication process, based on a careful examination of the underlying assumptions of the work. Ours, as noted above, have undergone such process as any other. This does not mean that the end product is without limitations, nor does it mean that it is the end of the story. New studies will undoubtedly build on ours, confirming, amending or reversing our results along the way. We have a responsibility to be humble about our work, especially when we present it to the outside world, but other researchers have a responsibility to ground their arguments when they criticize it.

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