# Authors' reply to the letter to the editor: Response to 'A comparative analysis of electricity generation costs from renewable, fossil fuel and nuclear sources in G20 countries for the period 2015–2030'

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**Authors' Reply to the Letter to the Editor: Response to 'A comparative analysis of electricity generation costs from renewable, fossil fuel and nuclear sources in G20 countries for the period 2015-2030'**

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**Abstract**

Jani-Petri Martikainen has raised a few concerns after examining in detail the peer-reviewed published article Ram et al. (2018) and the technical report Ram et al. (2017) in his letter Martikainen (2019). However, Martikainen (2019) fails to contextualise the approach in estimating the levelised cost of electricity (LCOE) across different power generation sources adopted in Ram et al. (2017) and Ram et al. (2018). Martikainen (2019) seems to raise issues that have already been clarified and further explained in the original published article as well as in the technical report. In an effort to ensure that the readers are not confused or misled by some of the claims made in Martikainen (2019), the authors of Ram et al. (2017) and Ram et al. (2018) have responded to all the concerns raised.

**Keywords**

Group of Twenty (G20), Renewable Energy, Levelised cost of energy (LCOE), External Costs

The actual costs of generating electricity are an important factor in the context of the energy transition taking shape across the world, and particularly across the G20 countries, to address the challenges of climate change. Additional to estimating LCOE, Ram et al. (2018) attempts to internalise some of the external and GHG emission costs across various power generation and storage technologies in all the G20 countries, from a present (2015) and a future (2030) perspective. Therefore, some of the assumptions in estimating the LCOE were in perspective to the present as well as future outlook. In this regard, the points raised by Martikainen (2019) are discussed below.

1. Martikainen (2019) claims that the assumed full load hours (FLH) in Ram et al. (2017) and Ram et al. (2018) for onshore wind power have been systematically exaggerated.

Whereas, the range of FLH derived for 2015 and 2030 are presented in the supplementary material of the article Ram et al. (2018) and a brief description of the methodology used for estimating this is also provided in Ram et al. (2018) as well as Ram et al., (2017). The FLH for onshore wind are estimated as presented in Bogdanov and Breyer (2016), wherein the assumed wind power plants consist of 3 MW wind turbines at 150 m hub height (Enercon, 2018). The dataset is used in a 0.45° × 0.45° spatial and hourly temporal resolution for real weather conditions of the year 2005. Feed-in full load hours for the various countries and regions are computed on the basis of the 0.45° × 0.45° spatially resolved single sub-areas' data using a weighted average formula. The sub-regional values are calculated using the rule: 0–10% best sub-areas of a region are weighted by 0.3, 10–20% best sub-areas of a region are weighted by 0.3, 20–30% best sub-areas of a region are weighted by 0.2, 30–40% best sub-areas of a region are weighted by 0.1 and 40–50% best sub-areas of a region are weighted by 0.1. This results in the minimum, maximum and median values of FLH and a broader range of values. In addition, average FLH of onshore wind power generation have been increasing over the last few years. The FLH adopted in this research are based on new wind turbines that have much higher FLH as compared to the average values, which consist of a significant amount of old wind turbines installed in some of the best wind sites. Moreover, it is observed that the expected full load hours for new wind turbines are 1.68 times higher than the 10-year average for the existing turbines (Fraunhofer IWES, 2018). In order to overcome this problem, FLH in view of the recent developments of wind turbines were computed.

The range of FLH estimated in Ram et al. (2017; 2018) are very much within agreeable limits. According to the Danish Energy Agency (DEA, 2017), for most wind turbines erected on land, the capacity factor is between 20 - 40%, or expressed in FLH it is around 1800 - 3500 h/a. Very good wind sites on land and offshore wind farms can generally reach a higher capacity factor of 45 - 60% (3942 - 5256 h/a), or even higher (DEA, 2017). Many of the recently launched wind turbines in the European market as well as the global market claim to achieve more than 3500 full load hours or over 40% capacity factor under suitable conditions (Vries and Buist, 2013). Around a decade ago, older generation turbines with relatively small rotors and rather low hub heights under such conditions would have capacity factors in the 20% range or less (Vries and Buist, 2013). In this context, the assumed median FLH of 3604 for the year 2030 seems quite conservative from current industry standards. Therefore, Martikainen (2019) suggesting that FLH assumed in Ram et al. (2017; 2018) are systematically exaggerated is quite baseless and far from reality.

(a) Furthermore, some of the best wind turbines in the EU have FLH within the range adopted for the EU and since the same range is used for 2030, the possibility to have much higher FLH by 2030 is quite high. Martikainen (2019) rightly points out that in the Stetter thesis (Stetter, 2014) -page 66- average full load hours for onshore wind power in OECD Europe were 2448 hours (for 2030). Nevertheless, he fails to have either comprehended or manages to ignore the methodology and chosen wind turbine for estimating those results on page 47 of the Stetter thesis (Stetter, 2014). In which, it is clearly mentioned that a wind turbine in accordance to the Enercon E-82 is used with a hub height of 127 m for 2030 (Stetter, 2014). Whereas, full load hours made available in the supplementary material of Ram et al. (2018) were estimated with the methodology of Stetter (2014), while adopting a more advanced wind turbine in accordance to the Enercon E-101 with a hub height of 150 m (Enercon, 2018). As recent trends have shown, the turbine sizes across Europe have been increasing and so has the output and capacity factors, which result in higher full load hours (Vries and Buist, 2013). As a matter of fact, Ram et al. (2017; 2018) have rather underestimated the development potential of wind turbines. The wind turbine used for estimations, E-101 with 3.05 MW is expected to yield 9.5 GWh annually (3107 FLH) for 7.0 m/s average annual wind speed (Swiss Energy, 2019), which is a standard value in many parts of Europe. For the same average wind speed, the newly developed and further improved E-160-EP5 generates about 17.5 GWh annually (3804 FLH) based on a 4.6 MW turbine (Enercon, 2019), which leads to higher specific yields of 22%. In addition, according to an IEA study (IEA Wind, 2017) the specific power of wind turbines available currently on the market is now less than 200 W/m$^2$, resulting in potential annual FLH up to or exceeding 4000 hours – a level difficult to imagine for land-based wind power a few years ago. The study (IEA Wind, 2017) has estimated FLH of wind power across Europe with a state of the art wind turbine of 150 m hub height in its ambitious scenario. The estimated FLH varies from 3074 – 5021 hours across Europe, with a median value of over 4000 hours. In comparison, the median FLH assumed in Ram et al. (2017; 2018) are much lower.

(b) Similarly, Martikainen (2019) raises the issue for Germany, wherein like the rest of Europe most of the new turbines being installed have much higher FLH, in the range of 2738 hours for 2017 (Fraunhofer IWES; 2018). This trend is set to continue with much higher FLH expected in the range of 3725 hours as hub heights reach 150 m and specific power reduces to 175 $W/m^2$ (IEA Wind, 2017). Therefore, the FLH assumptions in Ram et al. (2017; 2018) are well within the range of industry expectations by 2030.

(c) Martikainen (2019) also raises the FLH issue with respect to China. The trend is more so in China, where FLH have seen a substantial increase in the last few years. Some of the regions with high FLH were Fujian (2756 full load hours), Yunnan (2484 hours), Sichuan (2353 hours) and Shanghai (2337 hours) (China Energy Portal, 2018). Despite high curtailment and prevailing issues of wind power management, FLH have been quite high. Hunenteler et al. (2018) point out that China's wind turbines have been underperforming and with enhanced wind siting, model selection and increased hub heights, the capacity factors could be increased up to 49.2% and beyond, resulting in FLH in the range of 4000-4500 hours. The case of China substantiates the fact that current average FLH in countries are not the right measure to represent the performance of wind turbines. Whereas, a more complex method as adopted by Ram et al. (2017; 2018) to estimate FLH, represents far more accurately, the performance of state-of-the-art and future wind turbines, which are more relevant in estimating LCOE of wind power generation.

While Martikainen (2019) has made an effort to point out that average FLH in the respective countries are lower, Martikainen (2019) fails to acknowledge recent trends in the wind power industry and the impact on the FLH. As the objectives of Ram et al. (2017; 2018) were to estimate LCOE of wind power amongst other power generation technologies with a forward-looking perspective to the future up to 2030, the recent trends in the industry were crucial aspects to consider. Therefore, adopting a more complex methodology such as Stetter (2014) and further enhancing it by using a more recent wind turbine to estimate a range of FLH for wind power with a future perspective was necessary. Martikianen (2019) claims that the authors of Ram et al. (2017; 2018) attempt to hide FLH in the supplementary material. Whereas, to the contrary, the authors have made all assumptions, references and data available to readers in the supplementary material, which is standard scientific practice. Martikainen (2019) may lead to misinformed and misled readers, which should be avoided.

2. Martikainen (2019) points out that different discount rates of 10% for coal and nuclear power and 7% for other power sources were adopted.

Different discount rates have to be considered as different power generation technologies have different percieved risks. WACC is also a representation of the relative risk that various investors perceive in the development of a project. For this reason, a higher WACC was used for coal and nuclear power. Martikainen (2019) further suggests that the assumed rates do not seem to have any connection to actual funding costs and are rather an aesthetic assumption. This suggestion is inconsistent with the developments in the energy sector and disconnected from reality. We are currently seeing divestments from coal and nuclear power assets and there is a higher risk of stranded investments (Baron and Fischer, 2015). This risk is a result of accelerated phasing out of coal plants in many parts of the world due to climate change mitigation, and shut downs of nuclear plants in a post-Fukushima world. In addition, budget overruns in recent years of nuclear power projects have left investors sceptical (UCS, 2011; Moody's Investors Service, 2008; Pearce, 2017; Schneider and Froggatt, 2016), making it more difficult to raise capital. Therefore, a higher risk for stranded assets has to be taken into account. The overall assumptions used in the Ram et al. (2017; 2018) might even be perceived as conservative relative to many studies that suggest a much higher WACC for conventional power plants. A study by CE Delft (CE Delft, 2011), suggests that an interest rate of 10-15% for nuclear power plants is more appropriate. Given plant delays, construction cost overruns, equipment malfunctions, poor credit ratings, plant cancellations, and energy-market competition, most private investors/banks hesitate or even refuse all nuclear loans (Shrader-Frechette, 2009). Those few that will loan require 15% minimum-nuclear-interest rates (Shrader-Frechette, 2009). In this context, the interest rates assumed by Ram et al. (2017; 2018) can be considered as relatively conservative from a more realistic investment perspective. Martikainen (2019) suggests some sort of circularity in projecting nuclear power costs. Contrarily, Shrader-Frechette (2009) surveys 30 recent nuclear analyses and shows that industry-funded studies appear to fall into conflicts of interest and illegitimately trim cost data in several main ways. They exclude costs of full-liability insurance, underestimate interest rates and construction times by using ‘‘overnight’’ costs, and overestimate load factors and reactor lifetimes (Shrader-Frechette, 2009). Furthermore, Shrader-Frechette (2009) concludes that ‘Just as drug-industry studies sometimes trim adverse-health-effects data, nuclear-industry studies may trim cost-data – especially data that hasten their predicted decline’. This view is shared and validated further by others. For example, Wheatley et al. (2017) perform a statistical study of risk in nuclear energy systems and raise concerns regarding the inconsistent nature of data about nuclear incidents and accidents. Similarly, CE Delft, (2017) raise concerns on the credibility of information on nuclear power by the Dutch Government. The Japan Center for Economic Research estimates just the cleanup costs for Fukushima could mount to some 470 billion to 660 billion USD, however other estimates point that the overall costs could touch a trillion USD (Barnard, 2019). Taking into account the historic track record, it is not surprising that nuclear power has failed to attract private-sector financing. Therefore, the industry relies on governments for subsidies, including loan guarantees, tax credits, and other forms of public support. Moreover, these subsidies have not been small: according to a 2011 UCS report, estimates show that it has cost taxpayers more than the market value of the power that nuclear power plants helped in generating (UCS, 2011). It is also clear that when the full costs of insurance are included with current nuclear power systems, they are not economical (Laureto and Pearce, 2016).

Martikainen (2019) makes a novel suggestion that repeating the calculations with uniform discounting, varying the discount rate, and discussing how this relates to climate goals would be interesting. However, there are already many such studies as pointed out in Ram et al. (2018) and therefore the goals of Ram et al. (2017; 2018) were to highlight the LCOE of key power generation technologies across the G20 countries with and without the consideration of external and GHG emissions costs. Moreover, most LCOE estimations lack in providing a long-term purview of cost developments that can aid in developing plans and agendas for the future. Therefore, this research estimates LCOE in 2015 to represent the current trends and LCOE in 2030 to represent the likely development prospects of the various technologies across the G20 countries (Ram et al., 2018). Further, Martikainen (2019) suggests that the discussions in IPCC (2014) for lower discount rates have an influence on the results of Ram et al. (2017; 2108). In which case, the assumed WACC would have to be lower, in the range of 3-5%, as they are in many European countries. Egli et al. (2018) point out that the WACC is around 2.5% for solar PV and 2.75% for wind energy, with a 70:30 ratio of debt to equity in the case of Germany. Furthermore, the WACC of thermal power generation would have to be around 15%, as the social costs of these technologies have to be taken into account as suggested by the IPCC (2014).

3. GHG emissions costs.

In this research, a value of 7 €/ton of $CO_{2eq}$ was assumed based on the market value of GHG emissions in the EU for the year 2015. For 2030, a value of 74 €/ton of $CO_{2eq}$ was assumed based on estimates of the social costs of GHG emissions by the Stern Review (Stern, 2007). The recent report of the High-Level Commission on carbon price confirms $CO_{2eq}$ emission costs of up to 74 €/ton of $CO_{2eq}$ for the year 2030 (Carbon Pricing Leadership Coalition, 2017). However, it should be noted that there are a range of estimates related to the actual costs of GHG emissions from 30 to 165 €/ton of $CO_{2eq}$ (Moore and Diaz, 2015). A recent study by Ricke et al. (2018) estimates global social costs of carbon (SCC) values with a median of 417 USD/t$CO_2$ and a range of 177–805 USD/t$CO_2$. Therefore, the cost assumptions of $CO_{2eq}$ emissions over the period of 2015 to 2030 made by Ram et al. (2017; 2018) are well within the range of estimates. Martikainen (2019) suggests that the Stern report (Stern, 2007) estimated the costs of carbon with a discount rate of 1.4%. However, he fails to contextualise the application of discount rates, as stated in the Stern Report "the argument in the chapter and in the appendix and that of many other economists and philosophers who have examined these long-run, ethical issues, is that 'pure time discounting' is relevant only to account for the exogenous possibility of extinction" (Stern, 2007). Discount rates are among the most contentious and consequential aspects of the social cost of GHG emissions estimates. The impacts of climate change will be felt over many decades or centuries, whereas cutting emissions costs money now (Carbon Brief, 2017). One of the ways to estimate this is the "social time preference", which reflects human impatience. Another approach is the "social opportunity cost" of the choice between alternative investments. Moreover, a high discount rate suggests those alive today are worth more than the future generations. Therefore, an approach to discounting based on ethics, considers this is as wrong and supports a very low or even zero discount rate (Carbon Brief, 2017). In a major survey of 197 economists, the average long-term discount rate was around 2.25%. The survey found almost all agreed with a rate of between 1-3%, whereas only a few favoured higher discount rates (Drupp et al., 2015). From this perspective, it should be small. Therefore, the costs of GHG emissions as determined by the Stern Review on the economics of climate change is considered, which adopts a rate of 1.4%. Ram et al. (2017; 2018) estimate the LCOE of power generation technologies which are very much dependent on private and public investments that require a certain amount of return and are prone to risks that have to be factored in. Martikainen (2019) could, therefore, mislead and confuse readers with irrelevant comparisons without contextualising the cited research.

4. Capital expenditure of nuclear power plants

It is clearly stated in Ram et al. (2017; 2018) that for nuclear power, a low investment and overrun addition of 20% was assumed due to the longer construction times of nuclear power plants. This was also consistent with high IEA estimates. However, another source was used to estimate the high investment and overrun addition of 40% (Koomey and Hultman, 2007). This source was deemed to better account the reality of the international trend towards longer construction times and budget overruns. It also showed that such overruns have gotten progressively larger over time. Currently, nuclear power plants in Finland and France are seven years beyond their scheduled construction time of 5 years, and cost overruns are approximately 300% (Koistinen, 2012; Le Monde, 2012). The applied range of 20-40% of cost overruns is rather conservative, given the scientific analysis for 180 nuclear reactors that suggest costs overrun of around 117% on average. Moreover, there has been no single reactor that was completed within the planned budget and time frame (Sovacool et al., 2014a; 2014b).

5. Operations and maintenance costs as a percentage of capital expenditure.

This is explicitly stated in Ram et al. (2017; 2018) as being divided into fixed and variable operational and maintenance expenditures. $Opex_{fixed}$ is commonly expressed as a percentage of Capex per year, and represents costs unrelated to how many hours per year the plant operates. Such costs include material, personnel, administration and insurance costs, but do not include fuel or emissions costs. $Opex_{variable}$ represents costs that are directly related to the frequency and duration of plant operations. Some operations and maintenance costs, such as those related to pumps, fans and lubricating fluids, are incurred only when the plant operates. In the case of batteries, a similar value to $Opex_{variable}$ is calculated based on the costs related to storage losses. These losses are a function of the energy throughput and battery efficiency. In addition, cost trends in global renewable power generation indicate optimised operation and maintenance practices and the use of real-time data to allow improved predictive maintenance have further reduced operation and maintenance costs (IRENA, 2018). Furthermore, operation and maintenance costs have declined substantially in the case of solar PV and wind power. Based on a compilation of published reports, the US-based National Renewable Energy Laboratory (NREL) estimates that, for old solar PV systems, O&M was on average $20 per kW a year, whereas now it is closer to $7.50 per kW a year, indicating a decline of more than 60% (Vella, 2016). Similarly, the average operations and maintenance costs since 2008 saw a cumulative decrease of 38%, or just over 11% per year according to BNEF (Rose, 2012). The decline in O&M costs were driven by increased competition, as turbine manufacturers vie for service contracts, as well as by improved service performance of the underlying turbines (Rose, 2012). In this context, the assumptions for fixed operational costs ($Opex_{fixed}$) in Ram et al. (2017; 2018) are as follows,

- Wind onshore – 2.7% in 2015 and 2.2% in 2030
- Wind offshore – 3.7% in 2015 and 3% in 2030
- Solar PV Rooftop – 1% in 2015 and 1.5% in 2030
- Solar PV Utility scale – 1.1% in 2015 and 1.7% in 2030

These assumptions are well within the range of expectations, to the contrary of the claims made by Martikainen (2019).

6. Decommissioning costs

Decommisiong in the case of nuclear power plants has inherently been a liability and the point raised about discounting of decommissioning costs is a longstanding debate. The two sides of the argument are often advanced on the basis of ‘not discounting’ and therefore to opt for a void discount rate to the cause that the future generation interests would not be neglected with a clear preference for the present; and ‘discounting’ to retain a strongly positive rate with risks leading to arbitration in favour of the present generation to the detriment of future generations (Chirica and Havris, 2003). However, while physical decommissioning occurs at the end of a plant’s lifetime, some planning and preparation expenses for decommissioning are incurred throughout the lifetime of the project. Decommissioning plans are made even before construction begins. Such activities are often coordinated with permanent waste disposal planning and preparation, which can begin years before the plant is retired. As nuclear power plants are structurally complex and generate massive radioactive wastes, their decommissioning costs are more than other power plants (Matsuo et al., 2015). Hence for nuclear power plants, a decommissioning cost of 1100 €/kW was applied. Globally, there is very little actual experience and information related to fully decommissioned nuclear power plants. For this reason, estimates of future costs range from values as low as 200 €/kW for reactors in Finland (219 mUSD for two 440 MW VVER) to 1500 €/kW for reactors in Slovakia (1.3 b€ for two 440 MW VVER) (EC, 2016; IAEA, 2002). The companies E.on and Vattenfall estimate for their operations in

Germany decommissioning costs of 1200 €/kW and 1350 €/kW, respectively (Hirschhausen et al., 2015), whereas the first almost fully decomissioned nuclear power plant in Rheinsberg cost at least 600 m€ for 62 MW leading to more than 9600 €/kW (Deutscher Bundestag, 2011). In Ram et al. (2017; 2018) it is assumed that decommissioning costs globally will be 1100 €/kW in 2015 and 2030. As there is so little actual experience with decommissioning and long-term waste management of nuclear power plants and estimates of decommissioning costs vary so widely, a conservatism seems warranted. Moreover, it is ethically indefensible, because it is our duty to take into account the welfare of the future generations, especially when choices made today will have long lasting consequences in the future (Chirica and Havris, 2003). For these reasons, the decision to not use a discount rate seems appropriate.

7. LCOE of PV + Batteries

For LCOE calculations for solar PV + Batteries, FLH for batteries were assumed to be the same for solar PV rooftop. However, the ratio of storage capacity to generation capacity was varied, with a ratio of 1:1 assigned for low and median LCOE calculations, and a ratio of 2:1 assigned for high LCOE calculations. This takes into account that larger battery capacity would lead to higher LCOE. At the same time, this raises an important point. The LCOE for the solar PV + Battery system may not, therefore, be immediately comparable to the LCOE of the other generation technologies, but should be compared to a consumer's cost of electricity in order to determine if it is low or high. Solar PV electricity can be generated exactly at the point of final energy demand and batteries support this, thus the benchmark cost is the cost of final energy. There is a clear explanation in the methodology adopted for estimating the levelised cost of storage (LCOS) in Ram et al. (2017; 2018). Martikainen (2019) does not provide any specifics as why the methodology is not clear, but rather makes a vague statement about the formula not being self-explanatory, despite a detailed explanation of the formula provided in Ram et al. (2017; 2018).

8. References for cost assumptions

References for cost assumptions of all power generation technologies considered are provided in a comprehensive manner in Ram et al. (2017; 2018). Martikainen (2019) has misinterpreted the assumptions from IEA Photovoltaics Power Systems report (IEA-PVPS, 2016), as the capital costs of solar PV in France are in the range of 900-1100 €/kW and declining on an annual basis at around 10-15% (IEA-PVPS, 2017). Moreover, these costs are conservative as shown in the latest study of IEA-PVPS, where a complete breakdown of the investment costs of utility- scale solar PV plants in France is provided and the estimated cost is 800 €/kW (IEA-PVPS, 2018). Considering these trends, the assumptions made in Ram et al. (2017; 2018) are much closer to reality. Latest publications clearly indicate that the cost assumptions of Ram et al. (2017; 2018) are too high and could be further reduced. Current PV Capex values are lower in leading countries across the world than the assumed values in Ram et al. (2017; 2018), as published recently by the leading global PV organisation in the International Technology Roadmap for Photovoltaic (ITRPV, 2018). The PV fixed-titled system Capex for 2017 is 564 €/kW (750 USD/kW) and less than 376 €/kW (500 USD/kW) in 2028, in contrast to the low cost assumption of 390 €/kW for 2030 in Ram et al. (2017; 2018). Moreover, the median cost assumption for PV utility-scale in 2030 is considerably more conservative than the current PV industry estimate, in particular considering the current market cost of 564 €/kW, is less than the median estimate for 2030 of 606 €/kW in Ram et al. (2017; 2018). In addition, a state level regulatory commission has set benchmarking Capex for utility-scale solar PV for 2019-2020 at around 490 €/kW (38,819 INR/kW) in India (UERC, 2019), where solar PV costs have been declining rapidly. This is further validated by Capex declared by Fortum for utility scale-solar PV power plants in India at round 400 €/kW

(Fortum, 2018a; 2018b; 2019). Furthermore, the conversion ratio of US Dollar to Euro is considered as 1.33, which is a long-term exchange rate consistent with many studies and is applied to all technologies and all cases in the report. As using multiple exchange rates would cause distortions in the estimations, a uniform exchange rate based on long term values has been applied throughout the research. Recent market developments indicate that fixed-tilted utility-scale PV power plants attained a capex of 462 €/kW in 2019 and are expected to reach 275 €/kW in 2030, according to Vartiainen et al. (2019). These values are substantially lower than the assumptions in Ram et al. (2017; 2018) and further substantiates the trend of faster than anticipated progress in the PV industry. The main reason for the rapid decline in costs are the continued high learning rates of solar PV, which are around 24% for crystalline silicon PV technology in the long-term (Chen et al., 2018), but substantially higher at around 40% during the last 10 years (ITRPV, 2018). Whereas, the learning rates used by Vartiainen et al. (2019) for the projections until 2030 are just around 30%, substantially below the values of the past 10 years. As pointed out in Vartiainen et al. (2019), a low learning rate of 20% and a slow market development of PV capacity would lead to a capex of around 310 €/kW for fixed-tilted utility-scale PV in 2030, which is still 20% lower that the capex in Ram et al. (2017; 2018).

Furthermore, Martikainen (2019) has misrepresented the facts in the article of Kenning (2018); the project is an islanding demonstration as stated "It will also be a test case for deliberate 'islanding', where a section of the grid continues to provide power while disconnected from the main grid. This capability will increase the reliability of local supply and pave the way for other fringe of the grid locations." (Kenning, 2018). This indicates that the project has elements beyond just solar PV and batteries, a grid system, auxiliary controls and other smart systems, which add to the overall costs of the project. In addition the article states, 'for this testing, the remote town of Lakeland will be solely powered by solar and batteries for several hours at a time as a form of protection against blackouts' (Kenning, 2018). This project is rather a solution for the recent blackouts faced in Australia. Therefore, directly comparing the costs from Kenning (2018) with the costs for solar PV and batteries assumed by Ram et al. (2017; 2018), which are actually from another source - a study by European Commission Joint Research Centre (EC-JRC, 2014) - is a complete falsification and misleads readers. Furthermore, for Li-ion storage, the cost assumptions are comparable to estimates by others such as Bloomberg New Energy Finance (BNEF, 2015) and IRENA (IRENA, 2017).

It appears from Martikainen (2019), that there is an attempt to demerit comprehensively conducted research published after a rigorous peer-review process. Therefore, the authors urge Martikainen to contextualise the research and employ a broader outlook while comprehending similar research, before drawing hasty and false conclusions. With this response, the authors have not only reiterated the information, but have also validated the assumptions and results of Ram et al. (2017; 2018) with additional sources and cases for the benefit of readers.

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