The role of Photovoltaics towards 100% Renewable energy systems

Based on international market developments and Danish analysis

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Preface

In the light of recent developments of photovoltaic (PV) costs and technology, the aim of this report is to give a comprehensive understanding of the role of PV in the transition towards 100% renewable energy. In order to establish such an understanding, this report consists of a number of different technical and economic analyses, as well as reviews and analyses of public regulations schemes. In summary, it consists of:

- a review of global trends on the development of costs and capacities for PV;
- the expected future developments of PV installations in Denmark and the past development
- an energy system analyses of the role of PV in Denmark;
- an analysis of the potentials for rooftop PV in Denmark using GIS (Geographical information systems) divided upon ownership, municipalities and building sizes;
- Comparison of land use and renewable energy from PV and wind power
- An international review of global trends for public regulation and support schemes;
- a historic review of public regulation for PV in Denmark and the effects on PV capacity development
- case studies for the economics of PV in Denmark for different stakeholders;
- a discussion and evaluation of different support schemes and PV market construction in Denmark;
- recommendations and ideas for new public regulation for PV in Denmark.

While the case studies carried out in this report have Denmark in focus, the set of reviews and analyses included here for Denmark and in combination with global PV markets developments, can serve as inspiration for other countries worldwide. The role of PV is put into the context of state-of-the-art knowledge about how low-cost energy systems can be designed while also focusing on long-term resource efficiency.

This report is prepared by researchers from The Sustainable Energy Planning Group at the Department of Development and Planning at Aalborg University. It has been prepared in a period from June 2016 to September 2017. This report is partially financed by the projects BIPV Quality Cities, PV Active Roofs and Facades and Low Cost Active House BIPV. The projects are financed by the ForskVE program and granted by Energinet.dk.

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The results and recommendations in this report do not express the opinions of our partners in the three projects regarding the future role of PV. The findings and conclusions are solely the responsibility of the authors. The finding are divided into this report and an appendices report.

We hope this report can serve as inspiration in countries worldwide that are ambitious in regards to moving towards renewable energy, would like PV to play a role in this transition from fossil fuels and would like to avoid stop-go policies.

On behalf of the Authors

Brian Vad Mathiesen, September 2017

Contents

Nomenclature

AC - Alternating Current
As – Arsenic
BBR - Danish building and dwelling register
BIPV - Building Integrated Photovoltaics
BoS - Balance of System
BP - Baseline Projections
CHP - Combined Heat and Power
c-Si - crystalline silicon
DC – Direct Current
DKK – Danish Krone
EU – European Union
EUR – Euro
EVs – Electric Vehicles
FIP – Feed-in Premiums
FIT – Feed-in Tariff
Ga - Gallium
GIS - Geographical information systems
GJ - Gigajoule
GWh – Gigawatt hour
HPs – Heat Pumps
IDA - Danish Society of Engineers
IEA - International Energy Agency
In - Indium
INDC - intended nationally determined contribution
IRENA - International Renewable Energy Agency
IRR - Internal rate of return
KMS - Danish Cadastral and Mapping Agency
kW – Kilowatt
kWp – Kilowatt peak
LCOE - Levelised Cost of Electricity
m^2 – square metre
MWp – Megawatt peak
MW – Megawatt
NIMBY – Not In My Back Yard
NPV - Net present value
O&M – Operations and Maintenance
P - Phosphorus
PBP - Payback period
PSO - Public Service Obligation
PV – Photovoltaic
REN21 - Renewable Energy Policy Network for the 21st century
RES - Renewable Energy Sources
TGC - Tradable Green Certificates
TSO - Transmission System Operator
TWh – Terawatt hour
WEO – World Energy Outlook
Wp – Watt peak

Executive summary

There is no doubt that PV can play an important and significant role in the global energy system. The trends clearly indicate that the costs are falling and that the penetration has been substantially underestimated. An energy system based on renewable energy cannot be supported by only one technology. It comprises of energy savings, demand side measures, energy storage and energy efficiency as well as renewable energy sources. In that perspective, it is important to identify the role of PV in future integrated renewable energy systems using a smart energy system approach. PV has been subject to a positive development regarding costs and innovation but also subject to stop-go policies in many nations. This report gives insights into the role of PV moving nations towards 100% renewable energy by using international data and Danish case studies. The aim is to bring forward knowledge to *avoid stop-go policies* in order to facilitate stable long-term markets to further technology development and make it possible for *PV to play a role in the long-term* in a future renewable energy system.

The results and recommendations are into energy system feasibility for PV, land-use, GIS, ideas for public regulation, market reconstruction and support. The recommendations are based on reviews, energy system analyses, GIS, feasibility studies and empirical knowledge of different public regulations schemes globally and in Denmark. Also, the recommendations are seen in relation to the concrete potential role of PV, considering the costs of other renewable energy sources, such as onshore and offshore wind, primary fuel consumption, as well as smart energy system elements and energy storage technologies.

The status

The capacities for solar PV have increased on a very fast rate, since the beginning of this decade, reaching 300 GW, or 2% of the global electricity consumption. In 2016 only, more than 70 GW of PV capacity was installed worldwide, a capacity that accounts for 25% of the total installed power generation. Between 2009 and 2014, more PV capacity was installed than in the previous four decades. Most of this capacity is found in Asia, having China and Japan as the main PV markets. In Europe, the leader in PV installations is Germany, with over 40 GW of installed capacity, and most of the installations made in the past years are large-scale ones, a trend observed on a global scale too.

While the PV industry and cost projections had foreseen rapid cost reductions, none of the major international organisations working with energy scenarios for the future and projections had expected the developments in installed capacity and cost reductions to occur so soon. This is reflected in the many different projections of the development of PV made by organisations, such as IRENA, IEA, Shell or the WEC[1]. The IEA has constantly underestimated the projected capacities, e.g. the 2006 edition of the World Energy Outlook estimated the capacity for 2030 to be 145 GW, which has already been exceeded in 2014. The IEA Technology Roadmap reconsidered the growth rate of PV by 2025 from 11% in the 2011 editions, to 16% in the 2014 edition.

In Denmark, the IDA[2] reports from 2006 and 2009 have estimated the needed PV capacity for 2030 to be 700 MW and respectively 860 MW, but 863 MW were already installed until July 2017.

The massive increase in capacities has been seen in parallel with a fast decrease in costs and an increased learning curve. IRENA estimates that modules were the main driver for the decreasing costs of solar PV, with reductions reaching 80% between 2009 and 2015. By the year 2025, the costs of modules are expected to decrease by another third compared to 2015. On the other hand, the BoS (Balance of System) costs (inverters

[1] International Renewable Agency (IRENA), International Energy Agency (IEA), Renewable Energy Policy Network for the 21st century (REN21), World Economic Council (WEC)
[2] The Danish Society of Engineers (IDA)

and additional equipment) will be the main driver of reduction in the next years, with expected reductions of 50% by 2025. Given this, IRENA estimates that the cost of large-scale PV systems on a global level can reduce to €48/MWh by the year 2025. In some countries with high irradiation, projects were already tendered and won with bids of €20/MWh in UAE and €32/MWh in India. When comparing costs, one should be careful with comparing costs in won tenders (that may have already deducted earnings from sales of electricity) with the total costs normally compared used LCOE[3]. Also, PV should be seen in an energy system perspective and differences occur due to other reasons such as cost of materials for BoS and workforce. The costs used in this study are higher, as the main focus in the case studies is Denmark. The Danish Energy Agency uses international reports and estimates that the cost of a large-scale plants can reach €48/MWh by the year 2020 and €23/MWh by the year 2050, whilst the cost of small and medium sized systems that can be fitted on building rooftops can be between €69 to €59/MWh by the year 2020 and between €41 and €35/MWh by the year 2050. In the studies conducted in this report we are slightly more optimistic based on the latest price developments and also include rather wide range in sensitivity analyses.

Attention is also put to BIPV[4] internationally. The marginal extra costs of BIPV are still significant though, and a survey made on the BIPV market in Benelux and Switzerland estimated that the cost of BIPV can be up to 2 or more times more expensive than conventional PV systems (with roofing materials included). On a large-scale implementation level, conventional PV seems to be a better option. The cost of a BIPV roof is on average 4-5 times more expensive than for a roof without any PV included. There are however opportunities to further develop this technology and to identify niche markets, where they are applicable.

System benefits and feasibility of photovoltaic

From the review it was found, that demands should be made for PV manufacturers to enable them contribute to grid stability on the local and national level. In addition, none of the studies indicate that the need for the distribution or transmission grid is decreased. In fact, more control features are needed, which in the short term, until the technologies are developed, may be more expensive.

The type of analyses performed in this study is different from previous analyses as it includes the entire energy system and how dynamics occur across different energy sectors. Previously, studies focused mainly on the electricity sector, thereby not capturing all the system dynamics caused by the integration of PV.

The implementation of PV in Denmark is beneficial under the assumption that it is implemented in a transition together with other elements in the energy system. A set of recommendations are provided based on the findings of this study to suggest which direction the development of PV in Denmark should go towards.

Applying a LCOE methodology gives a clear indication of the expected decrease in PV prices. The effects into an energy system may however be different. The LCOE methodology has its limitations, and should not be used as a threshold for demonstrating that PV has lower costs than the electricity supplied by the grid. Such an event, also known as grid parity, can be considered as a damaging estimation, which can feed the belief that the electricity grid is just an added cost to the electricity bills, whilst in reality, the role of the transmission and distribution grids is crucial for the stabilisation and balancing of the entire energy system.

From the energy system analyses it was found that there are significant benefits with PV in the energy system. In the short term (until 2025), a level of 2.000-2.500 MW PV is recommended in Denmark, if price assumptions are in the range of 1,0-1,2 M€/MW (47-67 €/MWh) or below. It is cost-neutral to install 1.500-2.000 MW PV, equivalent to about 5% of the electricity demand.

It should be noted that the 863 MW PV capacity in all sizes currently installed has significantly higher costs than this level. Today, there is still relatively good room for PV in combination with wind power. If PV exceeds

[3] Levelised costs of Energy

[4] Building Integrated Photovoltaics (BIPV)

the 2.000 MW level, the energy system costs start to increase and the forced electricity export increases. In the Danish case, the CO_2 savings are rather limited, as a mix of mainly coal and biomass is replaced in 2020 and wind power is already more than 50% of the electricity supply. The fuel consumption decreases as long as the PV replaces condensing power plants and combined heat and power plants using biomass and coal. This occurs until about 4.000-4.500 MW, or about 15% of the total electricity demand in the 2020 energy system, however such a level would increase the costs.

In general, the first PVs installed have a higher value into the system than the subsequent ones, as they can replace more fossil fuel electricity, since the system has the capability to absorb it. On the other hand, the PV costs are still decreasing significantly indicating that the later installations might have lower investment prices.

In a smart energy system based on 100% renewable energy the situation is different. In the year 2050, when the costs of PV are expected to be substantially lower, the recommended capacity using the costs of small-scale PV systems is in the range of 5.000 MW (0,64 M€/MW or 41 €/MWh) and in the range of 10.000 MW using the costs of large-scale PV (0,52 M€/MW or 23 €/MWh). Both in the system analyses of 2020 and in 2050 there is a significant amount of wind power. In 2050, PV is analysed into a smart energy system with significantly higher electricity demands compared to today. This means that the fuel savings decrease rapidly after 5.000 MW PV, as the system is more efficient, flexible, able to use energy storages and has a rather large amount of onshore and offshore wind power. However, even with 10.000 MW, fuels are still being replaced. The disadvantage is that the forced export is rather high. When considering the economy of the energy system, 10-15% of the fluctuating energy should be from PV, while the remainder is from onshore and offshore wind power. If all PV plants are small scale, a 10% penetration is recommendable while this share increases to 15% with large PV systems. If fuel consumption is the primary indicator the PV share of the renewable electricity supply should amount to approximately 15%. In the IDA 2050 scenario the PV price has to be 0,5-0,7 M€/MW or less to decrease energy system costs, according to the results and assumptions in these analyses (40-year lifetime, 1% O&M, etc.).

The results for the recommended level of capacities are robust in relation to fuel prices within the ranges of PV analysed in this report. This is due to the system flexibility and to the fact that PV has the benefit of being able to replace condensing power plants also in combination with large amounts of wind power.

When replacing onshore wind power in the 2020 scenario, PV results in lower costs with 2.000 MW of capacity, assuming 2020 large-scale PV costs. For small-scale PV, the costs are neutral when replacing onshore wind power until about 1.000 MW. This is due to a better correlation between demands for electricity and PV production compared to wind power on its own in 2020. In 2050, when large-scale PV replaces onshore wind, the costs are at the same level, whereas for small-scale PV the costs are lower to neutral until around 4.000-5.000 MW.

Compared to offshore wind, PV has higher cost in 2020 for both small-scale and large-scale PV. In 2050 however, both small and large PV systems are able to compete with offshore wind power to a level of more than 10.000 MW or around 15% of the electricity demand.

The benefits of a diversified energy system were demonstrated in the energy system analysis of this report and also in other studies. These studies have shown that a feasible level of PV in the energy system is 20-40% PV compared to 60-80% wind power. Compared to previous studies the total system is included here as opposed to only looking at the electricity sector. The recommended level here and in the IDA Energy Vision for 2050 PV should be 10-15% compared to wind power with 85%-90%. This should be seen in the light of an electricity demand which is 2-3 times higher than today, so the PV production is significant in 2050.

In 2020, introducing flexible demand can reduce electricity export, however this does not affect the level of PV recommended here. In 2050, additional flexible demand in the conventional electricity demand does not

have a significant impact, as the system is already flexible with the additional demands in electric vehicles, heat pumps, electrolysers, etc.

Similar results are present with a grid scale or household battery indicating that this will not affect the overall recommendable level of PV installations. In fact, the overall costs increase when installing batteries while only reducing the forced export slightly in the 2020 system and has almost no impact on the 2050 system export.

The results of the analyses of PV are system dependent. Overall, the analyses show that replacing fossil fuels in other sectors, such as heating and transport, and increasing the demand for flexible technologies has value and can increase the feasibility of fluctuating renewable energy in general. Large-scale implementation of PV in the Danish energy system can under some circumstances reduce the total costs.

Land use and PV

The advantage of investing in large-scale PV plants is the lower investment cost, but a disadvantage is that such plants reserve large amounts of land that can only be used for electricity production. Denmark has a land area of 43.000 km^2 that has to be prioritized between various purposes. Land should be prioritized between nature, agriculture, urban structures and to some extent renewable energy production as biomass, wind power and PV. It is estimated that for implementing the 10.000 MW of large-scale PV capacity by 2050, an area between 110 and 120 km^2 (depending on the efficiency of PV) would be needed, which is the equivalent land area for 15.500 to almost 17.000 football fields or half of Greater Copenhagen. If the same capacity is installed as onshore wind, the needed land would be in between 20-22 km^2, which can be achieved with the possibility of using the farmland between the wind turbines at the same time. While some land may be infertile and more useful as fields for PV, the area needed to go towards 5.000-10.000 MW of ground-mounted PV is rather high and cannot be recommended as the only solution. Therefore, careful consideration should be made in deciding how much to install and where to place each of these technologies.

The present report demonstrated that there is a large potential for using the space already available on the roofs of buildings. The total technical potential is almost 50 TWh, for the whole country, even though not all this potential can be used due to the type of building, chimneys, windows or construction issues. Considering the long term target of 5.000 MW (equivalent to about 6,35 TWh), which should be possible to cover with roof mounted PV. The GIS mapping showed that if PV systems would be installed on all roofs of buildings with a built surface size of 500 m^2 or larger, it would be possible to get a PV potential of about 20 TWh in the whole country, which is 3 times the capacity recommended for 2050. This would cover an area of about 55-60 km^2 area on the roof and would not induce an additional land use. Nevertheless, it is important to highlight that not all rooftops can hold PV systems, but given the total potential, these should be enough to cover the area requirements. Large-scale PV has lower cost than small scale, that the most suitable roofs should be identified.

Some of the largest roofs can be found on buildings owned by businesses: for instance, industrial buildings and trade and storage houses in Denmark could hold PV installations with a total potential of 4,5 TWh. Within the privately owned buildings, half of their built surface correspond to single family houses, which represent only small roofs. However, in the private sector, there is also high PV potential share among commercial buildings connected to agriculture and forestry that might hold, in general, large roof areas which could carry 30% of the total PV potential in Denmark (around 14,7 TWh).

In the Appendices Report, it is possible to find five maps built with GIS, showing the Danish municipalities with different data. For instance, on the map with PV potential mapped only for built areas larger than 500 m^2, it is possible to see that most of the municipalities with a high density of large buildings are situated mostly in Jutland, indicating the density of industrial (business ownership) or agriculture (private ownership) buildings, where there would be potential for large rooftop PV installations. On the same Appendices Report

it is possible to find data on each region and each municipality, regarding the total built area, estimation of the area for rooftop PV installations and the total potential it could generate.

Public regulation and gradual increase in the PV penetration

From 2011 until 2015 Denmark experienced a boom in PV installation. As has been the case in many other countries a stop-go approach to the policy on PV has been used from the time PV costs were low enough on the international as to get a profit from a scheme that had been in place more or less since 1999. From the review of the Danish public regulation and support schemes it is evident that the regulation is back-trailing the development. Due to one change after another, the regulations have become more and more complicated. Gradually the schemes have become less and less favourable until today, where there is no new PV installations made in Denmark. In addition, there is a lack of medium and long-term political targets for PV, creating uncertainty for market investments.

The complete stop has significantly reduced the competences within this field. Therefore, there is a need to rebuild the sector gradually, if there is an aim to have PV in the Danish energy system and Danish companies should take part of the innovations and commercial opportunities within the sector.

PV costs are falling, and these have – like other renewables such as wind power – a need of a stable investment environment. Even when costs are lower than today, it remains very uncertain, that PV can develop and play a role using the short term prices electricity markets (also known as the energy only market).

If considering to establish a market for PV, one can learn from both previous Danish as well as international support and regulation schemes. From the technical analyses and case studies of business economics conducted here, the following issues are found to be crucial to address:

- Regulation should not be based on schemes that mix the demand side with the supply side. There are large risks of having lower incentives for electricity savings and risks of incentives to buy household level batteries. In addition, this also entails that passive house standards and building codes, are tightened to an extend where on-site supply has to be installed to reduce the energy demand further, which results in suboptimal PV installations e.g. in the voluntary Danish building code for 2020.
- Subsidies should not be based on exemptions from tariffs or taxes, as this serves as an indirect support for suboptimal placements of PV, as well as inducing a risk of lower funding for the electricity distribution and transmission grid.
- In order to limit the support and partly due to technical limitations, installations have been hindered to be larger than 6 kW for private installations. In the future, in order to enable use of lower cost roofs, this limitation should be assessed on a case to case basis.
- A new support scheme needs to be flexible in terms of new technological and price developments, in order to create a stable market and avoid new stop-go policies.
- A key issue is that a new support scheme should be easy to administer. This can be harder to achieve than anticipated, however a revision and evaluation process could be useful. Past approval administration has proven to be a show stopper in many cases, so strategies could be useful in the future.
- The ownership has been important for the economy in the past, due to the mix of supply and demand in the support and regulation. In a future support scheme, investments in PV should be independent of ownership.

To implement such medium-sized PV systems, a specially designed support scheme has to be established. In combination with knowledge of such a new system for companies and other stakeholders, local initiative from e.g. municipalities or organisations are needed. A tendering has the potential to follow decreasing costs

of PV, compared to using a simple FIT scheme set by the government. This could gradually increase from 50 MW in order to gradually build the capacity within the industry. In order to facilitate that the public spending are gradually reduced – it is recommended to gradually move into a FIP payment. This could allow bidders to have contracts with companies or private household, to hedge the costs, and reduce the bid in the tender.

In such a tender, community owned or co-owned systems should also be able to participate. This can have the several benefits. More suitable roofs and financing possibilities may be found and used in bids due to local knowledge. The profit margin of citizens tends to be lower and can help bring down the need to public support in combination with companies or roof top owners. The public acceptance levels are also increased with a degree of local ownership. Currently a tendering scheme with such features is being tested in Germany. This scheme allows community based organizations to join other private organizations in the PV tendering process, but with some benefits compared to their competitors: the project is allowed a longer period of realization, there are less requirements for taking part in the tender and finally, each winning community owned project is granted with the highest bid by any of the participant projects in irrespective of the price the project owners have entered with. The community-based organizations should be established by at least 10 citizens, living in the area where the PV system will be built. Alternatively, in Denmark, the bidders can also be municipalities, housing associations or any other entity with a wish to make a difference. There are several problems already visible in the German model. One way to handle false bids however could be that bids with local ownership are "only" guarantied the average winning price. This would still gradually reduce the public spending in combination with lower profit margins.

The tending scheme could have a minimum bidding capacity for a PV of approximately 40 kW, which is equivalent to approximately 450-550 m^2 of roof area. In order to make the tendering process accessible to more categories of bidders, as not all the roofs have such a large surface, the new support scheme should provide the possibility of joining the tender with the aggregated capacity of more rooftops together. Also, the legislation around the tender should be assessed carefully to better facilitate as many stakeholders participating as possible. As an example, one could have a PV leasing model, in which the owner of the roof takes over the PV after a period of 20 year. In general, special attention should be given to administrative barriers on a regular basis from a legal and stakeholder point of view.

In general, the 6 kW limit should be removed and be replaced by actual local limitations due to knowledge and investigations on the local grids. There can be local grid limitations and hence, part of the tendering process is to achieve approval from the distribution grid operator and the TSO. There may also be aesthetic issues regarding the placement of PV in urban settlements. In order to avoid time-consuming processes, strategies and procedures should be made in advance. Municipals should make PV strategies and action plans and the local distribution system operator should be encouraged to assess local limitations in advance. The national TSO could oversee the progress of the distributions grid system operator and should assess whether small changes in the grid could increase the amount of places where larger scale rooftop PV is technically possible to grid connect. The largest rooftop installations should make use of the new control features of the inverters, and be allowed to provide stabilization services to the grid. Gradually, as prices decrease and capacity develops, the smaller systems can also be upgraded to have the stabilization capabilities, as the inverters have to be replaced more often throughout the life of the PV system.

In combination with municipal efforts, a temporary support (e.g. 2 years) for knowledge sharing could be considered, as well as training and coordination of 8-20 local representatives who can inform companies, citizens and municipalities about the options for making bids or to join a tender. Regular energy planning coordinating new knowledge with the government and municipalities can also be considered.

It should be stressed that limitations of the rooftop capacity with referral to own consumption should be avoided. Production should be separated from the demand, to avoid suboptimal solutions and allow to balance the electricity production on a grid scale rather than on a building scale. This is one of the advantages

using the tendering scheme. This also implies that the existing requirements for PV should be removed from the existing building code. The energy system analysis done in this report has shown that household batteries increase the costs related to the energy system.

Innovations should be insured in the technology roll out and be promoted in several ways. Gradually, improved technical requirements for grid stabilization and management can prove important for larger roof-top installations and can connect Danish strengths within system design competences to enhance the knowledge and innovations amount those companies present in the Danish market. BIPV could be part of the new scheme for PV using an innovation market. By allowing this niche to develop, it can help to facilitate innovation in Denmark, and support a developing industry with a high potential. This support could represent a small share of e.g. 5% of the annual quota, which can be further increased if and when the BIPV market develops. This can be supported in a targeted tender for a limited capacity/production.

Key facts and recommendations

System benefits and feasibility of photovoltaic

- According to the energy system analysis, a maximum of 2.000-2.500 MW should be installed in the Danish energy system in 2020/2025, assuming the existing technology costs.
- If installing this PV capacity in the 2020 energy system, CO_2-emissions would reduce by approximately 400.000 t/year in the assumptions made here.
- Towards 2050, it is recommended to install not more than 5.000 MW of small-scale PV capacity or 10.000 MW of large-scale capacity from an energy system cost perspective.
- From a technical point of view additional fuel savings can be achieved by increasing the PV capacity, but this will also increase the energy system costs.
- PV and wind power should form the key components in the future energy supply. PV should account for 10-15% of the supply while onshore and offshore wind power should provide the remaining 85-90%.
- Flexible energy demands have a limited potential for improving the PV feasibility in both 2020 and 2050.
- Batteries for households are not recommended in any size to avoid limitations in regard to own consumption only. The balancing of the energy system should be promoted through a system redesign on a national or international level to enhance the general flexibility and need for fluctuating renewable energy.

Land use and PV

- Land should be prioritized between nature, agriculture, urban structures and to some extent renewable energy. In the case of PV, it is estimated that for implementing 10.000 MW of capacity by 2050, an area between 110 and 120 km^2 (depending on the efficiency of PV) would be needed, which is the equivalent land area for 15.500 to almost 17.000 football fields or half of Greater Copenhagen.
- There is a very large potential for using the space already available on the roofs of buildings (50 TWh/Year). Not all this potential needs to be used, but if only the largest roofs are used for PV, these roofs are more than sufficient, without taking up additional land area. If the roofs on buildings with a built area of more than 500 m^2 were all fitted with PV, then these would represent three times the needed area for achieving 5.000 MW capacity for 2050 or 20 TWh/year. Not all rooftops can be fitted with PV, but given the total potential, these should be enough to cover the area requirements. As PV costs are reduced, more buildings could be taken into account.
- When analysing the potential divided upon ownership for buildings, the private sector has a large technical potential in commercial buildings within agriculture and forestry, representing 30% of the

total rooftop PV potential in Denmark (around 14,7 TWh). Industrial buildings and trade and storage houses in Denmark could hold PV installations with a total potential of 4,5 TWh.

- In the appendices Report, it is possible to find five maps built with GIS, showing the potential for each Danish municipality with different data. Also included here is data on a municipal level regarding the local potentials divided into sizes of buildings.

Public regulation and gradual increase in the PV penetration

- The 'stop-and-go' policies have slowed down the capacity of the industry. These been going on since 2012 until today and. The full stop in new PV installations, which is currently the case, should be replaced with a long-term framework, reaching 5-10 year out into the future.
- The future support scheme for PV should incentivise the use of the largest roofs of buildings to their full capacity. Based on the technical and economic analyses performed in this study, it is recommended to incentivise and develop 5.000 MW of rooftop PV on the largest roofs available by 2050. Free-field PV can be a supplement, but requirements towards what areas can be occupied with PV is recommended, as onshore wind power has higher energy density.
- The industry has been subject of 'stop-and-go' policies for a number of years, there is a need for it to gradually build capacity again. The PV capacity increase should be done in small steps, starting with a quota of e.g. 50 MW in 2018. This quota can increase by e.g. 20 MW pr. year, for the next 5 years, until 2022, when a fixed quota of 150 MW/year could be established. This will allow the capacity to increase to approximately 5.000 MW by the year 2050.
- The PV industry is fast-forwarding, and the future regulation scheme should account for continued decrease in costs for modules and BoS. Hence, the support scheme should be self-adjusted by the market, to reflect the real costs of PV and avoid over- (or under-) compensation.
- In order to better reflect the fast decreasing costs of PV, a tendering scheme can be recommended, as it has the advantage of following the costs compared to using a simple FIT scheme set by the government.
- All the electricity produced by the solar PV installations should be sent to the electricity grid and the owners of the PV installations should be remunerated in the first phase via an e.g. FIT (until 2022). The FIT can gradually be replaced with a FIP, in order to decrease the support from the state. This could facilitate a process towards a self-sustaining market, although this is also dependent on potential changes in the electricity markets.
- The administrative procedures for tendering schemes should be simplified and could allow community based organizations to join other private organizations in the PV tendering process, offering them more benefits compared to their competitors to also stimulate citizen engagement or any other organizations (municipalities, housing associations, schools, etc.). If needed a boundary for community owned PV installations can be made, e.g. a radius of 50 km. The sizes of the shares, as well as percentage ownership locally can be considered.
- The minimum bidding capacity for a PV system is recommended to be approximately 40 kW, the equivalent of approximately 450-550 m^2 of roof area. In order to make the tendering process accessible to more categories of bidders, as not all the roofs have such a large surface, the new support scheme should provide the possibility of joining the tender with the aggregated capacity of more rooftops together.
- The 6 kW limit should be removed from the current support scheme and replaced with the requirement of using all the technical potential of the roof where the PV is mounted. In the same regards, the new support scheme should not be regulated based on the ownership
- Municipalities and grid operators should be encouraged to assess in advance the potential of the distribution grids and the national TSO could oversee the progress of the distributions grid system operator. Since these grids are needed in a future distributed production of electricity from PV, these

should be assessed to determine whether small changes in the grid could increase the amount of places where large-scale rooftop PV are technically possible to grid connect.

- Municipalities should be allowed and encouraged to establish their own strategies in regards to PV, with guidance from the central government and based on the potential assessed in this study.
- As a temporary support for knowledge sharing (e.g. 2 years), it can be recommended to set aside financing for training and coordination of 8-20 local representatives, who can inform companies, citizens and municipalities about the options for making bids or to join a tender. Regular energy planning coordinating new knowledge with the government and municipalities can also be considered. Special attention should be given to administrative barriers on a regular basis from a legal and stakeholder point of view. Energy planning using technical and economic knowledge can also help identify gradual improvements.
- In the first phase, the largest PV installations should be fitted with inverters that offer stabilization services. Then, when capacities grow larger and the inverters from smaller installations need to be replaced, all the connections should be upgraded to using invers with remote controlled features.
- If all the electricity is sent to the grid, this will allow to make a separation between electricity production and demand. This will incentivise energy savings and eliminate the danger of subsidizing the PV production based on exemption from tariffs and taxes.
- The requirements in the building codes to include PV systems with new constructions should be eliminated, to encourage the use of the PV systems on the largest roofs available (in new and existing buildings) and to separate the production from the consumption.
- A small share of the annual quota for PV capacity e.g. 5%, could be dedicated to BIPV, to encourage innovation and technology development.

1 Introduction

In 2015, at the COP21 summit in Paris, world leaders achieved a historic agreement for reducing the greenhouse gas emissions to a level that will keep the rising global temperatures to a level "well-below 2°C, aiming for 1,5°C" [1]. Leading up to this agreement the countries made intended nationally determined contribution (INDC) meaning what are the goals in regards to reducing the greenhouse gas emissions. Renewable energy has a key role in achieving these targets. In the transition towards energy systems based on renewable energy it is necessary to consider that there is no single technology that can solve the issue of climate change, but a multitude of technologies that will need to be carefully assessed, planed for and analysed from a socio-economic perspective before the implementation. Cost efficient societal change towards renewable energy requires knowledge about the role the various technologies. Investments in the sectors of the energy system are long-term. Policies that encourage investment decisions taken today will shape how the energy system will look in 2050.

Photovoltaics (PV) are one of the key technologies part of a future energy system. PV is the technology used to convert solar irradiance into electrical energy. It is also one of the most abundant and promising renewable energy sources that can allow us to decarbonise our energy system. The sun provides as much energy, as each hour, the amount of sunlight that reaches the earth is enough to supply the entire energy demand of the planet for one year. Not all of this solar energy can be harnessed, and the irradiance levels vary throughout the world, as shown in Figure 1. The distribution and intensity of solar radiation determines the efficiency of PV systems in a given area [2].

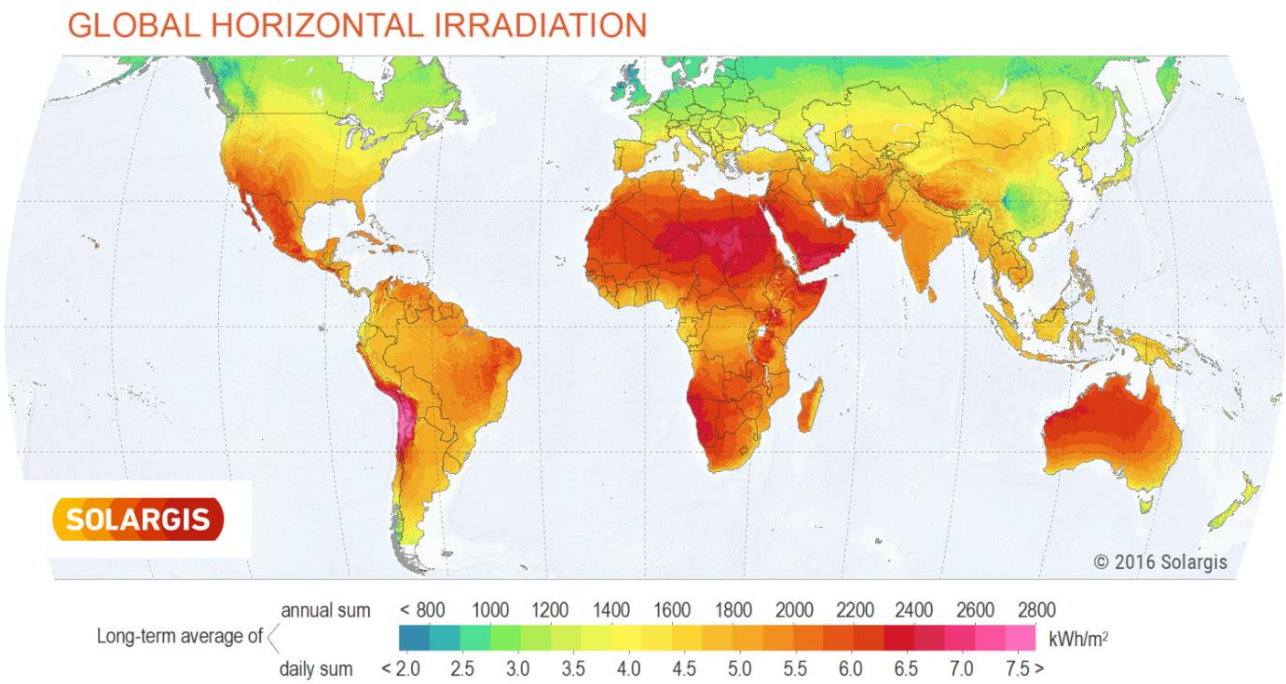


Figure 1: World solar irradiation map. Solargis 2016 [3]

The growing interest in renewables, has led to an industry growth of 21% on average, in the period between 1982 and 1997, with a growth rate in the latter years of the period that reached around 40% [4]. The main driver for this development was represented by residential installations in USA, Japan, India, Switzerland but also in many countries of the EU. In 1977, the installed production capacity was 500 kW, which grew to 2 GW in 2002, and then to 100 GW by 2012, a 50 times increase in ten years [5].

In countries where a large share of the electricity demand is a consequence of air conditioning, PV offer a good correlation between the production and demand profiles, as the production of PV peaks during the summer period and around midday. In the northern parts of Europe, the electricity demand is generally

higher during the winter and in the afternoon and evenings. Therefore, the potential for PV in Europe is assessed to be generally lower than in other parts of the world. The IEA (International Energy Agency) finds that the potential share of electricity produced by PV in Europe is limited to around 8%, or approximately half of the global potential of 16% of the total electricity production [6].

1.1 The purpose and aim for this report

Today, PV supplies almost 2% of the total electricity demand worldwide [7]. The main reason for this low share is that until several years ago, PV was a rather expensive technology. However, the technological improvements and the emergence of support policies have induced a global deployment that has exceeded even the most optimistic expectations of many energy associations. Until recently, costs for PV were high compared to other renewable energy sources. For many years however, it has been known within the PV industry that PV would become more and more competitive. According to a report issued in 2015 [8], grid-parity has been reached in 30 countries by 2015 and it is expected to cover 80% of the countries by 2017. Policy makers in such countries that had support schemes for PV were caught by surprise, e.g. Germany, Spain and Denmark. In fact the cost reductions globally has made it clear that policy makers find it hard on the one hand to support technology development and then on the other hand, when costs are reduced, to identify how to enable that PV can play a role.

The aim with this report is to bring forward knowledge to *avoid stop-and-go policies* in order to facilitate the technology development and make it possible for *PV to play a role in the long-term* in a future renewable energy system.

So far, the investments and the markets for PV were not strategically planned, and in some cases, these were influenced by sudden and foreseeable grid parity, sub-optimal cross-subsidisation from distribution grid tariffs or electricity taxes, and as a consequence, as in the case of e.g. Denmark, Germany and Spain “stop-and-go” policies. This has meant, that the role of photovoltaics in a future renewable energy system is unclear and that the industry is struggling with unstable market conditions. This affects businesses and craftsman, but also jeopardises the innovations and technology development that in turn can decrease the role of PV in the long-term. There are high risks that more countries will experience “stop-and-go” policies as the PV costs decrease.

Using international market developments, state-of-the-art knowledge and Danish case studies, the aim of this report is to provide a research-based, coherent analysis and guide on the potential role for PV in a renewable energy perspective. The findings are targeted for Denmark, but many of the findings are applicable for other countries with policies on transition to renewable energy.

Denmark is a unique case, as there is a long history and experience with support schemes and energy planning, a high amount of renewable energy, as well as an ambitious long-term target. Since 2006, Danish Governments have had the long-term goal for Denmark to have an energy supply based on 100% renewable energy in 2050. The concrete technology mix to reach this goal has not been decided yet, although several short and medium term goals have been established, e.g. 50% wind power in the electricity mix by 2020 [9]. Achieving these changes requires a system level approach that includes all sectors of the energy system, from electricity, heating to the transport sector. The report aims to show and document the inconsistency in the public regulation and support for investments in PV in Denmark in the past years as well as to propose a new set of solutions and strategies so that the society as a whole will benefit by the transition towards a 100% renewable energy system. Using GIS and energy system analyses with the aim of providing technical and socio-economic knowledge regarding the potential role of PV in a system and societal perspective, suitable suggestions for a new regulation for PV are proposed, one that can last longer, as costs are rapidly reducing, while also creating a stable investment environment. Therefore, the content of this report can be seen as a model for other countries in terms of how the investments in PV could be approached.

1.2 Methodology

The research is based on an international review from various organisations such as the International Renewable Agency (IRENA), International Energy Agency (IEA) or Renewable Energy Policy Network for the 21st century (REN21) on capacities, costs and supporting schemes for PV. This literature review is further followed by a review of costs, capacities and support schemes in a Danish context.

This is then continued by a GIS and energy system analysis but also by economic calculations of various case studies. The GIS analysis is made by the researchers at Aalborg University, and is based on a previous model developed for Denmark in 2012 [10]. The purpose is to assess the production potential for PV, the built surface area, and the types of ownership of the buildings along with their location. The energy system analysis is based on the IDA Energy Vision 2050 [11]. Using the review of support schemes, the case studies and the difference analyses of the role of PV new support schemes are proposed.

1.3 Structure of the report

The main findings, conclusions and recommendations from this report are summarised in the Executive Summary. The report is split in 10 main chapters and an appendices report. Two of the chapters focus on the international context, whilst the rest have Denmark as a subject of study.

- Chapter 2 begins with a short review on the technologies used for PV systems, types of modules and sizes, and then looks into the historic development of PV capacities and costs in a global context in the past years, but also at the underestimated growth in capacities and reduction in costs made by various organisations. This chapter establishes in what light should be seen the cost reductions, and how PV is currently benchmarked. It ends with an overview of the expected PV market developments and a comparison with the costs for wind.

- Chapter 3 focusses on the capacity and cost development for PV in Denmark. It also encompasses some of the projections made by various Danish organisation on how the PV market is expected to develop.

- Chapter 4 takes the system perspective in account, and makes a review of the effects of PV on the grid, but also looks into scientific journals on what are the recommended shares of solar wind power in Denmark in a future highly renewable context. This is then followed by a system analysis of Denmark made in the hourly energy system analysis tool EnergyPLAN, for the years 2020 and 2050. At the end of this chapter, this is all summarized to create an overview over the results of the analysis.

- Chapter 5 starts by addressing the issue of land-use for energy purposes and follows by making an analysis of the potentials for rooftop PV in Denmark with GIS (Geographical information systems) divided upon regions, municipalities, building ownership and building areas. The findings are summarised in a part conclusion.

- Chapter 6 makes an international review of public regulation and PV support schemes. The advantages and disadvantages of each scheme is presented to determine which schemes have which characteristics. The findings are summarised at the end of the chapter.

- Chapter 7 also looks into the public regulation and support schemes, but this time in a Danish context. The regulations that shaped the development of PV in Denmark are presented in the context of different building ownerships and a stop-and-go policy, with findings summarised in a part conclusion.

- Chapter 8 focuses on a set of case studies in the private or business economic consequences of different schemes. These calculations are also divided into different ownerships.

- Chapter 9 discusses the support schemes in the light of the findings of the previous chapters i.e. the potential technical and economic role of PV. It considers what are the barriers in the current regulatory framework, what should be the main characteristics of the future support schemes, to finally evaluate different possible new regulations schemes. The resulting recommendations are based on this and included in the executive summary.

In addition, an appendices report is part of this report, where it is possible to find:

- Appendix 1: Consists of tables with the technical photovoltaic potential in Denmark. This data is divided into:
    - National photovoltaic potential
    - Photovoltaic potential in the 5 regions
    - Photovoltaic potential in all 98 municipalities

- Appendix 2: PV potential in Denmark and Danish municipalities
    - Building density per municipality
    - Photovoltaic density per municipality
    - Photovoltaic potential per municipality
    - Photovoltaic potential for buildings smaller than 500 m^2 per municipality
    - Photovoltaic potential for buildings larger than 500 m^2 per municipality

- Appendix 3: Assumptions and data used in Chapter 8.

2 International development of photovoltaic capacities and costs

PV were initially developed to provide energy to the space program in the middle of the last century, but were then adapted to be used in civil off-grid installations during the oil crisis in the 1970s. Technology has evolved since then, and the first subchapter makes a short introduction on the existing and future technologies.

Traditionally, PV were labelled as expensive technologies, and therefore were not expected to have a significant role to play in the future energy systems. However, it is clear that PV systems have experienced a drastic increase in capacities and reduction in costs, during the last few years, and their role in the transition towards a renewable energy system has been underestimated [7], [12]–[15]. Therefore, this chapter aims to create an overview on the market development for PV in the past and coming years.

2.1 PV technologies and scales

PV systems are subject to a cell efficiency ratio, which today is averaging 18 to 21% [5]. This efficiency is improved, and in combination with technology innovations due to rapid deployment, the amount of electricity produced increases as the cost of electricity produced is reduced.

PV devices use a semi-conductor material to induce electricity by giving it additional energy, coming from solar irradiance. They work on the principle of activating electrons from their lower energy state to a higher energy state. This activation creates free electrons in the semi-conductor that provide in turn electricity.

A PV system consists of three main components: the module, the inverter, and the Balance of System (BoS) which includes all the other electrical and electronic connections and devices.

The different photovoltaic modules commercialized nowadays can be categorised according with the type of semi-conductor material used:

- *Crystalline silicon (c-Si) panels* – this technology can be subdivided into mono-crystalline and poly-crystalline panels. Today, the mono-crystalline PV panels are by far the most widespread PV panel, and contribute by about 80% to the total market. These use the silicon structures to form solar cells, which combined create the PV modules. Since the costs for silicon have decreased drastically in the recent years, the manufacturing costs for this technology have decreased too [16].
- *Thin film solar cells* – is the second most used as it offers the advantage of reduced costs in material and manufacturing, without limiting the lifetime of the cell. These types of cells are created by depositing thin layers of several microns in thickness on top of each other on a substrate made of glass or stainless steel. Compared to the silicon technology, which are several hundred microns thick, the thin film allows the production of flexible PV modules, as well as a reduced cost in manufacturing and cost of materials. Having a thinner layout of photovoltaic material, the thin film cells are generally less efficient than the c-Si panels, however since they provide the versatility of layering more types of photovoltaic materials, they have allowed improvements in efficiencies, gaining the largest market share after the c-Si technologies [16].
- *Monolithic III-V solar cells* – are made with elements from group III and group V of the periodic table (Ga, As, In and P) and are primarily used in space applications or in concentrated PV (with built-in lenses and mirrors). Concentrated PV use mainly the direct solar irradiation, but this is not very important considering Danish solar irradiation [17].

Increases in the efficiencies in the conventional c-Si PV and the development of new technologies, such as the concentrated PV and new types of more flexible modules, which can be used in areas with less direct sun-light, will increase the energy yields and further reduce technology costs. Nevertheless, so far, only PV modules using crystalline silicon or thin-film solar cells have been considered for grid connected systems [17].

In the future, there will be an increased potential for thin-film modules to gain more of the market share due to the technological improvements [16]. The costs for this technology are expected to reduce by 32% before 2025 [5]. The technology also holds the advantage of being more environmentally friendly than crystalline silicon systems [16].

The PV systems vary in size and capacity, and in this report, there are three categories analysed: small-scale, medium-scale and large-scale systems. The small-scale PV systems have capacities below 50 kWp and these are mostly found on the rooftops of private residential buildings. This category generally includes the Building Integrated Photovoltaics (BIPV), which are multi-functional building elements that generate electricity. The medium-scale PV systems have the widest range of capacities, and these span between 50 to 500 kWp. These systems are installed on the larger rooftops of buildings, such as the ones owned by housing associations, schools, or private companies. The large-scale PV systems have capacities of 500 kWp or more, up to several MWp, and are mounted on the ground, in open-field areas.

2.2 Rapid market development

The main contributor to the total PV capacities is represented by the small-scale and medium-scale installations, with approximately two thirds assigned to them. On the other hand, large-scale installations contributed by approximately 100 GW until 2017 [18]. Overall, the large-scale installations have a rapid increase in capacities, as together these provided an annual growth rate of 41% between 2000 and 2015 [19].

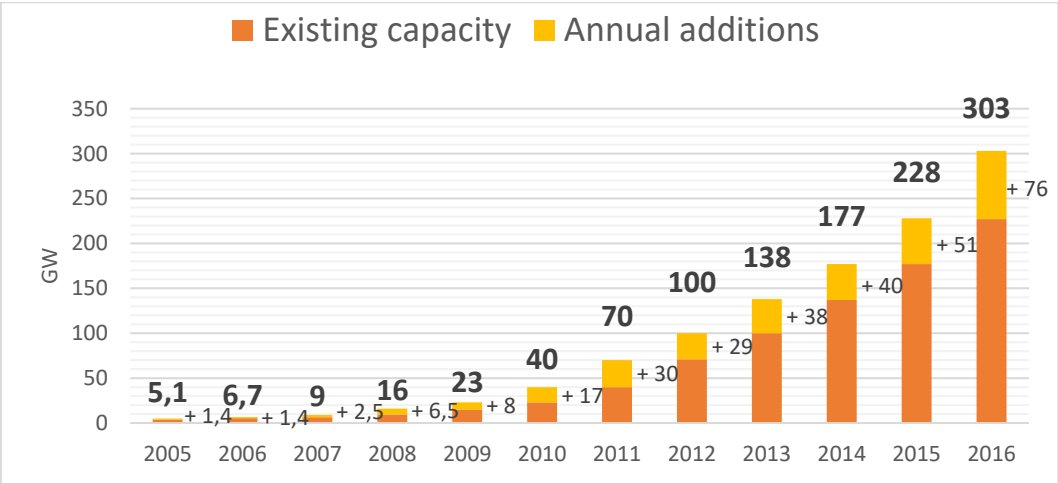


Figure 2: Global PV capacities (2017) [20]

In 2016, 76 GW of PV panels were installed worldwide [20], accounting for 25% of the total installed power generation. Between 2009 and 2014, more PV capacity was installed than in the previous four decades [6]. This increase in capacities was related to the technological progress, learning curve and economies of scale for large-scale projects, providing an average of 14% of price reductions per year, or approximately 75% of since 2006.

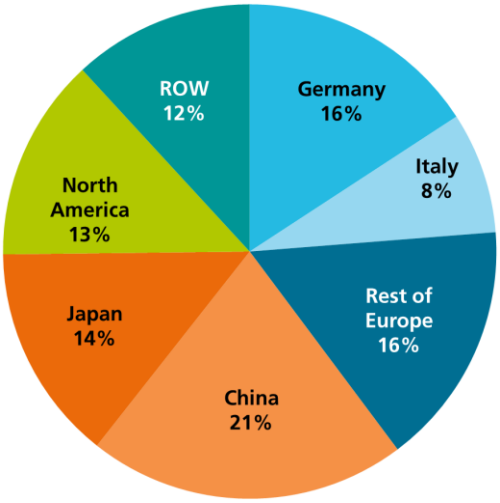


Figure 3: Solar PV installation by region. Data: IHS. Graph: PSE AG 2016 [19]

Globally, the installed capacity of PV had a mild growth until mid-2000, with several GW installed in the middle of the previous decade, which later turned into an exponential growth, reaching values over 300 GW, at the end of 2016 (Figure 2). The International Renewable Energy Agency (IRENA) estimated capacities to have reached 291 GW [15] by the end of 2016.

If in the past Europe was the main leader on the PV market, both in terms of production and installed capacities, the situation has changed. In the last 4-5 years, the Asian market recovered the gap, having now approximately the same installed capacity as Europe [19].

In Europe, Germany is leading in terms of PV capacities, accounting for over 40 GW installed capacity at the end of 2015, representing 16% of the total capacity installed world-wide at the end of that year [12].

A report issued by Fraunhofer ISE reveals that the majority of new installations in the latest years are represented by large-scale projects, and approximately 40% of the renewable energy produced in 2015 in Germany came from PV [19].

2.3 An underestimated growth for photovoltaics

As presented previously, the installed PV capacity has increased many times in the past decade and accounts for the highest increase among all other renewable energy sources [14]. The costs of PV have also plummeted in the same timeframe, and more cost reductions are expected, which will probably increase the implementation rate for PV even further. Nobody expected the considerable developments regarding the installed capacity and cost reductions to occur so soon, which is also reflected in the many different projections of the development of PV, as it can be seen in Table 1. Amongst others, organizations such as the IEA or Shell have underestimated the growth of this technology in their periodic forecasts.

*Table 1: (Left) Estimated global PV capacity by 2030 and 2050 according to various organisations and (right) estimated global electricity produced by PV by 2030 and 2050 according to different organisations. * Electricity production for 2016 is not available yet. ** Includes solar-thermal*

Projected year	2030	2050	Projected year	2030	2050
GW			**TWh/year**		
Installed capacity 2007 [21]	9		**Electricity production 2007** [22]	4	
Installed capacity 2011 [21]	69		**Electricity production 2011** [22]	61	
Installed capacity 2016 [21]	303		**Electricity production 2015** [22]	246*	
IEA WEO (2006) Alt. Policy [23]	145		**IEA WEO (2006) Alt. Policies** [23]	238	
IEA WEO (2010) 450 [24]	485		**IEA WEO (2010) 450** [24]	723	
IEA WEO (2014) hi-ren [25]	1720	4760	**IEA (2014) hi-ren** [25]	2370	6300
WEC (2016) Modern Jazz [26]	1011		**Shell (2008) Scramble** [27]**		7200
WEC (2016) Unfinished Symphony [26]	1100		**Shell (2008) Blueprints** [27]**		6100
IRENA (2014) Remap [28]	1250		**WEC (2013) Symphony** [29]		7400
IRENA (2016) Remap [30]	1760		**IRENA (2016) Remap** [30]		7500
Greenpeace (2012) [R]Evolution [31]	**1750**	**4550**	**Greenpeace (2012) [R]Evolution** [31]	**2600**	**7200**
Greenpeace (2015) [R]Evolution [32]	2800	6700	**Greenpeace (2015) [R]Evolution** [32]	3800	9900

For example, the IEA World Energy Outlook (WEO) has changed its projections of the global PV installed capacity in the past years, from predicting, in its 2006 edition, a capacity of 145 GW by 2030 [23], to predicting 280 GW by 2030 in its 2009 edition [33] (not mentioned in the tables above). The fact is that, according to Figure 2, in 2015, the installed PV capacity was 228 GW, and in 2016 it already exceeded the 280 GW for the year 2030, predicted by IEA WEO, back in 2009.

The *450 Scenario* of the 2010 edition of the IEA WEO, estimated a capacity of 485 GW by 2030, and a produced electricity of 723 TWh/year [24], a value which will be achieved in 2-3 years from year 2016 at the current growth rate.

The 2014 IEA Technology Roadmap had to reconsider the growth rates of the PV technology compared to its 2011 Edition - from 11% of total electricity production from PV by 2025 to 16% for the same year [6]. Their hi-Ren scenario in the 2014 Edition estimates the growth to 1.720 GW by 2030, which is in line with the estimations made by IRENA in the 2016 Remap scenario.

IRENA also encountered difficulties in estimating the future capacities of PV. For example, the increase between 2 editions of IRENA's Remap Roadmap for A Renewable Energy Future: (2014 and 2016 Editions) is from 440 GW to 780 GW for their Reference Scenario for 2030 [34]. The reference scenario estimates a growth of 38 GW/year, which is less than IEA's projections of 42 GW/year (by 2020) and less than what has already been installed in 2015 (50 GW) and 2016 (75 GW)-but also less than the average capacity installed in the past 5 years, of 47 GW/year. With the REmap option, IRENA expects the annual installation rate to double by 2030 to 100 GW/year. Greenpeace has the most optimistic estimate, with approximately 2.800 GW installed by 2030 [7], and it can further be observed, that the estimates made by Greenpeace in 2012 were later reiterated by IEA and IRENA.

Shell has also projected the share of electricity, produced by PV in 2050 [27], and matches the one made by the IEA in 2014, as shown in Table 1. However, compared to the estimations from Greenpeace in their 2015 report, Shell's projections still seem underestimated. Out of all of them, the estimations from the World Energy Council [26] are the most conservative, for both of their scenarios.

It is clear that there are differences in the analyses among international organizations, and consequently, a large variation in the estimated PV capacities, with major differences from one year to another and a clear tendency to underestimate the potential.

2.4 Rapid development of photovoltaic costs

Currently, PV investments represent more than half of the total investments in the renewable energy sector [7]. The massive growth in PV has several catalysts, the most important being the unexpected reduction of costs. The reduction of costs influenced all levels, from large utility scale projects to small residential ones, and has in both cases mainly been defined until now by the reductions in cost for the PV modules themselves.

2.4.1 Cost estimation methods

In the power generation sector, there are different ways of calculating the costs of electricity production. The levelised cost of electricity (LCOE), a benchmarking tool to assess the competitiveness of an electricity generation technology, is the most definitive way of expressing the economic value of PV installations. This method takes into consideration the entire lifetime of the system associated with its costs, divided by the total energy output, in order to estimate a price for unit of energy generated. The LCOE is also influenced by the climate area the PV installations are installed in, such as if snow or hail falls, the salt or humidity levels. The output of the LCOE is expressed in MWh/monetary unit [35]. The formula to calculate the LCOE for a PV installation is:

$$LCOE = \frac{\text{Total lifecycle cost}}{\text{Total lifetime energy production}} = \frac{I_0 + \sum_{t=1}^{n} \frac{A_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where I_0 is the investment cost, A_t includes all the related operation and management costs, *r* is the discount rate, E_t is the total energy produced in 1 year, *n* is the operational lifetime of the plant and *t* is a given year within the lifetime [12]. The expected lifetime of a PV project is considered to be between 20-25 years, but in many cases the lifespan can go beyond, providing these cases with an even lower LCOE.

Therefore, the LCOE is used to provide an overview of the minimum cost at which electricity has to be sold in order for the investment to break even during the lifetime, but also to remove the preference for one technology over another [35].

Starting from the formula mentioned above, more complex ways of calculating the LCOE can be used, which include more parameters, depending on the different stakeholders involved in the projects. Such parameters include the interest payments if the debt is financed, local incentives, the inflation rate or the depreciation level of solar panels. The latter one is considered to be very small throughout the lifetime of PV, and is estimated to be between 0,2 and 0,5% per year, even though other publications estimate it to be below 0,2% [35]. If necessary, the formula can also include transmission and connection fees to the grid, or taxes and subsidies.

There are multiple ways of calculating the LCOE, but the different methods are expected to provide similar results. Adding the factors mentioned above should only provide more accuracy to the calculations.

The formula, as presented above, was also used by IEA and IRENA to calculate the values of LCOE, which are further presented and discussed in this chapter. The value of the discount rate is very influential in such calculation. IRENA suggests to use 7,5% for OECD countries and 10% for the rest [5], whilst IEA uses 8% [6].

2.4.2 Benchmarking photovoltaic cost

An important milestone in the historical deployment of PV is considered to be represented by the moment in time when the LCOE achieves a cost level which is the same or below the cost of electricity provided through conventional sources. Known as grid parity, this is given by a decrease in costs for PV, combined with an increase of the prices for electricity from the grid, bringing the LCOE, in some countries, to levels similar or even bellow the LCOE provided by the grid operators [36].

While it is considered to be a useful benchmark, the validity of grid parity is dependent on the formula used for calculating the LCOE, and also on the availability and accuracy of the data used for this calculation. Thus, grid parity represents a complex relation between local prices of electricity and total system prices in an area depending on the size of the installation, supplier and/or geographical aspects, and it is catalysed by several driving forces:

- The learning curve – where the industrial processes have been optimised due to the high learning rate of 20% for PV systems;
- Growth of the PV industry – achieved mainly due to modularity and standardization;
- System performance – a potential low LCOE may not result in system benefits in all cases
- General electricity prices – a general trend has been an increase of electricity prices worldwide;
- The regulation schemes – which have enabled and supported the expansion of the PV installations throughout the years, and still do (The impact of regulation schemes on the expansion of PV is further explained in Chapter 5)

In 2015, approximately 30 countries managed to achieve grid parity, either on a national or regional level [37], and it is likely that more countries have reached this level by now (2017).

While the decrease of electricity cost per kWh from PV is always regarded as very good news, the aim of this reduction should not be to reach or get below the threshold of grid parity. Such an estimate can create the belief that the electricity grid is just another added cost to the electricity bills, whilst in reality, the role of the transmission and distribution grids is very important for the good functioning and balancing of the entire energy system. One could not balance the fluctuations in solar irradiance on its own whilst also achieving low electricity costs. To benefit from low electricity prices while also integrating a variety of renewable energy sources, the electricity grid needs as many connections as possible, as it is easier to mitigate the fluctuations in a larger system connected to other sectors or other countries.

2.5 The decreasing costs of large-scale photovoltaic systems

In this report, the inverter is often considered as part of the BoS to better explain the cost differences.

Regarding investments and installed capacity, large-scale installations of PV projects have experienced a higher impact of growth rate in the past years than small-scale PV projects for residential installations. The total investments for large-scale installations were over €81 billion in 2015, with the LCOE value expected to continue its decreasing trend. By 2025, the LCOE is expected to be reduced in more than 59% of the current levels [5].

PV modules have had the most abrupt price reduction rate due to a high learning curve, rapid possibility for deployment, and economies of scale (Figure 4). During the period between 2009 and 2015, the cost of PV modules decreased by approximately 80%, with an especially high reduction rate during 2011, where the production of modules exceeded the demand. In 2015, the weighted average prices for PV modules ranged between 460 €/kWp to 640 €/kWp. On the other hand, the BoS costs have not declined significantly, and today these represent 50 – 80% of the total costs of a PV installation. However, the costs for the inverters have been declining, ranging presently between 125 €/kWp and 160 €/kWp, with a learning rate of 18-20% [5].

As mentioned previously, the PV solar technology does not require extensive maintenance. But since the technology costs are decreasing rapidly, the O&M costs (operation and maintenance costs) tend to have a higher share of the total costs. In some markets, such as Germany or the UK, these account for 20-25% of the LCOE [5].

Accordingly, the system costs for large-scale PV plants were reduced by 56% from 2010 to 2015, and in 2015, the total investment cost was found to be around 1600 €/kWp (1800 USD/kWp), as presented in Figure 4 [7].

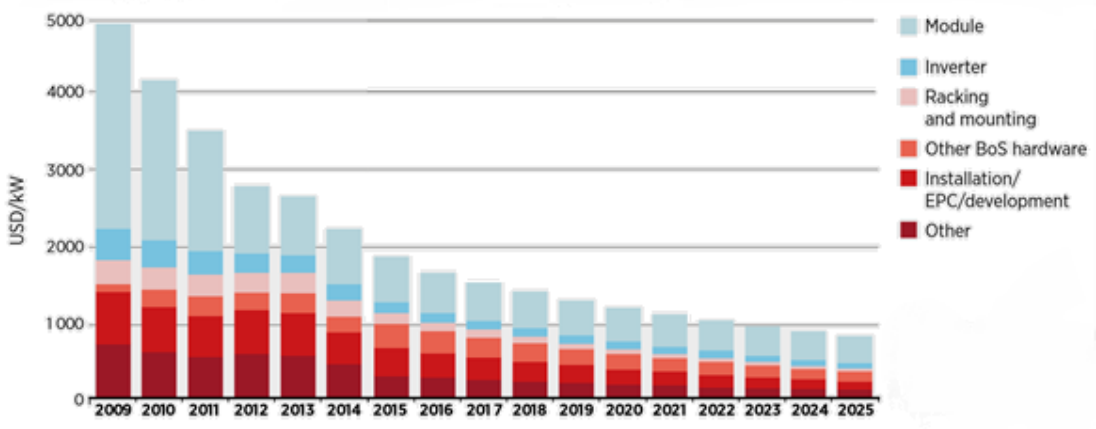


Figure 4 - IRENA price projections by 2025 for utility scale projects (2016 estimation) [7]

Even though the price of PV modules as a whole has decreased significantly year by year, these costs are still expected to decline by more than one third until 2025, depending on the technology, region and type of

deployment. PV module costs could be found in the range between 250 to 400 €/kWp by 2025, assuming that the future deployment of large-scale PV capacities will be between 1.700 and 2.500 GW by 2025, bringing with it a learning rate of between 18 to 22 % [5], meaning that by 2025, the overall investment costs in large-scale projects can be reduced to an average of 750 €/kWp, representing a total cost reduction between 43-65%, compared to 2015 levels.

The BoS costs are considered the main driver for reduction in the years to come, and these could be reduced by 55-47 % by 2025, depending on the development of the market for PV. This reduction is likely to come mainly from the learning curve towards best practices, and less from additional cost reductions from racking, mounting and installation processes. The inverter cost reductions will be influenced by the technological progress and the economies of scale, due to the increased presence of Asian competitors on the market. As presented in Figure 3, much of the capacity increased in the Asian market over the last years [5].

The overall reduction of costs for large-scale PV systems has clearly been reflected by the LCOE value. IRENA finds that the LCOE has been reduced by 58% between 2010 and 2015 to a level of approximately 110 €/MWh, which could further be reduced by another 59% between 2015 and 2025, to 48 €/MWh [5].

On a European level, the Danish Energy Agency [17] estimates the LCOE of large-scale PV systems to be between 48 €/MWh in 2020, whilst the costs for 2050 are expected to decrease to 23 €/MWh.

2.6 The decreasing costs of rooftop photovoltaic installations

The reduction in costs for the large-scale projects is also mirrored in the cost for rooftop installations. The decreasing price of modules has brought a decrease in the total system costs, and in 2015, €59 billion have been invested in rooftop PV projects worldwide [7]. The existing cost estimations and projections mainly focus on large-scale installations, therefore not as much data is available regarding residential applications. However, it has to be assumed that the overall decreasing trend also reflects on residential applications, even though no exact data is available.

Large-scale PV plants are generally more economically competitive than residential ones, given the economy of scale. There could be though high differences between international and national cost estimations. For example, the cost of residential PV installations in Germany is almost 20% lower than the average cost provided by IRENA for large-scale installations, as shown in Figure 5.

The price variations are rather high between different countries, ranging from 1.325 €/kWp in India to approximately 1.800 €/kW in Australia. Between 2010 and 2015, an important drop in prices was experienced in Australia, where the cost of rooftop PV declined from over 6.200 €/kW to 1.800 €/kWp

On a European level, in Germany, a country which already has a high capacity of PV systems, the estimated average price for rooftop systems with a capacity between 10-100 kWp was 1.270 €/kW at the end of 2015, according to Figure 5 [12]. In Denmark, the Danish Energy Agency provided an estimate on the cost of small and medium sized PV applications that is 1.470 €/kWp for the year 2017 [17]. In the future, the technology costs are projected to reduce to 1.250-1.070 €/kWp by 2020 and to 850-720 €/kWp by 2050. [7].

Therefore, the market for PV is very dependent on the national context, where PV installations are subject to various regulations, laws, support schemes or anti-dumping measures. There are variations from one country to another with important geographical variations, and these have a high impact on the LCOE.

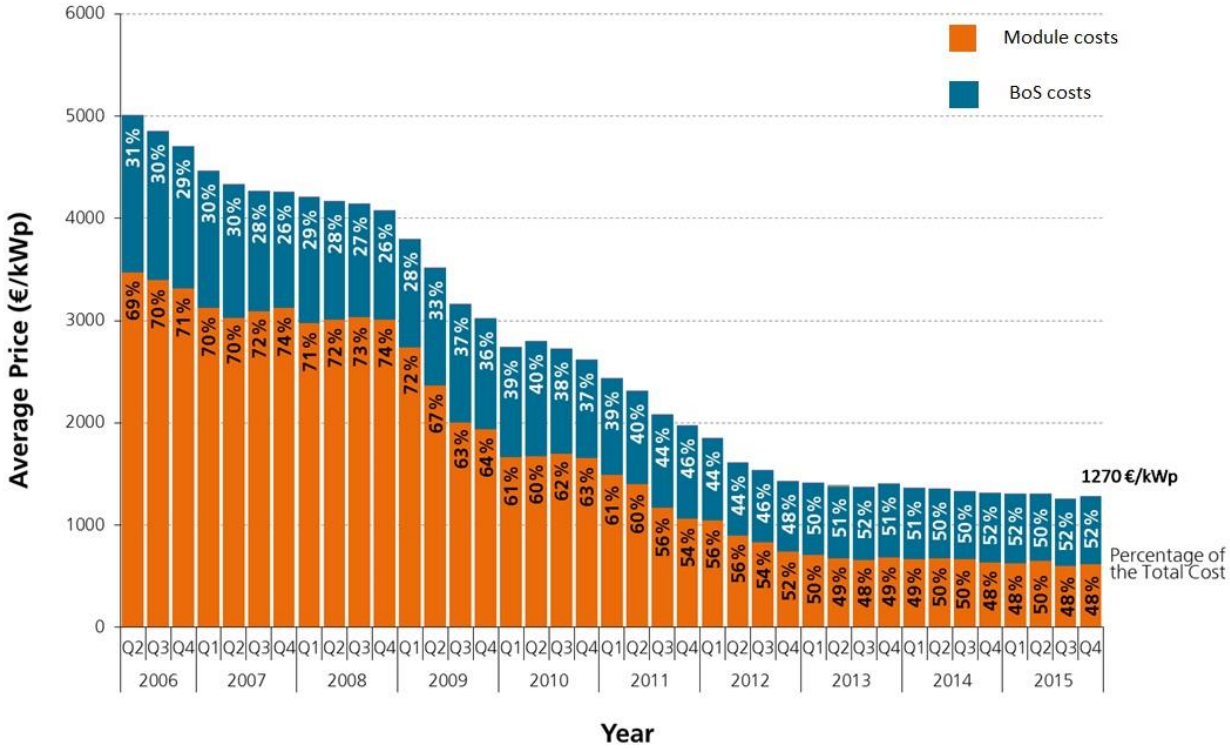


Figure 5: Average end customer costs for rooftop systems with power from 10-100 kWp in Germany. Data from BSW, PSE AG (2017) [12]

The LCOE for small and medium systems also had a decreasing trend in the past years, as for the large-scale applications. According to [17], the LCOE for small and medium PV systems was between 93-79 €/MWh for the year 2015. The estimations for the year 2020 are 69-59 €/MWh, but the costs are projected to decrease substantially to 41-35 €/MWh by the year 2050 [17]. Since these estimations were made in 2015, it is possible that these costs are already underestimated.

In the category of residential applications, the knowledge on the costs of BIPV is limited, because of the absence of a well-established market still in the stage of demonstrative, pilot projects. However, a survey made on the market of BIPV in Switzerland and Benelux has revealed that the price of BIPV is on average €200/m^2 higher than conventional roofing materials. This is the average cost between in-roof mounting systems (that take PV modules on a part of the roof), BIPV tiles and full roof solutions (where the rooftop is exclusively and specifically designed as a solar collector) [38].

The report suggests that the costs of BIPV vary significantly, and to highlight the cost difference, a comparison with conventional PV is made. Therefore, in [38], the cost of conventional PV with roofing materials included is estimated to be 3.000-4.000 €/kW[5]. On the other hand, the cost of BIPV tiles can span between 3.000-7.000 €/kW, in-roof mounting systems can span between 5.000-7.000 €/kW, whilst the full roof solutions have the largest range of costs, between 3.000-9.000 €/kW [38]. This makes the BIPV systems up to 2 to 3 times more expensive than conventional PV systems. It should be noted that the cost of BIPV tiles can be similar to conventional PV systems in some cases, as the price range shows.

2.7 An underestimated photovoltaic market

The growth of PV is dependent, to a certain level, on the assumptions about the future price developments. Therefore, the future price development of PV is examined in order to assess whether the previously projected price actually relates to the actual price development.

[5] A capacity factor of 11% is used.

For example, the 2006 edition of the WEO estimated that the costs for PV by 2030 were to be 2.200 €/kW on average, for both residential and large-scale projects [23]. Three years later, the WEO [39] reconsidered its estimates for the cost of PV installations to be between 1.750 – 2.100 €/kW for large scale projects by 2030. Thus, these costs were already achieved in 2015.

In their latest report, the IEA Technology Roadmap [6] was still conservative with its estimations for 2015, estimating a weighted average cost of 1.800 €/kW for both large-scale and residential projects, but with a high range of costs for residential installations (Figure 6). However, the bottom range of costs for large-scale projects is 1.300 €/kW, according to the IEA (2014), even though the Fraunhofer ISE [40] estimates a cost of 800-1.000 €/kW for large-scale projects. The same institute estimates that the cost for residential applications was between 1.200 – 1.600 €/kW in 2015 [40], which is already very close to the price estimations made for 2025.

For 2030, the IEA's range of estimations is narrowed, and the weighted average is 900 €/kW for large-scale projects and approximately 1.000 €/kW for residential applications by the year 2030, which is still not in line with the estimations made by IRENA, who assumes a cost of 750 €/kW by 2025 (Figure 6).

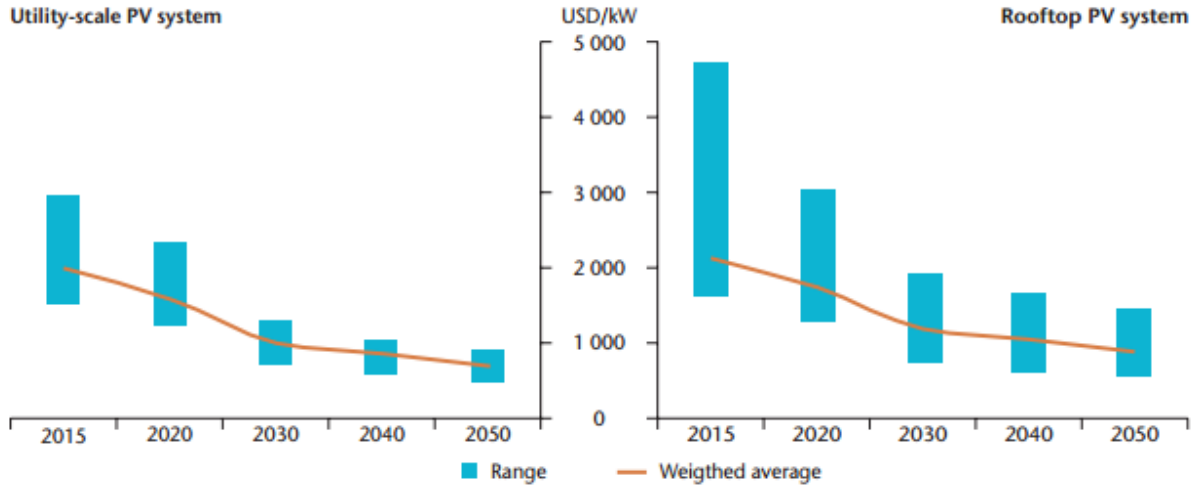


Figure 6: Estimated costs for utility and residential PV systems by 2050 (2014 estimation) [5]

The discrepancies in the estimations will probably be reduced in the following publications, due to a stabilization of the technology costs. IRENA only provides estimates until 2025, but the IEA narrows their range of costs for 2050, where the estimated cost of 550 €/kW for large scale projects is similar with the estimations made by Fraunhofer ISE for Germany [41] being between 300 to 600 €/kW.

The estimations for the LCOE are also different, depending on the publications. That is, the IEA Technology Roadmap [6] estimated a LCOE for large-scale projects of 96 €/MWh, but IRENA has a much more optimistic estimation of 55 €/MWh. For residential scale projects, the LCOE is estimated at 121 €/MWh by IEA, and even though IRENA does not estimate this cost, it is probably lower compared to the estimate from the Technology Roadmap.

2.8 Cost comparison of photovoltaic and other renewables

The LCOE for PV has decreased substantially in the past years, making the cost of electricity produced via PV to be lower than the price of electricity from the grid in some countries. For example, a tender for a 350 MW plant in Abu Dhabi has set a low record LCOE of €20/MWh in august 2016 [42]. In may 2017, in India, a tender for a 200 MW plant had a LCOE of €32/MWh [43]. These low prices are related to increase technology learning curves, high levels of solar irradiation, but also new and/or improved regulation strategies.

It is clear that PV is becoming cheaper than initially estimated, as it was demonstrated earlier in this chapter. This makes it more competitive on the renewable energy market, compared to onshore and offshore wind, especially in parts of the world with very high solar irradiation. However, a diversification of the energy supply would be more beneficial for the energy system, since combining different types of renewable energy technologies with different production profiles would create a better and more robust match between the supply and demand of electricity. This is further detailed in Chapter 4.

The costs for wind technologies are important in this case, as the deployment of solar and wind power should be done simultaneously, in order to harvest system advantages. The cost for onshore turbines has decreased in time, from values of 4.210 €/kW in 1983 to estimated values of 1.400 €/kW in 2015, and the main driver for cost reductions was given by the economies of scale, as the market reached 59,5 GW installed in 2015, compared to 6,6 GW in 2001. The LCOE has also been brought down to a weighted average between a minimum of 47 €/MWh and a maximum of 106 €/MWh. The lowest costs are found in China, whilst in Europe, the LCOE has a value of approximately 62 €/MWh [5].

In the future, the potential for cost reductions for wind power can originate from a learning curve, but also from an expansion of new wind farms and technological innovations (improved blades, turbines and towers). Thus, the costs are expected to reach a weighted average of 1.200 €/kW installed by 2025. The LCOE is also expected to decrease by 26% by the same year to average costs of 47 €/MWh, which are the lowest values traded today. Nevertheless, there is potential for further reductions to values as low as 25 €/MWh. In other words, it could be possible that the costs of PV and onshore wind to levelize by 2025 [5].

Offshore wind also has a high potential, as the costs for this technology are expected to decrease in the coming years too, however not at the same pace as PV and onshore wind. Nevertheless, offshore wind costs have already decreased multiple times in the past years, reaching costs of 4.105 €/kW in 2015. This is still considerably higher than the two other technologies, due to the higher installation and O&M costs, which are naturally higher because of the location of the wind turbines. This leads to LCOE values of around 150 €/MWh in 2015 [5].

Looking towards 2025, there is potential to further reduce the costs coming mainly from improvements in technology, process and operation of offshore wind parks. That is, the projected overall cost is expected to be in the range of 3.500 €/kW installed, representing a reduction of 35% compared to 2015. The LCOE can also be reduced to approximately 97 €/MWh, which represents a reduction by approximately 24% compared to 2015 costs. This is still two times higher than the projected LCOE for PV and onshore wind installations [5]. The investment costs as well as the LCOE of PV, onshore and offshore wind turbines are summed up in the following table:

Table 2: Investment costs and LCOE for according to [5]

	Investment cost (€/kW)		LCOE (€/MWh)	
	2015	**2025**	**2015**	**2025**
Large-scale PV	1.600	700	110	48
Wind onshore	1.400	1.200	47 ~ 106	25 ~ 47
Wind offshore	4.105	3.500	150	97

2.9 Summary of expected developments and photovoltaic costs

The costs and capacities for PV have seen an unexpected and abrupt decrease in the last decade, and the decrease was not expected by organizations such as the IEA, IRENA and others. Their estimations were in many cases far too conservative, and in most cases, the cost and capacity estimations for 2030 have already been achieved or surpassed in 2015. The important decrease in costs is mainly related to the market growth and the learning curve, since the technology has reached a certain level of maturity that does not foresee

any major technological breakthroughs. However, there is still room for technological improvements for various PV technologies, costs reductions being expected to come mainly from the amount of materials used, the cost of materials and improved manufacturing processes.

Large-scale projects attracted the majority of investments, and it is likely that these projects will continue to have the highest share of investments and installed capacity in the future too, compared to smaller scale installations. The price drop of the technology is expected to continue in the years to come. According to [44], the costs for PV modules will be reduced by another half until 2030, whilst the BoS will have a reduction of 30-40% by the same year. Since the price of modules has decreased considerably already and does now represent less than 50% of the total costs, even with an additional reduction of 50%, these will have less impact than the reduction coming from the BoS. These reductions will lead to system costs of 750 €/kW by 2025 for large-scale projects [7]. The estimated LCOE by the same year by IRENA is expected to be 48 €/MWh for the year 2025, but other organisations, such as the DEA, estimate to reach this cost by the year 2020. However, whilst IRENA makes global estimations, the DEA has a more European/Danish focus.

Small and medium sized projects are also subject to large price reductions. An example can be observed in Germany, where a doubling in the installed capacity is found to reduce the prices by a constant average of 23% [12]. The average costs for rooftop PV systems in Germany were estimated to be 1.270 €/kW at the end of 2015 [12], which is close to the estimations made by the DEA for the same year. In the future, the technology costs are expected to be reduced to 720 €/kW for the medium-scale PV applications and to 850 €/kW for the small-scale ones.

In the category of small and medium sized PV systems, there are also the BIPV systems, a niche technology, but which has good potential for cost reductions in the future. Currently, such systems are in most cases two times more expensive than conventional PV systems with roofing materials included, reaching costs of 7.000-9.000 €/kW, as estimated in [38] (the cost of a conventional PV system would be 3.000-4.000 €/kW with the roofing materials included) [38]. If the conventional PV modules would be installed on existing larger rooftops, probably 3-4 roofs could be installed for the price of one, due to the economies of scale. Therefore, it is a strategic decision which types of systems should be used, as capacity deployment with focus on conventional PV systems could make more sense in a first phase, until the industry develops and prices decrease.

With today's high prices for BIPV, along with a currently undeveloped industry, it is difficult for this niche to get a relevant share of the PV market or the construction sector, since the cost of a BIPV roofs is on average 4-5 times more expensive than for a roof without any PV included. To allow this technology develop, support would be needed by the state through public regulation schemes. BIPV holds the advantage of being a technology with business and innovation potentials that can give Denmark or other countries wanting to be part of developing the PV technology a part of the economic potentials.

Another important conclusion to take from this chapter is related to the understanding of LCOE and its role in the choice of technology, as using it as a benchmark has its limitations. Grid parity is often used as a comparison model when it comes to the very low electricity prices coming from PV installations. However, even though it is important to decrease the technology costs and thus to replace fossil fuelled electricity sources as much as possible, the comparison of LCOE should not be made with the cost of electricity provided from the grid, but with the other electricity sources. The electrical grid is as important as the electricity resources, and in order to achieve a 100% renewable energy system, the connections have to be done on an intra- and inter-national level, and this can only be done through the transmission and distribution grids. For comparison, Figure 7 illustrates the LCOE for various technologies to highlight that the choice of technology for the future cannot rely solely on the costs of technologies. In some hours low cost renewables can replace expensive peak load. In other hours there is too much intermittent renewable energy sources in the grid which risk being wasted or have a very low value. For the large-scale integration of wind and solar power,

energy system analysis is needed to allow for a cost-effective transition towards such a highly renewable energy system also using energy storages and energy savings. Hence, this is performed in Chapter 4.

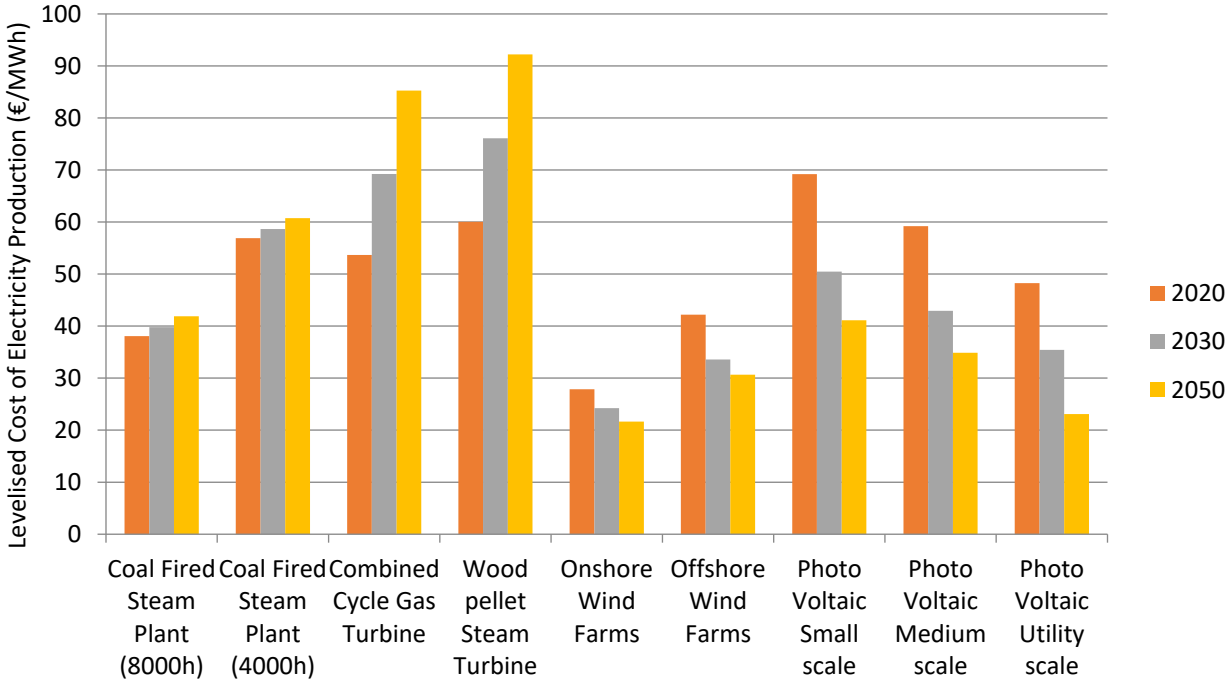


Figure 7 - LCOE of various types of electricity production systems for producing 1 TWh of electricity based on the costs from the Danish Energy Agency 2015 [17]. *The cost of large-scale photovoltaic is estimated to be 25% than in DEA 2015, in line with the estimations from Fraunhofer ISE* [19] *and IRENA* [5]

3 Danish development of photovoltaic capacities

The Danish Parliament agreed on a long time goal for achieving independence of fossil fuels by 2050. However, the concrete technology mix to reach this goal has not been decided yet. As this is a very complex task, with many possible solutions, several analyses have been conducted to understand how the independence from fossil fuels could be achieved. The following chapter summarizes the results from some national analyses, conducted between 2006 and 2016, regarding the role of PV in the future fossil-free scenario. But first, this chapter will present an overview over the current capacities and costs for PV in Denmark.

3.1 Installed photovoltaic capacity in Denmark

The history of PV installations in Denmark is shorter than in other countries, as the first time the accumulated capacity passed the first MW was in 2011. The situation rapidly changed in the coming year, as in 2012 alone, approximately 370 MW of PV capacity was installed. However, this installation rate was reduced by more than 50% in 2013, when around 147 MW of PV capacity was installed, whilst in 2014, just 28 MW of PV capacity was installed. In 2015 the installation rate grew again to 163 MW, to then decrease in 2016. Currently, half way in 2017, only 2 MW of PV capacity was installed. Overall, there is a total of 863 MW of PV installed until the month of July 2017 in the Danish energy system [45]. This is illustrated in Figure 8.

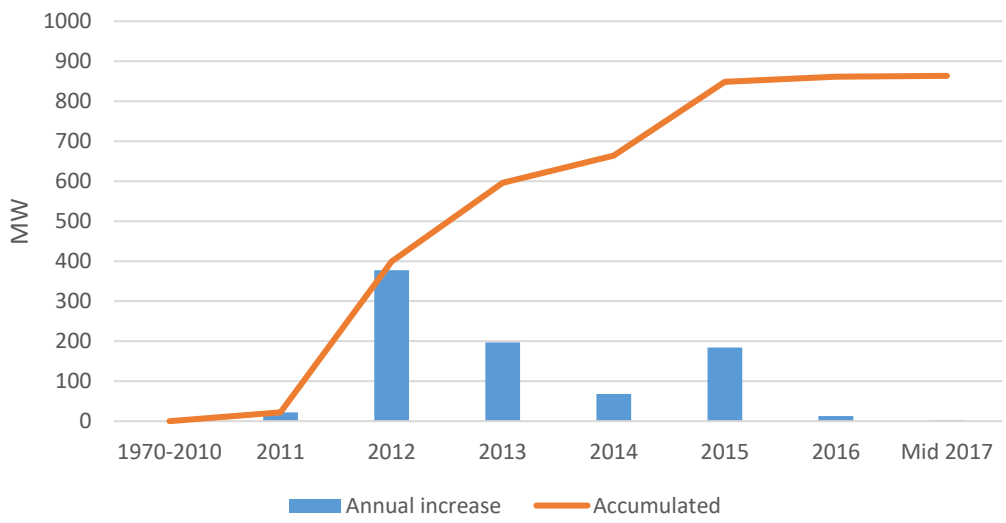


Figure 8 – Installed PV capacity in Denmark

3.2 Projections and scenarios with photovoltaics in Denmark

Several studies were conducted seeking to influence or project the level of PV in the future. The following paragraphs reflect the conclusions from these previous studies and, even though it can be difficult to compare their results directly, as they were based on different assumptions and applied to different time periods, some tendencies can still be derived.

3.2.1 Scenarios from the Danish Society of Engineers

The Danish Society of Engineers (IDA) has conducted several analyses of how a future energy system, based on 100% renewable energy should be designed.

The first analysis was published in 2006 and proposed a vision on how the energy system should develop towards 2030 in order to move towards a 100% renewable energy system. This analysis finds that it is both technically and economically feasible to reduce CO_2 emission by 60%, in comparison to 1990, and that it is

beneficial to install a total capacity of 700 MW of PV by 2030, expecting to produce around 2% of the electricity demand by 2030 [46]. In this study, the price for PV was expected to be 1.000 €/kW (7.500 DKK/kW) in 2015, which is lower than the actual prices observed in 2015. In 2016, the investment costs for rooftop PV installations was within the range of 950 – 2.000 €/kW, lower than the identified prices from 2015, as illustrated in Figure 4, which indicates that the prices continued to drop. In all, the actual numbers show that the analysis of the development of PV was underestimated, as the capacity identified as recommended in 2030 was surpassed more than 15 years earlier, in 2011.

In 2009 IDA published the report "The IDA Climate Plan 2050", which describes how the Danish CO_2 emissions can be reduced by 90% by 2050. The study found it suitable that 9-10% of the total electricity production (found to be 50,36 TWh in 2050) should be covered by PV [47]. This corresponds to an installed capacity of approximately 3.400 MW of PV, annually producing 4,5 TWh of electricity, out of which 680 MW was expected to be implemented in 2030, covering around 3% of the electricity production [47]. This capacity was found to benefit the energy system under the assumption that the price for PV would be around 1.000 €/kW, for both 2030 and 2050, which is relatively high in comparison to the actual prices, when taking into account the expected future price reductions. IDA's forecast for 2030 was indeed underestimated, as the actual development of PV capacities in Denmark has been much faster than predicted. In order to reach the predicted capacity in 2050, approximately 136 MW of PV would have to be installed annually, when considering IDA's predicted capacity in 2030. But if one considers the actual installed capacity in 2016, only around 79 MW of PV capacity would have to be installed annually, assuming that there would be an evenly distributed growth towards 2050.

Already in 2009, IDA acknowledged that the economic situation for PV was soon to change fundamentally, as PV was expected to be able to produce electricity at a lower price than the consumers would be paying (including taxes), within the period from 2015 to 2020, and that PV would became competitive to conventional electricity production around 2030 [47].

In 2015, IDA released a new analysis on how to achieve a 100% renewable energy system. The "IDA Energy Vision 2050" has increased the expectations for PV significantly and concludes that a much higher capacity of PV should be implemented in the future Danish energy system, in combination with wind power and biomass CHP plants [48]. According to this study, it is found to be feasible to implement approximately 3.127 MW and 5.000 MW PV in 2035 and 2050, where the prices are expected to be approximately 820 €/kW [6] (6.100 DKK/kW) by 2035 and around 690 €/kW (5.133 DKK/kW) in 2050 respectively. An installed capacity of 5.000 MW is found to provide an annual electricity production of approximately 6,35 TWh[7], corresponding to approximately 6% of total electricity production in 2050, or 107 TWh [48]. One of the reasons for the huge deviations in the electricity production is that the newest analysis assumes a vast development of electrolysers that induce an additional electricity demand of 40,43 TWh. This was not the case in the analyses from 2009, where electrolysers only were assumed to use 7,5 TWh of electricity.

In comparison to their earlier analyses, the installed capacity of PV is increased significantly and the assumed investment costs are also reduced to a much lower level. In the IDA Energy Vision 2050 the investment cost in 2035 is assumed to be around 14% higher than IRENA projections for 2025 and the IDA prediction for 2050 is only 4% lower than IRENA's estimate for 2025.

In order to reach the predicted capacities in 2035 and 2050 respectively, there would have to be implemented 126 MW annually towards 2035 and 2050, if assuming an evenly distributed installation rate.

[6] € 1 = 7,44 DKK

[7] Assuming 1.272 full load hours

3.2.2 Scenarios from the Danish Energy Agency

As a follow-up to the Energy Agreement from March 2012, the Danish Energy Agency conducted several analyses of how the Danish energy system should develop towards 2050. These included sector analyses and a more overall scenario analysis, which elucidates some possible scenarios for the Danish energy system.

In the analysis, a total PV capacity of 2.000 MW is included in 2050, where half of it is assumed to be installed in 2035, corresponding to an electricity production of 0,85 TWh in 2035 and 1.7 TWh[8] in 2050. This corresponds to 1,9 to 3,7% of the total electricity production in 2050, depending on the scenario. However, this is found to increase the total costs of the transition to a 100% renewable energy system, as the increase of the investment costs exceeds the systemic benefits that PV can provide in an energy system with a high share of wind power, as they produce electricity at different periods [49].

This conclusion is very sensitive to the assumed costs of PV, which have dropped significantly. This fact is not reflected in the Scenario analyses, where an investment cost of 1.100 €/kW (8.184 DKK/kW) is assumed in 2030 and 900 €/kW (6.696 DKK/kW) in 2050. This is based on their Technology Data catalogue [50], which is significantly higher than what IRENA predicts and what is assumed in IDA's Energivision 2050. In order to fulfil the forecast of the Scenario analysis, only 37 MW of PV would have to be installed annually in the period from 2017 to 2050.

The Danish Energy Agency also made the Baseline Projections (BP), which reflect the development of the energy system based on the coming years. There has been a development in the assessment of the role that PV will play in the future. Therefore the BP from different years are analysed. Before 2012, PV was not even represented in the projections, but the reports from 2012, 2014 and 2015 did include PV.

The projection from 2012 finds that the capacity of private PV installations increases to 1.125 MW in 2020 and to around 3.000 MW in 2035, corresponding to an electricity production of 2,6 TWh or approximately 6,7% of the total electricity production. Furthermore, it is assumed that 5 MW of large-scale PV is installed every year during the projection period. This results in a total capacity of 1.165 MW in 2020 and 3.115 MW in 2035 [51]. If the projection towards 2035 should be reached, there would have to be installed around 125 MW of PV each year.

The BP for 2014 predicts an installed PV capacity of 1.000 MW in 2020, which correspond to a production of 2,7% of the total electricity demand. The capacity is assumed to increase by 50 MW annually towards 2025, resulting in an installed capacity of 1.300 MW in 2025.

In the Baseline Projection from 2015, the expected installed capacity of PV is projected to develop as illustrated in Figure 9. As illustrated, the PV capacity is projected to increase significantly towards 2025, doubling in 2020 and increasing more than four times in 2025, in comparison to the present capacity. In 2020, the capacity is expected to be around 1.800 MW, corresponding to approximately 5% of the total electricity production, and in 2025 the installed capacity is expected to exceed 3.000 MW, representing 7,5% of the total electricity production. This would require an annual installation rate of around 120 MW.

[8] Assuming 849 full load hours, which was applied in the analysis [49]

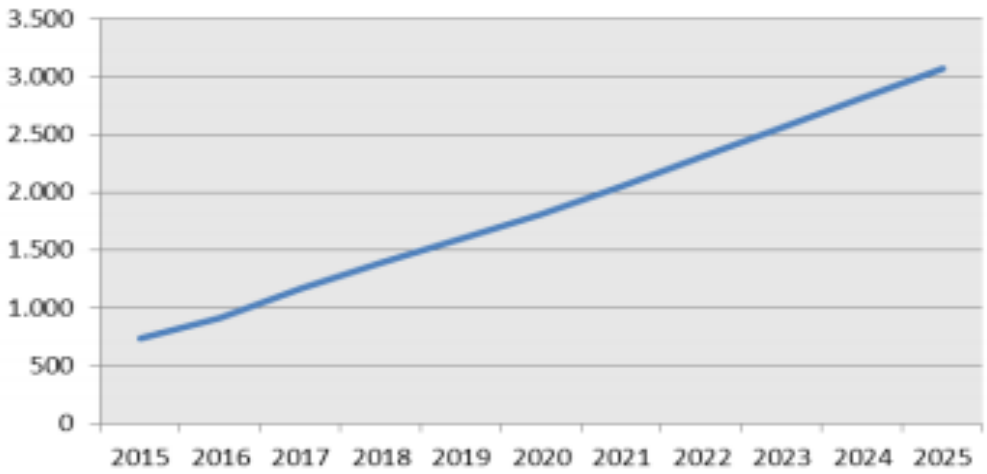


Figure 9 - The projected capacity of PV in Denmark towards 2025 according to the 2015 BP [43].

It is recognized that the actual development of PV capacity cannot be expected to be linear, as illustrated in Figure 9, but this assumption does not change the result of the projection significantly [52]. In the 2017 BP, the projections are a bit less optimistic, as PV is found to produce 4% of the total electricity demand in 2020 and up to 7% in 2030 [53].

3.2.3 Scenarios from the Danish Transmission System operator – Energinet.dk

The Danish Transmission System Operator (TSO) Energinet.dk recently made a projection of the development of PV in Denmark towards 2040, illustrated in Figure 10 and Figure 11.

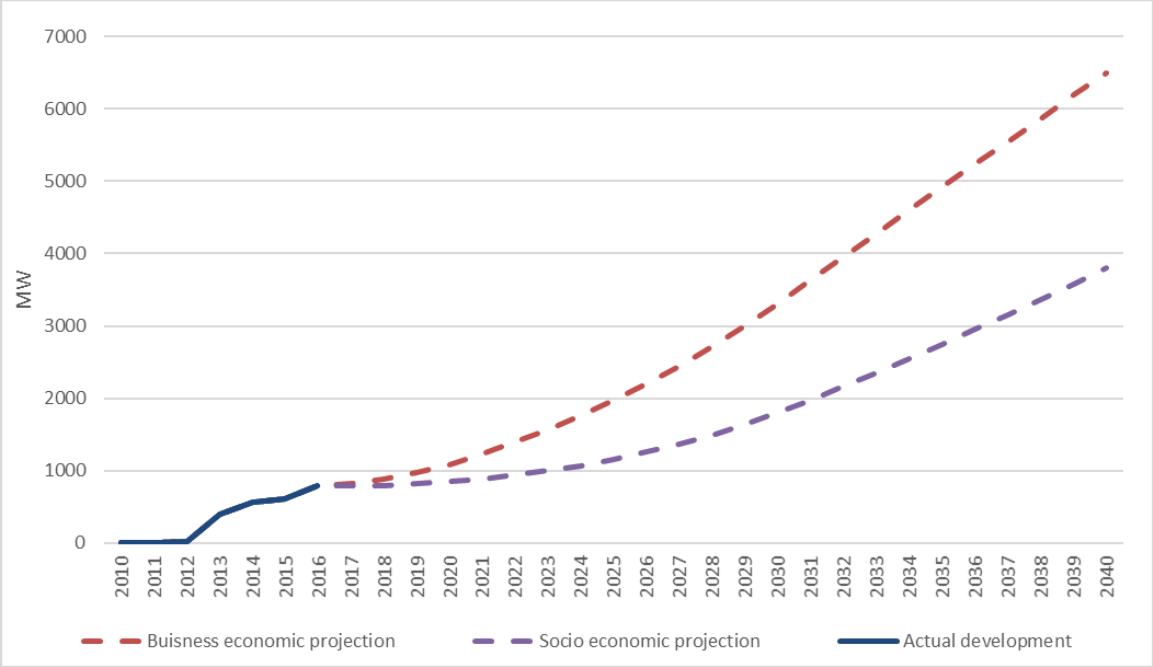


Figure 10 - Projection of the implementation of PV towards 2040. The figure includes both business and socio-economic projections and does not include battery solutions. Based on data from [46]

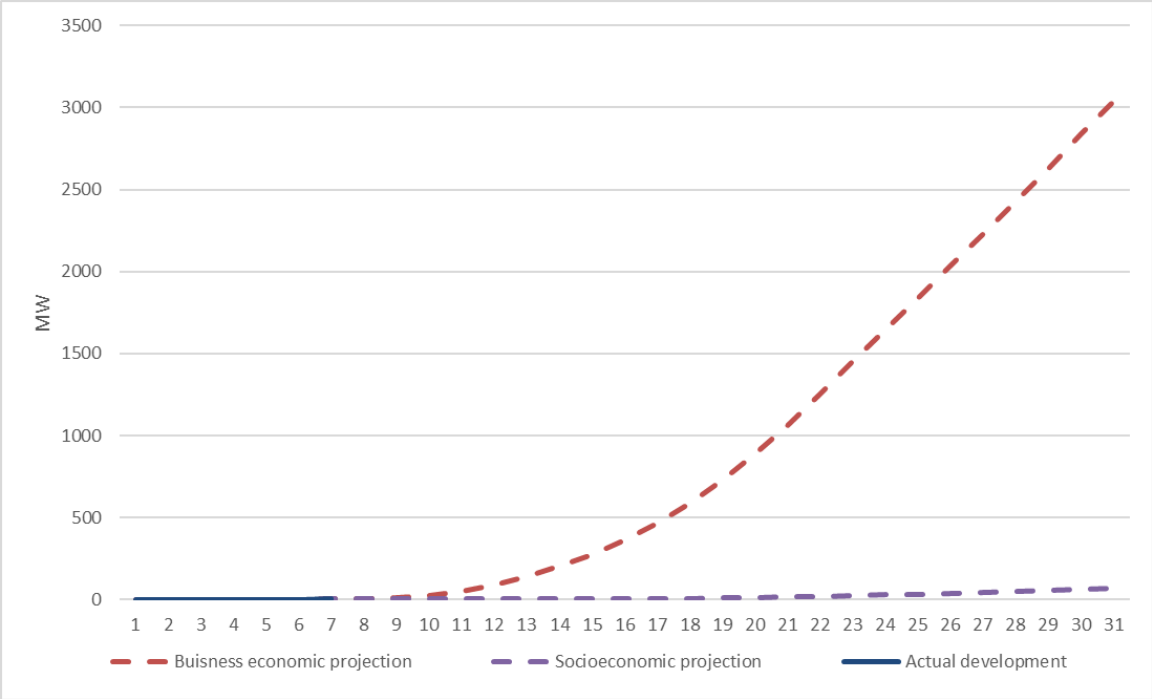


Figure 11 - Projection of the implementation of PV in combination with batteries towards 2040. The figure includes both business and socio-economic projections. Based on data from [46]

As illustrated in the two figures above, Energinet.dk projects a rapid development of PV towards 2040. The analysis subdivides the development of PV into installations with or without batteries and analyses the development from both a business and socio-economic perspective [54].

As shown in Figure 10, the business and socio-economic projections for PV installations without batteries are roughly coinciding with each other and show that the PV capacity is projected to be around 1.800 MW in 2025. The analysis also shows that in 2040 a capacity of 3.900 MW of PV should be installed if the development is projected on the basis of socio-economic assumptions, however from a business perspective the analysis projects that more than 5.000 MW should be installed [54].

The combination of PV and batteries is found to become profitable for the investor after 2020, where a significant development is expected towards 2040, where the projection shows that around 3.000 MW of PV combined with battery should be installed. However, if the projection is made with socio-economic assumptions, it is found that the combination of PV and batteries is not profitable and the development is found to be insignificant.

In total, Energinet.dk analysis projects a development of around 7.500 MW, if the projections are made on business economic assumptions. The usage of socio-economics reduces the projection to around 5.500 MW. Energinet.dk finds that the capacity is expected to be approximately 2.200 MW and 1.400 MW in 2025 according to the socio-economic projection.

3.2.4 Summary of photovoltaic in scenarios and projections in Denmark

All of the above mentioned studies agree that the installed capacity of PV will increase significantly in the future and even though there are disagreements about the exact capacity, the tendencies are similar, as illustrated in Table 3, where the previously described capacities are listed chronologically (year of the analysis).

Table 3: Summary of how different analyses projects the future PV capacity and their price assumptions (if existing).

	2025	2035	Long term (after 2035)
IDA 2006	-	700 MW (2030)	-
IDA 2009	-	860 MW (2030) *1.000 €/kW (7500 DKK/kW)*	3400 MW *1.000 €/kW (7500 DKK/kW)*
BP 2012	1.165 MW	3.315 MW	-
ENS Scenario	-	1.000 MW *900 €/kW (6700 DKK/kW)*	2.000 MW (2050) *900 €/kW (6696 DKK/kW)*
BP 2014	1300[9] MW	-	-
BP 2015	3.074 MW *920 to 1.125 €/kW (6844 to 8.370 DKK/kW - according to type of plant)*	-	-
IDA 2015	-	3.127 MW *420 €/kW (6.100 DKK)*	5.000 MW (2050) *690 €/kW (5.133 DKK)*
Energinet.dk 2016	2.200 MW *920 to 1.125 €/kW (6844 to 8.370 DKK/kW - according to type of plant)*	5.000 MW *420 – 1.000 €/kW (2030) – according to type of plant)*	6.500 MW (2040) *690 to 850 €/kW (2050) – according to type of plant)*

As illustrated in Table 3, there are variations in the projection periods, but there is a clear tendency that the current PV will increase. The values of this increase are dependent on the future market conditions.

There is also a clear tendency that the changes in the development of PV in Denmark have been much more drastic and rapid than suggested in the above mentioned analysis. It can be identified a relatively clear correlation between the assumptions about the future prices and the installed capacity. This can also explain the gradual increase in the predicted capacities, as the analyses were not able to foresee the high price reductions (or changes in the regulation) that PV has been subject to.

A very drastic increase in the implementation rate can be identified in 2012, where the price of PV modules dropped significantly. This, combined with an inflexible subsidy scheme, which could not adapt to the price development made an investment in PV very profitable.

As the early analyses above does not reflect this, it leads to a general underestimation of the future capacities, as for example the DEA foresees a capacity of only 1.000 MW in 2035, which is very low when taking into account that more than 800 MW are currently implemented. This drastic change in the growth rate is taken into account in the newer analyses, showing an increasing expectation for the capacity of PV, where between 1.300 and 3.000 MW is expected.

However, as a direct consequence of the increasing installed capacity of PV in Denmark and thereby the increasing costs affiliated with the subsidies, the regulation in Denmark was changed, which put an effective end to the fast implementation of PV in the country. This is further analysed in Chapter 7.

[9] With an annual increase of 60 MW, as assumed in [110] which underlies the BP 2014.

4 Role of Photovoltaics in the energy system

In this chapter the potential effects of expanding PV on the electricity distribution grids as well as on the system level are assessed through a literature review. In addition, energy system analyses of the role of PV in the national system are assessed, using Denmark as a case study. Previous studies on the national energy system level analysed the challenge of integrating large capacities of PV and wind power in the energy system of Denmark to find the optimal balance, but looked at the electricity sector only [55], [56]. In this chapter, the potential and role of PV in the future integrated smart energy system is analysed, considering sizes, costs as well as energy storage and flexible demand options.

4.1 Grid effects of Photovoltaics

The PV capacity is growing fast, and this creates a challenge for grid regulators to integrate the large capacities, from both small and large-scale projects, of intermittent and fluctuating electricity, which also varies according to a seasonal availability. An increased distributed or centralised PV capacity can be problematic for transmission and distribution grids if not planned accordingly.

The key factors to inquire on the topic of grid integration are related to: the role of the inverters and their ability for providing reactive power, the ability of the regulators to supply quality electrical power and the opportunity of using various types of storage to integrate even more capacities. These types of situations are specific for developed energy systems, initially based on using mainly fossil fuels to produce electricity, and which now face new issues integrating large amounts of renewable electricity.

Since PV are converting the irradiance of the sun in Direct Current (DC), the conversion of the current to Alternating Current (AC) has to be done via an inverter, which can pose several challenges to distribution utilities. Some of the fluctuation in current production (like when clouds are passing by) can be mitigated by using fast-acting inverters and automatic voltage controllers on the feeders. A common issue with operating PV is related to the reactive power flow fluctuations, as the voltage rises and variations. This makes it critical for grid operators to understand what can be the impact on both local, national and supra-national level regarding fluctuating solar power [57]. When new PV modules are installed, these generate large amounts of active power, so the transmission lines require more reactive power. This reactive power is generally supplied by regulators through power stations or cogeneration plants.

Given the exponential growth of PV capacities, it is also a matter of how the new capacities are distributed. A distributed capacity reduces the need of expanding the grid and generally does not put additional stress on it. However, if utility scale PV plants are built within grids with low electricity demand, more investments need to be done in the transmission network and transformer stations. In this way, the transmission of the new capacities has to be done strategically, to keep the costs low and maintain a high level of power quality.

If the share of PV is high, it can affect the distribution and transmission systems, as transmitting additional reactive power in the grid is generally more expensive than producing it locally. This can also create implications for substations and distribution lines, such as increased losses and line loading. Such a line loading, supplied by a feeder, has to be able to take the surplus power of the installed PV [57].

Consequently, it is important that the new-generation of inverters can provide more control features, as well as a better integration with the system regulators. Until now, the system regulators did not allow PV operators (or any of the renewable energy producers) to balance the grid, and in case of any faults, these would have to be disconnected. This situation is already changing in countries as Germany, where, since 2011, with the release of the new Grid Code, utility operators are allowed to balance the grid in case of faults [58]. To do this, the inverter must be provided with additional control features, such as the possibility of remaining connected to the grid in case of failures, and not delivering any active power directly after the

fault, to stabilise the grid. Another aspect is the ability of this inverter to supply only reactive power to the grid, and support it in case of any faults [59]. For example, in Germany, the implementation of the Low Voltage Directive[10], in the beginning of 2012, has induced that the inverters are required to also perform the task of stabilising the grid, and the feed-in management should be controlled remotely by the operator or by an automatic reduction of the real power provided by the PV to 70% [12].

Besides the ability of the inverters to supply grid stabilisation services, another technology can be used to balance the increased amounts of renewable energy in the electricity networks, such as the synchronous condenser. This is a rotating device that can generate reactive power whenever necessary, stabilise the transmission grid voltage and provide short circuit support. When power plants are decommissioned to make room for renewables, the grid can lose stability. The decommissioning of power plants presents the possibility of converting the electricity generators of existing plants in synchronous condensers. This could prove as a solution to balance the networks. Such projects have already been put into practice in countries such as Denmark, Germany and USA [60].

Grid scale batteries can also be considered as a way of balancing the network, as these can provide immediate response to the fluctuating energy provided by PV (when clouds are passing by, or during a storm). These systems are also capable of absorbing and delivering both active and reactive power, and can reduce the impact of well-known issues with PV generation, such as the frequency and voltage issues. However, their main disadvantage is the high costs [61].

In other words, the nature of distribution for PV plants, independent of their size, has to be done in a controlled way, and the feed-in should be done in a decentralized manner, without putting too much stress on the transmission lines and reducing the need and costs expanding the grid. The advantage of PV is that, in principle, it can offer grid regulation services at lower prices, and are suitable to be integrated in grid management systems to further contribute to grid stability and power quality [12].

In the case of Germany, the power generation profile of PV fits well with the load profile of the electricity grid current. According to Fraunhofer ISE, (2017) [12], the PV production will not exceed the demand, even in case it should expand in capacity in the coming years. With improved predictability of solar irradiation, power plants can be regulated down, though issues might occur with coal fired or nuclear plants having slower start-ups/ramp-downs, as these plants react to residual fluctuating loads on a limited level [12].

From this review it has been found that requirements should be made for PV manufactures to contribute to the grid stability on the local and national level. In addition, none of the studies indicate that the need for the distribution and transmission grid is decreased. In fact more control features are needed, which in the short-term, until the technologies are developed, may be more expensive.

4.2 Energy system analyses of photovoltaics in Smart Energy Systems

As Denmark shifts towards 100% renewable energy supply, focus should be put on energy savings, energy efficiency as well as on a major electrification and use of renewable energy from wind and PV in order to have a sustainable use of biomass [48]. Today, the electricity demand is 25-35% of the end energy demand in most developed countries, while the remaining goes to meet mainly the heating and transport demands. This means that the renewable electricity production will need to increase. In the future low carbon energy system in Denmark and other countries, the question is how much of this renewable electricity will be delivered from wind power and how much from PV?

[10] Low Voltage Directive VDE AR-N-4105

4.2.1 Previous energy system analysis on the mix of photovoltaics and wind power

In Lund, (2006) [55], it is investigated the optimal mix of different renewable electricity production types in a Danish energy system, including wind power, PV and wave power. The study was done within the context of the Danish reference energy system for the year 2020. The study focused only on the electricity sector and did not investigate the mix in a future renewable system that involves flexibility creating technologies, such as large-scale heat pumps, or thermal storage.

Nevertheless, the study provides useful starting knowledge about the ratio of wind power and PV for different renewable electricity proportions and within the constraints of the electricity system. The amount of renewable electricity from each production type was determined by the total amount of excess electricity production in the system. Ancillary services needed within the electricity system, such as grid stability restrictions remained in place. Meaning that in the analysis, at least 30% of the power must come from ancillary service power units, and that 350 MW running capacity of large power stations is available. This constrains the potential for renewable electricity integration.

The conclusion in the study is that the mix of PV depends on the total electricity produced from renewable electricity sources. When the total renewable electricity production is over 80% of demand, PV should cover 20-40% and wind 60-80%. These results should be seen in combination with other measures such as investment in flexible energy supply, demand systems (large-scale heat pumps, thermal storages) and the integration of the transport. The integration of electricity from fluctuating sources also depends on the flexibility on the demand side and the flexibility of the rest of the system, but this was not considered in the study [55].

In Gorm, Rodriguez (2013) [56], the mixture of wind and PV is investigated with consideration of the flexibility of the system. However, the study does not consider technical, regulatory or economic constraints, such as grid stability constraints or minimum power plant standby, as was done in [55]. By excluding these constraints more renewable electricity integration is enabled.

The study found an optimum level of wind and PV by looking at the minimum amount of excess electricity production from renewable electricity in Denmark. The study goes further by considering the flexibility creating technologies and looks at different energy arbitrage technologies (i.e. round-trip energy storage), and how they influence the mixture of renewable technologies. These technologies could be electric batteries, or coupling electricity and heating creating virtual storage.

The study shows that when wind power is over 50% of the electricity production the excess electricity increases. Therefore, PV is needed to reduce the excess electricity. The study finds that the optimal mixture of wind/PV is 80/20 percent, and this not only decreases the excess electricity but also has a higher potential for arbitrage technologies. When the Danish electricity system has a high share of renewable electricity, the wind/solar mix can vary by about 10% without significant differences in excess electricity production. This is a similar finding as in [55]. When the absolute share of renewable electricity is above 75%, seasonal storage, e.g. hydrogen, is required to use the excess electricity. The study concludes that a 20% share of PV would need a large number of storage units to reduce excess electricity. The authors continue by saying that the alternatives would be to export electricity or dump the electricity into heating and transportation [56].

Both studies find that a combination of wind and PV have a positive synergy effect and help to reduce excess electricity production. However, both studies look at the electricity sector in isolation and do not consider the impact on the wind PV mix when electrifying the other energy sectors such as transport and heating. The question is whether this is also the case in future integrated smart energy systems?

4.2.2 Analysis of photovoltaics in a 2020 and 2050 Danish energy system

In this section, the role of different types of PV from small-scale household PV to large-scale utility field based PV is identified through energy system analysis, considering energy storage, energy savings and more. This is analysed in a number of energy system scenarios using Denmark as a case.

Types of analyses conducted and main assumptions

First of all, PV is analysed is a "Denmark 2020" scenario continuing the current trends in the energy system. It represents similar characteristics as the existing system. This scenario has a high wind power share equal to 50% of the electricity demand, a high amount of CHP with large heat storages, a large biomass consumption as well as PV production. It is developed based on [53].

Since 2006, several scenarios for the transition towards a 100% renewable energy system in a Danish context has been put forward [47], [62]–[67]. The second scenario used in the analyses here is the 'IDA 2050' Energy Vision for Denmark developed in [48]. This scenario represents state-of-the-art knowledge for energy system for Denmark in 2050 for achieving the political targets of 100% renewable energy. In the scenario, the use of residual biomass resources is kept within reasonable boundaries regarding the per capita use. This scenario is created with a smart energy system focus, implementing cross-sectoral initiatives and energy storages. The scenario comprises a number of measures, including energy savings in different energy sectors compared to a 2050 business-as-usual scenario for Denmark. These include savings in heat demands (~42% of total heat demand), electricity savings (25%), stabilisation of the industrial demands, as well as significant changes in the transport sector. In addition, alterations are carried out on the supply side, where significant amounts of renewable energy sources are installed, in particular wind power and PV, as well as renewable heating sources. Finally, conversion to biofuel based technologies are carried out where no alternatives exist. The fuel and technology prices have been updated according to existing projections for 2050. A detailed description of this scenario is available in [48].

These two scenarios form the basis for the PV analysis in this report. Furthermore, specific aspects of these scenarios potentially impacting the feasibility of PV are investigated more thoroughly for drawing conclusions regarding PV and its role in the future Danish energy system. Additionally, the PV technologies are analysed for various price assumptions, including small and large-scale PV systems.

The analysis includes:

1. The impact of installing PV in the Denmark 2020 and IDA 2050 scenarios
2. The impact of different levels of PV installation costs
3. The impact of different fuel prices on PV installations
4. The balance between PV and wind power in the Denmark 2020 and IDA 2050 scenarios
5. The feasibility of PV with less electric vehicles and heat pumps in the IDA 2050 system
6. The feasibility of PV with large grid and household batteries installed

The analysis evaluates the feasibility of PV in terms of costs (total energy system costs), energy consumption (primary energy supply), CO_2-emissions and the energy system flexibility (electricity exchange). These parameters are only possible to investigate when applying a high-resolution energy system analysis tool analysing the entire energy system. For this reason, the EnergyPLAN tool was been used [68].

The EnergyPLAN model is an advanced freeware energy systems analysis tool for modelling national energy systems analysis. It was developed in 1999 at Aalborg University, Denmark and has continuously been expanded on since. EnergyPLAN has more than 5.000 registered users and is used in more than 100 research papers published in international peer-reviewed journals. The main purpose of the model is to assist in the design of national or regional energy planning strategies on the basis of technical and economic analyses of the consequences of implementing different energy systems and investments.

The model is a deterministic input/output model, which can model the whole national, regional or local energy system including heat and electricity supplies as well as the transport and industrial sectors. The model is designed to model the large-scale integration of renewable energy and smart energy systems with a focus on the integration of electricity, heating, cooling, industry and transport.

The level of PV capacities analysed here takes the point of departure in the maximum PV potentials of 49 TWh/year in Denmark identified in Chapter 5 as roof top installations. This is however the theoretical potential and will not be possible to install in reality due to cost reasons or due to unsuitable roofs. In order to have a range of results using a large part of the potential, it is assumed that 50% (24,5 TWh/year) of this potential is the highest PV production going from 0% in the energy system analyses in the IDA 2050 scenario analysis. The aim is somewhere within this range to identify a suitable level. The same approach is chosen in the "Denmark 2020" analysis although here the maximum level analysed is assumed to be 25% (12,25 TWh/year) of the technical potential. In other words, the maximum level used in the analyses is not the recommended level for 2020 and 2050, but rather a method to analyse the impact of PV installations. In the 2020 scenario, the maximum PV production analysed corresponds to 34% of the total electricity demand (36 TWh/year) while the PV share of the electricity demand (94 TWh) in the IDA 2050 scenario is 26%. The significant difference between the scenarios in terms of electricity demand is due to a heavy electrification of transport and heating sectors in the IDA 2050 scenario. It is also important to remember that the maximum PV potential analysed in the analyses are 19.300 MW, which equates a land area of 212 km^2, which is 0,5% of the entire Danish land area. In terms of investments, 19.300 MW PV capacity is equal to 2,6% of the total energy system annualized investment costs in the IDA 2050 scenario.

The governmental baseline for 2020 expect 1.400 MW of PV to be installed [53]. The current level is 870 MW. In the IDA 2050 scenario the PV capacity is 5.000 MW. These capacities are removed as an outset and then gradually more and more PV is included. It is assumed that the capacity factors for PV are 12% in 2020 and 16% in IDA 2050. Given these capacity factors and the PV production, the installed PV capacities are listed in Table 4 with a stepwise increase of 10% for each capacity installed until the maximum level is reached.

Table 4: Total PV capacities and production analysed in each scenario.

PV capacities (MW)										
	# 1	**# 2**	**# 3**	**# 4**	**# 5**	**# 6**	**# 7**	**# 8**	**# 9**	**# 10**
Denmark 2020	1.190	2.380	3.570	4.760	5.950	7.140	8.330	9.520	10.710	11.900
IDA 2050	1.930	3.860	5.790	7.720	9.650	11.580	13.510	15.440	17.370	19.300
PV production (TWh)										
Denmark 2020	1,22	2,45	3,67	4,9	6,12	7,35	8,57	9,79	11,02	12,24
IDA 2050	2,45	4,9	7,35	9,8	12,26	14,71	17,16	19,61	22,06	24,51

It is important to notice that this analysis is not an estimate of how much PV should be installed within a given time frame, but rather an analysis of the impact and feasibility of installing various PV capacities under different conditions.

The PV prices assumed for the analyses for 2020 and 2050 are listed in Table 5. The low and high prices are calculated as a 25% reduction or increase compared to the medium prices.

*Table 5: PV prices assumed for 2020 & 2050 for the analysis. *Danish Energy Agency technology catalogue [17], ** Danish Energy Agency technology catalogue reduced by 25% as this is more in line with expectations from Fraunhofer ISE [19] & IRENA [5]*

PV price assumptions		2020		2050	
	Unit	Small systems	Large systems	Small systems	Large systems
Low investment prices	(M€/MW)	0,94	0,77	0,64	0,39
Medium investment prices	(M€/MW)	1,25*	1,02*	0,85*	0,52**
High investment prices	(M€/MW)	1,56	1,28	1,06	0,65
Operation and maintenance	% of investment	1	1	1	1
Lifetime	Years	35	35	40	40

In Table 6 the costs are listed in €/MWh. Small scale PV in 2020 and 2050 corresponds to the medium cost assumptions in Table 5, while the utility scale PV corresponds to the large systems in Table 5 with medium cost assumptions. This illustrates that the energy system analyses here corresponds to a wide range of sizes and costs.

Table 6: Levelised cost of electricity production for three system sizes [17] ** Danish Energy Agency technology catalogue reduced by 25% as this is more in line with expectations from Fraunhofer ISE [19] & IRENA [5]*

Levelised Cost of Electricity Production (€/MWh)				
Plant	Year			
	2015	2020	2030	2050
PV small-scale (<50 kWp)	93	69	50	41
PV medium-scale (50-500 kWp)	79	59	43	35
PV utility-scale (>500 kWp)	65	48	35	23*

The fuel prices assumed for the analysis are listed in Table 7. High and low fuel prices are assumed to be 25% reductions or increases compared to the medium fuel prices.

Table 7: Fuel prices assumed for the analysis.

Fuel prices (€/GJ)		Coal	Fuel oil	Diesel	Petrol	Natural gas	Biomass	Dry biomass
2020	High prices	4,0	14,9	22,9	20,1	11,9	9,9	5,9
	Medium prices	3,2	11,9	18,3	16,1	9,5	7,9	4,7
	Low prices	2,4	8,9	13,7	12,1	7,1	5,9	3,5
2050	High prices	3,5	14,5	20,0	20,5	10,4	7,5	13,6
	Medium prices	2,1	8,7	12,0	12,3	6,2	4,5	8,2
	Low prices	2,8	11,6	16,0	16,4	8,3	6,0	10,9

Other cost assumptions for energy technologies, lifetimes, etc. are based on the cost database developed in conjunction with the EnergyPLAN tool [69]. This database is available for download on www.energyplan.eu and further details can also be found in [48].

The PV capacity implemented in the Danish energy system is highly correlated with development of prices and technology. The price development in Denmark is closely correlated to the international price development as described in Sections 2.7 and 2.8.

The impact of varying amounts of photovoltaics in 2020 and 2050

In the first energy system analyses included, the PV capacity if gradually increased. In this part of the analysis the energy system costs in the Denmark 2020 scenario indicates a clear trend that the total energy system costs increase when increasing the PV capacity as the additional investments exceed the savings in fuel costs. The increase is rather small with low amounts of PV. This cost increase occurs especially for prices representing small PV installations, while the increase for larger PV systems is lower (Figure 12). With large PV installations the costs start to increase after about 2.000 MW depending on the price assumptions.

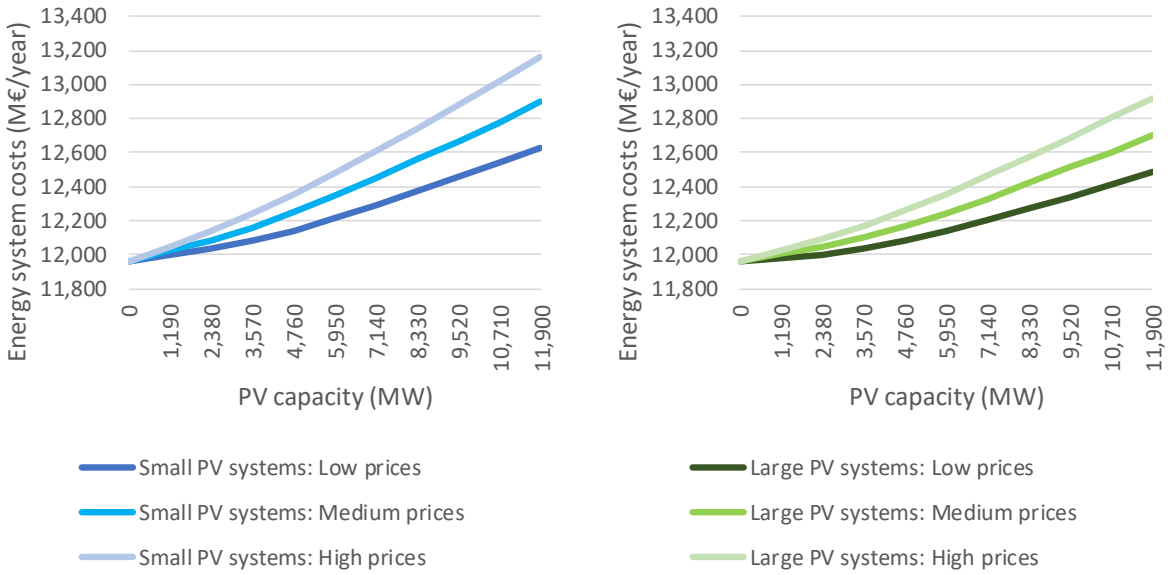


Figure 12: The energy system costs in the Denmark 2020 scenario with various PV capacities for small and large PV systems.

In the IDA 2050 scenario, installing small PV systems still increases the total costs, but at a lower rate. When assuming that all PV installations are large systems with low investment costs, the overall energy system costs may even decrease. For medium PV prices in large installations, the energy system costs decrease when increasing the PV capacity until a point around 5.000-7.000 MW. For large PV installation using high prices, the overall energy system costs increase after installing approximately 3.000-4.000 MW, while for the low PV prices the system costs are reduced in all cases (Figure 13). The reason for the reduction in overall energy system costs is that PV replaces other types of electricity production with higher costs. However, the PV capacities cannot continue to grow as the energy system also requires dispatchable production from e.g. power plants and CHP plants in the periods with no sun. Hence, the increasing PV production also leads to growing electricity export which adds less value to the energy system than the PV production that can be integrated in the energy system. This means that in the IDA 2050 scenario the PV price has to be 0,5-0,7 M€/MW or less to decrease energy system costs, according to the results and assumptions in these analyses (40-year lifetime, 1% O&M, etc.).

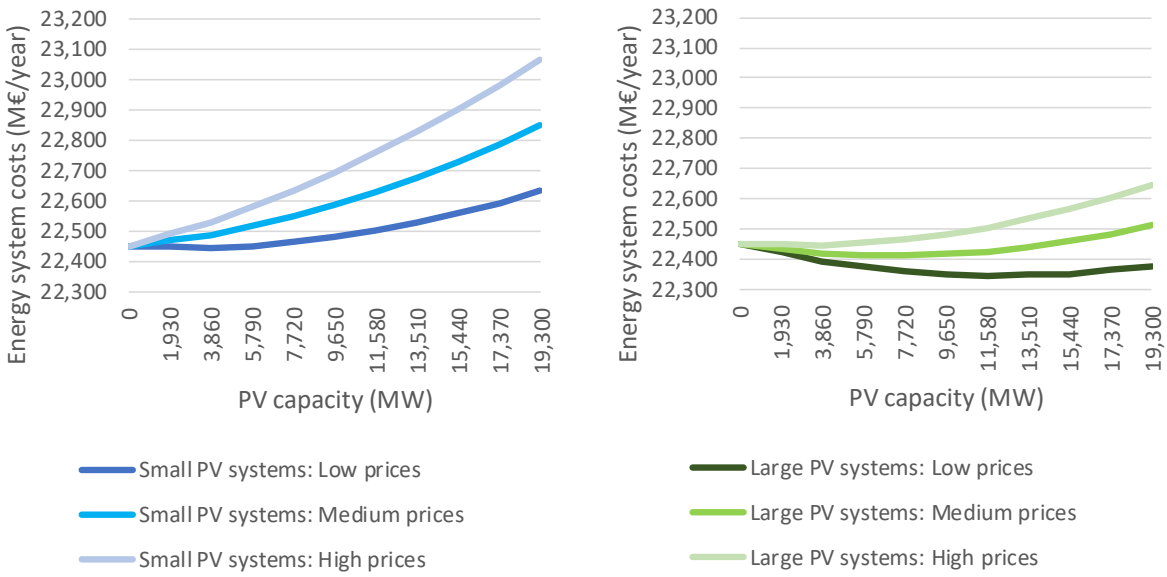


Figure 13: The energy system costs in the IDA 2050 scenario with various PV capacities and for small and large PV systems.

The analyses show the significance of the PV prices on the overall system costs in both the Denmark 2020 and the IDA 2050 scenarios. However, in the 2050 IDA scenario the PV prices are lower than the current prices and leads to overall energy system cost reductions when assuming that all PV installations are large systems. If large systems with medium PV prices are installed the PV capacity might be up to around 4.000-7.000 MW with similar overall system costs as installing no PV capacity.

Increasing the PV capacity also impacts the energy system fuel consumption, which is illustrated in Figure 14 and Figure 15. The impacts are however limited in terms of the entire energy system as PV only directly influences the electricity sector, which is a smaller part of the entire energy system. Hence, the PV production increases by up to 12 TWh, but only reduces the coal and biomass consumption with a total of up to 7 TWh. The Denmark 2020 energy system is not able to accommodate these high PV capacities and therefore a large share of the PV production is exported, see also Figure 16. The fuels that are saved elsewhere due to the electricity export depends on what is assumed to be replaced in the neighbouring countries. The fuel savings are largest until reaching a capacity of approximately 2.000-2.500 MW, which equals approximately 7% of the electricity demand.

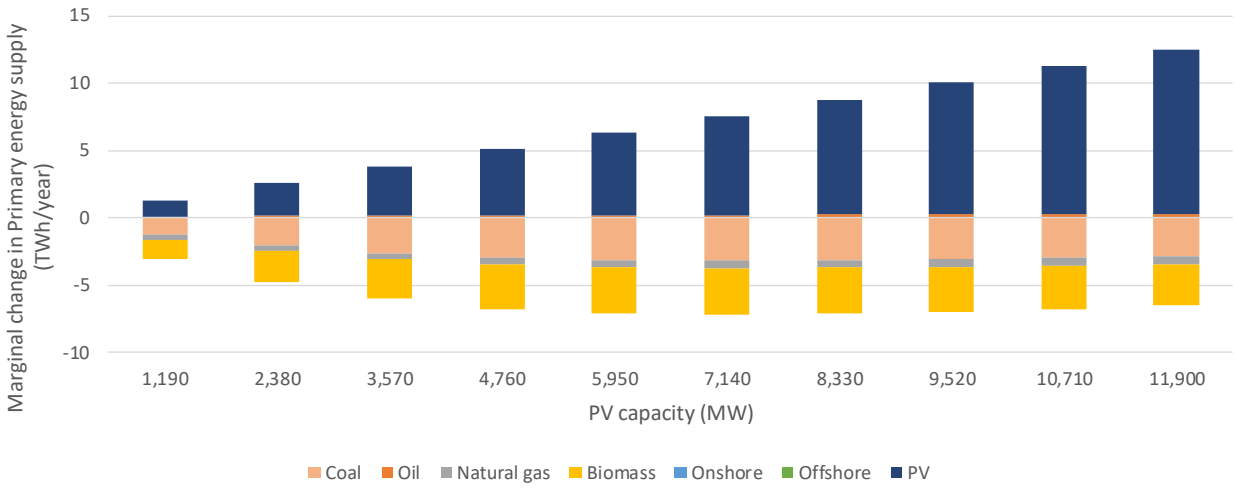


Figure 14: The marginal change in primary energy supply compared to installing no PV in the Denmark 2020 scenario.

A similar trend is clear in the IDA 2050 scenario where the PV production increases by up to 24 TWh while reducing the biomass consumption by up to 12,5 TWh. In this scenario biomass is used for electricity production through biomass gasification and is the only type of fuel replaced by the increasing PV capacity. The first capacity of PV gains much larger fuel savings than the last installed capacity due to the energy system's ability to integrate the PV production and the effect on electricity export.

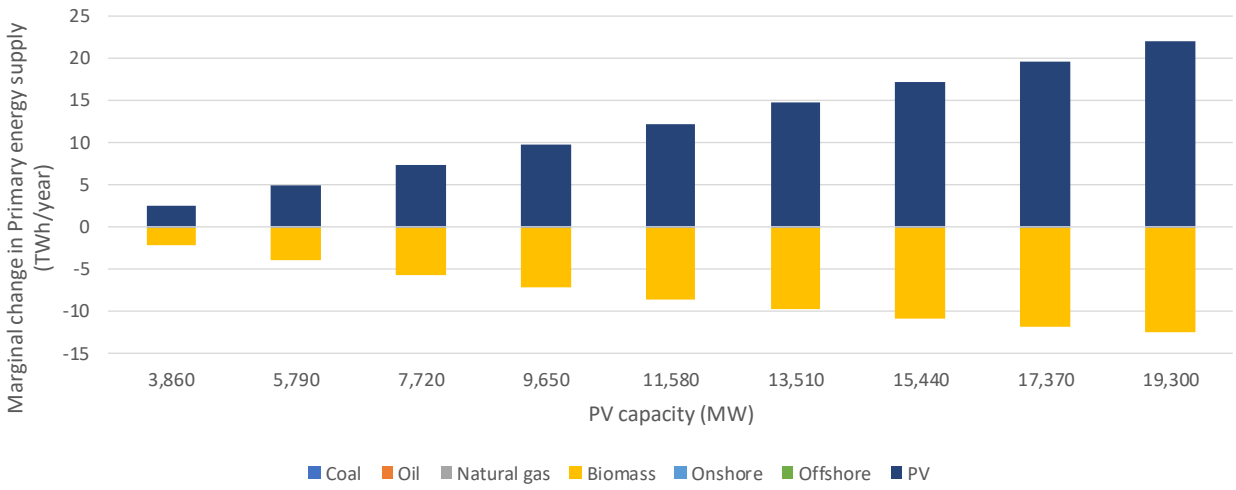


Figure 15: The marginal change in primary energy supply compared to installing no PV in the IDA 2050 scenario.

In both the Denmark 2020 and IDA 2050 scenarios the overall primary energy supply grows when increasing the PV capacity, however the fossil fuel consumption decreases in Denmark 2020 and similarly, the biomass consumption decreases in the IDA 2050. The introduction of more PV in the energy systems therefore only has a limited impact on the overall primary energy supply, i.e. the fuel reduction with the highest PV capacity in the IDA 2050 is approximately 12,5 TWh of biomass compared to a total primary energy supply of more than 160 TWh.

The increasing PV production has a large impact on the electricity exchange as the energy system is not able to utilize all the PV. In the Denmark 2020 scenario the electricity export increases from less than 2 TWh with no PV capacity installed to around 11 TWh with the full PV capacity installed (12,5 TWh PV production), equal to almost 1/3 of the electricity demand.

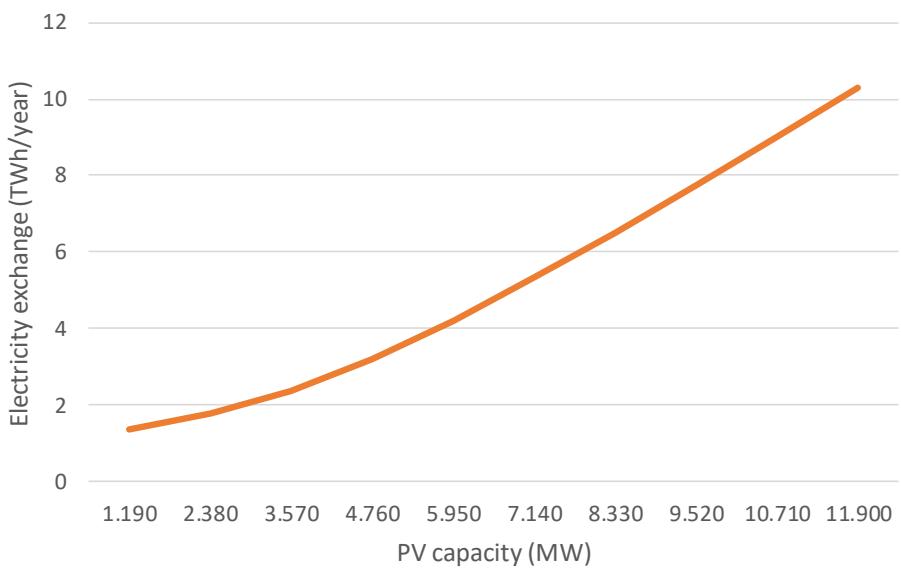


Figure 16: The electricity exchange for various PV capacities in the Denmark 2020 scenario.

In the IDA 2050 scenario a similar trend is evident as the electricity export increases when the PV capacity increases. However, this energy system is more flexible due to more focus on sector integration and storage options and is therefore able to integrate a higher share of the PV production. With the highest PV capacity (PV production of 24,5 TWh), approximately 14 TWh of electricity is exported, equal to approximately 15% of the electricity demand.

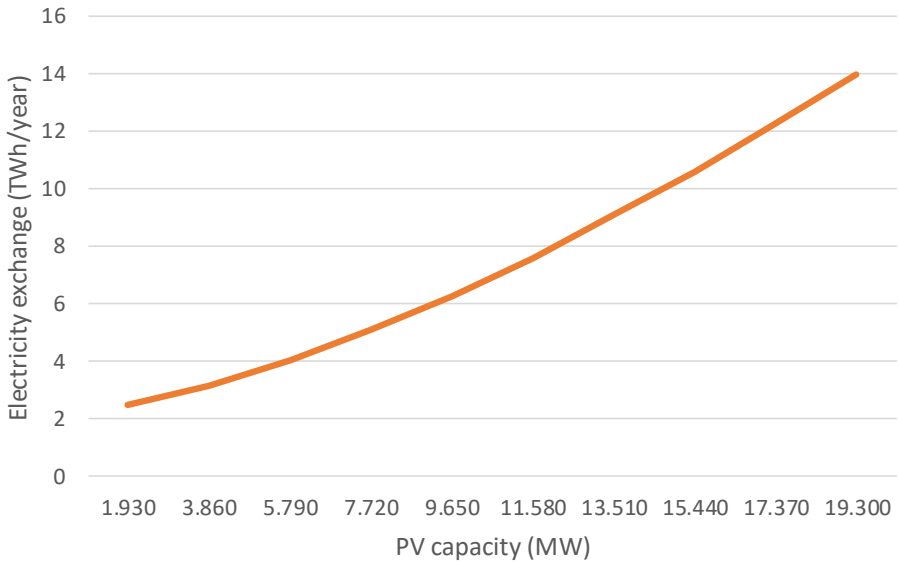


Figure 17: The electricity exchange for various PV capacities in the IDA 2050 scenario.

The analyses of the electricity exchange indicate that it is crucial to focus on the energy system's abilities to integrate the increased renewable electricity production. When increasing the PV capacity, the electricity exchange also increases depending on the system flexibility and opportunities for integrating the PV. This was also visible for the primary energy supply where less fuels were replaced in the cases where no additional PV production could be integrated in the energy system.

The CO_2 emissions are also slightly impacted in the Denmark 2020 scenario as a consequence of the changes in the fuel consumption. The largest decrease in these analyses occurs until 5.000-6.000 MW of PV capacity is installed, while the emissions start increasing again with higher capacities. This is because until 5.000 MW other supply technologies based on fossil fuels can be replaced, while after this capacity the majority is exported. Hence, the energy system can no longer accommodate the integration of further PV. When installing the full potential of almost 12.000 MW, the CO_2 emissions decrease by approximately 500.000 t/year compared to no PV, which corresponds to a reduction of 3,2% of the total energy system emissions. The overall impact on the CO_2 emissions from increasing the PV capacity is therefore limited and other sectors such as the transport sector has more influence on the overall CO_2 emissions.

Installing more PV in the IDA 2050 scenario has no impact on the CO_2 emissions as only renewable sources are replaced.

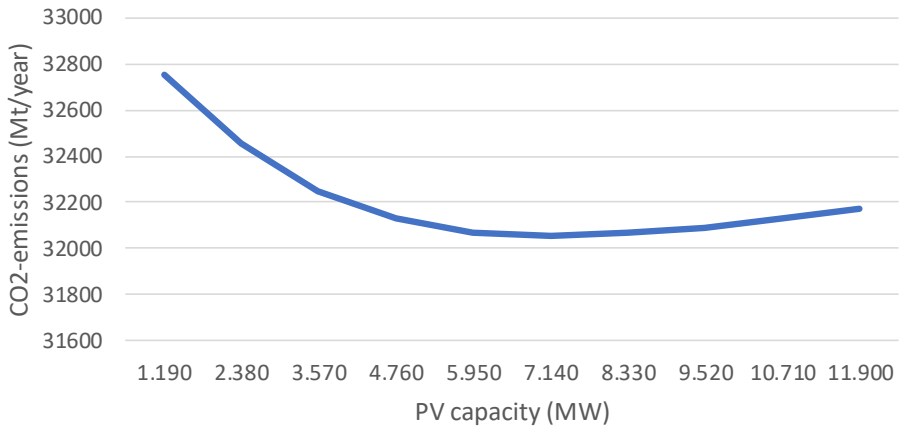


Figure 18: The changes in energy system CO_2-emissions with various PV capacities in the Denmark 2020 scenario.

Sensitivity analyses using different fuel prices in combination with photovoltaic

The impact of fuel prices on the PV feasibility has also been analysed. The fuel prices assumed are outlined in Table 7. The fuel prices have limited impact on the feasibility of PV in the Denmark 2020 scenario as it can be seen in Figure 19. From the figure, it is visible that the fuel prices have higher impact on the overall energy system costs than on the impact of PV feasibility since increasing the PV capacities lead to growing energy system costs for all fuel prices and PV prices. This is related to the previous findings about the limited decrease in fuels in the energy system.

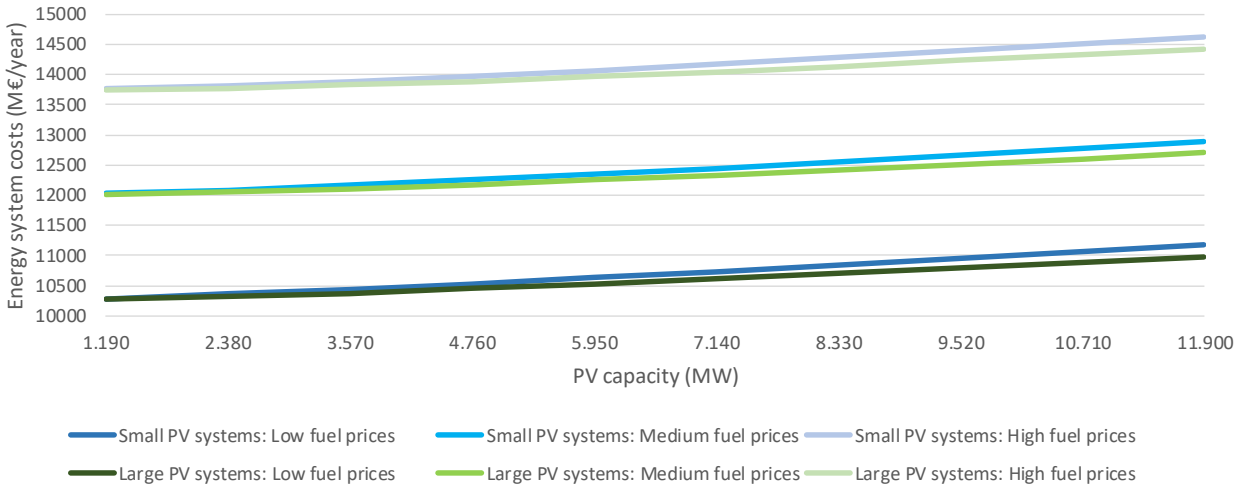


Figure 19: The impact of PV with different fuel prices in the Denmark 2020 scenario.

In the IDA 2050 scenario the fuel prices also show limited impact on the feasibility of PV. The relation between the small and large system costs remain almost constant. However, when assuming large system costs for PV investments and either medium or high fuel prices the overall energy system costs decrease when installing more PV. For the medium fuel costs, the lowest costs are for approximately 7.000 MW PV and for high fuel costs the lowest costs can be found with approximately 8.000 MW PV.

In both the Denmark 2020 and the IDA 2050 scenarios the PV feasibility is only slightly impacted by the fuel prices.

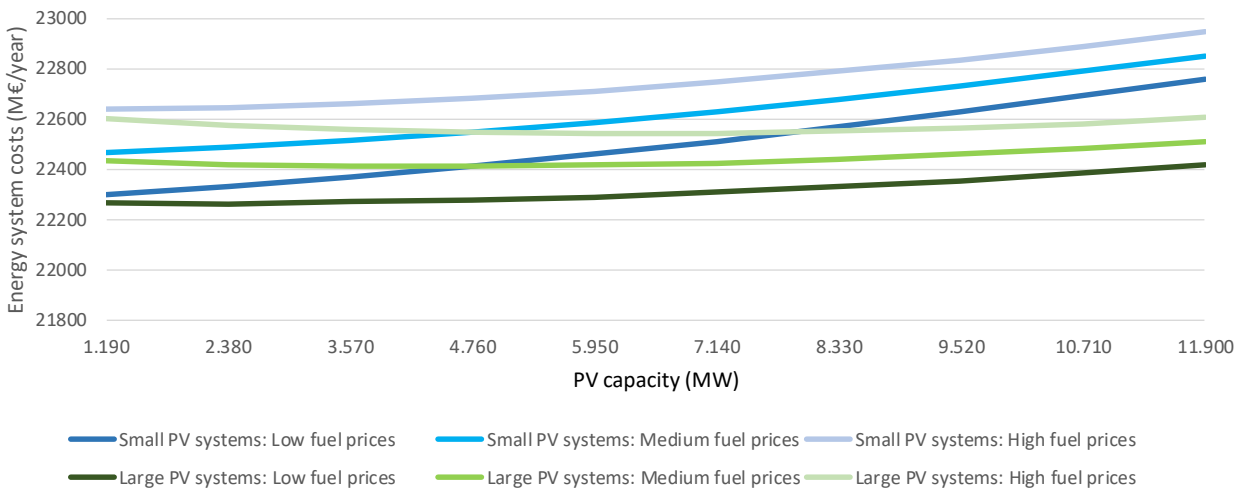


Figure 20: The impact of PV with different fuel prices in the IDA 2050 scenario.

The balance between wind power and photovoltaics

The next type of analyses investigates the balance between installing PV and wind power for both energy system costs and electricity exchange. The combined PV and wind power production in the analyses is constant for the Denmark 2020 the IDA 2050 (the already installed production). The respective production for each technology is listed in Table 8.

Table 8: The PV, onshore and offshore wind power production in the Denmark 2020 and IDA 2050 scenarios.

	Denmark 2020			**IDA 2050**		
	PV	Onshore	Offshore	PV	Onshore	Offshore
Production (TWh/year)	1,44	7,33	11,60	6,35	16,20	63,76
Share of electricity demand (%)	4%	20,3%	32,2%	6,7%	17,2%	67,7%

The energy systems costs increase when reducing the onshore wind power production and increasing the PV production with small system PV costs. When installing larger PV systems and thereby reducing the investment costs, the overall system costs decrease until a point around 2.000 MW PV, which can be defined as the technically optimal potential in 2020/2025. This is despite the higher electricity production prices from PV compared to onshore wind power, but is caused by an improved alignment between electricity demand and production. This means that less electricity has to be exported or wasted and creates greater value to the energy system. In the Denmark 2020 scenario, replicated from the Danish Energy Agency, 1.400 MW PV is installed. Assuming 2020 costs for small PV systems, there seems to be a system benefit, see Figure 21. It is also worth noting that in the Denmark 2020 scenario in general there is still a lot of room for renewables in general.

When replacing offshore wind power with PV production the energy system costs increase regardless of assuming small or large PV system costs. In this case, the benefits of better alignment are less significant than for onshore wind power.

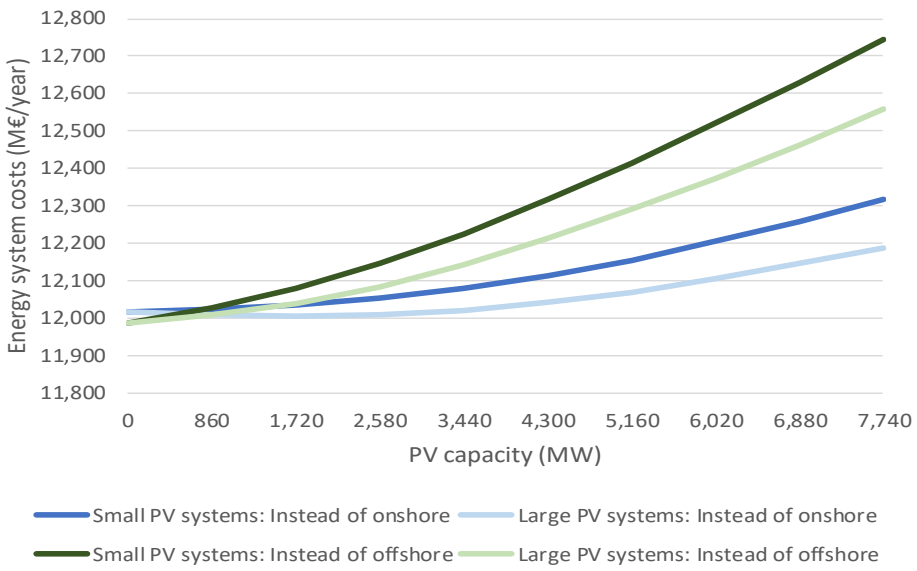


Figure 21: Energy system costs with different balances between PV and wind power in the Denmark 2020 scenario.

In the IDA 2050 scenario the costs are largely unchanged when replacing onshore wind power with PV for both small and large PV systems. For small PV systems the costs however increase slightly when replacing onshore wind power. Again, this is caused by improved alignment between electricity demand and production when the renewable production is spread on more sources.

In the IDA 2050 scenario, 5.000 MW PV capacity is installed with a total energy system cost of 22.639 M€, indicating a mix of small and large PV system costs as can be seen in Figure 22.

Offshore wind power has higher costs than onshore wind power, which is also visible from Figure 22. Here, even small system PV costs lead to a reduction for the first 4.000-5.000 MW PV. When assuming large system costs for PV, the PV capacity can be even higher while reducing the energy system costs when replacing offshore wind power. In this case, the overall system costs reduce until a capacity of 7.000-10.000 MW PV. The recommendable PV share is therefore 10-15% PV production of the electricity demand when considering small-scale PV systems and around 15% with the large-scale PV systems (≈10.000 MW).

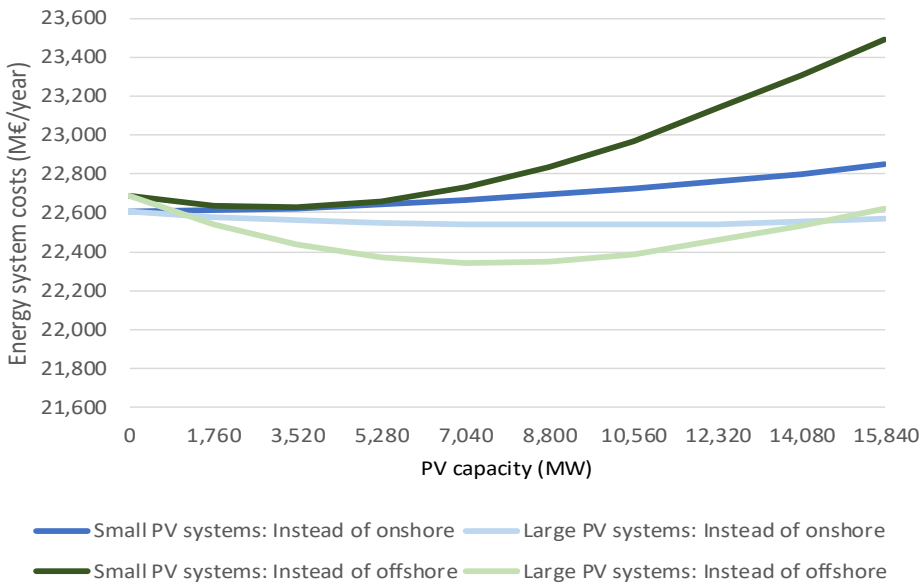


Figure 22: Energy system costs with different balances between PV and onshore wind power in the IDA 2050 scenario.

The influence of electric vehicles and heat pumps

The focus in this analysis is on the impact of PV when changing the share of electric vehicles (EVs) and heat pumps (HPs) in the energy system. This is relevant because these technologies provide flexibility to the energy system and therefore might impact the feasibility of PV. As these technologies are almost non-existing in the Denmark 2020 scenario only findings for the IDA 2050 scenario are included.

Three types of variations are carried out for the IDA 2050 scenario. Firstly, a scenario where the share of electric vehicles is reduced from 75% of all cars and vans to 37,5%. Secondly, a scenario where all electric vehicles are replaced by biofueled technologies, and finally a scenario with no electric vehicles and no heat pumps, both in district heating areas and other areas. The PV capacities analysed here are different from previous analyses, but this has no impact on the overall results.

For all scenarios, the impact of changing the PV capacity is insignificant as the energy system costs only change slightly as can be seen in Figure 23. Regardless of the PV capacity, the energy system costs remain almost constant for the three scenarios.

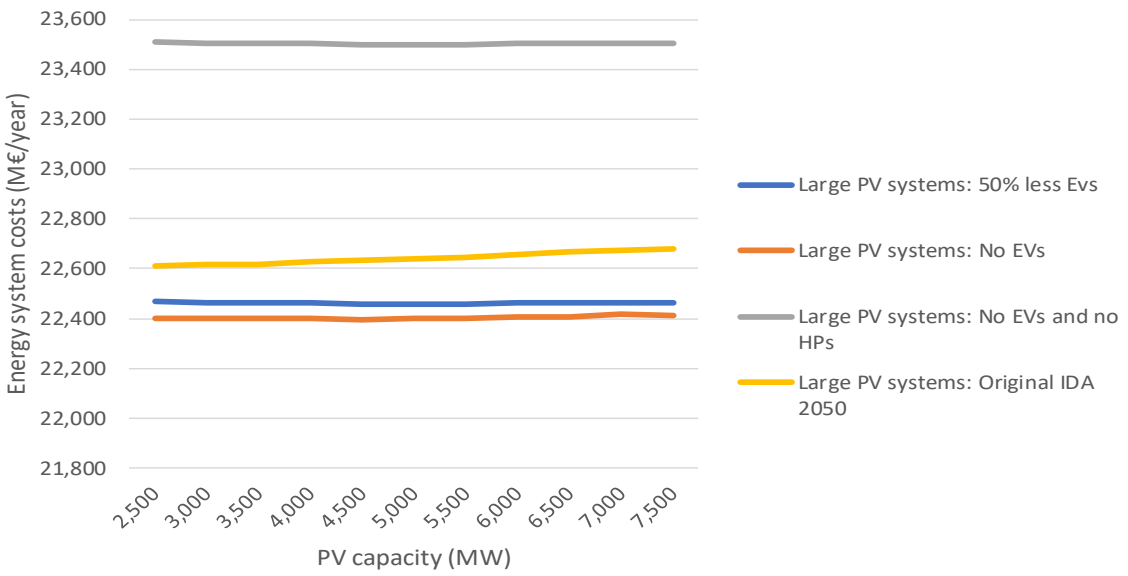


Figure 23: The energy system costs for various PV capacities with 50% less EVs, no EVs, and no heat pumps in the IDA 2050 system.

For electricity exchange the electricity export grows in all scenarios when increasing the PV capacity as it can be seen in Figure 24. For all situations, the electricity export increases by around 50% when the PV capacity is 50% higher. The electricity export grows due to a less flexible energy system when there are no electric vehicles and heat pumps and because the overall electricity demand decreases resulting in less “space” for installing PV in the energy system.

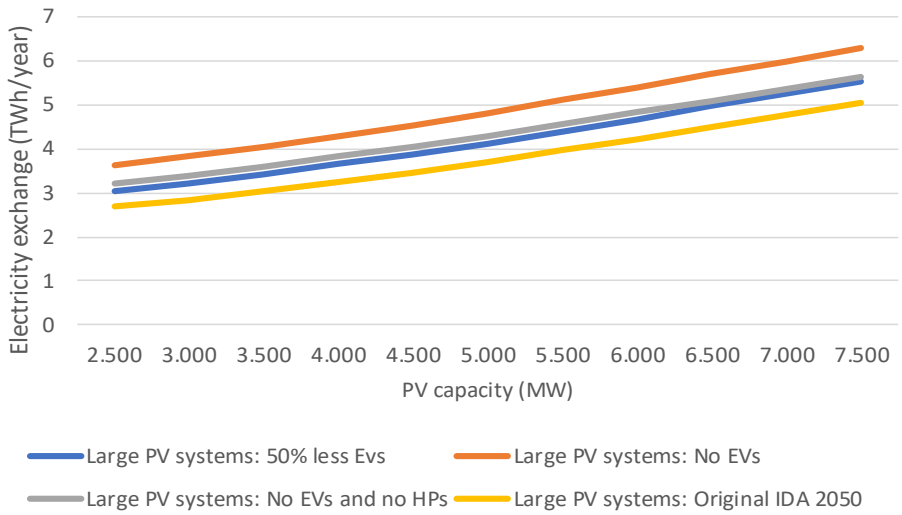


Figure 24: The electricity export in the IDA 2050 scenario when increasing the PV capacity.

Another technical solution that has been analysed in connection with PV is through converting a larger share of the conventional electricity demand into a flexible demand that can be shifted over one day or over one week. Flexible demands in this regard includes measures such as moving electricity demands from peak periods to other periods via smart appliances, industrial production moving to night time, etc. These results indicated no significant impact on the feasibility of PV and hence, the results are not presented here. The findings proved only slight reduction in forced export even when considering 30% of the conventional electricity demand as flexible over one day (25% of demand) or one week (5% of demand). Furthermore, the energy system costs increased due to the additional investments necessary to facilitate a higher share of flexible demands.

The effects of Electricity storage in batteries

Recently, concepts combining electricity storage via batteries and PV systems have emerged. This has also been analysed in this report, both for large battery systems connected to the electricity grid and systems where the batteries are installed in the individual households.

Large grid-connected batteries

For the larger grid battery systems the following specifications have been assumed. The battery capacities are specified in Table 9 and have a similar capacity to the 1-day flexible electricity demand that was investigated.

Table 9: Specifications for large batteries used in the analyses. The investment costs are based on best estimates and are by nature uncertain.

		2020	2050
Battery investment costs	**€/kWh**	300	200
O&M	**% of investment**	1%	
Lifetimes	**years**	20	
Efficiency	**Round-cycle-losses**	90%	
Medium battery	**Capacity (MW)**	1.076	922
	Storage (GWh)	2,15	1,84
Large battery	**Capacity (MW)**	2.690	2.305
	Storage (GWh)	5,38	4,61

The analysis shows that installing batteries increases the energy system costs in the Denmark 2020 scenario for both large and small PV systems as can be seen in Figure 25. This is due to increased investment costs which exceed the savings in fuels.

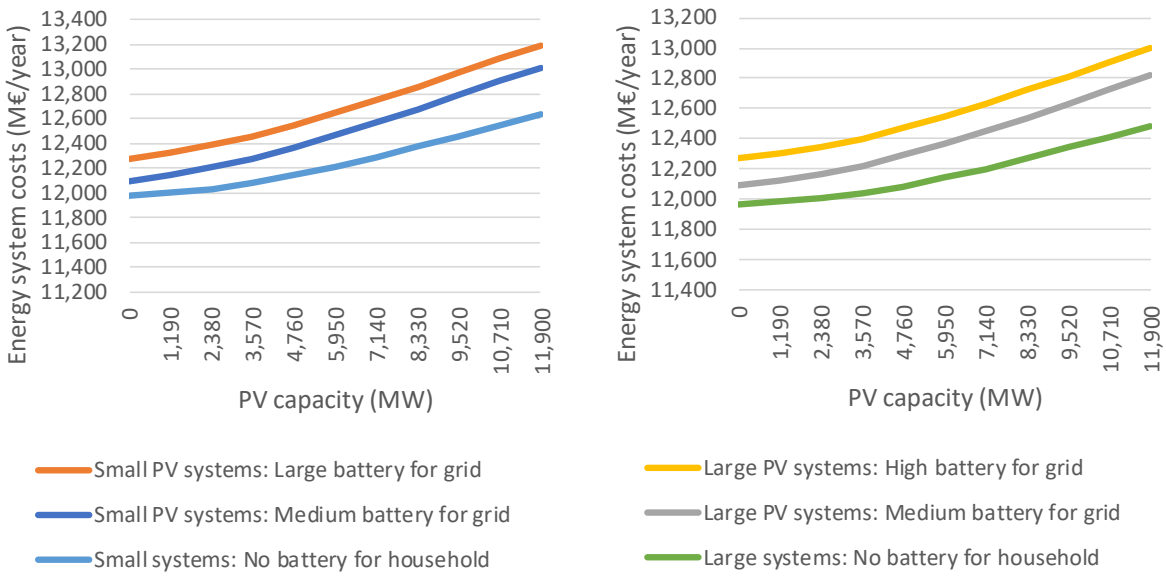


Figure 25: Energy system costs in the Denmark 2020 scenario with large batteries installed for small and large PV systems.

Installing large batteries in the Denmark 2020 scenario will lead to a reduction in the electricity exchange. In Figure 26 it can be seen that the reductions in exported electricity from the first batteries (the medium battery capacity) provides the same benefits as the larger battery capacity. The reduction in export amounts to 0.5-4 TWh depending on the PV capacity installed.

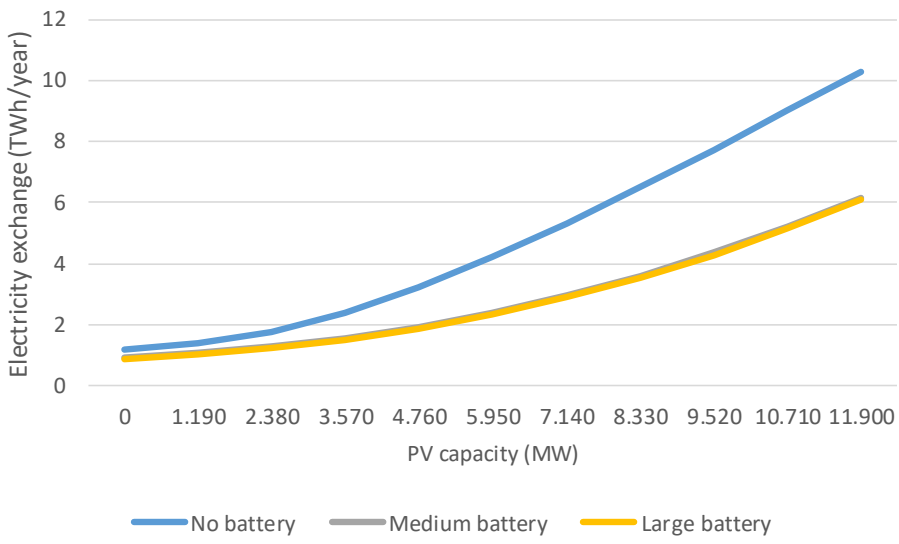


Figure 26: Electricity exchange in the Denmark 2020 scenario with large batteries installed.

The trends are similar in the IDA 2050 scenario as the energy system costs increase when installing batteries. Also in this case, the benefits are almost similar between the medium and high battery capacities.

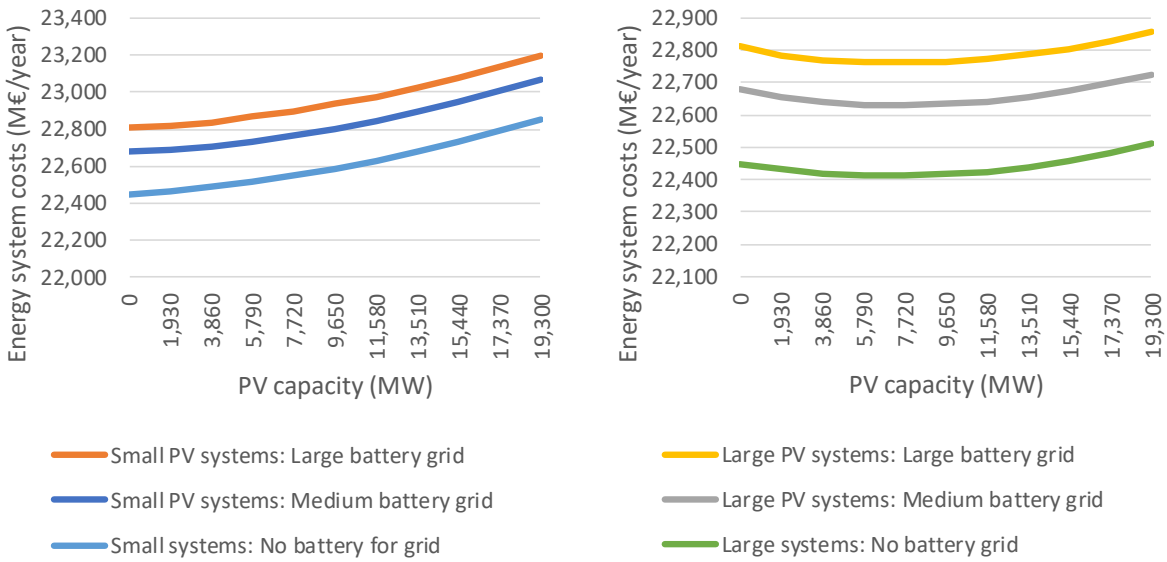


Figure 27: Energy system costs in the IDA 2050 scenario with large batteries installed for small and large PV systems.

For electricity exchange the batteries have almost no impact in the IDA 2050 scenario. In the IDA 2050 energy system numerous other options are available for storing or converting the PV energy. Examples of these technologies are flexible technologies such as electrolysers, heat pumps and electric vehicles.

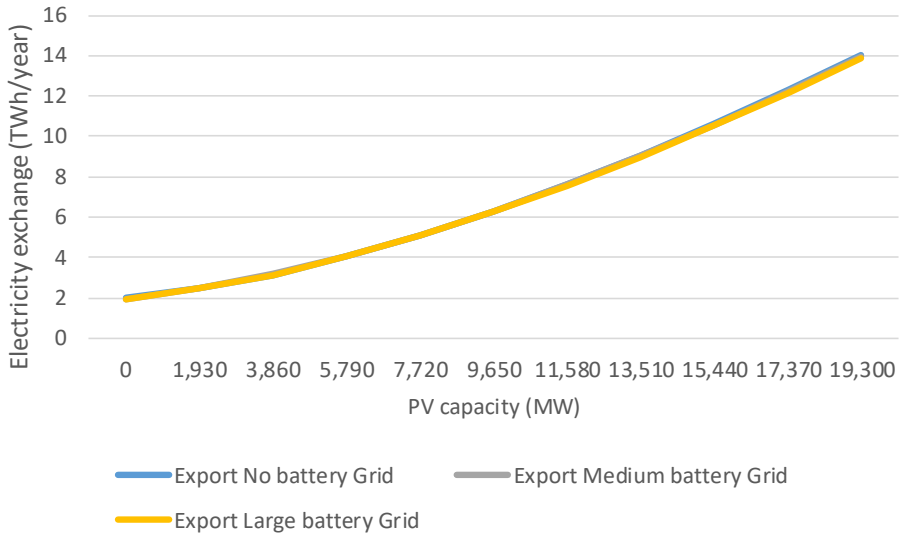


Figure 28: Electricity exchange in the IDA 2050 scenario with large batteries installed.

Small household batteries

A different type of batteries has also been analysed in the form of smaller household batteries such as "powerwalls". In this case, the batteries are assumed to be installed in the individual houses rather than on the electricity grid. This results in changes to the PV production profile to reflect that some of the electricity is stored in the households rather than being transmitted to the electricity grid. In addition, different battery costs have been assumed to reflect the sizes of the batteries.

Table 10: The specifications for the household batteries used in the analysis.

		2020	2050
Battery investment costs	€/kWh	400	300
O&M	% of investment	1%	
Lifetimes	years	20	
Efficiency	Round-cycle-losses	90%	

The changes in the hourly PV production profile are illustrated in Figure 29 for one year, as a result of the batteries. The differences in the figure show that some of the peak production periods are changed and that the profile is flatter throughout the year.

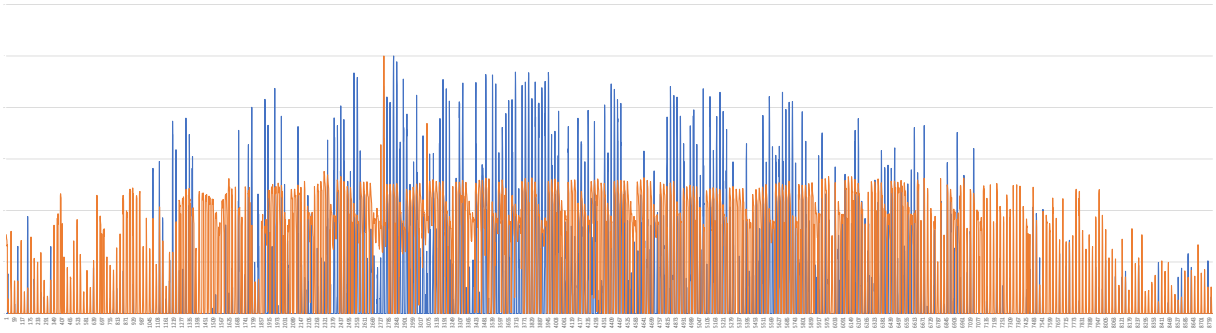


Figure 29: Hourly PV distributions for one year before and after installing household batteries. The orange line indicates with batteries and the blue line indicates with no batteries.

Installing household batteries leads to higher energy system costs for both large and small PV systems in the Denmark 2020 scenario and in the IDA 2050 system. This is caused by the higher investments that exceed the savings in fuels. In theory, the household batteries are designed to store energy from peak production during daytime to periods where the production is lower. However, this also coincides with the peak electricity demand, which occurs during daytime and hence, PV electricity is charged to the batteries in the periods where the electricity demand in the energy system is highest. Because of this, other electricity generating technologies have to supply electricity during the day, thereby increasing the fuel demand. The fuel savings that occur from the discharge of the batteries during evenings and nights is very comparable to the additional fuel consumption that takes place during daytime and the net impact on the fuel consumption is therefore zero when considering lower PV capacities. This impact is evident for both the Denmark 2020 and the IDA 2050 scenarios. When the PV capacities increase towards the higher end of the potentials, the batteries have a minor positive impact on the overall fuel consumption, but is almost negligible.

The impact from household batteries has to be considered in relation to the electricity consumption in individual households. These consumers are responsible for approximately 1/3 of the total electricity consumption and has therefore a limited impact on the overall electricity distribution. Furthermore, PV summer peaks are of a magnitude that are difficult to store and will need to be injected into the electricity grid. Also, during winter periods the consumers relying on PV and battery solutions will in many cases depend on electricity from the grid in the periods where the sun is not providing sufficient energy to meet the demands.

The impact of installing household batteries is negligible for reducing electricity export and fuel consumption, but will lead to higher energy system costs. If batteries should be part of the future energy system they should therefore be implemented on a grid scale where it is possible to operate these in a manner that benefits the entire energy system rather than only the individual consumer.

4.3 Summary of system integration of PV

Maintaining the grid stability whilst also integrating large amounts of renewable energy should be main focus in a future scenario with higher levels of renewables. Good practice examples can be taken from Germany, which has managed to integrate large capacities of PV without affecting the grid. The production profile of PV fits well with the load profile of the electricity grid, so the electricity production from PV never exceeds the demand, even in the case of expanded PV capacity [12].

This also relates to the fact that Germany only allows inverters with control features to be added to the new PV grid connected systems since 2012. These inverters have the task of stabilising the grid, and the feed-in management can be controlled remotely by the operator or by an automatic reduction of the real power provided by the PV to 70% [12]. Besides the ability of the inverters to supply grid stabilisation services, another technology to be used in the stabilisation task are the synchronous condensers. These are rotating devices that can generate reactive power whenever necessary, stabilise the transmission grid voltage and provide short circuit support. Old decommissioned power plants present the possibility of converting the electricity generators of existing plants in synchronous condensers, and such projects have already been put into practice in countries such as Denmark, Germany and USA [60].

Another helping factor in the correct management of the electricity grid is related to the location of the generating capacity. A distributed capacity reduces the need of expanding the grid and generally does not put additional stress on it [12]. And this relates with the findings of the system analysis performed in this study for Denmark, further presented.

The energy system analysis for Denmark has showed that until 2025, a level of 2.000-2.500 MW PV is recommended if price assumptions are in the region of 1,0-1,2 M€/MW (47-67 €/MWh). This also shows that it is cost-neutral to install 1.500-2.000 MW of PV, equivalent to about 5% of the electricity demand, considering the costs above.

Today, there is 863 MW of PV capacity in all sizes installed with higher costs than the level stated above, with good room for PV in combination with wind power. If PV exceeds the 2.000 MW level, the energy system costs start to increase and the forced electricity export increases. In the Danish case, the CO_2 savings are rather limited, as a mix of mainly coal and biomass is replaced in 2020 and wind power is already more than 50% of the electricity supply. The fuel consumption decreases as long as the PV replaces condensing power plants and CHP plants using biomass and coal. This occurs until about 4.000-4.500 MW or about 15% of the total electricity demand in the 2020 energy system.

The first PVs installed have a higher value into the system than the subsequent ones, as they can replace more fossil fuel electricity, since the system has the capability to absorb it. On the other hand, the PV costs are still decreasing significantly, indicating that the later installations might have lower investment prices.

In a system based on 100% renewable energy the situation is different. In the year 2050, when the costs of PV are expected to be substantially lower, the recommended capacity using the costs of small-scale PV systems is in the range of 5.000 MW (0,64 M€/MW or 41 €/MWh) and in the range of 10.000 MW using the costs of large-scale PV (0,52 M€/MW or 23 €/MWh).

In 2050, PV is analysed into a Smart Energy System with significantly higher electricity demands compared to today. This means that the level of fuel replaced decreases rapidly after 5.000 MW, as the system is more efficient, flexible, and capable of using energy storages and has a rather large amount of onshore and offshore wind power. Even with 10.000 MW of PV capacity, fuels are still being replaced, but the disadvantage is that the forced export is rather high.

When considering the economy of the energy system, 10-15% of the fluctuating energy should be from PV, while the remainder is from onshore and offshore wind power. If the PV plants are small-scale, a 10%

penetration is recommendable while this share increases to 15% with large-scale PV systems. This is an important result, as small-scale PV systems also have the advantage of providing the benefit of distributed production and reduced grid investments and stability [12].

In the 2050 scenario, the PV price has to be 0,5-0,7 M€/MW or less, to decrease energy system costs, according to the results and assumptions in the present analyses (40 year lifetime, 1% O&M, etc.). The results for the recommended level of capacities are robust in relation to fuel prices within the ranges of PV analysed in this report. This is due to the system flexibility and to the fact that PV has the benefit of being able to replace condensing power plants also in combination with large amounts of wind power.

When replacing onshore wind power in the 2020 scenario, PV results in lower costs with 2.000 MW of capacity, assuming 2020 large-scale PV costs. For small-scale PV, the costs are neutral when replacing onshore wind power until about 1.000 MW. This is due to a better correlation between demands for electricity and PV production compared to wind power on its own in 2020. For 2050, when large-scale PV replaces onshore wind, the costs are at the same level, whereas for small-scale PV the costs are lower to neutral until around 4.000-5.000 MW.

The benefits of a diversified energy system were demonstrated in the energy system analysis of this report and also in other studies. These studies have shown that a feasible level of PV in the energy system is 20-40% PV compared to 60-80% wind power. Compared to previous studies [55], [56], the entire system is included here as opposed to only looking at the electricity sector in isolation. The recommended level for PV in this study and in the IDA Energy Vision 2050 [11] should be 10-15% compared to wind power with 85%-90%. This should be seen in the light of an electricity demand which is 2-3 times higher than today, and accordingly the PV production is substantial in 2050.

In 2020, the introduction of flexible demand can reduce electricity export, however this does not affect the level of PV recommended here. In 2050, additional flexible demand in the conventional electricity demand does not have a significant impact, as the system is already flexible with the additional demands in electric vehicles, heat pumps, electrolysers, etc.

Similar results are present with a grid scale or household battery indicating that this will not affect the overall recommendable level of PV installations. In fact, the overall costs increase when installing batteries while only slightly reducing the forced export in the 2020 system and has almost no impact on the 2050 system export.

The results of the analyses of PV are system dependent. Overall, the analyses show that replacing fossil fuels in other sectors such as heating and transport and increasing the demand for flexible technologies has value and can increase the feasibility of fluctuating renewable energy in general.

5 GIS analyses of photovoltaics in Denmark and Danish municipalities

The energy system analysis in Subsection 4.2.2 recommends that a PV capacity of 5.000 MW should be installed in the Danish energy system by 2050 in the form of small sized PV systems, or up to 10.000 MW if large-scale PV are chosen. Since this analysis was system dependent, it is also necessary to analyse this capacity deployment from the perspective of the availability of space, either on the rooftop of buildings or on the ground.

Therefore, this chapter puts in balance the issue of land use, by shortly analysing the availability of land for the deployment of ground mounted PV. Then, it describes the Geographical Information Systems (GIS) analysis for determining the possibility of deployment for PV systems on the rooftop of buildings in Denmark. The results of the GIS analysis are presented in this chapter, where an emphasis is put on identifying larger roofs and on the ownership of the buildings, divided by municipalities. A large number of maps and tables with data on the photovoltaic potentials is included in the Appendices Report, in Appendices 1 and 2.

5.1 Land use, PV and renewable energy

More attention is put lately on the issue of land-use for energy related purposes. For example, a report issued in 2017 [70] makes a connection between the increased land use for bioenergy and the impact it has on food prices. The report is based on a literature review of the interaction between biofuel demand and food prices. The consensus in the literature and among researchers is that biofuel demand and biofuel policy results in increased food prices [70].

Ground-mounted PV systems are also known to occupy rather vast areas of land. The largest solar park in use today is situated in China, has a capacity of 1.500 MWp and occupies 43 km^2. Another one, in India, has a capacity of 900 MWp and occupies and area of 24 km^2 [71]. Both of these parks are located in areas with relatively high irradiation factors compared to Northern Europe for example.

The capacity factor for PV plants in Denmark is on average 11%, and is projected to increase to 16% by 2050, as estimated in the IDA Energy Vision 2050 [48]. In this case, if the estimated capacity for large-scale PV plants, of 10.000 MW, found in Section 4.2.2, would have to be laid on the ground, then this would occupy an area between 110 and 120 km^2 depending on the efficiency of the PV systems. This is the equivalent land area for 15.500 to almost 17.000 football fields or half of Greater Copenhagen.

If the same capacity would be installed as onshore wind, the needed land area would be in between 20-22 km^2. And this can be achieved with the possibility of using the farmland between the wind turbines at the same time. While some land may be infertile and more useful as fields for PV, the area needed to go towards 10.000 MW of ground-mounted PV is rather high and cannot be recommended as the only solution.

The growing PV capacities and the attractiveness of the low price for large-scale PV plants could mislead the stakeholders to direct the investments towards this type of plants. However, studies have shown that if unsustainable amounts of land are used for energy production, there is a danger that this will likely affect the production and cost of food [70]. The needed land area to produce biomass is very high, since the fuel has a low energy content. It is estimated that for producing 1 TWh of energy from biomass, approximately 500 km^2 of land area would be needed. Biomass is a key fuel in the transition towards a 100% renewable energy system and since the competition for land is likely to be high, a strategic approach should be considered. Therefore, where possible, the increase in capacity for PV should be done on the remained available area - on the rooftop of buildings in Denmark - preferably taking into account the potential to use large surfaces. The potential of this approach is analysed in the following chapters.

5.2 Existing estimates of the PV potential in Denmark

Even though it has not been investigated thoroughly, the Danish Energy Agency assessed the theoretical potential for PV in Denmark to be approximately 16–17 TWh, assuming that 25% of the total rooftop area is utilized [72].

Möller and Nielsen (2012) [10] analysed the potential for the municipality of Aalborg and Greater Copenhagen region using the Solar Atlas. This study concludes that the theoretical PV potential is around 4,5 TWh in Aalborg municipality and 8,6 TWh in Greater Copenhagen. Of this potential, the greatest share consists of medium-sized PV installations, corresponding to PV installations on single or multifamily houses. This analysis is used as basis for comparison in this report, in order to validate the results from this chapter.

5.3 Set-up of a GIS-based solar atlas for roof-mounted PV

The estimation of the potential for PV is based on the Solar atlas [10], which was developed at Aalborg University. The atlas is based on an elevation model, where all of Denmark is divided into squares with a resolution of 1,6 m x 1,6 m (Figure 30). The elevation model is developed by The Danish Cadastral and Mapping Agency and includes both elevations of the ground and objects such as buildings and trees [10].

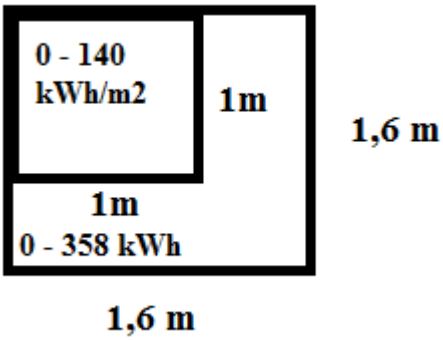


Figure 30: The 1,6 x 1,6 m square used in the GIS analysis

By using GIS, it is possible to estimate the maximum value for the potential PV production for all roofs in Denmark. First, the solar radiation is calculated for each square that is within a roof, taking into account the geographical location, inclination and orientation of each individual roofs, as well as shadowing from other objects, such as buildings, etc. Due to the high resolution of the elevation model, it is possible to calculate the solar irradiation for individual parts of the roof, so that the effect of e.g. shadowing is better reflected in the potentials. It has to be noted that shadowing from other buildings is considered, but to reduce the calculation time, shadowing from other objects such as trees is not taken into account in the calculations [10].

In order to calculate the potential PV production, the efficiency of a typical PV installation has to be taken into account. This was found to be 11% when the solar atlas originally was made, but the efficiency is expected to increase significantly in the next few years, to approximately 16% [11]. The methodology behind the solar atlas is documented in more detail in [10].

The potential PV production per year varies from 0 to 140 kWh/m^2/year, as illustrated in Figure 31. This potential is calculated for each square, but as these do not have an area of 1 m^2, but are 1,6 x 1,6 m^2 or 2,56 m^2, the calculated potential has to be multiplied with 2,56 in order to obtain the actual PV potential for each square. Thus, the potential per square varies between 0 and 358 kWh per year.

Figure 31: The PV potential calculated for a cell size of 1,6 x 1,6 m. Resolution 1:5000

The energy system analysis in Section 4.2 shows that it is not necessary to use all available potential. In order to take this into account solely the squares with the highest potentials, the squares with a potential inferior to 90 kWh/m^2/year were not used in the calculations, reducing the total potential by approximately 15%.

Further, the potential is summed at each individual building, which also sorts out another 10% of the total potential. When the potentials are summed, it is only the squares that lie within the building's roof area that are included. When this is not the case for all squares, it is due to inconsistency between the datasets that contain the buildings polygons and the solar atlas. Besides, some of the squares only lie partly within a roof, which reduces the potential further, as only the squares where the centre is located within the roof, are allocated to the buildings. These factors reduce the total potentials and are deducted before calculating the total potentials per building.

Furthermore, it is important to note that the building area data from GIS represents the total built area of the buildings on the ground, which can be different from the total area of their roofs. In addition, GIS cannot identify areas not suitable for PV installations, either due to the existence of other elements on the roofs (e.g. windows, air conditioning, chimneys… etc.), or due to the fact that some buildings might not be able to hold PV modules. In this way, this will lead to further reductions of the total potential PV production and should also be taken into account.

As illustrated in Figure 32, there is a clear correlation between the size of the buildings and the potential, as the potential is summed per building.

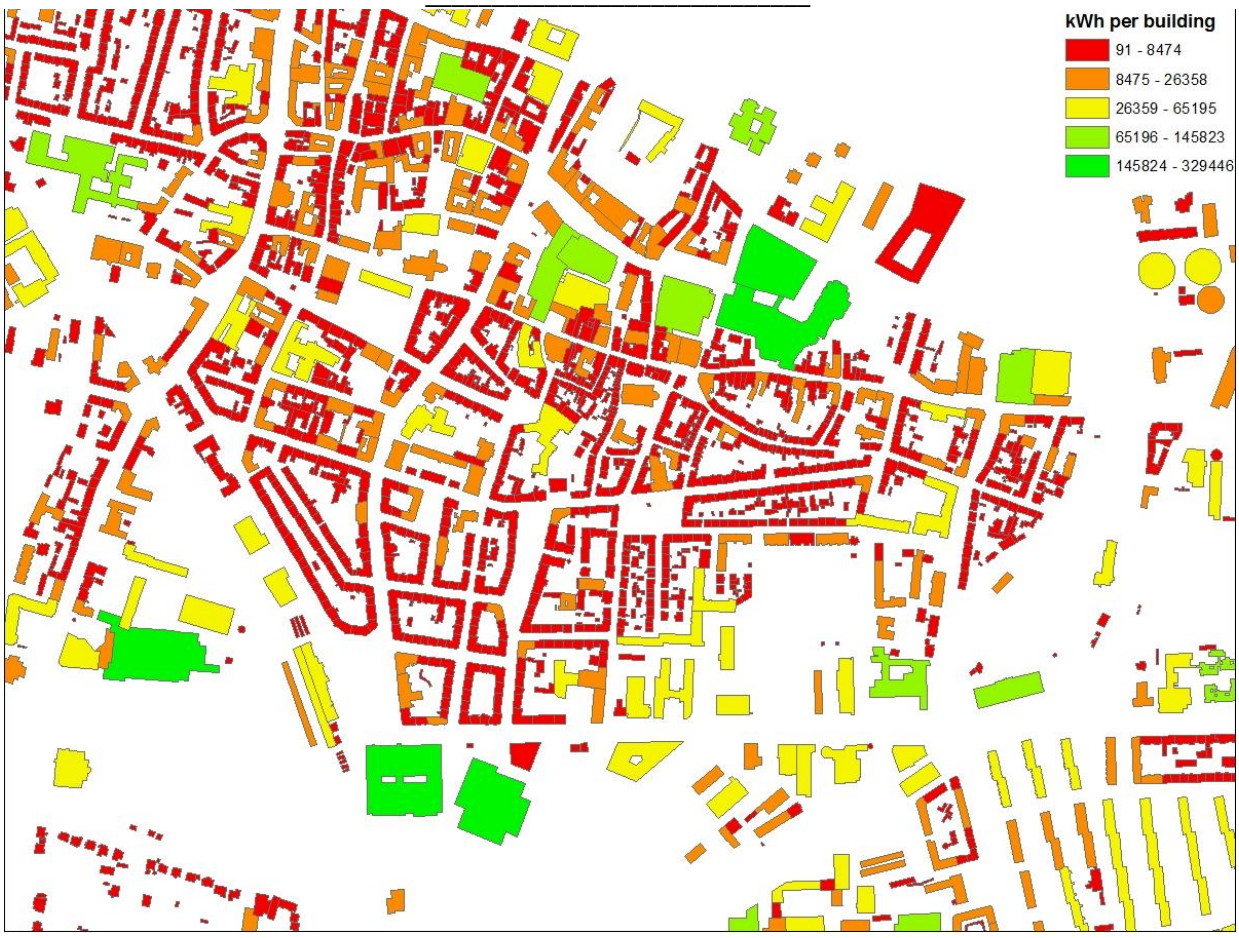


Figure 32: The potential for PV, summed for buildings polygons. The map shows a section of the city of Aalborg in 1:5000

5.4 Regional potentials for PV

The total potential for roof mounted PV for each region of Denmark is illustrated in Table 11, assuming that 100% of the suitable roof area is utilised.

Table 11: Total technical potential for roof mounted PV in each Region in Denmark.

TWh/year	Region Nord	Region Midt	Region Syd	Region Sjælland	Region Hovedstaden	Denmark (total)
Total Potential	7,16	12,68	12,33	8,70	8,17	**49,04**

As shown in the table above, the total theoretical potential for PV is found to be around 49 TWh/year, which corresponds to a total installed capacity of approximately 39 GWp. This is based on the assumption that the PV installations will have 1.272 full load hours annually (which is also the assumption in IDA´s Energivision 2050). In comparison, the total electricity consumption in Denmark was 33,6 TWh in 2015 [73].

Regional differences in the potential can be identified, where the largest potential is found in Region Midt, with a capacity of 12,68 TWh. In the other end of the scale is Region Nord, with a potential of 7,16 TWh.

The similar analysis done in 2012 for Aalborg municipality and Greater Copenhagen identifies a potential of approximately 4,5 TWh/year in Aalborg Municipality and 8,6 TWh/year in Greater Copenhagen. This report finds a potential of 1,6 TWh in Aalborg municipality and 8,17 TWh/year in “Region Hovedstaden”, which is used for comparison as it is unclear which municipalities are included in “Greater Copenhagen” in the above stated analysis.

There are relatively large differences between the results from the two studies, where [10] identifies a significantly higher potential than this report. These differences could be a consequence of the assumptions about which buildings should be excluded, where the analyses from 2012 exclude all areas with a solar radiation of less than 600 kWh/m^2/year. The solar radiation is on average around 1.000 kWh/m^2/year in Denmark, and normally does not deviate by more than 10% [74]. This choice might cause very few buildings to be sorted out, which naturally leads to a higher potential in [10]. As described above, the potential is significantly larger in [10], which indicates that the identified potentials in this chapter are conservative compared to some other reports.

Comparing the results from this report to the estimate made by the Danish Energy Agency, the present analysis identifies a similar potential if the share of roof area is taken into consideration. The Danish Energy Agency finds a total potential between 16 and 17 TWh in Denmark, under the assumption that 25% of the roof area is used for PV [72]. This fits well with this project as we find a total potential of 49,4 TWh/year with a utilization of around 60% of the roof areas. As described above, there can be several reasons for deviations, and furthermore it has to be kept in mind that a relatively large share of the potential is sorted out due to data limitations and the assumption that it is only profitable to utilize the share of squares with potential higher than 90 kWh/m^2/year.

In the above, the regional potentials are examined. However, in order to identify more local differences, the potential for each municipality in Denmark is examined in the following section.

5.5 Potential for the municipalities in Denmark

From the analyses of the potential for roof mounted PV in Denmark it is found that the greatest potentials are centred on the larger cities, which is clearly connected to the building density being higher in the proximity of these areas, as illustrated in Figure 33.

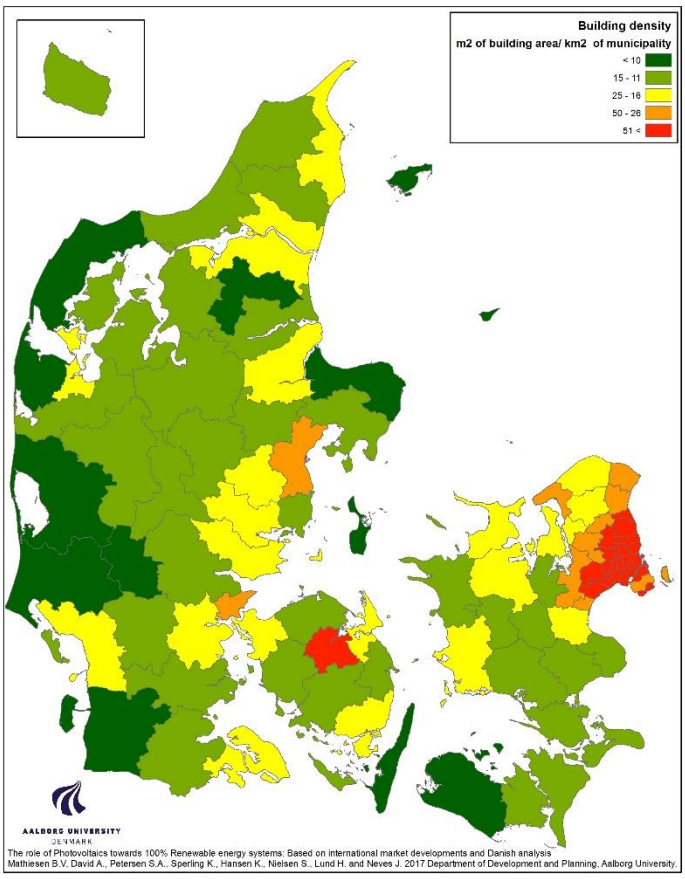


Figure 33: The building density for each municipality in Denmark (m2 of building area/ km^2 of municipality). Shown in 1:2.500.000 and available in Appendix 2.1, in the Appendices Report

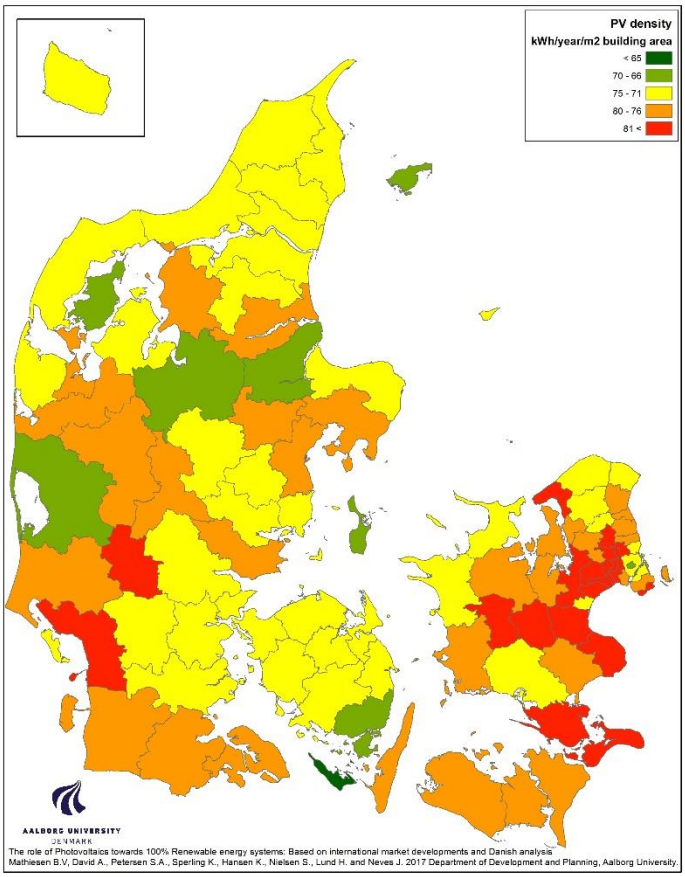


Figure 34: Potential PV production calculated per km². Shown in 1:2.500.000, and available in Appendix 2.2, in the Appendices Report

When comparing Figure 33 to Figure 34, it is possible to see a correlation between the building density and the potential for PV. Another way to examine this is by plotting the correlation between the PV potential and the number of inhabitants in each municipality, as illustrated in the following figure.

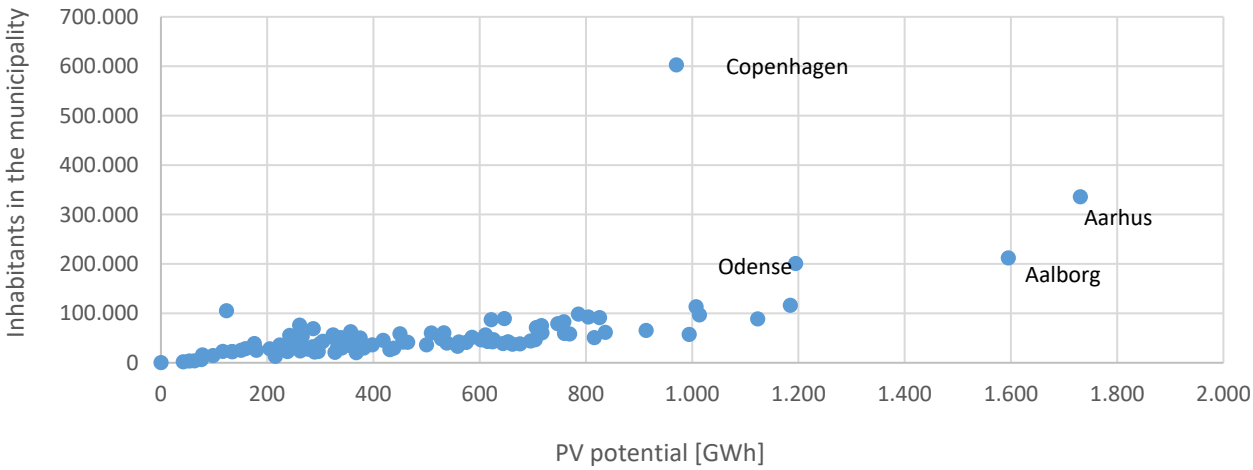


Figure 35: Total potential PV production as a function of the number of inhabitants for each municipality in Denmark.

Looking at Figure 35, there is a clear correlation between the potential for PV and the number of inhabitants in a municipality, except for the largest cities in Denmark, where a larger share of the building stock consists of multi-storey buildings with relatively small roofing areas, compared to the number of inhabitants. In Appendix 2.3, in the Appendices Report, the total PV potential for each municipality can be found.

As described in the above paragraphs, there is a substantial theoretical potential for rooftop PV in Denmark, which by far exceeds even the most optimistic predictions of the capacity to be installed in the Danish energy system. These analyses can become an important tool for Danish municipalities, when forming energy strategies and plans, including mapping the potentials for different renewable energy sources, as an important aspect [75].

The calculated potentials are, however, not necessarily evenly distributed in relation to ownership of the buildings, which becomes relevant as Danish PV regulation depends on the ownership. Therefore, the potential for each region is subdivided in accordance to ownership, in the next paragraph. This is used as an indicator for which type of ownership a potential PV installation can be expected to have.

5.6 Distribution of potential upon building ownership

As described in Chapter 7, there can be significant differences in terms of which regulation and subsidy scheme is applicable depending on the ownership of the PV installation. However, as the actual ownership of a potential PV installation is hard to foresee, it will be assumed that the ownership of the building will reflect the ownership of the PV installation. The identified potential is thus subdivided into the following building ownership categories:

- Private (building code: 10)
- Housing associations, including private housing cooperatives (building code: 20 + 41)
- Businesses (building code: 30 + 40)
- Municipalities (building code: 50 + 60)
- Other public buildings (building code: 70 + 80)
- Other, including buildings containing privately owned apartments and buildings having several ownerships (building code: 90)
- Unknown

Figure 36: The ownership of each building. The map shows a section of the city of Aalborg in 1:5000

These categories are based on the Danish building and dwelling register (BBR), which contains information on the ownership of each building in Denmark. The register contains 10 ownership codes, which are grouped as described above. The buildings are subdivided in accordance to these categories, as shown in Figure 36.

There are some limitations to the available data in the BBR. It has therefore only been possible to identify the ownership for 76% of the buildings. This is either due to missing data for the building ownership in the BBR or that the data is recorded with imprecise coordinates, leading to building information not being projected to the specific buildings. In spite of these uncertainties and data limitations, this analysis can still provide an estimate of how the potential for roof mounted PV is distributed amongst the different ownerships categories. The potential for each ownership is illustrated in Figure 37.

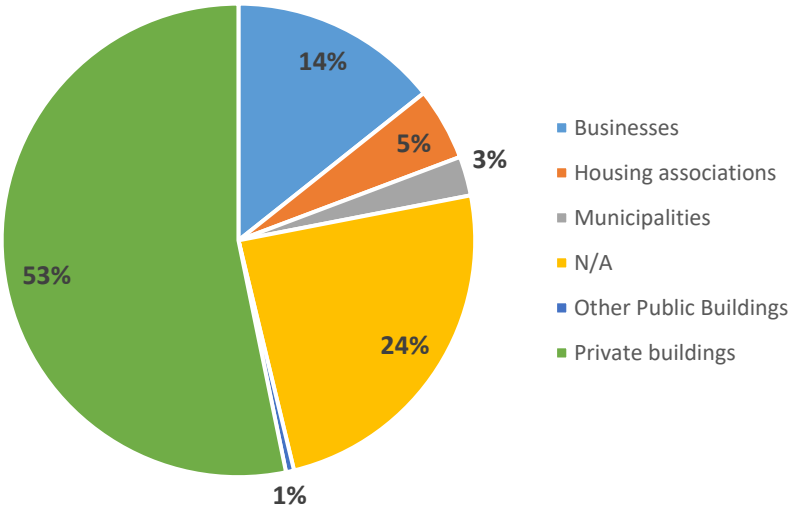


Figure 37: PV potential divided upon building ownership in percentage of the total technical potential.

As illustrated in Figure 37, around half of the potential for roof mounted PV is placed on privately owned buildings, which by far holds the largest potential. Businesses and municipalities hold 14% and 3% respectively, while the other categories hold between 1 and 5% each.

It has to be kept in mind that it has not been possible to identify the building ownership for 24% of the buildings, these are labelled N/A. This is due to incompliances between the coordinates for the dataset containing the BBR-data and the dataset containing the buildings. This induces that the BBR data cannot be merged with the buildings, resulting in missing ownership codes, summed as “unknown”. These missing data represent an uncertainty.

Inside each type of ownership mentioned in the previous figure, there are different types of buildings that can be divided according with their use. In Figure 38, it is possible to see, for each ownership type, which groups of buildings offers the highest share of PV potential and that half of the potential roof mounted PV in private buildings correspond to single family houses. This means that these type of buildings could carry a quarter of the total potential for roof mounted PV in Denmark, however, since single family houses represent only small roof areas, these type of buildings are not the most attractive when planning regulations for large-scale PV installations. In the private ownership, there is also high PV potential share among commercial buildings connected to agriculture and forestry that might hold, in general, large roofs, and which represent 16% of the PV potential in private buildings, or 30% of the total PV potential in Denmark (around 14,7 TWh/year in this type of buildings).

In the case of business owned buildings, 33% of its PV potential could be installed in industrial buildings (2,3 TWh/year) and 31% in trade and storage houses (2,2 TWh/year), both assumed to represent, in general, large roofs.

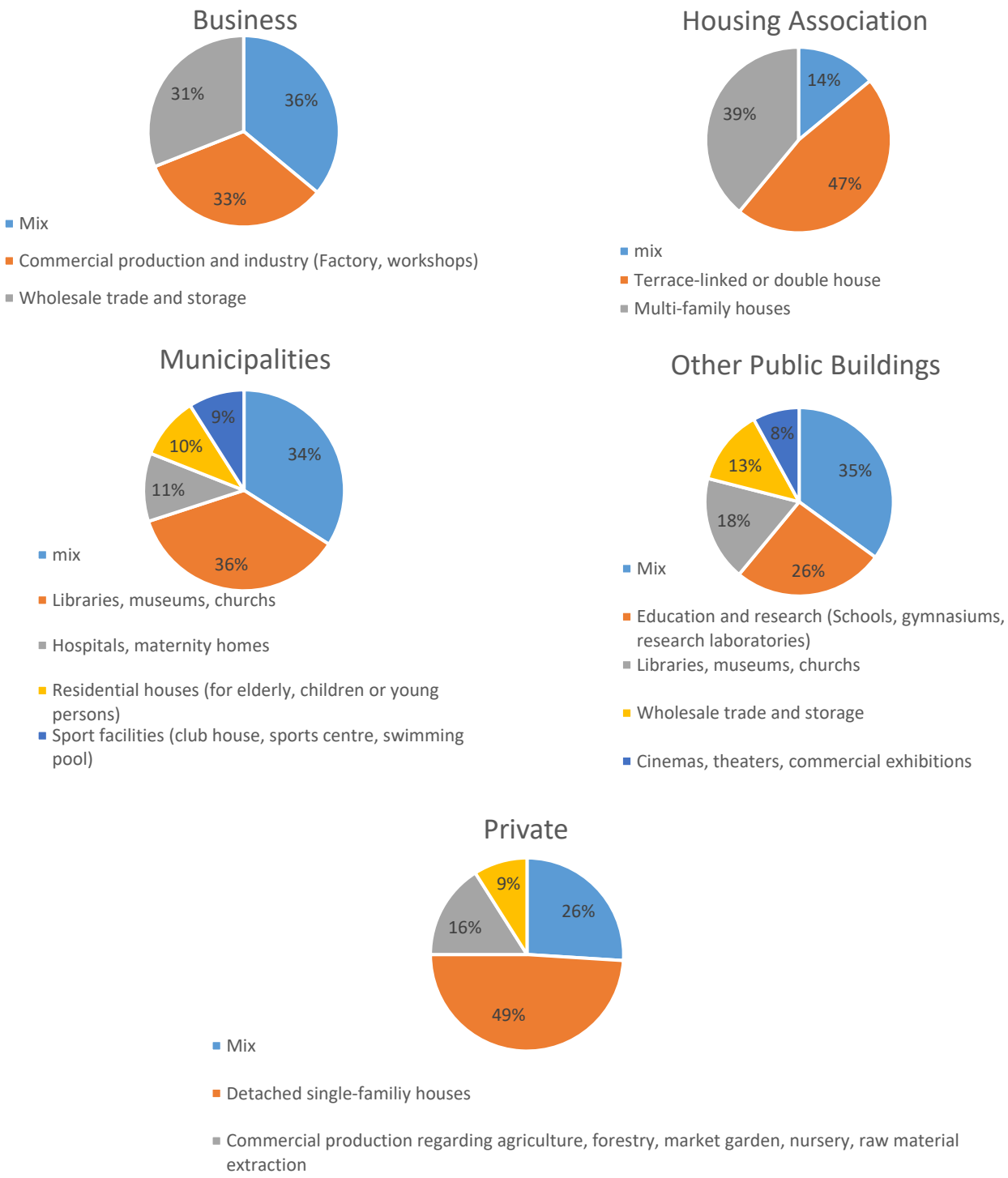


Figure 38: PV potential divided upon the main building groups for each ownership, in percentage of the total technical potential

5.7 PV potentials in Regions and Municipalities

In order to identify eventual regional differences, the potential for each ownership category is extracted for each region. As illustrated in Figure 39, there are regional differences regarding the distribution of the potential. However, the trend is similar on a national scale, where, by far, the largest potential for all regions is on privately owned buildings followed by businesses and housing associations.

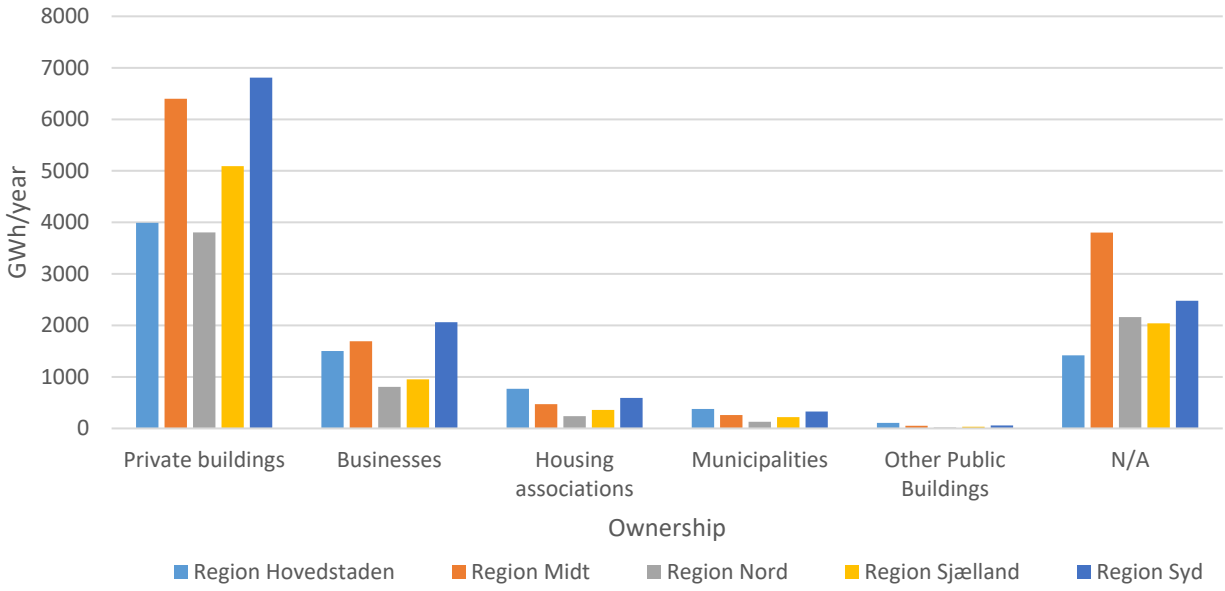


Figure 39: Technical potential for PV divided upon building ownership for each Region of Denmark.

There can though be more pronounced differences, when looking at a municipal scale. Below, in Table 12, the building ownership is presented for the municipalities of Albertslund, Frederiksberg and Lolland, which are expected to be different in relation to building area, density, ownership and PV potential.

Table 12: Comparison of three Danish Municipalities with different characteristics.

	Albertslund	Frederiksberg	Lolland
Building area (m^2)	2.238.105	1.846.648	8.256.448
PV potential (m^2)	1.831.066	1.138.614	5.723.075
PV potential (GWh/year)	205	127	654
Potential (kWh) per m^2 building area	92	69	79

There is a correlation between the built area and the potential PV production. However, as represented in the table above, there can be identified differences on a municipal scale. It becomes clear from the table above, that the production per m^2 varies significantly. Where it is approximately 69 kWh/m^2 in Frederiksberg, it is as high as approximately 92 kWh/m^2 in Albertslund and around 79 kWh/m^2 in Lolland. This indicates that the building types differ and this difference has an influence on the potential at the level of individual municipalities, as the potentials for areas with a high share of single family housing, like Albertslund and Lolland, are expected to be very different from densely build urban areas with a high share of apartment blocks like Frederiksberg.

As shown in Figure 40, the types of building ownership differ significantly, when comparing Frederiksberg with Lolland. The most significant difference is the share of private buildings, which constitute over 82% of the building area in Lolland and only 29% and 18% in Albertslund and Frederiksberg respectively. This is also reflected in the PV potentials, where 81%, 26%, and 17% is related to private buildings in Lolland, Albertslund

and Frederiksberg respectively. However, the category "N/A" represents 24% of the building area in Frederiksberg, and as it includes buildings divided into several privately owned apartments, the share of privately owned buildings is in reality expected to be slightly higher.

Another clear difference between the three municipalities is the share of housing associations and businesses, which is significantly lower in Lolland. However, Albertslund has a much higher share of businesses than Frederiksberg.

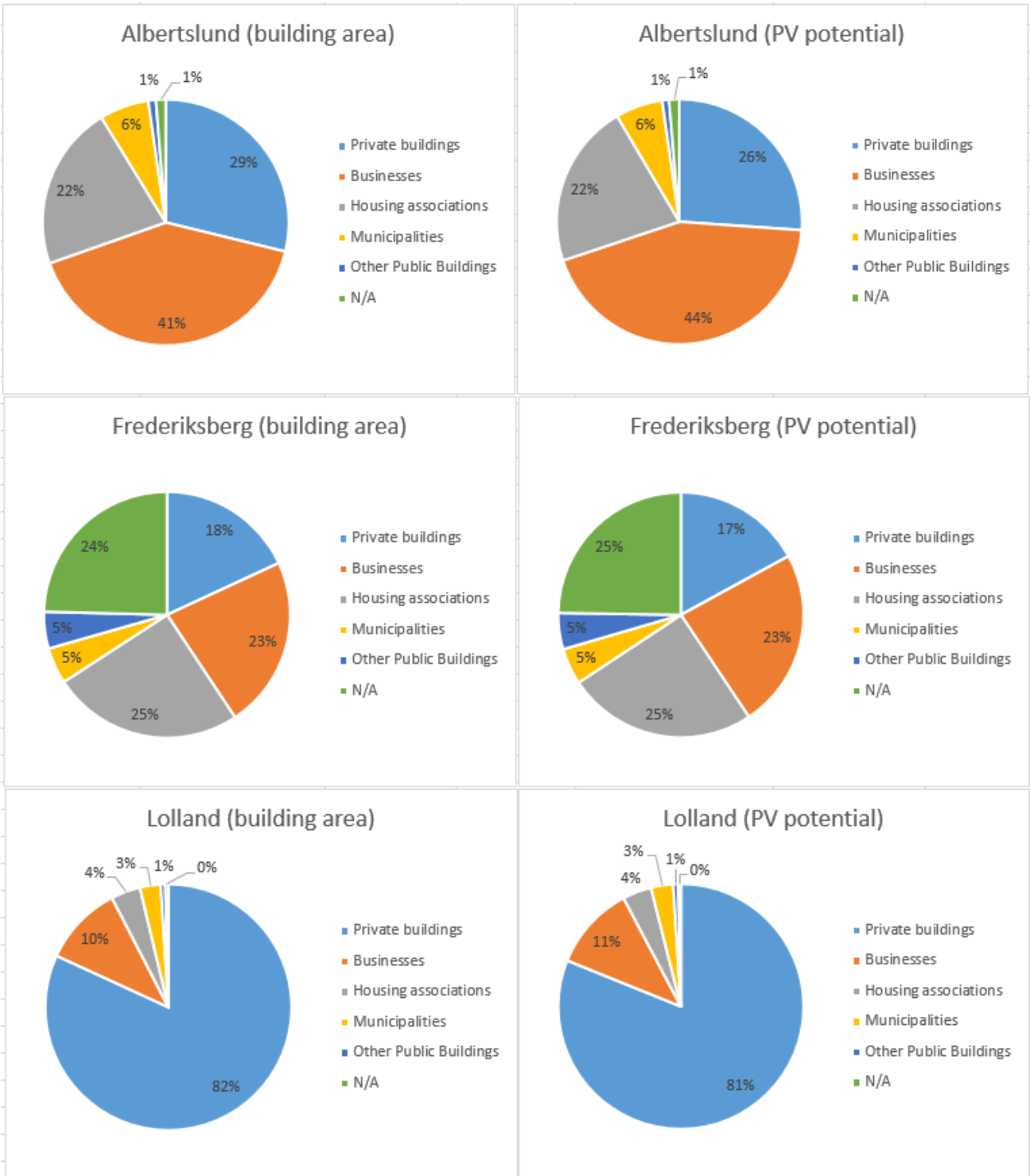


Figure 40: Distribution of the building area and PV potential upon building ownerships

This becomes important in relation to any future regulations, as it should be acknowledged that regulation that favours a specific ownership structure could lead to a high implementation rate of PV in some

municipalities and not affect the implementation in others. Another factor that influences how the individual PV installation is regulated is the size of the installation, which is explored in the following section.

5.8 Distribution of potential upon building area

It is important to mention that there is a large difference in the prices for PV installations according to the size, because of the economies of scale. Therefore, the PV potential is extracted in accordance to the built area in m^2, which is used as an indicator for the roofing area, as the roofing area is not listed in BBR. Figure 41 illustrates the potential for PV from each interval of building areas.

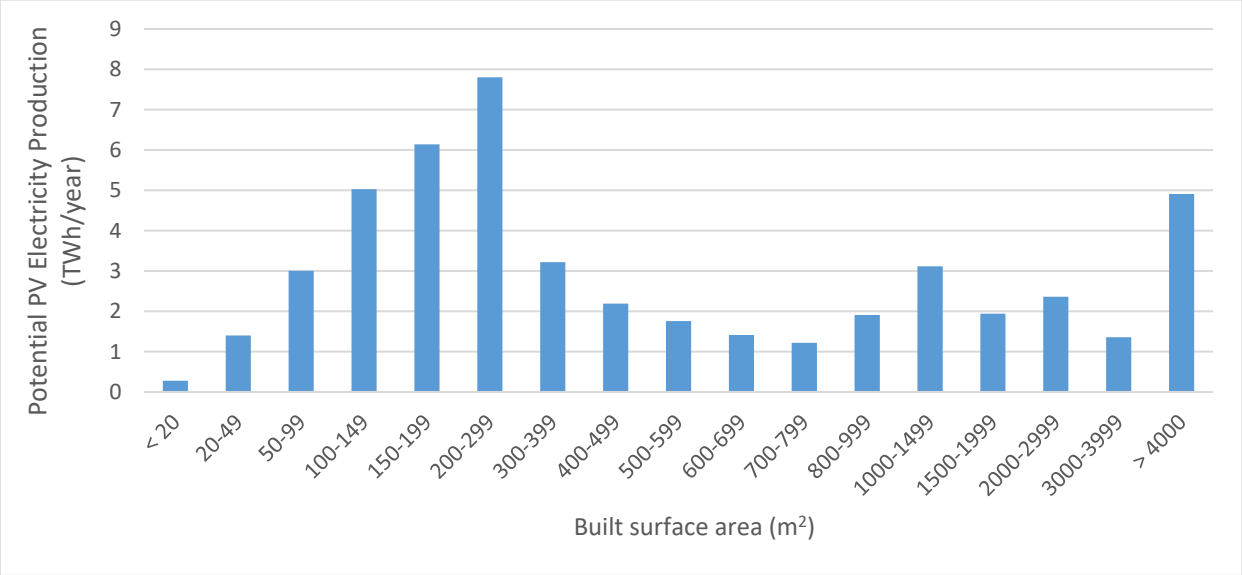


Figure 41: Maximum theoretical technical potential for roof mounted PV divided upon building area, as an indicator for the roofing size.

As illustrated in Figure 41, a large share of the potential is centred on building areas between 50 and 400 m^2, as well as a relatively high potential for buildings with a building area of more than 4.000 m^2. This can also form an important input for future support schemes and public regulation, as it would be most beneficial to utilize the largest roofs first (lowest cost kWh/m^2 due to economies of scale). In Appendix 2, in the Appendices Report, maps of the geographic variation of the roof sizes is available, showing the potential on municipality level with maps including buildings respectfully smaller and larger than 500 m^2.

The largest roofs to consider first for PV installations could be: farmhouses and agricultural buildings (both included in the private ownership category), industrial buildings, factories and warehouses (included in the business ownership category), museums, hospitals and sport facilities (included in the municipality or other public building ownership), as shown in Figure 38.

5.9 Summary of rooftop PV systems in Denmark

In this chapter, the PV potential for rooftop PV in Denmark has been analysed. A short consideration on the potential of deployment of PV as ground-mounted systems has shown that such an approach would take valuable land area that could be used for other purposes, such as for agricultural or for energy production via other more efficient means, e.g. onshore wind turbines. Since the energy system analysis showed that not more than 5.000 MW of PV capacity in small and medium sized PV systems should be installed by 2050 (about 10% of total renewable energy production from PV and wind power) a natural step was to investigate the potential for this deployment in Denmark.

The potential was found by developing a solar atlas for Denmark that is based on a GIS model, where the annual solar production for all roofs in Denmark is estimated based on a 2,56 m^2 grid. The solar potential is estimated based on annual solar radiation, taking into account the inclination of roofs and shadow effects of other buildings. After making the model for all roofs, only the areas with a potential higher than 90 kWh/m^2 were used for the further analysis as these were deemed the best roofs. With these estimations, a total potential of 49,04 TWh/year for all of Denmark was found, which is a relatively high potential compared to the total electricity consumption in Denmark, that is around 33,6 TWh/year. However, it should be kept in mind that the potential includes all roofs in Denmark and does not consider if there are obstacles on the roofs, or if the roof has the technical potential to support PV. So, utilizing all the 49,04 TWh/year is an optimistic scenario, but it is hard from such a general model to estimate these influences on the total roof area available.

The PV potential is also analysed on municipality level, where it is found that the potential is larger in more populated municipalities, naturally due to the larger amount of roof space in these municipalities. The chapter also examines the potential in regards to the ownership of buildings. Here it is found that around 53% is on privately owned buildings, out of which around half is single family buildings. Another important aspect is that around 30% of the PV potential is represented by large roofs on agricultural and commercial buildings.

The chapter also analyses the potential in different size categories, where it is clear that the potential on large roofs is significant and around 20 TWh/year could be produced on buildings with a built area larger than 500 m^2. The potential on large roofs varies significantly among municipalities, which illustrates how large the local differences are. This clarifies the need for detailed mapping of the potential for PV, providing valuable information for the planning process for the future implementation of PV as well as for designing a supporting regulatory framework.

6 International development in public regulation and support schemes

There are several milestones in the relatively short history of PV. The first market infusion with PV happened during the space program, when PV was considered as being the best alternative for generating electricity in space. The second diffusion of PV was in the 1970s, when given the oil crisis and the high costs and lack of fuel, PV technology was adapted to also function in domestic applications [36]. The third major event was enabled by the shift in regulation strategies, by introducing rooftop PV programs and public regulation schemes, which enabled the exponential deployment of PV at present, and which is estimated to continue worldwide, on a similar trend in the years to come [36].

The renewable energy electricity sector is most likely the one experiencing the most different types of policy support. These policies can be differentiated between different characteristics such as regulatory or voluntary, direct or indirect, capacity oriented or cost oriented. These policies are either employed individually or combined. Some of the most important policies are detailed bellow, along with countries and regions where they are used.

The main goal of these mechanisms is to increase the market for PV technologies and thereby accelerate cost reductions, which they have done to a large extent already. And as explained in this report, the costs have been reduced dramatically. The overview of the regulations in this section is based on a review of international studies concerned with PV support mechanisms.

6.1 Feed-in tariff and Feed-in premiums for photovoltaic

This type of policy is currently the most popular one. It is a publicly set tariff, which is paid by utilities or governments to PV producers, either from a limited budget or by financing it through the customer's electricity bills, as price supplements, but where the sum of Feed-in Tariff (FIT) and electricity price is fixed. FIT can vary according to solar resource conditions in order to stimulate the investments in the technology in the whole country [76]. The price paid for electricity is either for a specific period of time, or for a pre-determined production. In its most common form, producers of renewable energy are exempted from participating on market conditions, and receive the guaranteed price by delivering the power to the grid. The FIT can be fixed (for a technology group), time-depending (based on day/night, peak/off peak) or indexed (depending of the exchange rate, thus not certainly known at the time of investment) [77].

It is important to mention that the FIT also can take other forms, and can be referred to as feed-in premiums (FIP). Such a premium can be an add-on to the market price by having a specific target price, the FIT is thus paid as the difference between the target price and the premium price, as it was used by Denmark at the beginning of 2000. The FIP is also guaranteed for a fixed period of time or as a determined amount of production [77].

Some countries have introduced a gradual reduction of the FIT to stimulate cost reductions over time, as it is suggested that these FIT models are effective in supporting the growth of PV. On the other hand, actual cost reductions for PV production and installation may well be larger than the fixed annual reduction of the FIT. For this reason, FIT reductions have to be adjusted annually to the rate of cost reductions. Germany is most likely the most well know example. These adjustments are also made in many Asian countries, which had to review their rates both positively and negatively. New rates were introduced in China, Japan and the Philippines. In Algeria, the state implemented a FIT for PV projects of at least 1 MW, whilst Ghana established a temporary cap for utility scale projects until it can assess the impact of all existing and on-going projects [14].

Until 2011, at least 15 European countries have adopted FIT schemes, among which are the countries with the largest numbers of installed PV capacities: Germany and Spain. Some countries, such as France, Malta or Poland increased their support, whilst Germany removed the FIT for projects of 0,5 – 10 MW in size, replacing it with a tendering scheme [14].

In the USA, FIT continues to exist in several states, whilst Nova Scotia (Canada) closed the FIT to all new applicants as it reached the projected 125 MW by the end of 2015, whilst Ontario introduced new rates to small projects for support its 240 MW target for 2016 [14].

6.2 Tradable Green Certificates (TGC) and photovoltaics

The Tradable Green Certificates (TGC) are granted for the production of a certain amount of renewable energy and can be traded between energy producers on a TGC market. This certificates are based on publicly quantified renewable energy targets and their price depends on their amount; i.e. their price decreases with increasing numbers of TGC on the market, meaning that energy producer are closer to fulfilling their quotas. Thus, the TGC are referred as an instrument to control the quantity, although they are usually considered less efficient than using the FIT as a scheme to boost renewable implementation [76].

At the end of 2015 the TGC were used as a measure to promote the use of renewable energy technologies, including PV, at a national level in 26 countries. Nowadays, they still remain popular at a local level, and no less than 74 states/provinces/counties use TGC's. The pace for adoption of such measures has slowed down in the last years, and only two new additions were made in 2015, both on a sub-national level. However, some US states have revised their TGC policies, some negatively and some positively [14].

6.3 Tendering schemes and photovoltaics

Tendering schemes are typically employed in combination with other policy types, creating distinct characteristics for the planning authority, and risk aspects. In a tendering process, the potential investors compete in a process to win the opportunity to develop their project by giving their bid for the required support level. The lowest bid is then selected as the winning one. Also called a reverse auction, tendering schemes represent a procurement mechanism where PV capacity is competitively solicited from sellers, which offer bids at the lowest price they are willing to put forward. Such schemes have taken place in Asia, South America and the Middle-East, and this type of competitive bidding has gained momentum in recent years. No less than 64 countries are using tendering schemes, and new low price records have achieved through the last years [14].

6.4 Net metering for photovoltaics

PV owners only pay for their net consumption, as the produced electricity is defined as having the same value as the electricity that is consumed. This allows PV owners to 'store' the produced electricity in the grid and use it at a later time [76]. Net metering is generally used to support the deployment of residential projects in households, so the producers can get payments for the surplus electricity supplied in the grid. In some cases, it can be accounted with a FIT, to better support large-scale projects [14].

Net metering policies were in place in 52 countries at the end of 2015, and in recent years the adoption of such policies has slowed down because of the challenges in paying the rates to electricity producers and the adoption of connection fees for self-generators. New policies for implementing net metering can be found in India, Columbia, Ghana, Nepal or countries in the Middle-East. In Brazil, the net-metering capacity was extended from 1MW to 5MW. In some US, states such regulation strategies are being rolled-back or revised. Another example is the surcharge for self-consumption in many PV systems in Spain [14]. Net metering can be done on different time scales as well, from an annual basis down to an hour or instantaneous, which will have a large effect on the profitability.

6.5 Capital subsidies and tax credits

Capital subsidies can be direct subsidies where a share of the PV investment is publicly funded, but also indirect subsidies which can take the form of low-interest loans [76].

Tax credits can be:

- A production tax, which is a tax break on the electricity sold to the grid;
- An investment/installation cost tax, which is a deduction on investment and installation costs;
- To lower the VAT on investments.

The most notable example is the USA, which approved extensions on its production- and investments taxes Other countries with similar mechanisms are India, Jordan, Mongolia and Pakistan [14].

Regarding capital subsidies and tax credits, these are no longer used as main policy instruments to simulate the growth of PV, but mainly as supplementary instruments in conjunction with other mechanisms, such as FIT and TGC [76]. In other cases, such as Japan, tax breaks are planned to be removed, in order to liberalise the electricity market.

6.6 Effectiveness of the support schemes

There is existing literature describing the effectiveness of different regulation schemes. Most of the literature is focused on the comparison between the FIT and the TGC, as these instruments have been the most popular in the recent years, whilst tendering and other schemes have not been considered as effective in promoting renewable energy. However, in recent years, the trend has changed, as explained below. Tendering schemes may have the potential of overcoming some of the weak points of other regulatory instruments.

The effectiveness of a policy is one of the most important criteria of success, defined by its ability to deliver the desired result in the right amount of time. The targets can be set as minimum levels, where the policies are set to deliver the maximum deployment in a given time frame, or as maximum levels, and are considered as effective when they deliver the exact target [78].

6.6.1 Feed-in Tariff and Tradable Green Certificates

These regulation schemes are subject to market and non-market risks aspects. One of the most used regulation instruments, the FIT, has been argued to provide guaranteed access and priority to the network, thus minimizing the overall risk of the investment, given its fixed tariff. Such FIT schemes offer transparency and simplicity between all parties involved, as much of the agreements are defined by the regulatory arrangement, therefore reducing the overall costs. The FIT systems are better known to be able to provide long-term stability and resources for R&D, which will ultimately improve the efficiency. By decreasing the price of the FIT in time, the cost-savings can be passed to the ones which pay for them, those being the consumers [78], [79].

On the other hand, in the TGC schemes, the producers are exposed to the price and volume risks by operating on an open market where the green certificates can be traded. As the producers and buyers are obliged to seek long-term contracts and a vertical integration, this makes these schemes more capital intensive, with higher transaction costs, splitting the income into two elements - the price of electricity and the price of greenness - both being exposed to price fluctuations, as none is pre-determined [78], [79].

In a FIT scheme, the electricity suppliers are obliged to buy all the output, thus reducing the risk. With the TGC, there is no guaranteed market, and the electricity producers are still required to negotiate the price with the buyers, creating uncertainty, and so the TGC market faces a problem of attracting sufficient investment. Risks can be reduced in other ways too, such as through banding, where PV can be prioritized by incentivizing the investment and adding more value to the MWh produced. However, the TGC does not differentiate in terms of scales for technologies [78].

Therefore, risk reduction is an important strategy in order to achieve the maximum deployment, and if the deployment is targeted for a pre-determined time frame, these policies are often considered as the most effective ones, in this case of TGC. Others find that risk reduction stems for electricity price stabilization, being relevant as it affects the efficiency of the system, as is the case of FIT. The two types of policies, FIT

and TGC, differ in the allocation of the welfare, making the FIT more advantageous, as it not only provides the welfare, but it also provides a method to control it [78].

Along with the economic market risks, other non-market risks such as policy stability, predictability and public acceptance are important in reducing costs for investors and reducing the risks for society. It is argued at this stage that it is more important for society to bring rapidly down the cost of technologies, rather than to introduce the PV relatively slowly [80].

In [78], the multi-level perspective is used to demonstrate how regulation strategies can help technologies' transition from the protected niche levels into the actual regimes. The FIT is presented as the most recommended solution to deploy new technologies, as compared to the TGC, where the support costs are not minimised. Having the latter implies the use of a uniform certificate price, where the cheapest technologies receive higher support than required, creating the necessity of introducing banding for a specific technology [78].

In the first transition phase, the integration in the grid system is not considered as a pressing issue, as up to 20% of renewables [55] could be integrated in a national grid without any significant changes to the system. Such a transition period can well be regulated by the FIT or TGC, which both allow the deployment of high volumes of renewable energy.

In the second phase, when larger quantities are integrated, two new factors become important: (1) the security of the grid and (2) system flexibility. Since all the renewable energy producers need to contribute to balancing the grid, they can be incentivised to do so. It is suggested that at this stage the fixed prices can switch to sliding premiums, such as with the FIP. However, it is important that this happens concomitantly with market design changes, as towards the end of the second phase (that of the integration into the regime), the technologies should be able to self-develop - like in the case of Germany, which removed the FIT for the small capacity projects. Finally, the regulatory framework needs to be well adjusted, so the technologies self-sustain themselves. That is, with FIT, the guaranteed support level should be gradually reduced, so that the players on the market voluntarily opt out. This would not happen with a FIP or TGC, as no producer would give up an add-on to the market price [78].

6.6.2 Tendering schemes

Recent literature focuses mainly on comparing FIT and TGC schemes, as tenders were dismissed in the early 2000 as not being efficient enough [81]. However, the recent years have brought some changes to the way these instruments are used and, depending on the context, can prove as the right instruments to overcome some of the weak points of other instruments such as FIT and TGC.

The FIT was defended as providing very good revenue certainty, since it mainly is technology specific, and proved as a good tool to reduce the risks. However, support is not always adjusted to the generation costs, as it is happening with PV whose costs have changed in the recent years, resulting in a support instrument not adapted to the actual context. FIT systems with low support levels resulted in little installed power in some cases, as in Greece. When the tariff was too high (or adjusted too slowly, as it happened in Spain), too much support was given to the producers, increasing the growth rate to a disruptive level, where around 2 MW of PV was installed from 2007 to 2008. In comparison, until 2007, Spain had around 500 MW of PV installed in their energy system [82].

Therefore, it can be considered that tenders better reveal the costs for technologies, bringing more efficiency to the regulatory system and making sure the producers are not overly supported. Banded tenders allow for the support to be connected to generation costs, compared to the TGC [83].

Tendering schemes and FIT do share common advantages as both provide a reliable and long-term income, allowing the investors and regulators to know in advance the amount of support they will receive. On the

other hand, tenders provide the possibility of also knowing the quantity too (unless FIT has a quantity cap) and the total amount of support to be capped, allowing the investors to compete for the entire budget [83].

Nevertheless, tendering has also some disadvantages. Due to the need of planning ahead, tendering might turn more expensive, which together with the uncertainty of the final price and/or tendering schedule, can discourage smaller companies to take part in the auction, reducing competition. Oppositely, if the competition is high, it might lead the producers to implement projects in high solar irradiation areas, with a risk of creating the NIMBY (Not In My Back Yard) syndrome, and also to affect the distributed balance of the grid, thus triggering more expenses. A shared disadvantage with other types of supporting schemes is the inability of these instruments to react to the market signals, as the producers are not encouraged to balance the demand side [83].

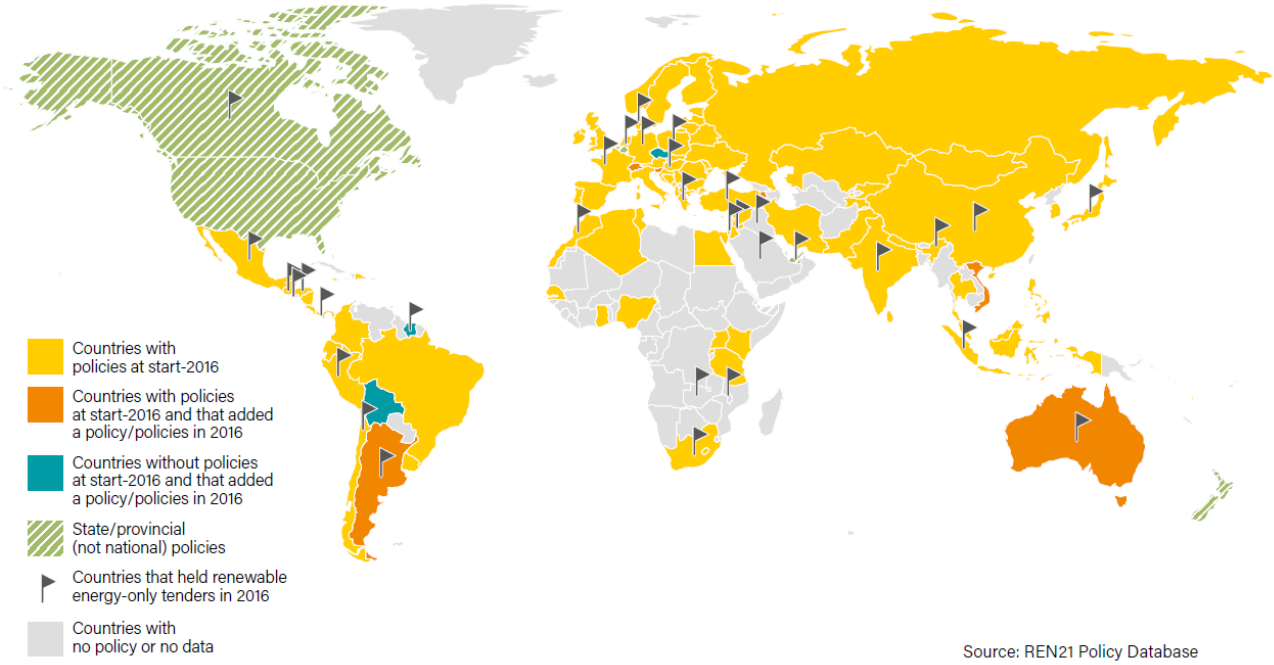
Therefore, in order to achieve their purposes, tenders need to address several issues, such as the auction design, the banding, the use of sites for the renewable energy production, the number of bidders, contracts awarded and penalties for the non-completion of the projects [83]. Other authors [84] present the importance of guaranteeing the awarded schemes an affordable connection to the grid, emphasizing that should be an integral part of the tendering process, so that the tender schemes finally can deliver the electricity at the agreed price. Another important point is the need for an effective coordinating mechanism, and also the certainty of carrying projects to completion [84].

Thus, tenders reflect the national/regional context where they are applied, and are mainly designed for mature and stable markets, proving more functional for large projects than for smaller ones. They also tend to make it hard for citizens level projects or cooperative projects. Tenders are useful for governments that want to plan the exact capacity to be implemented, whilst the FIT would be more suitable for developing large volumes.

6.7 Summary results regarding public regulation and support schemes

To be able to conclude on the effectiveness and trends for regulating schemes on a European and global level several observations need to be made. The first trend observed was related to the use of price-control instruments mainly, such as the FIT, FIP and also tendering schemes. These types of instruments are implemented in most countries looked upon. It should be noted that FIT was used in the first stages and tenders in the later stages were companies had larger capacities to bid. FIT has proven effective in the first stages. Tenders can be considered as the right instrument to use, as long as these are correctly designed for their purpose and if larger facilities are wanted [77].

Another observation is related to the combination of regulation policies, since different countries use multiple instruments (Figure 42), as countries discovered the need to differentiate the support in terms of installation sizes (and sometimes technology types). The most popular combinations nowadays are between FIT and other instruments like: tenders, FIP, and also TGC. The combination between several instruments can bring both positive effects, for example the FIT applied over a TGC can facilitate investments for small investors, but can also decrease the market volume for TGC, making it less efficient [77].



Note: Figure shows countries with Renewable Portfolio Standards, feed-in tariffs/premium payments and net metering policies. Countries are considered to have policies when at least one national-level policy is in place; these countries may have state/provincial-level policies in place as well. Diagonal lines indicate that countries have no policies in place at the national level but have at least one policy at the state/provincial level.

Figure 42: Countries with Renewable Portofolio Standards, feed-in tariffs/premium payments and net-metering. These countries are considered to have support schemes when at least one policy is in place. These countries have state or regional policies in place. Source: REN21 (2017)

Given these three trends, it can be concluded that there is an increasing number of converging regulation measures on European level, which could potentially be extrapolated to a global level as well. The current development of the regulation strategies on a European level demonstrate an orientation towards price-control schemes in more and more countries. Secondly, these tools are differentiated on a national/regional level, with mainly having the FIT used for small projects and the tendering schemes for larger ones [77].

In other words, the combination of support mechanisms can impact the development of PV significantly. Thus, just as for other renewable energy technologies, clearly defined long term policies and mechanisms instead of “stop-and-go” policies seem to be crucial for PV development [76].

7 Public regulation and support schemes for photovoltaics in Denmark

Both the price development of PV and the support schemes have a huge effect on the deployment of PV installations. In this chapter the history of PV in Denmark shows an example of how stop-go policies have developed over time. The changes made in the Danish regulation and settlement schemes for PV are compared to the observed development of PV installations in order to indicate to what extend the changes in the Danish regulations have had a direct impact on the implementation of PV throughout different periods.

7.1 Regulation and settlement schemes for private household level photovoltaics

In this section the initial development of photovoltaics in Denmark is described in a period from 1999 until now. The period is characterised by starting with rather high PV installation cost and small installations to lower costs and grid parity with larger and larger capacities installed.

7.1.1 The first support scheme (1999-2003)

The first support scheme for private PV[11] plants was adopted by The Danish Parliament in 1999, as a pilot scheme during a 4-year period. This period was subsequently extended and in 2006 it was made permanent [85]. The support scheme was mainly applied to private PV owners, but PV installations placed on non-commercial buildings were also eligible to make use of the scheme, if the plant would not exceed 6 kW per 100 m^2 of constructed area.

The support scheme, which commonly is known as the net-metering scheme, made it possible to “store” the electricity production in the grid, when it exceeded the demand and hereafter use a corresponding amount of electricity free of charge and exempted from the electricity tax [85]. The ratio between production and used electricity was only accounted for once a year, which made it possible to “store” the surplus electricity during the summer to the winter months, when the demand is high and the electricity production from the PV installation is low. Until 2004, any surplus electricity production that exceeded the annual demand was sold to a feed-in-tariff of 60 øre/kWh or 7,8 eurocent/kWh, during the first 20 years of operation [86], [87].

7.1.2 The 60/40 settlement (2004-2012)

In 2004, the settlement of surplus electricity was changed so any surplus production should be settled at a feed-in-tariff of 60 øre/kWh (or 7,8 Eurocent/kWh) during the first 10 years, and hereafter at a feed-in-tariff of 40 øre/kWh or 5,2 Eurocent/kWh the following 10 years [86]. This settlement is often referred to as the “60/40 settlement”. In 2008 the tax exemption was supplemented by an exception from the Public Service Obligation (PSO).

As described in Section 2.5 and 2.6, the price of PV-panels dropped significantly during the period until 2012 and furthermore the electricity price, including taxes, increased [88]. These factors in combination with the adoption of some accommodative rules of taxation, such as more favourable depreciations, made an investment in a private PV-installation very profitable for the owner, which led to a drastic growth in the installation rate of residential PV plants.

7.1.3 The hourly net metering scheme (2012 -)

As a direct consequence of this development, and the rising costs for the Danish state induced by the support of PV, The Danish Parliament adopted a political agreement on the 15th of November 2012, with the purpose of reducing the provided subsidy for PV owners when using the net metering scheme. The agreement changed the fundamentals of the net metering scheme, as it prospectively only was possible to “store” the electricity in the grid within the same hour as it was produced, hourly net metering. This reduced the benefits

[11] Private PV includes small-scale PV installations owned by private persons and mostly installed on the roof of privately owned buildings, such as single family houses.

from net metering quite significantly. It was however also agreed, that any surplus electricity production in a delimited period could be settled at a feed-in-tariff of 130 øre/kWh or 16,9 eurocent/kWh in a 10 year period [89]. After this period the electricity was to be sold to market price.

As an attempt to take further price reductions for PV installations into account, this settlement price was gradually reduced, so it would become 60 øre/kWh in 2018. In 2015 and 2016 the fixed prices would be 102 and 88 øre/kWh (13,3 eurocent/kWh and 11,4 urocent/kWh) respectively.

The hourly net metering scheme and the high settlement price was extended to include all PV-installations with an installed capacity lower than 400 kW [89]. Shortly after the adoption of the agreement, it became clear that large field constructed PV-power plants of several MW_p could be entitled to the settlement price of 130 øre/kWh, which was not the intent of the regulation. This was possible as the PV-plants could be divided into sections of 400 kW and the capacity limit thereby could be evaded.

As a consequence, a new complementary agreement, which restricted the types of PV-plants being entitled for the high feed-in-tariff, was adopted on the 19th of March 2013. Prospectively only private PV installations with a capacity of 6 kW or below and roof mounted or building integrated PV would be entitled to the high settlement price [87].

However, there were indications that this delimitation of the settlement scheme was not enough to curb the fast installation rate and thereby reduce the costs of the PSO and thereby the electricity consumers affiliated with the settlement of PV. Therefore, a new political agreement was adopted on 11th of June 2013, with the purpose of further restricting the entitlement to the high feed-in-tariff and thereby reduce the PSO costs for the deployment of PV in Denmark. First of all, it was agreed that the high feed-in-tariff should only be provided for private PV installations, with a maximum capacity of 6 kW, as opposed to previous where also roof mounted or building integrated PV installations was entitled, regardless of the capacity. Furthermore, the settlement scheme was limited to a total capacity of 20 MW/year. The administration of this pool, as well as the 60/40 settlement, is delegated to the Danish TSO, Energinet.dk [85], [90].

7.1.4 End of the 60/40 settlement scheme

During April 2016, Energinet.dk received a vast amount of applications for 60/40 settlement for PV installations. In a short amount of time applications amounting to a total capacity of 4.500 MW was received, whereas 4.000 MW came in April alone [91]. In comparison, this capacity corresponds to approximately one third of the total electricity capacity in the current Danish energy system [92]. As a direct consequence of this explosive amount of applications and the induced increasing costs for the Danish electricity consumers (PSO), which was estimated to approximately 11 billion DKK [91], the Danish Parliament adopted a new law that closed the 60/40 settlement on 3rd of May 2016.

This means that the current support scheme for private PV installations, with hourly net metering and a settlement price of 130, 102 or 88 øre/kWh, depending on when the plant was installed, is limited to an annual capacity of 20 MW. Additional installations do still have the possibility to make use of the hourly net metering scheme, but any surplus electricity is settled in accordance to the spot market price [93].

7.1.5 Summary of support schemes for household photovoltaics

The above-mentioned changes in the support schemes for private PV installations, until 2016, are summed up in Table 13. As mentioned before, the changes in the regulation and settlement of private PV installations have had a significant effect on the amount of PV which is installed.

Table 13: The changes of the settlement scheme for private PV owners in the period from 1999 to April 2016. 1 øre corresponds to approximately 0,13 Eurocent (August 2016).

Changes of the settlement scheme for small household level PV from 1999 to April 2016[12]		
Period	**Net metering**	**Additional FIT**
1999 – 2004	Yearly net metering (Not excepted for PSO)	Spot market price
2004 - 2008	Yearly net metering (Not excepted for PSO)	Feed-in-tariff of 60 øre for the first 10 years and 40 øre the following 10 years
2008 -2012	Yearly net metering (Excepted from PSO)	Feed-in-tariff of 60 øre for the first 10 years and 40 øre the following 10 years
November 2012	Hourly net metering	130 øre for the first 10 years[13], hereafter the spot market price
March 2013	It was agreed that only private PV installations[14] (up to 6 kW) and roof mounted or building integrated PV would be entitled to the high settlement price.	
June 2013	If was agreed that only PV installations up to 6 kW would be entitled to the high settlement price and only for total capacity of 20 MW annually	
May 2016[15]	Hourly net metering	Spot market price

7.1.6 Correlation between of household PV installations and regulatory changes

Figure 43 illustrates the annual installed capacity of private PV installations as well as the accumulative capacity. Almost no PV was installed until 2011. During 2012 and 2013 the installation rate had the highest increases, which is why these years are examined in more detail. Figure 44 illustrates the installed capacity on a monthly basis for 2012 and 2013.

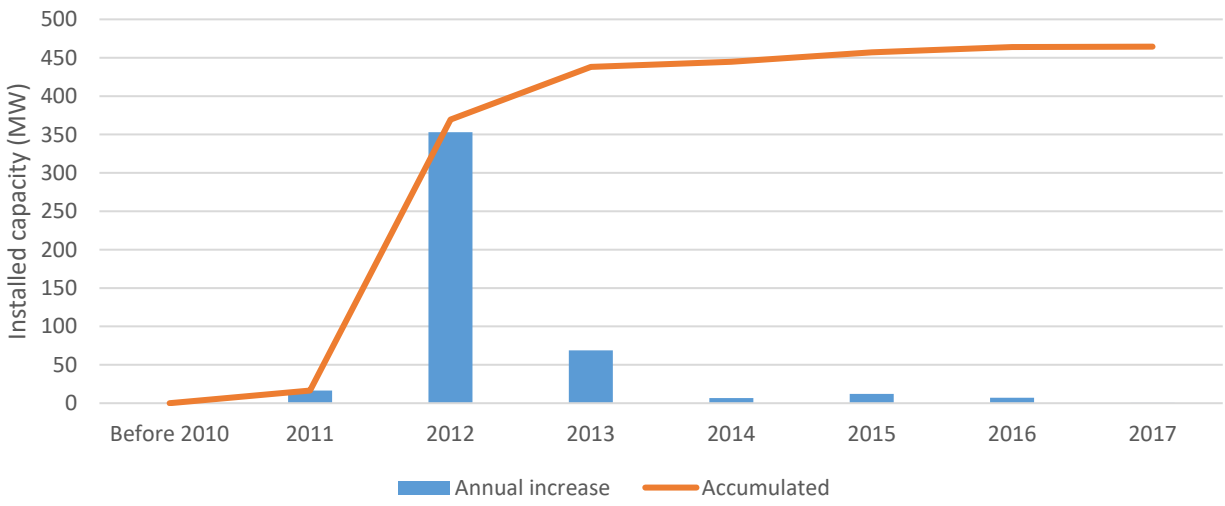


Figure 43: The annual development of the installed capacity of private PV installations with maximum 6kW and the accumulated capacity. The figure is based on data from Energinet.dk - extracted media 2017.

As described at the beginning of this chapter, the settlement scheme was based on similar principles during the period from 2008 to November 2012, where the net metering scheme was changed from annual to

[12] Including PV installations placed on non-commercial buildings with a maximum capacity of 6 kW per 100 m^2 of constructed area
[13] Applicable for all PV installations with a capacity of maximum 400 kW
[14] Also applies to privately owned PV installations on the ground, as long as the capacity is below 6 kW
[15] Only installations which is not included in the 20 MW.

hourly. This change has clearly had an impact on the installation rate, which was reduced significantly in the following months. This change in the settlement scheme did most likely reduce the installation rate even more than reflected in Figure 44, as several installations were bought and notified before November 2012 and thereby settled in accordance to the yearly net metering scheme [85]. This can explain the gradual reduction in the installation rate.

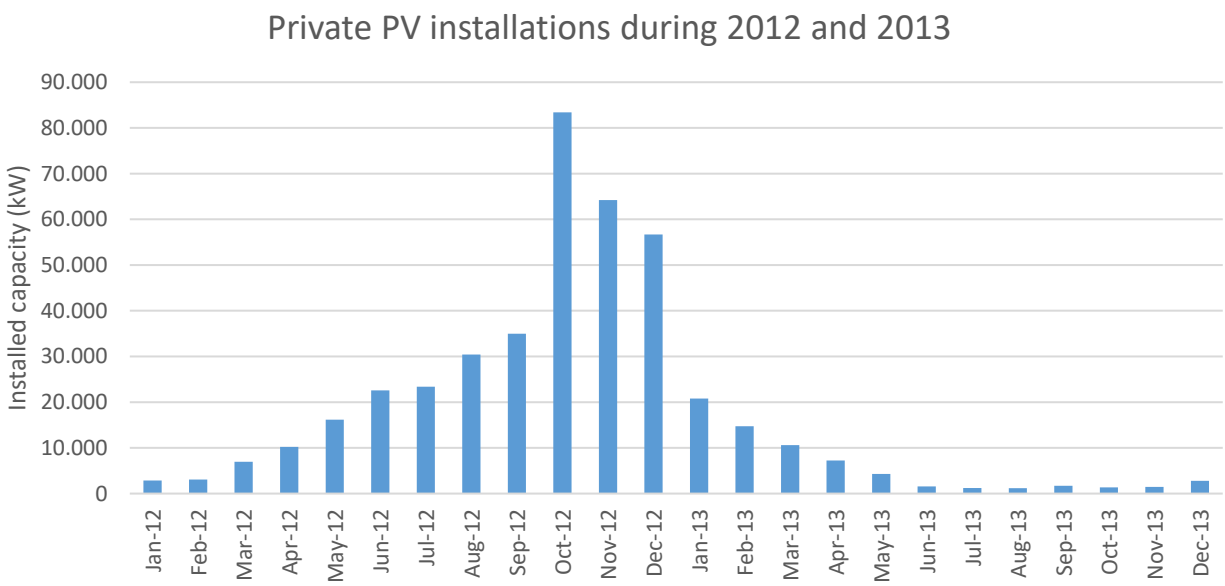


Figure 44: Monthly installation of private PV during 2012 and 2013, where the largest capacity was installed. The figure is based on data from Energinet.dk extracted medio 2016.

7.2 Regulation and settlement schemes for non-private PV installations

The regulation and settlement schemes for non-private PV installations have also changed significantly and several times. Non-private PV installations can be divided into three categories, which influences the settlement scheme:

1) Roof mounted or building integrated PV installations;
2) Commonly owned PV installations[16] – connected to consumption unit;
3) PV installations – not connected to consumption unit (ground mounted plants).

As it was the case for private PV installations, the settlement scheme has been changed several times. The most significant changes are coinciding with the changes for private PV installations, as described above.

Before 2004, all non-private PV installations were settled to a feed-in-tariff of 60 øre/kWh (or 7,8 Eurocent/kWh) for the first 20 years [86], [94]. This was changed in 2004, where the "60/40 settlement" was adopted, which these PV installations prospectively should be settled in accordance to.

This was applicable until the political agreement from 15th of November 2012 was adopted, which amongst others had an aim of making it more attractive for businesses to establish large-scale PV installations. Therefore, it was agreed to increase the settlement price for PV plants with a capacity of maximum 400 kW to 130 øre/kWh. Furthermore, it was agreed that large commonly owned PV installations could be settled to 145 øre/kWh (or 18,9 Eurocent/kWh) during the first 10 years, hereafter the surplus electricity was sold to

[16] The definition of a commonly owned PV installation is that it is owned by either a group of private persons (guild), which all own an equal share of the installation. The capacity is limited to 6 kW for each person and the installations cannot make use of net-metering. Furthermore, different kinds of housing associations are included. For these, the capacity limit is 6 kW per housing unit and the net-metering is limited to the electricity consumption used in common facilities such as lighting in the stairway [111].

the spot market price. For common PV installations owned by a group of private persons it is a prerequisite for this high feed-in-tariff, that the PV installation does not have the possibility to make use of the hourly net metering scheme. For installations owned by housing associations the hourly net metering scheme can only be used for the building operation electricity, which is applied for common facilities such as lighting in stairways, building operation, wash houses etc. [87].

PV installations with a capacity that exceed 400 kW were still settled in accordance to the 60/40 settlement. This regulation made it possible to circumvent the capacity limit, by dividing the PV installations into modules of 400 kW. This made it possible for ground mounted plants to be settled to the high feed-in-tariff of 130 øre/kWh. As a consequence, a complementary agreement was adopted on 19th of March 2013, with the purpose of closing the loophole [94].

This agreement abolished the capacity limit, but it was specified that the high feed-in-tariff only could be provided for private PV installations with an installed capacity below 6 kW as well as roof mounted and building integrated PV installations. Furthermore, it was also specified that the feed-in-tariff of 145 øre/kWh only could be provided for commonly owned PV installations, which was roof mounted or building integrated.

For commonly owned PV installations not connected to a consumption unit (free field plants) it was decided that these could be settled to a feed-in-tariff of 90 øre/kWh or 16,9 Eurocent/kWh.

All of the above mentioned feed-in-tariffs were gradually reduced to 60 øre/kWh during the following 5 year [87]. PV installations, which were not within the scope of these high feed-in-tariffs could be settled in accordance to the 60/40 settlement.

As a consequence of the political agreement, from June 2013 a new law was adopted, which induced the possibility for tenants to be settled equally to building owners. However this required a consensual agreement between all of the residents of a whole residential complex [85]. This was necessary, as the tenants renounced their rights to act as individuals on the electricity market and change their supplier at their wish [95].

7.2.1 Summary of support schemes for non-private photovoltaics

As described previously, the 60/40 settlement was abolished in 2016, which meant that PV installations not being implemented within the 20 MW limit are now settled to the spot market price, instead of the 60/40 settlement. In Table 17 a summary of the support schemes for non-private PV installations is listed.

Table 14: The changes of the settlement scheme for non-private PV owners, such as private businesses, housing associations etc. in the period from 1999 to May 2016. 1 øre correspond to approximately 0,13 Eurocent (August 2016).

	Non-private photovoltaic installations		
Period	**Type of PV installation**	**Net metering[17]**	**Feed-in-tariff**
Before 2004	All non-private PV	-	60 øre/kWh in 20 years
2004 - 2012	All non-private PV	-	60/40 settlement
November 2012	All non-private PV up till 400 kW	Hourly	130 øre for the first 10 years[18], hereafter the spot market price
November 2012	Commonly owned PV	Hourly – only of consumption in common facilities	145 øre/ kWh in 10 years
November 2012	PV installations with a capacity of more than 400 kW	Not possible if the installation is defines as being a production plant	60/40 settlement

[17] Provided, that they are eligible in accordance to the Danish net-metering act.
[18] Applicable for all PV installations with a capacity of maximum 400 kW

19. March 2013[19]	Roof mounted or building integrated PV (up till 400 kW)	Hourly	130 øre/kWh in 10 years
19. March 2013[6]	Commonly owned, roof mounted or building integrated PV	Hourly – only of consumption in common facilities	145 øre/ kWh in 10 years
19. March 2013[6]	Free field PV plants	-	90 øre/kWh in 10 years
19. March 2013[6]	Other PV installations	-	60/40 settlement
June 2013	Same as described above (march 2013), but limited to a total capacity of 20 MW. Installations which are not included in these as well as free field plants are settled in accordance to the 60/40 settlement.		
May 2016	All[20]	Hourly – same rules as of march 2013	Market price

7.2.2 Correlation between installations of non-private PV and regulatory changes

In this sections the development of installations in private businesses, Public housing associations and PV installations not connected to consumption unit (ground mounted) is correlated with the regulatory changes.

Private businesses

Figure 45 illustrates the annual installed capacity of PV owned by private businesses, defined as all companies which is not either municipality owned or public housing associations. The installation rate fell significantly from 2013 to 2014, were it was reduced by more than 50% and reduced further in 2015. The effect of the political agreement from March 2013 does not seem as drastic as it was the case for private PV installations. However, the data indicates that the installed capacities in 2014 and 2015 are implemented within the 20 MW limit, which is eligible to be settled in accordance to the "old" settlement scheme. This seems plausible, as the sum of the installed capacity for private businesses, public housing associations and municipalities is around 15 MW in 2014 and 18 MW in 2015, so all of the capacity can be included in the 20 MW being eligible to the high feed-in-tariff.

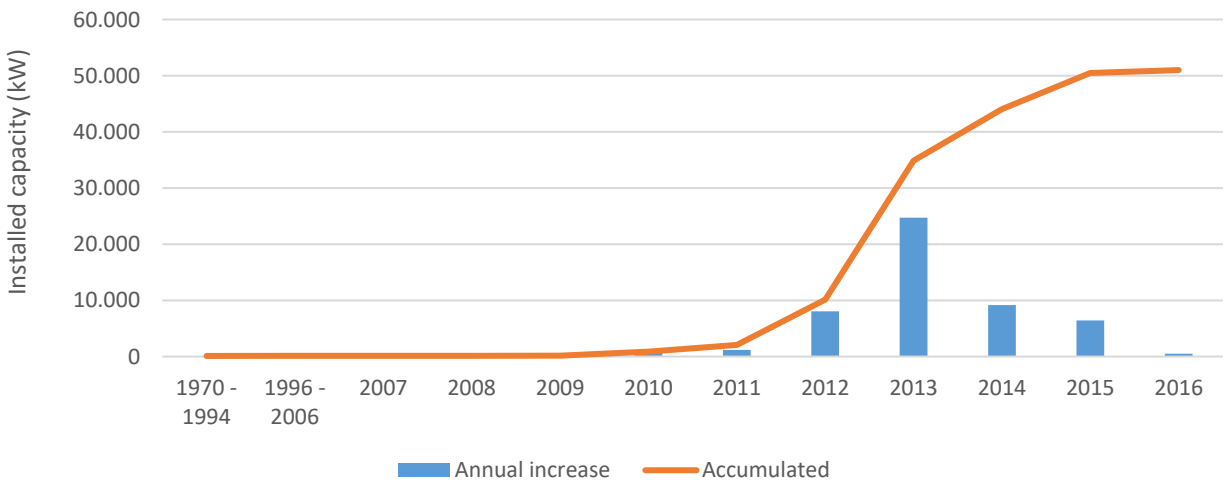


Figure 45: The annual development of the installed capacity of PV installations owned by private businesses (columns) and the accumulated capacity. The development from 1970 to 1994 and 1996 to 2006 are summed as the development are insignificant. It should be noted that the data for 2016 only includes the first half of the year. The figure is based on data from Energinet.dk extracted medio 2016.

As illustrated in Figure 45, the installed capacity during the first half of 2016 is very limited. Even though the 60/40 settlement was abolished in April 2016, this is not expected to affect the installation rate as drastically

[19] The feed-in-tariffs are gradually reduced towards 60øre/kWh during a 5-year period.

[20] Except the 20 MW which is settled in accordance to the settlement scheme as described under March 2013

as the development suggests. This is due to the fact that 20 MW is still eligible to the attractive settlement as mentioned above, and the 60/40 settlement in principle only should be relevant to PV installations which are not undertaken by these. It has to be kept in mind that the data only reflects the first half of 2016.

Public housing associations

As it was the case for private businesses, the installation rate owned by public housing associations fell from 2013 to 2014, however not as much. In fact, the installation rate increased from 2014 to 2015, which most likely is due to the above mentioned reasons. Furthermore, the possibility for tenants to be settled on the same basis as building owners, which was induced in June 2013, could affect the incentive for housing associations to install PV positively. As it was the case for PV plants owned by private businesses, the installation rate is reduced to around zero for the first half of 2016.

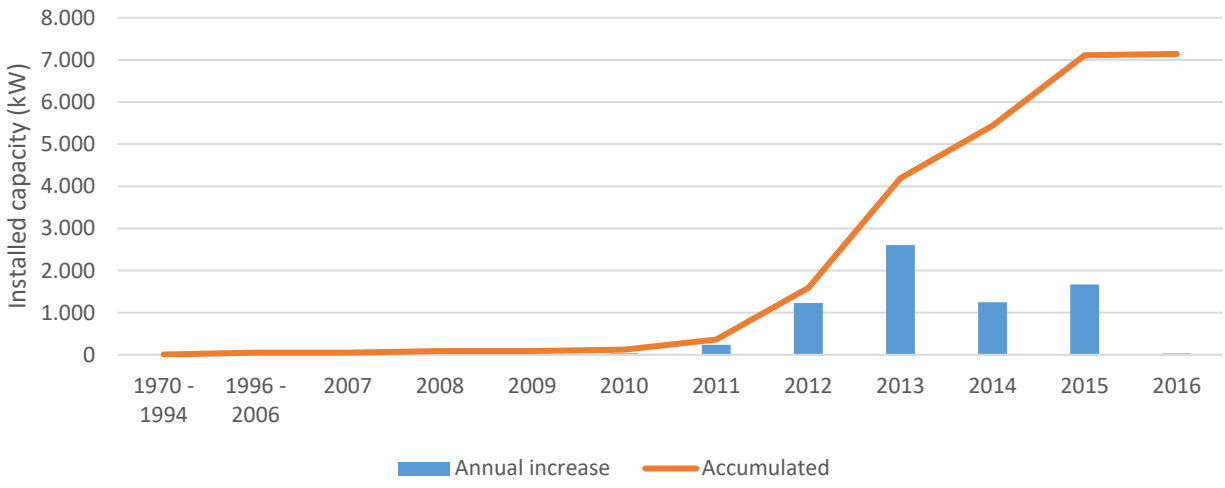


Figure 46: The annual development of the installed capacity of PV installations owned by public housing associations (columns) and the accumulated capacity. The development from 1970 to 1994 and 1996 to 2006 are summed as the development are insignificant. It should be noted that the data for 2016 only includes the first half of the year. The figure is based on data from Energinet.dk extracted medio 2016.

PV installations not connected to consumption unit

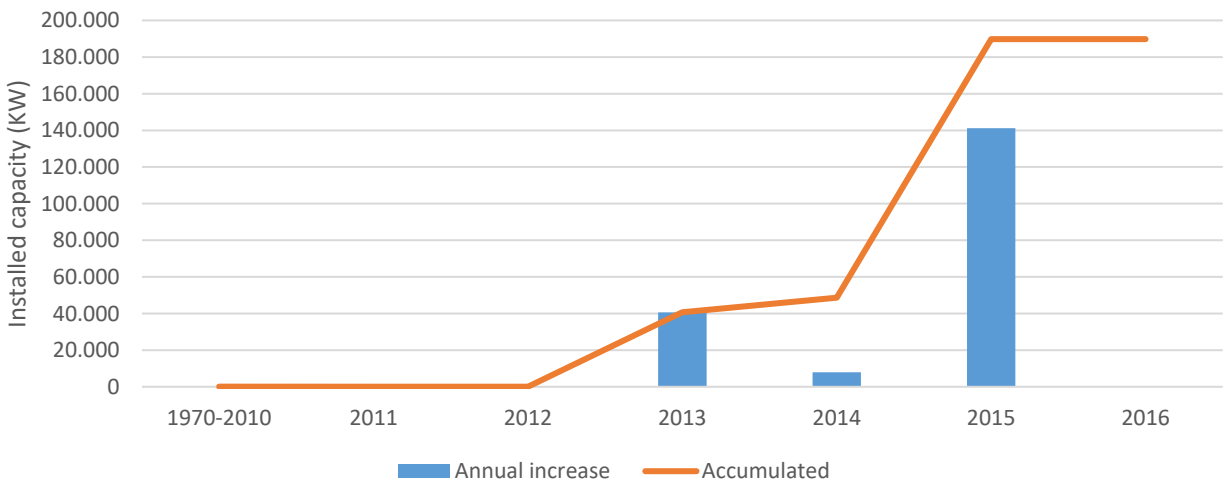


Figure 47: The annual development of the installed capacity of free field PV installations (columns) and the accumulated capacity. The development from 1970 to 1994 and 1996 to 2006 are summed as the development are insignificant. It should be noted that the data for 2016 only includes the first half of the year. The figure is based on data from Energinet.dk extracted medio 2016.

In the period from 2013 to 2015, it was installed a total of 785 PV plants, out of which 782 had a capacity of 400 kW or below. Especially in 2015, it is strongly indicated that the installation rate is a consequence of the

before mentioned loophole, as 354 of the 356 plants which were put into operation, each have a capacity of between 390 and 400 kW. These are furthermore placed within just 6 different postal areas and are put into production at approximately the same time. As it was the case for the private PV installations, the fact that most of the plants were put into operation in 2015 indicates that it takes some time before the plants become operational, even though they are notified before the legislative change and are thus eligible to the more favourable settlement scheme. This tendency is also reflected in the data from 2014. There has not been installed any free field plants during the first half of 2016.

7.3 Regulation of municipally owned PV installations

In addition to the above mentioned changes in the settlement schemes for non-private PV installations, the municipal engagement in PV projects is subject to further regulatory conditions. These are described in the following sub-sections.

7.3.1 Corporate separation

In the political agreement from June 2013 it was specified that municipal owned PV installations should be considered as electricity production units, which induced that they prospectively should be regulated in accordance to the Danish Electricity Act. As a consequence of this, municipally owned PV installations are obligated to be organized in separate corporations, with limited liability [96]. It has to be noted that this does not apply for the state or the regions. There are several exemptions from this, depending on the type of PV installation and when it is installed. The possibilities for exemptions are described in following:

- PV installations installed before 28th of June 2013 are exempted from these rules, by law. This exemption ceases if the capacity of the original installation is increased. In this case, an application has to be sent to Energinet.dk in order to obtain an exemption. This is also the case for PV installations which are installed after the 28th of June 2013.

- Municipally owned PV installations installed after the 28th of June 2013 can be exempted if:
  1) The PV installation is constructed as part of the construction of new buildings.
  2) The PV installation is included in the calculations of a buildings energy frame, which forms the basis for the building permit.
  3) The municipality have applied Energinet.dk for an exemption and have received an undertaking [97]

The possibilities for exemptions for PV installations which are not included in the above are limited to an annual capacity of 20 MW. These exemptions are given in accordance with the “first come, first served” principle.

7.3.2 Deduction from block grands

Another consequence of the fact that municipally owned PV installations are regulated by the Danish Electricity Act is that a profit, being the result of the PV installation, is to be deducted from the block grands, which each municipality is given by the Danish Government. This is stated in § 37 of the Danish Electricity Act [96]. The legislation regarding the deduction of block grands is administrated by The Danish Energy Regulatory Authority (Energitilsynet).

The Danish Energy Regulatory Authority have assessed that any cost reductions being achieved by the use of net metering are to be defined as a profit and thereby also have to be deducted from the block grants [98].

This means, that it is the total annual cost reductions that are to be deducted from the block grants, when any expenses such as maintenance costs and depreciations are withdrawn [99].

However, there are legal constructions of municipal companies, which can exempt the municipalities from the deduction in block grants, which is described in the following four models for legal construction of municipal companies:

Model 1 - If utility companies are a part of the "municipal administration", the municipality is deducted from their block grants equivalent to all profit which is obtained from the utility companies. This legal construction of companies is illustrated in Figure 48.

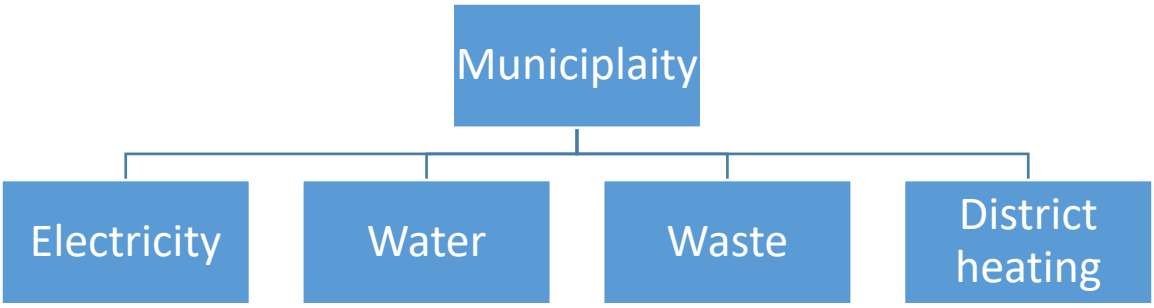


Figure 48: Legal construction where utility companies are part of the municipal administration. Based on [100]

As illustrated in Figure 48, the utility companies are organised within the same company as the rest of the municipality. However, the PV installations are obligated to be organised in separate corporations, in appliance to the Danish Electricity Act, which means that this organizational option for exempting block deductions is not legal.

Model 2 - In a situation where the companies are organised with a municipality owned holding company, which is separated from the "municipal administration", as illustrated in Figure 49, the municipally is not necessarily deducted from their block grants.

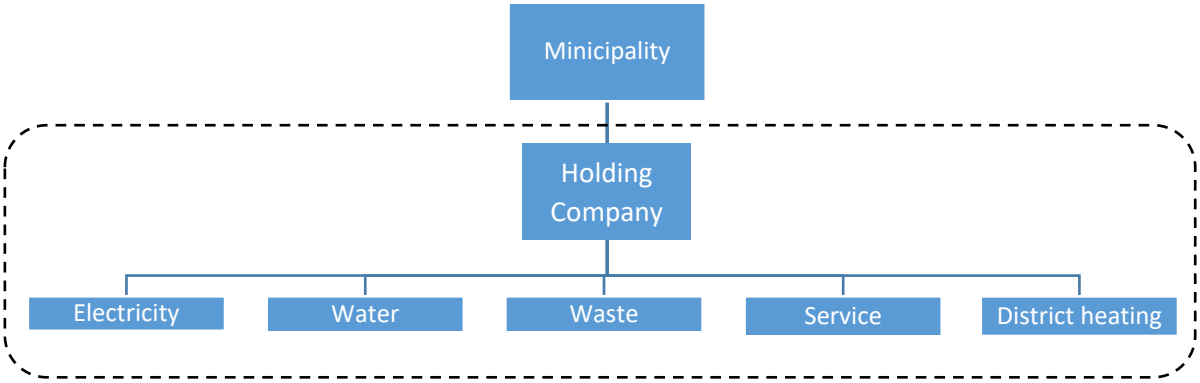


Figure 49: Legal construction where utility companies are organised with a municipally owned holding company, which is separated from the "municipal administration. Based on [100]

This legal construction of the municipally owned utilities enables the municipality to use profit from one utility such as electricity produced by PV within the holding company, with that limitation that grants from the electricity or district heating sector cannot be transferred to the water or waste sectors.

Model 3 - The utility companies can also be organized so the municipality owns a common utility company, which owns a number of subsidiary utility companies, as illustrated in Figure 50.

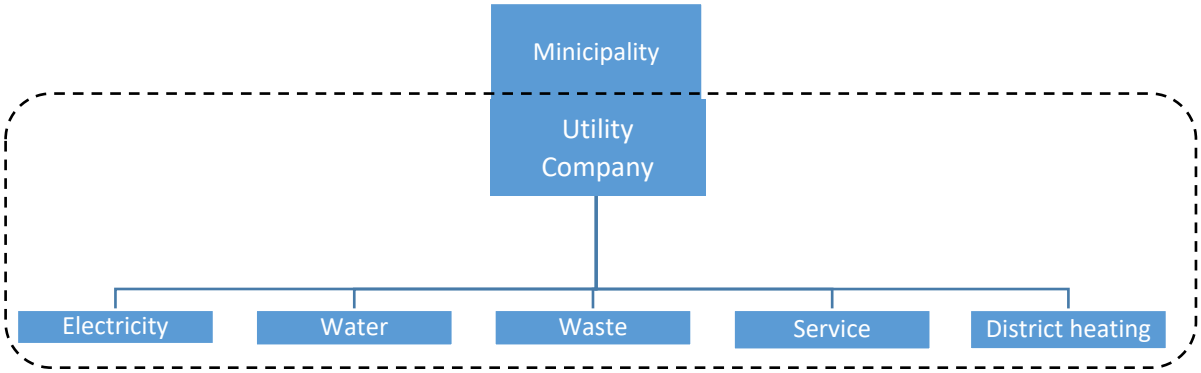


Figure 50: Legal construction where the municipality owns a common utility company, which owns a number of subsidiary utility companies. Based on [100]

This construction enables the municipality to transfer funds between the different utility companies without deduction in the block grants, much similar to 2). However, this model induces an increased control of the financial statements in order to ensure that funds are not transferred to the municipality.

Model 4 - The utility companies can be organised as separate corporations without affiliation, as illustrated in Figure 51:

Figure 51: Legal construction where utilities are organised in separate corporations without affiliation. Based on [100]

In this case any funds that are transferred between the utility companies and the municipality are deducted from the block grants. [100]

As described above, it is possible to make a legal construction of municipally owned companies (owning PV installations) where it is possible to transfer funds (in this case profit from PV installations) to other utility companies, but not to municipalities' own funds.

7.3.3 Correlation between installations of municipality owned PV and regulatory changes

As described earlier in this section, the most influential regulatory change, besides the settlement, is the definition of PV installations as being a separated electricity producing utility, which took effect in June 2013. Even though the impact on the installation rate is not as evident as it was the case for private PV installations, the installed capacity was still around half in 2014 and 2015 compared to 2013. As indicated earlier, the data indicates that this can be a consequence of the 20 MW limit, which can be settled in accordance to the more attractive settlement scheme. Furthermore, it is also possible to obtain an exemption from the corporate separation for a total capacity of 20 MW, which the installed capacity in both 2014 and 2015 lies below. This makes it possible to make use of the hourly net metering scheme, if the plants have a capacity of a maximum of 400 kW and are roof mounted or building integrated, provided that an exemption is obtained.

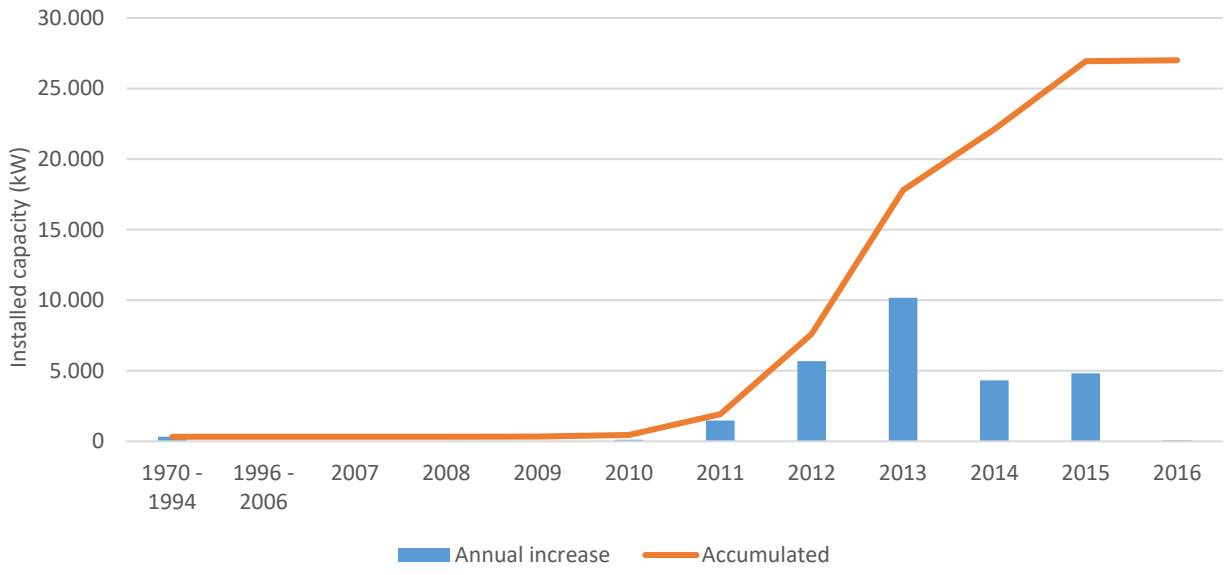


Figure 52: The annual development of the installed capacity of municipality owned PV installations (columns) and the accumulated capacity. The development from 1970 to 1994 and 1996 to 2006 are summed as the development are insignificant. It should be noted that the data for 2016 only includes the first half of the year. The figure is based on data from Energinet.dk extracted medio 2016.

7.4 Changes in 2017 and current settlement

In 2017, several changes have been made in order to further restrict the development of PV in Denmark. First, in May 2017 it was proposed that the hourly net metering scheme should be terminated for all PV installations except residential PV installations with a capacity of maximum 6 kW. As of May 22 2017, the hourly net metering was replaced by momentary net metering.

Furthermore, the tariffs that the own consumed electricity is exempted from are changed. This means that the own consumption in the future will have to pay the subscription fee to the power grid company for the total electricity consumption, where it has only payed for the difference between the total electricity production and consumption before the change [101]. This will reduce the value of the own consumption.

As it has been documented in this chapter, the implementation of PV was almost completely stopped already before the further tightening of the regulatory framework. On this basis, there is a very strong indication that these reductions in the settlement schemes will only continue limiting the further implementation of PV, bringing the development to a complete stop. The changes in the regulations for PV in Denmark, have been done in order to reduce/control the public spending via the PSO.

It is found that there is a correlation between the regulatory changes and the actual implementation of PV, where the changes led to drastic reductions in the implementation rate of PV in Denmark. The “stop-and-go” has affected the development significantly and, for all of the ownerships, it can be observed that the implementation rate has been reduced drastically and that very few PV installations were built in 2016 and 2017 (Figure 8). The regulatory changes in 2017 can be expected to reduce the implementation rate even further, basically stopping the development of PV in Denmark.

Table 15: Overview of current support schemes

Type of plant	Net metering	Supplementary FIT
Residential installations (existing) (6kW)	Hourly	Market price
New Residential installations (6kW)	Momentary	Market price
Residential installations up till 20 MW (new installations)	Momentary	0,74 (reduced from 1,30) kr./kWh
Non private installations	Momentary	Market price
Non private installations up till 20 MW	Momentary	0,77 (reduced from 1,45) kr./kWh
Free field plants		Market price[21]

[21] Technology neutral tenders are considered for 2018 and 2019.

8 Case studies: stakeholders' business economy in photovoltaics

In order to evaluate how the regulatory changes, described in Chapter 7, have affected the business economy of investments, five cases are examined:

1) An average residential PV installation
2) A housing association
3) A public school
4) A commercially owned PV installation
5) A free field PV installation

For each case study, the relevant settlement schemes are briefly introduced at the beginning of the chapter, followed by the results from the business economic analyses. The purpose of the case studies are to evaluate the business economic profitability for different types of PV installations of different ownerships. Furthermore, the analyses are used to demonstrate the dynamics of the Danish regulation of PV.

In these analyses, the business economic profitability is evaluated by:

1) Net present value (NPV), which shows the difference between the present values of cash inflows and outflows;
2) Internal rate of return (IRR), which describes at which internal discount rate the NPV becomes 0;
3) Payback period (PBP), which shows at which year the accumulated revenues surpasses the accumulated costs.

In order to evaluate the economics of the cases, an Excel model has been developed. This calculates the discounted cash flow for the different cases, which is normally applied to assess the profitability of an investment. The method is appropriate to be used when analysing multi-period investments, because it takes into account the costs and benefits throughout the whole calculation period. The analyses takes into account any costs, such as investment costs, operation and maintenance (O&M), as well as benefits, such as savings from net metering and revenues from sales of electricity to the grid. The analyses assume a technical lifetime of 30 years for the PV installation itself. However, the service life for the inverter is significantly lower, normally between 10 and 20 years.

In these analyses it is assumed that the inverter is changed every 10 years. The reinvestments in new inverters are assumed to correspond to 100.000 DKK (€ 13.440) for large-scale PV installations and 10.000 DKK (€ 1.344) for small-scale PV installations. PV installations are in general not subject to large O&M costs [5]. In these analyses, the annual O&M costs are assumed to correspond to 0,8% of the investment costs. The investment costs and the hourly production of the PV installations are actual data from the case-installations. However the production data has only been obtained for one full year, but in order to take into account that the production from PV installations tends to decrease gradually, the production is assumed to be reduced by 0,8 % annually. This results in the productivity being reduced by 24% during the service life of the PV installation, which is in accordance to the guaranties provided by many PV manufactures.

These assumptions are detailed in Appendix 3, in the Appendices Report.

8.1 A residential roof mounted photovoltaic in private ownership

Residential PV installations have historically been subject to an intense development in Denmark, a consequence of several coinciding positive factors of which an important is the annual net metering scheme.

In the following, the business economy for a residential PV installation is analysed, when settled in accordance to both the yearly net metering as well as the hourly net metering, supplemented by different FIT's for the electricity that is sold to the grid. The regulation and profitability of residential roof mounted PV installations is especially important, as over half of the total potential for roof mounted PV consists of private residential buildings.

The PV-installation have a capacity of 5 kW, with an annual production of 3.645 kWh. The annual electricity demand of the building where these are installed is 3.755 kWh. Since it was not possible to obtain the hourly distribution of the demand, an average from 37 private households, which were monitored in 2012 were used for distributing the electricity consumption on an hourly basis. The total investment cost for the PV-installation is found to be approximately 64.500 DKK or € 8.700 [102]. The cash flow of an investment in a 5 kW residential PV installation, settled in accordance to the different historic regulations that has been used in Denmark, are illustrated in the following figures.

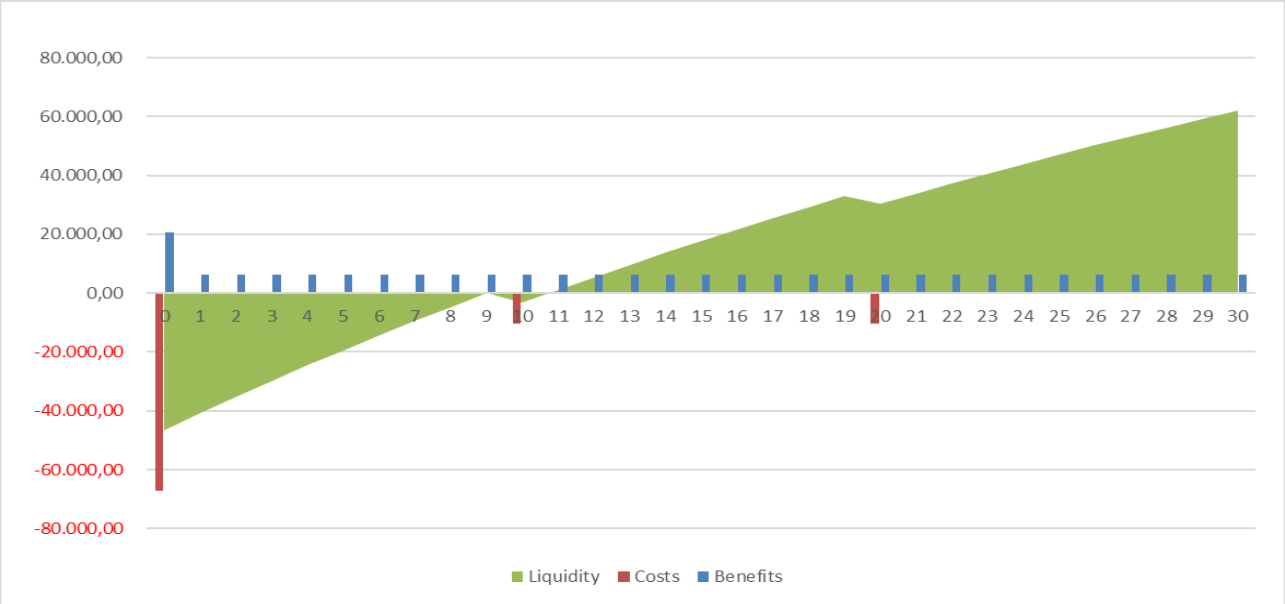


Figure 53: Discounted cash flow of residential PV installation, subsidized through yearly net metering and the 60/40 settlement.

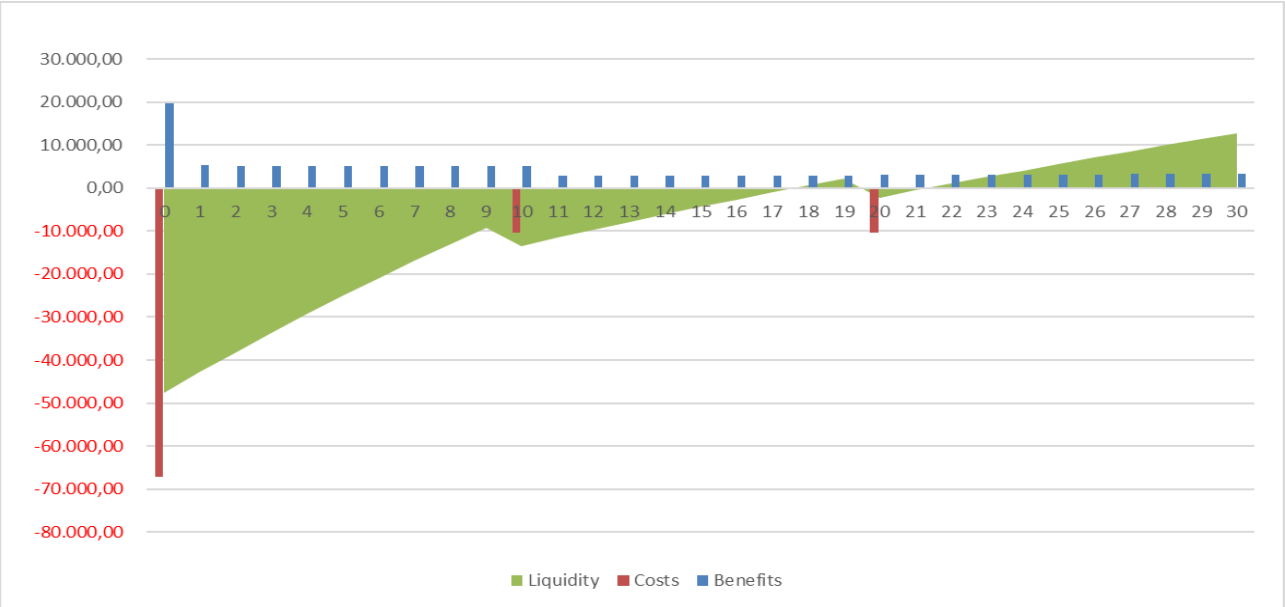


Figure 54: Discounted cash flow of residential PV installation, subsidized through hourly net metering and a supplementary FIT of 1,30 DKK/kWh of electricity sold to the grid, during the first 10 years of operation.

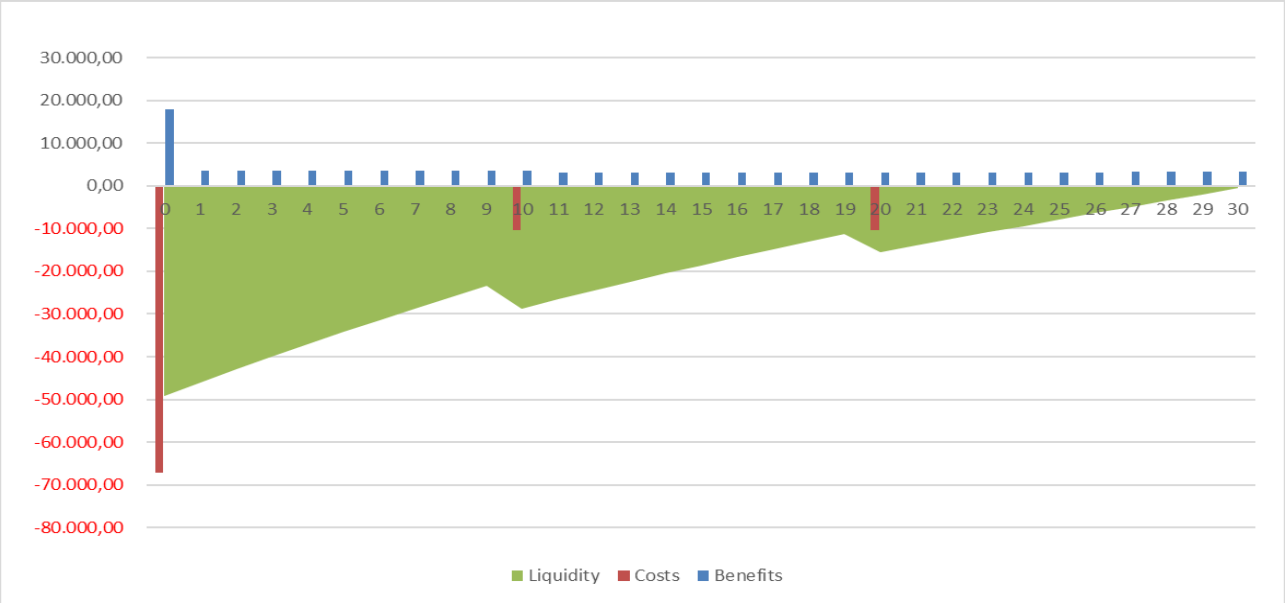


Figure 55: Discounted cash flow of residential PV installation, subsidized through hourly net metering and the 60/40 settlement.

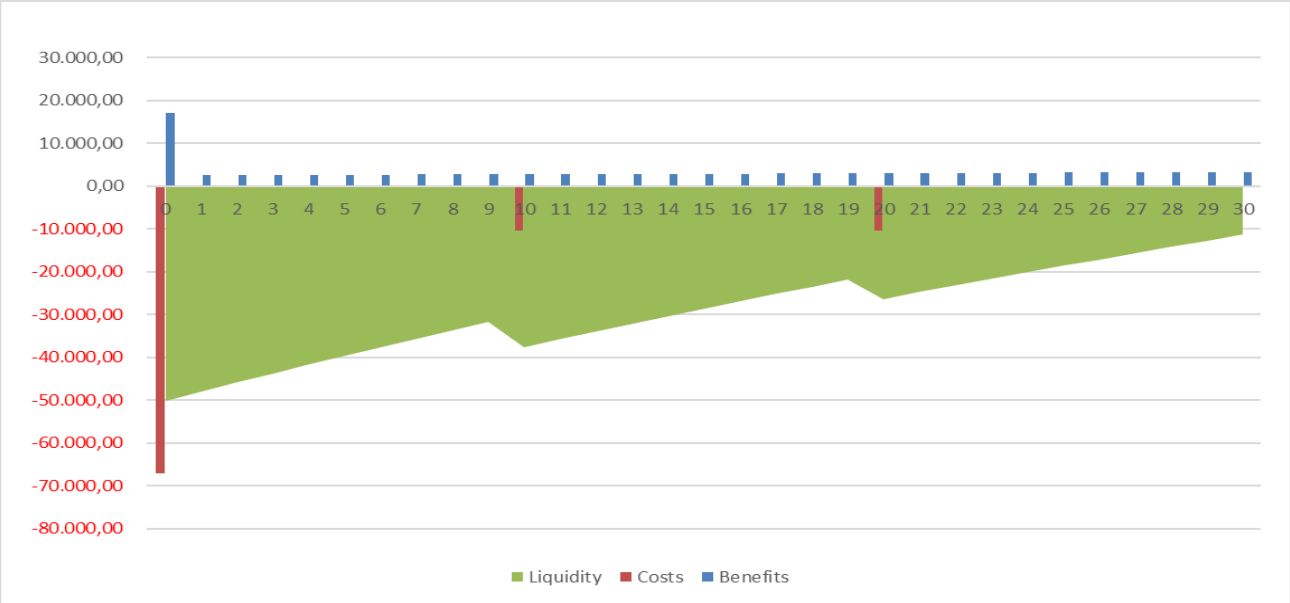


Figure 56: Discounted cash flow of residential PV installation, subsidized through hourly net metering and market priced sale of electricity to the grid.

From the above figures it can be deducted that the profitability of a residential PV installation was basically eliminated as the settlement schemes have changed.

As described above, the implementation of the annual net metering was a contributing factor to the fast implementation rate for residential PV, even though the surplus production was settled according to the 60/40 settlement. However, as the PV production and the household electricity demand are almost identical on an annual basis, it means that around 97% of the produced electricity is defined as own consumption, which makes the supplementary FIT almost uninfluential in relation to the business economy.

However, as described previously, the net metering scheme was made hourly in November 2012, which changed the characteristics of the settlement of residential PV installations fundamentally. This negatively influenced the project economy, mainly due to the reduced amount of electricity that is defined as own consumption, reduced to 35% of the production.

This is illustrated by Figure 54, where the FIT of 130 øre/kWh is used for settling the electricity that is sold to the grid. The reduced share of own consumption makes the supplementary FIT much more influential, as the majority of the production is settled in accordance hereto. The feed-in-tariff of 130 øre/kWh is sufficient to ensure a positive project economy, but in comparison to the annual net metering scheme, the NPV is reduced by a factor of around 6.

In June 2013, this high supplementary FIT was limited to a total pool of 20 MW of PV capacity. PV installations not entitled to this were settled in accordance to the 60/40-settlement. Figure 55 illustrates the project economy for the project, if settled in compliance to the 60/40-settleemnt. This was not sufficient for the investment to break even, as the NPV is negative.

As of April 2016 the 60/40 settlement has been abolished, so any residential PV installation not included in the before mentioned 20 MW pool, can only sell any surplus electricity production to the spot market price. As shown in Figure 56, the market price is not high enough to pay back the investment, and results in a negative NPV of -14.751 DKK, or € 1.980, and an IRR of 0%.

The economic key figures for the metering scheme in combination with the different supplementary feed-in-tariffs are summed in Table 16.

Table 16: Economic key figures for residential PV case

	Annual Net metering	**Hourly net metering**		
Settlement of surplus electricity		**20 MW pool**	**60/40 settlement**	**Market price**
NPV	62.016	9.967	-2.239	-14.751
IRR	11%	5%	2%	0%
PBP	10,76	18 (22[22])	0,00	0,00

This means that the business economy of the PV installation has gradually been reduced to a level that makes an investment in a residential PV installation unprofitable from a business economic perspective. It has to be kept in mind that PV has, in general, gone through relatively large price reductions in the period. Under the given assumptions, a price reduction of 16 % is sufficient to make the investment profitable, even with no supplementary FIT.

In general, the case study shows that the business economics for a residential PV installation are very much dependent on the characteristics of the net metering scheme. The higher the share of PV production that can be settled in accordance to the net metering scheme, the better the profitability. Therefore, it becomes crucial for the economy if the net metering is settled either on an annual or an hourly basis. Furthermore, it is found that the supplementary FIT has a relatively large impact on the business economy, when using hourly net metering, as a substantial share of the electricity is sold to the grid.

The dimensioning of the PV installation is crucial for residential PV, as the share of own consumption has to be kept as high as possible, and as a larger installation not necessarily increases the electricity production that can be settled in accordance to the net metering, but would have to be sold to the grid. This increased revenue from the sale of electricity is, in most cases, not enough to justify the increased investment costs, making the investment less profitable.

[22] As a consequence of the reinvestment in the inverter to liquidity of the projects turns negative again in year 20, resulting in a “second PBP” of 22 years.

However, the combination of hourly net metering and market price can be profitable if the PV installation had been smaller, as a larger share of the production could be settled in accordance to the net metering. This is illustrated in Figure 57, where the PV installation is down-scaled to 3 kW.

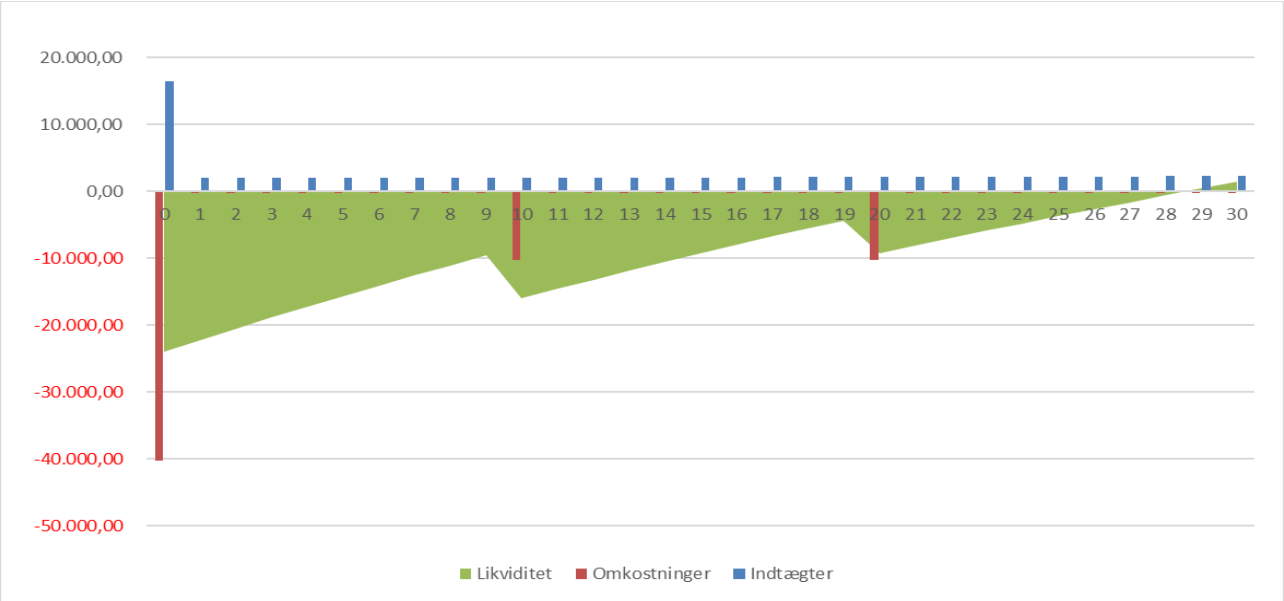


Figure 57: Discounted cash flow of a 3 kW residential PV installation, subsidized through hourly net metering and market priced sale of electricity to the grid

As illustrated in Figure 57, the higher share of own consumption, increased to approximately 50%, and lower investment costs are sufficient to make the investment profitable, resulting in an NPV of 1.376 DKK, or €185.

Other types of buildings having different characteristics than the residential sector, such as housing associations or public schools. These have a larger share of electricity consumption during the day, which leads to different economics, as analysed in the following paragraphs.

8.2 Photovoltaics owned by housing associations

As described before, a housing association has the possibility of making use of the hourly net metering of the share of electricity being used for common facilities, such as lighting in stairways etc. In addition, there has historically been different supplementary FIT for the electricity which is sold to the grid. These changes affect the economy of the project, and therefore the project economy is calculated for each of the recent settlement schemes.

Firstly, the calculations are made as if the project was settled in accordance to the hourly net metering scheme and a supplementary FIT of 1,45 DKK/kWh for electricity that is sold to the grid. This has been possible in the period from November 2012 till March 2013, when this settlement was limited to an annual capacity of 20 MW, as for the residential PV installations.

The analysed PV installation has a capacity of 618 kW, with a measured production of 612.287 kWh in 2015. In comparison, the housing association has a common electricity consumption of 1.753.874 kWh. On an annual basis, the PV production corresponds to one third of the total electricity consumption for common facilities. However, as the net metering is settled on an hourly basis, this does not necessarily mean that a high share of the production can be defined as own consumption. If the production is compared to the consumption on an hourly basis, it is found that a relatively large share of the production occurs in hours, when the electricity consumption surpasses the PV production. On an annual basis, around 73% of the production is defined as own consumption, while the remaining 27% is sold to the grid.

The total investment cost for the PV installation was 6,9 mill DKK excluding VAT, corresponding to €925.000. After 10 years, the reinvestment in the inverter is assumed to be 100.000 DKK.

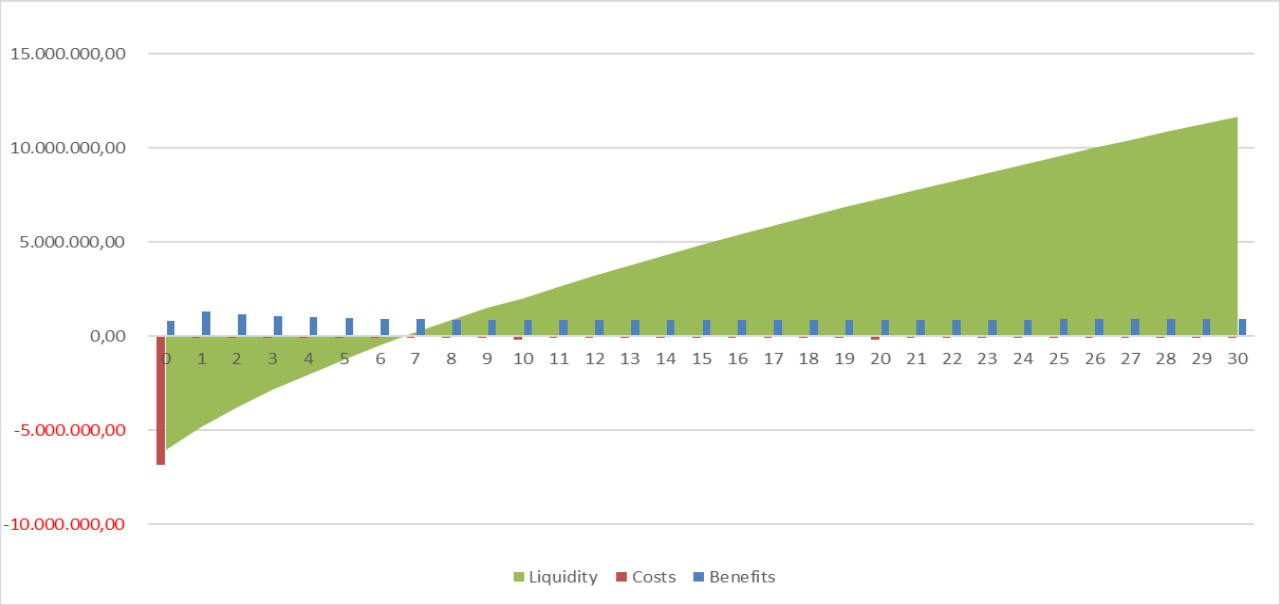


Figure 58: Discounted cash flow of PV installation, owned by housing association subsidized through hourly net metering and any electricity that is sold to the grid is sold to the market price.

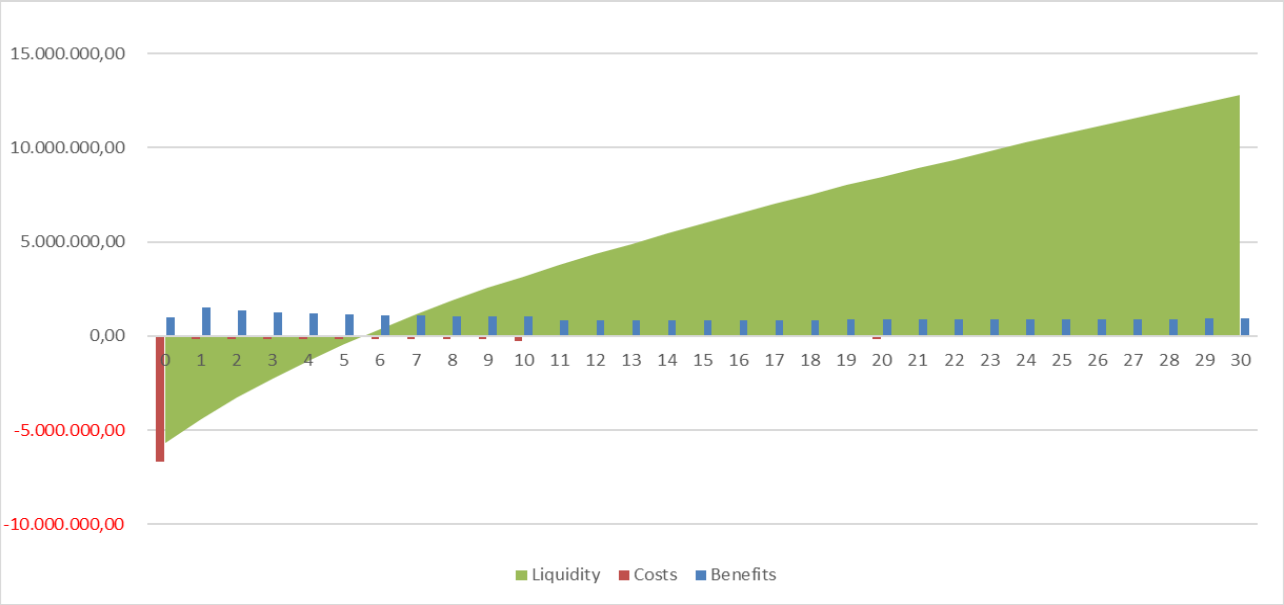


Figure 59: Discounted cash flow of PV installation owned by housing association subsidized through hourly net metering and a FIT of 1,45 DKK/kWh of electricity that is sold to the grid during the first 10 years of operation.

Figure 59 illustrates the cash flows as well as the liquidity for the project for 30 years, if settled by the combination of hourly net metering and a feed-in-tariff of 1,45 DKK/kWh. The calculations of the project economy results in a NPV of approximately 12,7 mill DKK, corresponding to around €1,7 mill[23]. The IRR is 18% and the payback period is found to be just below 6 years.

However, this favourable settlement of PV was limited to a capacity of 20 MW in March 2013. Any additional PV installations would still be entitled to make use of the net metering scheme, but any surplus electricity is settled in accordance to the market price. Figure 58 illustrates the cash flow for this scheme.

[23] Exchange rate: 7,44, 10/10 2016

If Figure 58 is compared to Figure 59, it becomes clear that the change of the supplementary FIT does not affect the project economics significantly, as even when settled in accordance to the market price, the NPV is 11,5 mill DKK or €1,5 mil. with a payback period of just below 7 years and an IRR of 15%. This is because 73% of the electricity production is defined as own consumption, which drastically reduces the importance of the supplementary FIT, as simply less electricity is delivered to the grid. The economic key figures for this case are summed in Table 17.

Table 17: Economic key figures for the case installation owned by a housing association

	Hourly net metering		
Settlement of surplus electricity	**60/40 settlement**	**20 MW pool**	**Market price**
NPV	11.994.760	12.666.697	11.514.445
IRR	16 %	18 %	15 %
PBP	6,3	5,6	6,7

As illustrated by the calculations, the changes of the supplementary FIT does not affect the business economy significantly. What really matters is how large a share of the electricity production is, that is defined as own consumption. Another important observation is that the project economy is favourable in all of the examples described above.

8.3 Photovoltaics in a public school

The PV installation on the public school was established in 2014-2015 and has a capacity of 126 kW. The total investment was approximately 1,27 mill DKK or €170.000, excluding VAT. The installation had a total production of 108.619 kWh during 2015 and the total electricity consumption of the school was 845.386 kWh.

As described in Section 7.2, PV installations have the possibility to make use of the hourly net metering scheme, but in opposite to a PV installation on a housing association, it is the total electricity consumption that forms the basis for how much of the production is defined as own consumption. Any surplus electricity is settled to a supplementary FIT of 130 øre/kWh, but as mentioned above, this has been limited to a total capacity of 20 MW since March 2013.

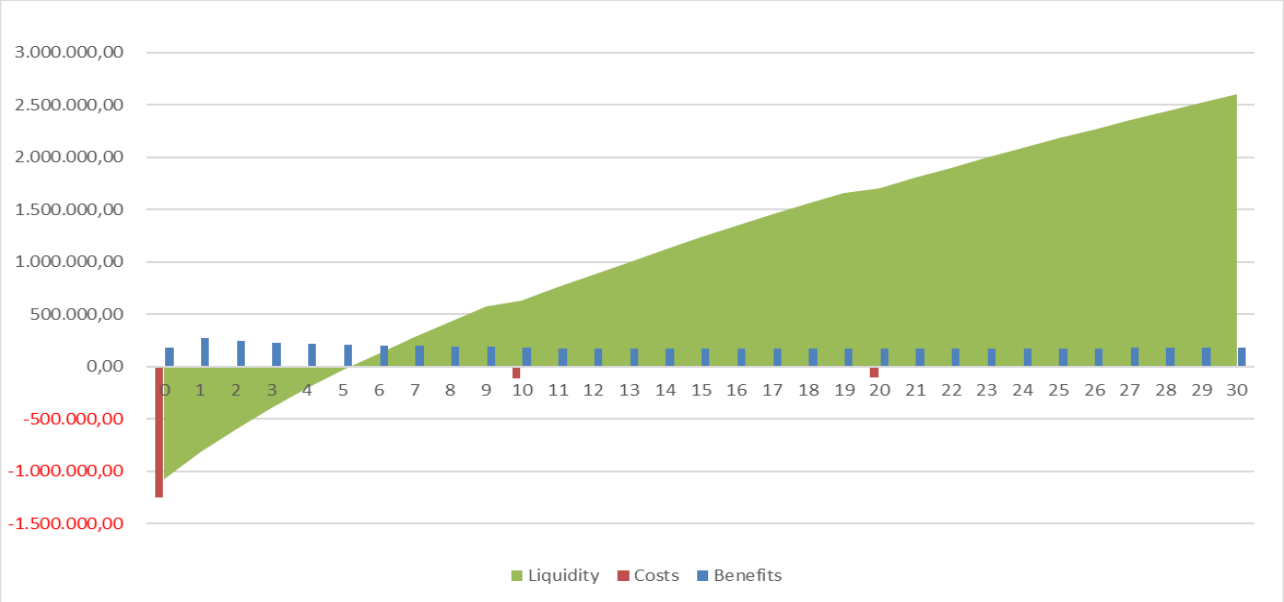


Figure 60: Discounted cash flow of PV installation, owned by a public school subsidized through hourly net metering and a FIT of 1,30 DKK/kWh of electricity that is sold to the grid during the first 10 years of operation.

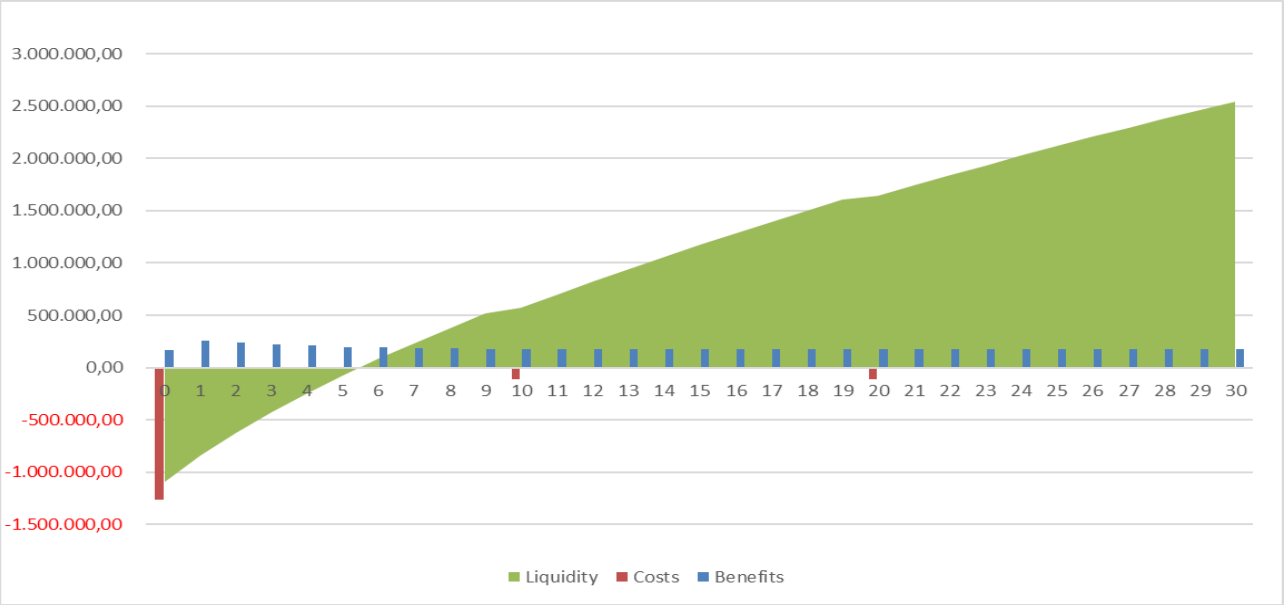


Figure 61: Discounted cash flow of PV installation, owned by a public school subsidized through hourly net metering and any electricity that is sold to the grid is sold to the market price.

The cash flow for this case is illustrated in Figure 60, with a supplementary FIT of 130 øre/kWh and Figure 61 where the surplus electricity is sold to the market price.

As illustrated in Figure 61, the installation is paid back in just over 5 years and over the lifetime of the investment, the NPV becomes around 2,6 mill., corresponding to €350.000. The IRR is 19%.

If Figure 60 and Figure 61 are compared, they look almost identical. However, there are small differences: as the NPV is reduced to around 2,5 mill (€336.000), the payback period is around 5 and a half years and the IRR is reduced to 18 %. However, the changes are minor, which is a consequence of that a huge share of the electricity is settled in accordance to the net metering, where 91 % of the production is coinciding with the electricity consumption on an hourly basis.

The economic key figures, when the PV installation is settled by the net metering scheme in combination with the different supplementary feed-in-tariffs, are summed in the following table.

Table 18: Economic key figures for the case installation owned by a public school

	Hourly net metering		
Settlement of surplus electricity	**60/40 settlement**	**20 MW pool**	**Market price**
NPV	2.560.147	2.592.720	2.530.834
IRR	18%	19%	18%
PBP	5,39	5,22	5,49

The results show that many of the same characteristics, as described for the housing association, also apply for a public school, which also shows favourable project economy in all of the examples described above.

Both housing associations and public schools are entitled for net metering, which is the main reason for the profitability of the investment. The higher the share of PV production that can be settled in accordance to the net metering scheme, the better the profitability. This is due to the fact that every kWh of electricity defined as own consumption substitutes a kWh from the electricity grid and thereby every kWh in principle has a value of 1,7 DKK/kWh.

In the investigated cases, the share of own consumption is relatively high, which reduces the impact of the supplementary FIT, as the amount of electricity that is sold to the grid is very limited. Furthermore, the supplementary FIT is of less value than own consumption in all cases.

If any electricity is sold to the electricity grid, the PV owner would have to pay taxes of the income generated. In 2015 the percentage of taxation was 23,5 % for commercial PV owners [103].

8.4 A commercially owned photovoltaic

The case of a commercially owned PV installation consists of a 320 kW PV installation, with a total production of approximately 290.000 kWh. This was installed at a business with a total electricity consumption of around 1.130.000 kWh. On an annual basis, this results in that 85% of the PV production is consumed within the business on an hourly basis and the remaining 15% is sold to the grid.

It has not been possible to identify the investment costs of the concrete PV installation, therefore an average investment price of 10.500 DKK/kW, or 1400 €/kW, was used. This results in a total investment of 3.360.000 DKK, or €452.000.

Unlike the previous cases, private businesses can occasionally be entitled for a reduced electricity tax, so instead of the 87,4 øre/kWh that normally is paid, they would only have to pay 0,4 øre/kWh for the share of electricity that is used for industrial processes. As it has not been possible to identify the share of electricity that is used for which purpose, it is assumed that 100 % of the electricity consumption is used for industrial processes, as this would illustrate the largest difference in comparison to the above cases and thereby better illustrate the different dynamics that this results in. Any revenue that is generated from the sales of electricity is subject to taxes, which also reduces the profitability of selling electricity to the grid. This is not the case for the savings obtained by net metering, which are not subject to taxes.

A commercially owned PV installation is entitled to use the hourly net metering scheme. As the largest electricity consumption occurs during the operating hours in daytime, a relatively high share of the electricity is defined as own consumption. In this case, 85% of the produced electricity is defined as own consumed on an hourly basis, but this does also reduce the influence of the supplementary FIT. Figure 62 illustrates the cash flows as well as the liquidity for the project for 30 years if settled by the combination of hourly net metering and a supplementary FIT of 1,45 DKK/kWh, that the project could be entitled to, if included in the 20 MW pool. The investment results in a NPV of around 1,24 mill DKK or € 167.500 during the 30 years period. However, as the investment also is relatively large, the payback period becomes around 18 years. The internal rate of return is 6%.

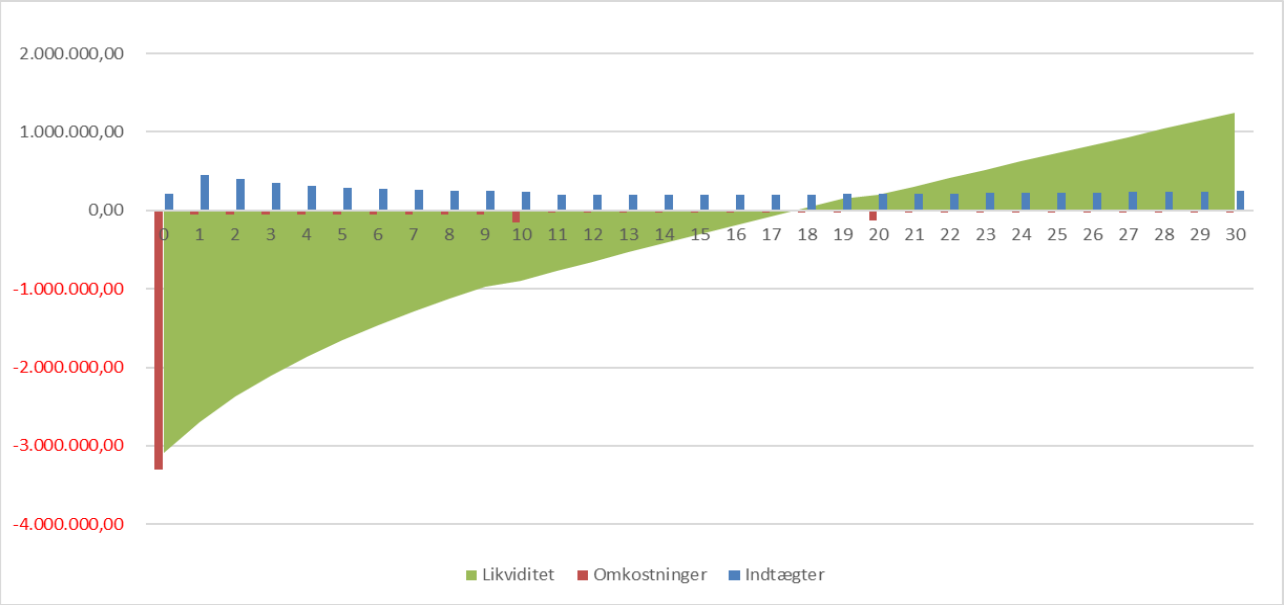


Figure 62: Discounted cash flow of PV installation, owned by an industrial business, subsidized through hourly net metering and a FIT of 1,45 DKK/kWh of electricity that is sold to the grid during the first 10 years of operation.

If the supplementary FIT is changed to correspond to the 60/40 settlement, the cash flow would look as illustrated in Figure 63. The change of supplementary FIT does only have a limited effect on the business economics. The NPV is reduced to around 1,1 mill. DKK or € 143.000 with an IRR of 5 % and a payback period of approximately 20 years.

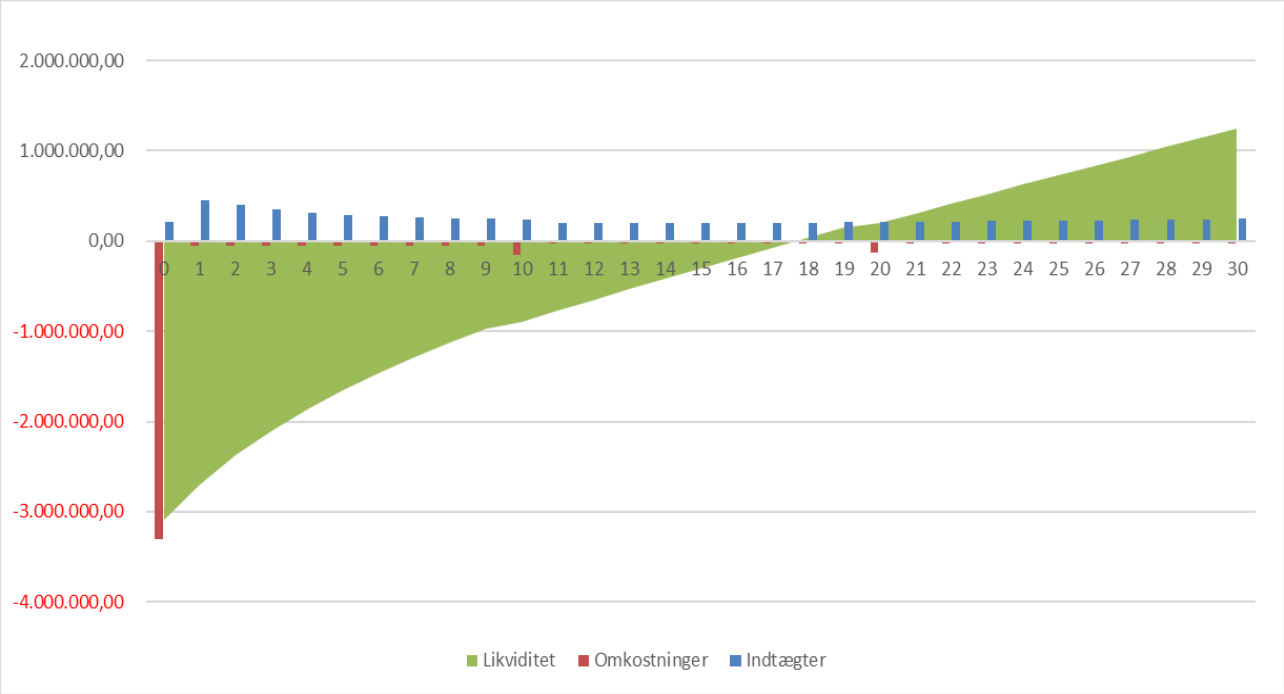


Figure 63: Discounted cash flow of PV installation, owned by an industrial business, subsidized through hourly net metering and the 60/40 settlement.

Even when changing the feed-in-tariff to the market price, the project demonstrates positive economics, as illustrated in Figure 63. When settled in accordance to the market price the NPV becomes approximately 960.000 DKK or €129.000, with an internal rate of 5% and a payback period of just under 21 years.

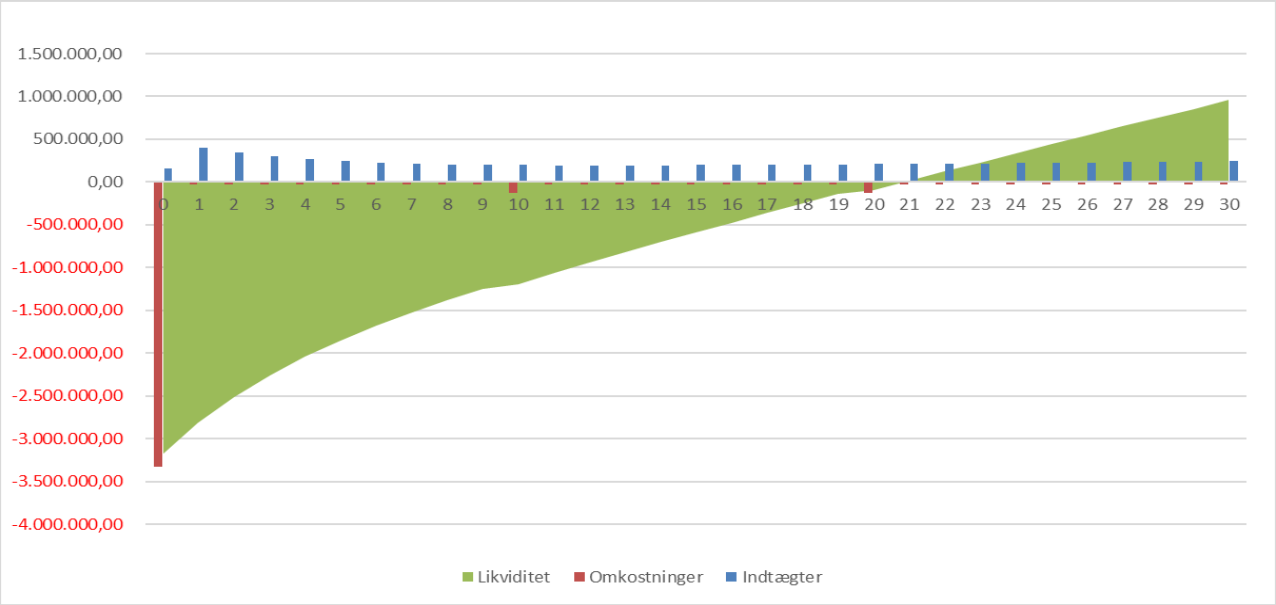


Figure 64: Discounted cash flow of PV installation, owned by an industrial business, subsidized through hourly net metering and market priced sale of electricity to the grid.

The economic key figures, a commercially owned PV installation settled by the net metering scheme in combination with the different supplementary FIT's are summed in the following.

Table 19: Economic key figures for the commercially owned case installation

Hourly net metering			
Settlement of surplus electricity	**60/40 settlement**	**20 MW pool**	**Market price**
NPV	1.063.960	1.243.634	956.993
IRR	5%	6%	5%
PBP	19,70	17,68	20,85

Even though almost all of the PV production is own consumed, the profitability is significantly lower than it was the case for both the housing association and the public school. This is mainly because of the reduced taxation of electricity, that the business is entitled for. Instead of paying 87,8 øre/kWh in electricity tax the businesses are entitled for a reduced tax of only 0,4 øre/kWh. This reduces the value of own consumption and thereby the business economic profitability of the investment. However the investment is still found to be profitable, regardless of the supplementary FIT.

8.5 Ground mounted photovoltaic installations

The FIT for free field plants has changed significantly during the recent years. In the following, the business economics are evaluated for the different settlements. The analysed case consists of a 2,1 MW free field PV installation, which provided a total production of 2.140 MWh in 2015. The total investment is around 20.000.000 DKK, or €2.688.570.

As described in Section 7.2, the regulatory framework made it possible for large ground mounted PV installations to be settled in accordance to a FIT of 130 øre/kWh during the first 10 years and hereafter in accordance to the market price. This was only possible for a short period. In order to be entitled hereto, the PV plant is divided into 5 separate plants with a capacity of 400 kW each. However this does not affect the calculations except for the FIT. As mentioned before, this case utilised a loophole in the regulation, which entitled the project for a high FIT, as the regulation was intended that large free field plants should only have

received 90 øre/kWh. The business economics for the case are illustrated in Figure 65, if settled to 130 øre/kWh and in Figure 66 for 90 øre/kWh.

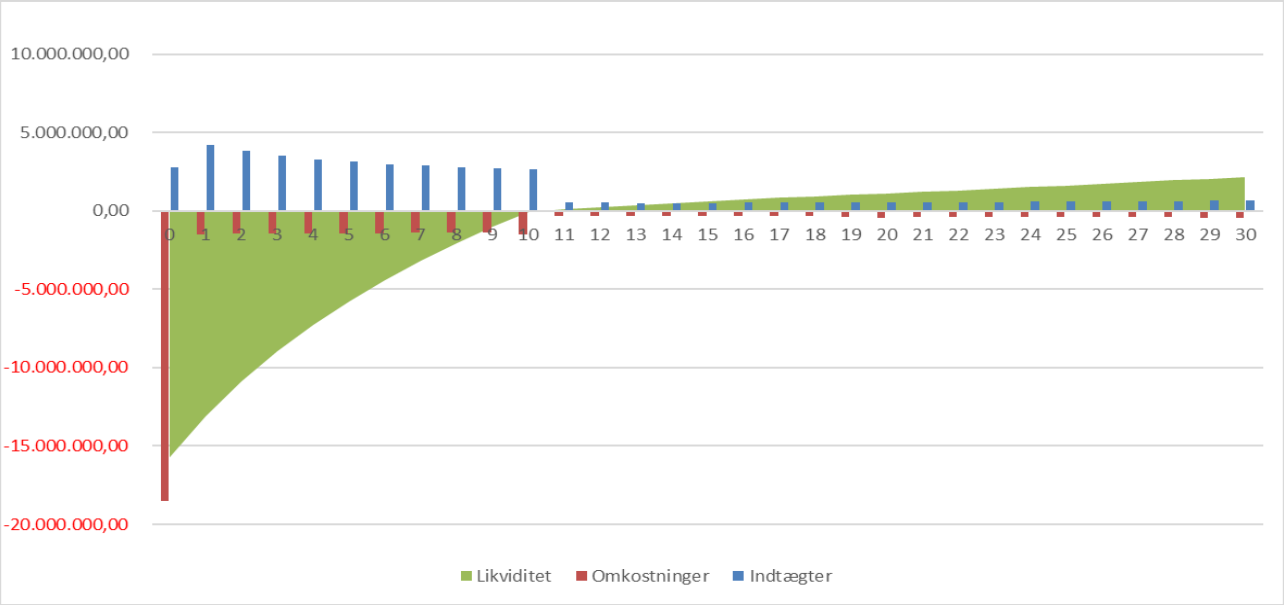


Figure 65: Discounted cash flow of ground mounted PV installation, settled to 1,30 DKK/kWh of electricity sold to the grid, during the first 10 years of operation.

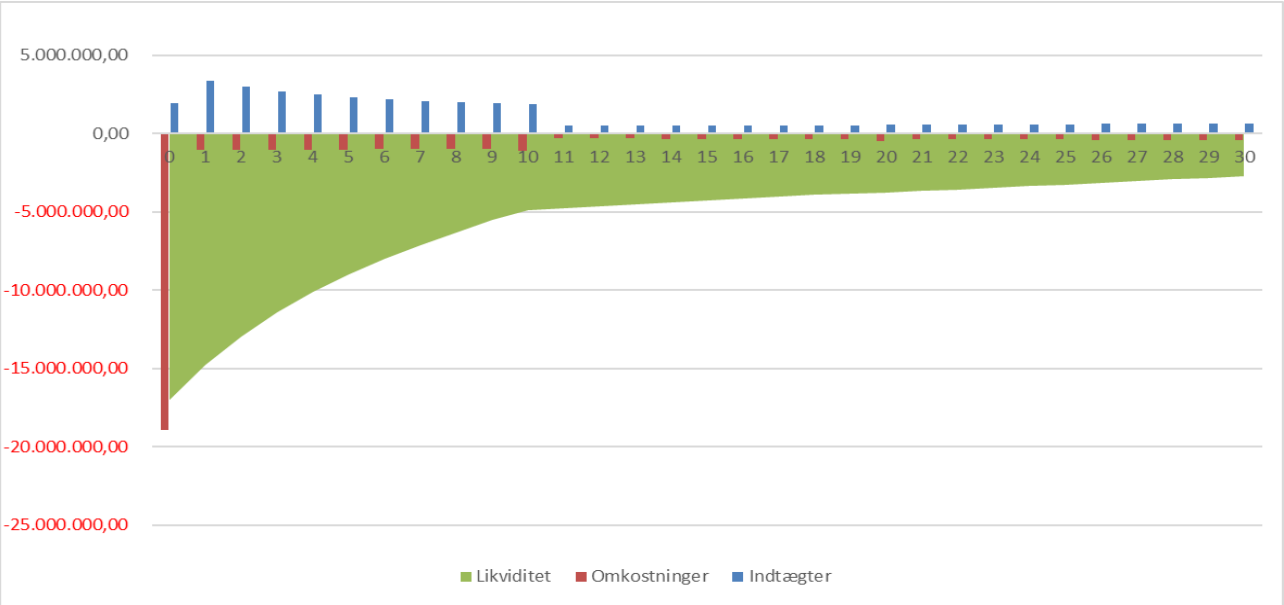


Figure 66: Discounted cash flow of ground mounted PV installation, settled to 0,90 DKK/kWh of electricity sold to the grid, during the first 10 years of operation.

As shown in Figure 65, the business economics have different characteristics than for the cases that has been analysed previously, as a relatively high income is generated during the first 10 years, where the project is entitled for the FIT of 130 øre/kWh. However, when this lapses, the annual income is reduced significantly, as the production is now settled in accordance to the market price which, on average, was 17 øre/kWh in 2015. This construction of the settlement scheme induces that the investment is paid back in just around 10 years, but as the revenue is reduced hereafter, the NPV is only around 766.000 DKK or € 103.000, which is relatively low compared to the previous cases. This is also illustrated by the IRR which is only 3%.

A FIT of 90 øre/kWh will deteriorate the business economy significantly, making the investment unprofitable. In this case, the NPV of the project would show a deficit of 4.100.000 DKK or € 551.000, resulting in an IRR of -2%. As illustrated in Figure 66, the tendencies are similar to what is illustrated in Figure 67, where it is shown that the majority of the revenue is generated during the first 10-year period, and is significantly reduced hereafter where the electricity is sold to the market price.

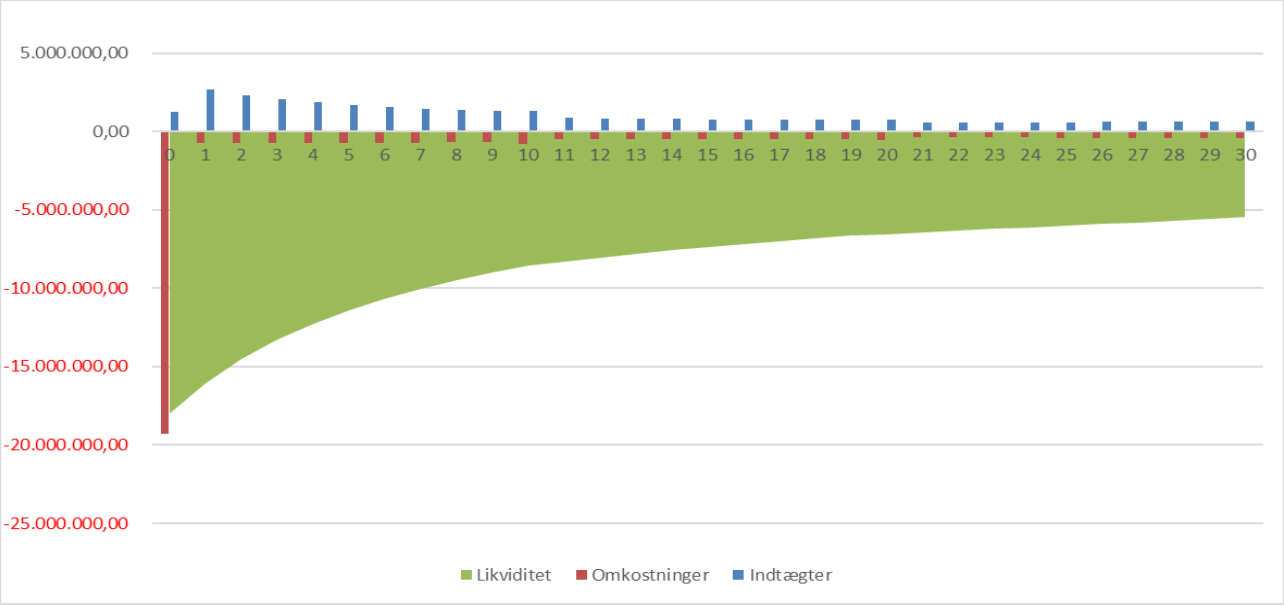


Figure 67: Discounted cash flow of ground mounted PV installation, settled in accordance to the 60/40 settlement.

When the settlement scheme was changed in June 2013, free field plants were not included in the new settlement, which could be obtained for a total capacity of 20 MW annually. Thereby, free field PV plants should be settled in accordance to the 60/40 settlement. As illustrated in Figure 67, the 60/40 FIT are not high enough to payback the investment, making the business economically unfeasible. The NPV shows a deficit of around 6.300.000 DKK, or €845.638, which is also reflected in the IRR, which is -3%.

The project economics is worsened further if the PV installation is settled without subsidies, which is the current situation for free field plants. This situation is illustrated in the following figure.

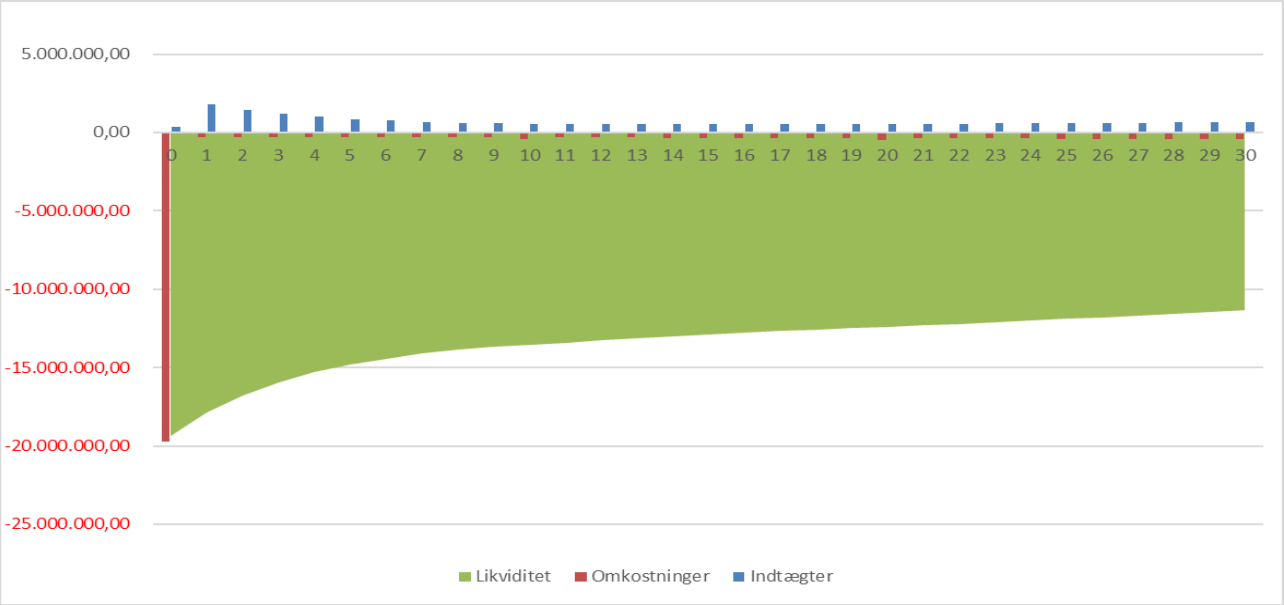


Figure 68: Discounted cash flow for ground mounted PV installations settled to the market price (not subsidized).

Opposite to the findings from the previous cases, the FIT has a huge impact on the project economy for free field plants, which is obvious, since net-metering is not relevant. In general, the economic benefits are much lower than for projects which can make use of net metering, making the investment substantially more unsecure.

Table 20: Economic key figures for ground mounted case installation

Settlement of electricity	60/40 settlement	Intended FIT for free field plants	Loophole	Market price
NPV	-6.279.756	-4.107.648	766.289	-12.993.446
IRR	-3%	-2%	3%	-10%
PBP	0,00	0,00	10,47	0,00

From the above, it can be concluded that the FIT should be relatively high in order to achieve a positive project economy for the case. However, the income generated from selling electricity to the grid is taxed, which is not the case for electricity settled in accordance to the net-metering. This means that the taxation has a larger impact on a free field plant, as all of the production is sold and thereby has a significant impact on the project economy.

8.6 Summary of case studies for business economics of photovoltaics

From the cases using net-metering, it is the general trend that the share of own consumption has the largest impact on the business economics. Therefore, the changes from annual to hourly net-metering are found to deteriorate the project economy significantly for the analysed cases, especially where there is low correlation between the actual electricity consumption and the PV production. This induces that the dimensioning of the PV installations will be optimized in accordance to the own consumption and not the actual technical potential on the roof on which the installations are implemented on. Furthermore, this reduces the influence that the FIT will have on the project economics, if the installation is dimensioned correctly.

The profitability will thereby depend on the electricity price and the taxes that can be saved by own consumption. The taxation and the value of own consumption is significantly lower for installations which are owned by commercial businesses, as they are exempted from most of the electricity tax.

However, this does not imply for the ground mounted PV installations, which are not entitled to net metering as these are not connected to a consumption unit. Therefore these installations are very dependent on the FIT.

It can be concluded, that even though the profitability has been gradually reduced by the regulatory changes, it is still possible to achieve a positive business case if the production profile fits well with the demand profile. However, as described previously, the installation rates for all types of PV installations have dropped significantly, which indicates that other barriers also have an influence on the implementation. These are analysed in the following chapters.

9 Discussion of support schemes for photovoltaics

If there is a political goal or wish of promoting PV, there are some technical, economic and non-economic barriers that would have to be addressed. These barriers are discussed in this chapter in combination with the knowledge about the role of PV in a future energy system as well as the knowledge from previous support schemes internationally and in Denmark. Finally, the advantages and disadvantages of the different support schemes are evaluated. The aim with this chapter is to further the knowledge about the support schemes in relation to the technical and economic knowledge we have about PV, as well as to make, in this report, some concrete suggestions on how to support PV in Denmark, in the executive summary.

9.1 Current regulatory barriers and challenges for new support schemes

The regulation of PV in Denmark and other countries has been subject to many changes during a relatively short time period, and for every change, the regulation has become more complicated when looking at the Danish case (see Chapter 7). This is found to be a very influential barrier that has a significant impact on the implementation rate for PV, as it has gradually reduced the economic incentives for PV. Just as importantly, it has created an uncertainty about the future regulation.

Furthermore, there are several transitional arrangements making PV installations installed within a certain period entitled to a higher FIT in accordance to an older settlement scheme. These does not represent themselves a barrier but Energinet.dk has to approve all these applications, creating a barrier as the processing time can be relatively long. The estimated processing time for these applications can be up till 45 weeks, which is considered as too long, especially if the construction/renovation of the buildings in itself has a tight timeline.

A characteristic of all the changes is that they have been back-trailing the price development of PV, which has been faster and more drastic than regulators and policymakers expected. As a direct reaction to this (and the increasing profitability of an investment in PV), the regulation has been changed many times ad-hoc in order to avoid “over compensation”. This illustrates the need for a robust and flexible regulation and settlement of PV, as the technological development goes fast. Already in 2012, this was foreseeable, and a suggestion separating production payment and demand was provided by the researchers behind this report [76].

Another aspect affecting the development of PV in Denmark is the lack of politically agreed targets for PV, as opposed to wind power, which can contribute to create uncertainty for potential investors.

Furthermore, the capacity limit of 20 MW can form a barrier, delimiting the implementation of PV. However, as it has been identified in Section 3, the installed capacity is lower than the limit for all of the included types of PV. This indicates that the uncertainties and both economic and non-economic barriers represent obstacles so important, that the capacity limit itself does not form a significant barrier. Based on the above, following barriers are identified:

1. “Stop-and-go” approach to the settlement schemes, which has gradually been made more and more unfavourable and increased the uncertainties affiliated with a PV investment;
2. The regulation is back trailing the development and becomes more and more complicated;
3. Long processing time for applications;
4. Lack of medium and long-term political targets for PV, creating uncertainty for market investments.

The development of residential PV installations has been very fast, but it stopped almost as fast as it began. One significant reason is most likely the so called “lemming effect”, where a positive or negative attitude towards a certain technology is created, which increases or reduces its implementation rate. The fast implementation of residential PV could be an example of this, where the implementation rate increased quite significantly over a short period of time, even though the settlement scheme had been present several years

before the boom occurred. The reason for the boom is most likely a result of coinciding factors which all contributed to the positive attitude towards PV and thereby the high implementation rate. The most influential factors are indicated to be:

- Falling prices for PV
- Very beneficial settlements and an increasing awareness of these
- The lemming effect and a general positive attitude towards PV in the population, where the media also could play a significant role

The announcement of the regulatory changes that happened in the beginning of 2013 in Denmark have affected the implementation rate in the last part of 2012, as people would invest in PV under the beneficial regulation.

Furthermore, there are identified additional barriers for the engagement of the municipalities. Even though the potential from the municipally owned buildings is relatively small, there are some special regulatory barriers that only apply for municipalities, which are important to understand their possibilities. The requirement that PV installations have to be organised in separate corporations with limited liability, can form a barrier for municipal involvement in PV projects, as hourly net-metering is only possible if the PV installation is owned entirely by the same legal person that uses the electricity. This is not possible if it has to be organised in a separate corporation with limited liability, which thereby reduces the economic incentive for a municipality to get involved in PV-projects. Thereby, the incentives for municipalities to invest in PV becomes directly dependent of their possibilities to obtain an exception.

As PV are regulated in accordance to the Danish Electricity Act, the municipalities are not allowed to obtain low interest loans in KommuneKredit[24] [96]. This induces, that municipalities will have to obtain loans on market conditions, resulting in a higher interest rate. For a municipality, this can be seen as a barrier. This, in combination with the reduced economic incentives as a result of the changes in the settlement, can form a significant barrier.

Lastly, the advanced legal constructions of companies, which have to be established in order to avoid deduction from the block grants from both electricity savings and potential profit for sale of surplus electricity production, can be a barrier, as they require a lot of administration and can be relatively expensive to establish [104]. Thereby, the establishment process of such company constructions also reduces the economic incentive for a municipality to make an investment in a PV installation. Furthermore, this adds to the complexity of the rules to be taken into account before deciding on a PV investment. This very complex regulation is also found to be an important barrier.

Some municipally owned district heating companies, harbours and water suppliers have a general tax exemption which lapses, if they invest in a PV installation. In some cases, this would not only affect the income which is generated from the sale of electricity, but all of the company. This reduces the incentives significantly, as the taxation would have much higher impacts on the company´s economy than any revenue that can be generated from a PV installation [105].

Based on the above, the following barriers are identified as influential on the incentive for municipal engagement in PV projects:

5. Hourly net-metering is not possible because PV installations have to be organised in separate corporations with limited liability and uncertainties regarding the possibilities of exemptions;
6. The lack of low interest funding through KommuneKredit;

[24] KommuneKredit is a non-profit organisation which offers low interest loans for Danish municipalities and Regions [112].

7. Expensive and complicated legal constructions of municipal companies have to be established in order to avoid deduction from block grants.

Therefore, it can be concluded that there are both economic and non-economic barriers having an effect on the implementation rate for roof mounted PV in Denmark. In order to overcome these barriers, and to ensure that the profitability of the investment is sufficient to facilitate an implementation rate accommodating the needed capacities as identified in chapter 4, characteristics for a potential new regulatory framework are discussed in the following.

9.2 Main Characteristics for support schemes and markets for photovoltaic

Based on the above barriers and the conclusions from various chapters, we propose the following characteristics for a new PV scheme:

1. Separation of demand and supply
    - Lower incentives for electricity savings
    - Incentives for unwanted decentral battery solutions
    - Wrong incentives in the building codes beyond 2015
2. Subsidies should not be based on exemptions from tariffs or taxes
3. Not limiting the installation size
4. Flexible in terms of new technological and price developments
5. Easy to administer
6. Independent of ownership

9.2.1 Separation of demand and supply

As described in Chapter 7, the majority of the subsidies are provided indirectly, as a consequence of the net-metering scheme. There are some problematic consequences related to this type of subsidies, which are addressed in the following.

Lower incentives for electricity savings

The profitability of an investment in a PV installation is very dependent on the amount of own consumption, as this has a much higher value than the share which is sold to the grid, due to the exemptions from taxes. This creates a lack of incentives for reducing the electricity consumption, as this also will reduce the amount of own consumption and a higher share thereby would have to be sold to the grid, at a much lower economic value.

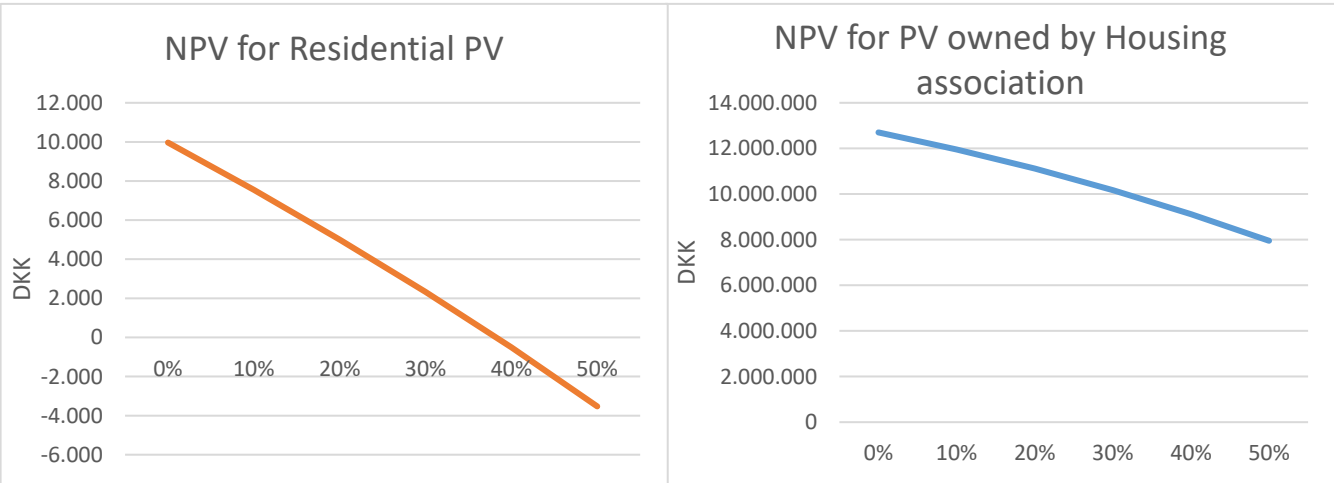


Figure 69: The NPV for PV installations owned by a housing association and a residential PV

Figure 69 shows the NPV of a PV installation owned by a housing association and a residential PV installation respectively, as a function of electricity reductions from 10% to 50%. It is based on the settlement with hourly net metering and the high FIT of 130 øre/kWh. The electricity savings are assumed to be evenly distributed amongst every hour of the year. It has to be kept in mind that any savings imposed by the reduced electricity purchase are not taken into consideration in these examples.

Looking at the graphs it becomes clear, that any electricity saving will reduce the NPV of the investment, when hourly net-metering is used. The same tendency would be observed if annual net metering had been used although the reductions would only occur when the annual electricity consumption would be reduced below the total annual PV production. The above described tendencies would only be more evident if the FIT was changed to a lower value, which is the case for the current settlement scheme. The proposed regulation should therefore not reduce the incentives for electricity savings.

Incentives for unwanted decentral battery solutions

The profitability of a PV installation is highly dependent on the share of electricity that can be own consumed, which also incentivises the implementation of small decentralized battery solutions, which are found to be unbeneficial for the overall energy system as well as the socio-economy. It is therefore recommended, that a future subsidy scheme separates the settlement of the PV production from the consumption of electricity and thereby not incentivizing the implementation of battery solutions. This is especially problematic for residential PV installations, as most of the PV production occurs during the day where most people are not at home, resulting in a relatively low electricity demand within the household and thereby a relatively low own consumption, which can be increased by implementing a battery. This incentive is not as evident for PV owners that have a higher consumption during the day, as they already have a high share of own consumption and the increased profitability, as a consequence of implementing a battery, would most likely not be sufficient to cover the investment in such.

Furthermore, the huge incentive to consume the electricity within the building is found to be unbeneficial, as it reduces the benefits that the implementation of PV can have on the overall energy system, which in some cases can benefit from decentralized electricity production.

Especially private households are incentivised to implement PV (or other renewable energy electricity production units) in order to fulfil the energy performance according to Building Regulations, which implies that the implementation of PV is defined as being an energy saving. This is problematic, due to several reasons:

- There is the risk that electricity will be stored in the building, in spite of high electricity demands elsewhere in the energy system, which are being supplied by fossil fuels. This could alternatively be substituted with the PV production, reducing the consumption of fossil fuels.
- With the implementation of battery solutions, a situation where the electricity demand is reduced, as electricity is used form the batteries, even though the production of renewable energy production is high and the demand (and prices) are low.

These reasons make decentral battery solutions extremely expensive, as these are found to be around 100 times more expensive than thermal storage and around 1000 times as expensive as gas and liquid fuel storages [106]. Furthermore, individual storage is more expensive than large-scale storage, due to economics of scale, making the installation and operation of a large battery of 10.000 kWh substantially cheaper that the operation of 1.000 decentral batteries of 10 kWh in individual buildings [106].

In the IDA Energy Vision 2050, it has been demonstrated that the role of the building stock is limited when it comes to providing flexibility to the energy system, as this can be provided much more cost effectively elsewhere in the energy system [11]. It is also important that the mismatch between the energy production and consumption does not influence the energy system significantly, but the aggregated mismatch can have

a significant impact. Therefore, the mismatch should also be levelled out on an aggregated level, since this is more cost effective and beneficial to the energy system. If trying to limit the mismatch in each individual building, situations can occur where the battery in one building is charged while it is discharged in another building. This leads to increasing energy losses, which could have been avoided as the two mismatches could level each other out on an aggregated level. This will also lead to a severe over dimensioning of the storage space required in the system, which increases the costs further [106].

Wrong incentives in the building codes beyond 2015

In the Danish Building Code (BR15), energy frames after 2020 are defined for new residential and non-residential buildings for the net primary energy demand. For residential buildings and non-residential buildings these energy frames are 20 kWh/m2 /year and 25 kWh/m2 /year, respectively. In order to achieve the strict BR15 – 2020 energy levels, it is permissible to install energy production units on-site or nearby the buildings, for example solar PV in combination with a battery. However, this is not a recommended solution in the context of the energy system, where cost-effective targets should be set for the insulation of buildings and cost-effective support schemes should be promoted for renewable. This is further elaborated in Mathiesen et.al, 2016 [106].

9.2.2 Subsidies should not be based on exemptions from tariffs or taxes

Most of the subsidy that is provided for net-metered PV installations consists of the exemption of taxes, tariffs for distribution, transmission and PSO. Figure 70 illustrate the distribution between direct subsidies for the electricity production which is sold to the grid and the indirect subsidies which are provided as exemptions from taxes and PSO for the electricity that is settled in accordance to the net metering:

Figure 70: Distribution between subsidies in 2 cases of PV installations

As illustrated in the figures above, over 50% of the total subsidies are provided indirectly through the net metering. This is not found to be beneficial, as it makes difficult to adjust the level of subsidy. This will mainly be dependent of the taxation of electricity and how this would change in the future. Furthermore, it makes the level of subsidy less transparent.

All PV owners will depend on the electricity grid to some extent, even with household level batteries, as the PV installation in some hours produces more electricity than is consumed and vice versa. Therefore, the subsidies for PV should not be based on an exemption from tariffs, which amongst others are used to maintain the electricity grid. The PV owners should contribute to maintaining the grid as well if not the increasing expenses should result in increasing prices for the remaining electricity consumers without PV.

On this background it is found to be beneficial that the new subsidy scheme separates the subsidies for PV and the taxation of electricity and that any subsidies thereby are given as direct subsidy.

Another aspect that becomes evident from Figure 70 is that for commercially owned PV installations, the majority of the subsidies are provided through the exemption from the PSO, as electricity for industrial

processes is taxed by the minimum amount, as defined by the European Commission (0,4 øre/kWh). However, the Danish PSO is about to change, which would drastically reduce the profitability of the investment in PV. This is also an argument for separating the settlement of PV from the electricity consumption and the payment for this.

9.2.3 Not limiting the installation size

As concluded in chapter 5, it is more economically feasible to utilize the larger roofs for PV installations in comparison to smaller roofs due to economy of scale. Therefore, a new settlement scheme should not provide incentives for limiting the installed capacity for each installation, but should facilitate that all of the available roofing area is utilized if the solar radiation is favourable. In fact, a future support scheme should incentivise larger roof installations over 400-500 m^2.

This is not the case with the current subsidy scheme, where the capacity for residential PV installations is limited to 6 kW, while some roofs may be larger and could have had more capacity. With larger capacities installed, the chances of self-consumption is also smaller. This tendency is evident, because the investment increases in relation to the size of the PV installation, which was not the case for the electricity savings, where the investment in the savings is excluded.

9.2.4 Flexible in terms of new technological and price developments

Another aspect, making it difficult to adjust the level of subsidy when using a net-metering scheme, is that the subsidies are dependent on the development of taxation and tariffs. In the Danish case, the net-metering scheme is supplemented by a FIT, but the FIT does not affect the profitability of the investment significantly, in most cases. This can be problematic as the FIT is the only parameter that can be adjusted in accordance to the price development. A new subsidy scheme for PV should, to a larger extent, be able to take into account future price developments of PV.

The prices of PV installations are expected to decrease between 43-65% until 2025, as described in Section 2, with BoS costs accounting for the largest cost reductions. Module and inverter costs are also expected to decrease further during the coming decade. Moreover, researched cell efficiencies are continuously increasing: as an example, crystalline silicon cells can in theory reach efficiencies of up to 40-50% in comparison to 20-25% currently achieved [107]. Altogether, this means that system prices and PV electricity production costs are expected to decrease significantly in medium term.

These future developments require any domestic PV regulation scheme to be flexible, due to a number of reasons:

- Installing large PV capacities in the short term will reduce the potential to exploit future cost reductions due to better PV plant design and improved components etc.
- The Danish PV industry identifies inverters, energy system integration and storage, BIPV and building-adapted PV solutions, technology-integrated PV solutions (e.g. solar pumps) as some of the main Danish competences in the PV sector [107].
- Apart from inverters and research in PV cells, most components of traditional PV systems are developed and produced outside Denmark, and are therefore not as dependent on Danish PV regulation, but more on the demand in larger PV markets. It is also very likely that Danish inverter and cell development is mainly driven by larger markets, for instance, in Germany and China.
- It can therefore be doubted to what extent a Danish support scheme actually drives cost reductions in PV systems currently being installed in Denmark.

As a consequence, a new PV support scheme should regularly respond to these developments in PV technology, by:

1. Continuously (for example annually) adapting the support scheme to the development in PV system prices;
2. Continuously developing provisions that help support and develop core competences within the Danish PV industry (for example within BIPV, technology-integrated PV, energy system integration) through e.g. R&D funding and new technical standards.

9.2.5 Easy to administer

Another aspect found to pose a barrier to the implementation of PV, is the long processing times for Energinet.dk to approve applications. The processing time should be reduced as much as possible, why a new subsidy scheme should be easy to administer. The implementation of PV will most likely include a very diverse type of projects, from small-scale residential installations to large free-field plants of several MW. This has to be reflected in the administration of a new subsidy scheme, which has to be able to handle both types without making it hard to administer. Furthermore, the regulation of PV should be streamlined, and all of the different regulation types should be abolished and replaced by a more clear set of rules. An example on this could be that PV should no longer be a requirement of the building code for 2020 (BR2020).

9.2.6 Independent of ownership

As described in Chapter 7, the current subsidy scheme is much dependent on the ownership of the PV installations, an unbeneficial solution that can reduce the incentives for some projects, even though the technical circumstances can be very favourable. The leading principle should be that the most favourable places for PV should be utilized at first, regardless of the ownership of the building. Furthermore, it could be made easier to form “PV-cooperatives”, where several private persons form an investor group, or invest together with a company or farmer, who has an available rood. This can facilitate that the lowest costs options are used, and so that those citizens who can no longer get support for a household level PV installation can now be a part of a bigger unit. In this respect long term rental models could be considered, where after 20 years e.g. the installation is transferred to the owner of the roof.

9.3 Evaluation of public regulation schemes for photovoltaics in Denmark

In the following, a recent proposal regarding daily net-metering is analysed. Furthermore, FIT/FIP, TGC and tendering schemes are found to be effective in promoting PV in different countries around the world, see Chapter 5. Therefore, these subsidy schemes are discussed in relation to the above-mentioned characteristics.

9.3.1 Evaluation of net metering schemes

Recently, it has been proposed to make the net metering scheme daily (24 hours) instead of hourly. The arguments for this are that the Danish electricity grid has the necessary capacity to handle the daily fluctuations of PV production. Furthermore, it would reduce the incentives for investments in decentralised battery solutions found to be unbeneficial for the energy system. In chapter 8 an hourly net metering scheme was analysed. In the following, the economic consequences of a daily net metering scheme are analysed for the cases also analysed in chapter 8.

Housing associations

For housing associations, the shift from hourly to daily net metering will induce that around 99% of the electricity that is produced is consumed for common facilities in the building, meaning that the electricity is settled in accordance to the net metering. As almost the entire production is settled in accordance to the net metering scheme, the supplementary feed-in-tariff becomes almost un-influential. Therefore, the cash flow is very positive when settled on a daily net metering scheme. As illustrated in Table 21, the change to a daily net metering scheme will improve the project economy significantly in comparison to the current (hourly)

net metering. It is to be seen that the NPV is increased to around 16,4 mill DKK or € 2,2 mill, resulting in an IRR of 21% and a payback period of just below 5 years.

Table 21: Evaluation of net meeting combined with different settlement schemes for housing associations

	Hourly net metering			Daily net metering		
Settlement of surplus electricity	**60/40 settlement**	**20 MW pool settlement**	**Market price**	**60/40 settlement**	**20 MW pool settlement**	**Market price**
NPV (DKK)	11.994.760	12.666.697	11.514.445	16.413.264	16.423.774	16.407.908
IRR	16 %	18 %	15 %	21 %	21 %	21 %
PBP	6,3	5,6	6,7	4,8	4,8	4,8

A public school

In the case of a public school, there is 100 % compliance between the PV production and the consumption, making the feed-in-tariff redundant, as no electricity is delivered to the grid. With daily net metering the NPV is 2,8 mill., or € 376.000, giving an IRR of 20%. The total investment is paid back in just under 5 years.

Table 22: Evaluation of net meeting combined with different settlement schemes for a public school

	Hourly net metering			Daily net metering		
Settlement of surplus electricity	**60/40 settlement**	**20 MW pool**	**Market price**	**60/40 settlement**	**20 MW pool**	**Market price**
NPV (DKK)	2.560.147	2.592.720	2.530.834	2.835.462	2.835.462	2.835.462
IRR	18%	19%	18%	20%	20%	20%
PBP	5,39	5,22	5,49	4,95	4,95	4,95

Household PV installations

In the case of a household PV installation settled in accordance to a daily net metering scheme and any surplus electricity is settled to the market price. Even if the surplus electricity is settled to the spot market price, the change in the net metering scheme is sufficient to make the investment profitable, as the NPV is found to be around 19.500 DKK, or around € 2.618, with a PBP of 21 years, when taking into account the additional investment in a new inverter in year 20 of the 30-year lifetime. This is due to the fact that a larger share of the electricity is settled in accordance to the net metering scheme, which corresponds to 61%. Therefore, this reduces the influence of the feed-in-tariff and improves the project economy, resulting in a NPV of 33.871 DKK, or € 4.546, with a PBP of around 13 years.

Table 23: Evaluation of net meeting combined with different settlement schemes for household installations

	Annual Net metering	Hourly net metering			Daily net metering		
Settlement of surplus electricity		**60/40 settlement**	**20 MW pool**	**Market price**	**60/40 settlement**	**20 MW pool**	**Market price**
NPV (DKK)	62.016	-2.239	9.967	-14.751	26.674	33.871	19.511
IRR	11%	2%	5%	0%	6%	8%	5%
PBP	10,76	0,00	18 (22[25])	0,00	16,10	13,21	19 (21[26])

[25] As a consequence of the reinvestment in the inverter to liquidity of the projects turns negative again in year 20, resulting in a "second PBP" on 22 years

[26] As a consequence of the reinvestment in the inverter to liquidity of the projects turns negative again in year 20, resulting in a "second PBP" on 21 years

As described above, a change to a daily net metering scheme can make the economics of an investment in PV more profitable, for all of the analysed cases. However, as described in Sub-Section 7.1.3, there are some unbeneficial characteristics with the current net metering scheme. In the following, it is investigated, if a daily net metering scheme reduces the influence of these.

Separation of demand and supply

As the net metering is still significantly more profitable than delivering the produced electricity to the grid, the daily net metering scheme will still provide very little or no incentive for electricity savings, as it will reduce the amount of electricity that can be settled in accordance to the net metering.

The change to a daily net metering scheme increases the share of own consumed electricity for all of the analysed cases. For both the housing association and the public school, almost the entire production is own consumed. This will reduce the incentives for the implementation of decentral battery solutions, as the usage hereof will be very limited.

For the residential PV installation, the share of production that is own consumed corresponds to around 60% which induces that there still will be an incentive to install a battery in order to increase this, as it will increase the economic benefits. Under the assumptions that a battery is installed, increasing the share of own consumption to 100%, the NPV will be increased to around 62.000 DKK, or around € 8.300. However, the increased investment in a battery is not taken into account in this estimate.

It can thereby be concluded, that the daily net metering does not incentivise electricity savings and still incentivises the implementation of battery solutions.

Subsidies should not be based on exemptions from tariffs or taxes

As a larger share of the PV production is settled in accordance to the net metering scheme, the share of subsidies that are based on exemptions from tariffs and taxes are increased in comparison to the hourly net metering scheme, which intensifies this problem. In the case of both the public school and the housing association, the subsidies will be entirely dependent on the development of the taxes, tariffs and the electricity price, making it impossible to take into account future price reductions of PV installations. This problem is also intensified in comparison to the hourly net metering scheme, as the share of own consumption is increased.

Not limited to a certain capacity

As described, the profitability of the PV investment is dependent on the share of own consumption, which induces that the plant should be dimensioned in order to reach the highest possible share hereof. Therefore, as it was the case for the hourly net metering scheme, the incentive for installing a plant which has a production that is higher than the electricity consumption is very limited.

Flexible in terms of new technological and price developments

The net metering scheme will also on an hourly basis be subject to high risks of being jeopardised due to falling prices. The profits are already rather good and would increase, while the level of public spending will also have to increase.

Easy to administer

In comparison to an hourly net metering scheme, the daily net metering is estimated to cause a similar administrative burden.

Independent of ownership

The daily net metering scheme can be made independent of the ownership, depending on the actual design of the subsidy scheme.

The pros and cons for a daily net metering scheme are summed in Table 24. As described above, a daily net metering scheme has many of the same problematic characteristics that has been identified for the current hourly scheme.

Table 24: Advantages and disadvantages of daily net meeting

Daily net metering	
Pros	**Cons**
Increased profitability	Not adjustable in accordance to price development
	Profitability depends on share of own consumption
	No incentive for electricity savings
	Incentivises decentral battery solutions
	Subsidies based on exemption from tariffs and taxes
	Very little incentive to install large capacities of PV

9.3.2 Feed-in-tariff/Feed-in-premium

A feed-in-tariff/Feed-in-premium has the potential to address many of the characteristics that are described in Section 9.2.

Separation of demand and supply

One of the main characteristics for the FIT/FIP is that all of the production is sold to the grid, and that it therefore is totally separated from the electricity consumption [78], [79], which eliminates the incentives for implementing battery solutions. As the total production is sold to the grid at a predetermined price, the profitability of the PV investment is not affected by any reductions of the electricity consumption [78].

Subsidies should not be based on exemptions from tariffs or taxes

As a consequence of the separation of the production and the consumption, all of the subsidy that is provided will be given as direct subsidies, and is thereby also separated from both tariffs and taxes.

Flexible in terms of new technological and price developments

The FIT/FIP can also be adapted to the future price development, as the FIT can be revised as needed in order to avoid “overcompensation” [78]. Furthermore, the following characteristics can be addressed, however not as a consequence of the FIT-scheme itself, but to a higher extent of the design of the supplementary regulation and the actual design of the settlement scheme.

Not limited to a certain capacity

There are two aspects to take into account, as the subsidy scheme should not be directly limited to a certain capacity, such as it currently is for the case of residential PV, which is limited to 6 kW. This can be addressed in the design of the FIT-scheme and promoting those sizes that are feasible for society. It is also important that the FIT/FIP scheme does not indirectly limit the capacity which is profitable to install, as it is the case for the net metering scheme.

Easy to administer

It may be hard to determine that appropriate level of the FIT/FIT. If such a scheme is chosen, it can be recommended to have revisions of the level every 3-6 months also in accordance with the desired role out rate of capacity [83]. It should also be noted that one FIT/FIP does not fit for all types and sizes. This may make the scheme harder to administer however. On the other hand, the investors may find this scheme easy to administer.

Independent of ownership

A FIT-scheme can easily be made independent of the ownership, but it could be designed as to facilitate the implementation of certain types or sizes of PV using the ownership, if that is found to be beneficial.

Table 25: Advantages and disadvantages of Feed-in-tariff/Feed-in-premium

FIT/FIP	
Pros	**Cons**
Easy adjustable in accordance to price development	Hard to determine the correct FIT
Separates production and consumption	Hard to control public expenses
Incentivises electricity savings (cf. above)	
Can be differentiated for different types of PV installations and sizes	
Easy administration	

9.3.3 Tendering scheme

A tendering scheme has several commonalities with a FIT-scheme, such as stability and long-term revenue for the investors, but the largest difference is that it is up to the investor to determine the revenue needed for a specific project to be realized. This also induces that the scheme will be self-adjustable in accordance to the price development, as the investor is incentivised to bid at the lowest possible price, as it will increase the chances for the project to win the tender, but also reveal the real costs of the project [83], [84]. Some of these characteristics are discussed below:

Separation of demand and supply

Like the FIT and FIP, with the tendering schemes all the electricity is sent to the grid, separating it from the electricity consumption, thus there is no incentive to install battery solutions. Also the potential energy savings are not affected by the implementation of this support scheme.

Subsidies should not be based on exemptions from tariffs or taxes

This is another common feature with the FIT/FIP schemes, since production is separated from the consumption, and all the support in subsidies is offered as direct support.

Not limited to a certain capacity

At this step, the similarities with the FIT/FIP schemes come to an end, as the tendering schemes have a lower capacity limit, and are not suitable for small-scale projects due to the level of administration and costs to organise such auctions [83]. Furthermore the smaller PV installations will never be able to achieve as low bid prices as the larger installations, which means that the huge potential for small scale residential plants will most likely not be utilized by tendering. This however does not mean that several plants cannot be aggregated as long as the bidder would handle that administration.

Independent of ownership

At this step, the similarities with the FIT/FIP schemes come to an end, as the tendering schemes have a lower capacity limit, and are not suitable for small-scale projects due to the level of administration and costs to organise such auctions [83]. Furthermore, the smaller PV installations will never be able to achieve as low bid prices as the larger installations, which means that the huge potential for small scale residential plants will most likely not be utilized by tendering. However, in Germany, the implementation of a specially designed tendering system has allowed community owned projects to be awarded projects. This new tendering scheme allows citizen involvement by offering them increased advantages compared to the competitors, such as less requirements for taking part in the tender and the winning project is granted with the highest bid by any of the participant projects in irrespective of the price the project owners have entered with [58].

The shape of the tendering scheme is decided by the authorities and can determine the potential owners, e.g it can only be reserved for large companies. For example, the main bidders for the large-scale offshore wind projects in Denmark are typically DONG, Vattenfall or E.ON [84]. This type of ownership also creates the incentive to concentrate the power plants in specific locations (due to the low cost of land, high irradiation values), possibly creating the NIMBY phenomena and/or increasing the costs with the transmission grid (in case the costs with the transmission grid is not paid by the investor) [83]. On the other hand, demands can be made for the ownership when the bids are made by giving these an advantage, if this is wanted by the authorities to avoid local opposition, etc.

Flexible in terms of new technological and price developments

The tenders have the ability of “self-adjusting” the price of the support, as the bids are generally reflecting the real costs of the technology, so the risk for overcompensation is low [83]. Depending on how the tender is constructed, bidders with low profit margins such as citizens may be ruled out or find it difficult to participate. This could make the winning bids more expensive than necessary.

Easy to administer

It cannot be expected that private persons have knowledge and resources to make accurate calculations of the economics of a PV investment, and for such a “small” investment it is not expected to be beneficial to hire a consultant to do the actual calculations. Private individuals also have a disproportionate access to finance, negatively affecting the competition. Furthermore, a tendering scheme for small residential PV installations is expected to result in a high number of small bids, which induces a substantial administrative burden, as every bid has to be evaluated in order to identify the winner.

Table 26: Advantages and disadvantages of Tenders

Tender	
Pros	**Cons**
Self-adjustable (done by the investors) in accordance to price development	Does not fit for small residential plants as it will induce a high number of applications that have to be assessed. The owners cannot be expected to have the needed competences to handle the tendering process.
The settlement price would be project specific	May rule out bidders with low profit margins
Could be beneficial in relation to ground mounted plants of several MW	Necessitates clear political targets and strong regulation
Reduction of the support level over time	A tendering process can be costly and heavy administratively.

9.3.4 Tradable Green Certificates

Another subsidy scheme used for promoting renewables including PV is the Tradable Green Certificates (TGC), where the authorities define a mandatory share of demand for renewable generation and the TGC market then finds the price needed to reach this target. The pricing of these certificates is based on supply and demand, where each PV producer will receive a certain amount of certificates for each MWh of produced electricity, which then can be sold to the obligated buyers. The idea is that the price of the certificates corresponds to the marginal costs of a new investment in renewable energy [108]. Subsidy schemes require authorities both to set renewable targets and to find the sufficient level of subsidies that will ensure targets to be met. In a TGC market system, the authorities can focus on the renewable target, leaving the price setting to the certificate market.

Separation of demand and supply

As with the FIT/FIP and tendering schemes, the TGC certificates are also based on selling the electricity to the grid in order to be subsidised, so there is no incentive for installing batteries. Also there are no reduced incentives for energy savings.

Subsidies should not be based on exemptions from tariffs or taxes

The production cannot be exempted from tariffs and taxes as it is sold to the grid from where the consumers have to buy it, therefore paying the corresponding amount of taxes.

Not limited to a certain capacity

The green certificates are not limited to a certain capacity, but generally these are used to support large installations.

Flexible in terms of new technological and price developments

The scheme is indifferent to the cost development and will help chose the renewable option with the lowest costs. This may hinder PV in ever getting built however.

Easy to administer

The main administration issues refer to determining the right amount of volume of renewables to be deployed on the market, making it less difficult to administer than other types of regulation schemes.

Independent of ownership

A TGC scheme can be independent of the owner, but it could be banded to facilitate the implementation of PV projects [78]. The TGC is cost effective, in the sense that it facilitates the implementation of the cheapest alternatives first, where this can have some advantages in relation to the cost-effectiveness it poses, and an important disadvantage in relation to promoting the implementation of PV, as it still can be more expensive than onshore wind and conversion of CHP plants to biomass [109].

Therefore, if these alternatives (wind, biomass CHP) are to be implemented first, the overall energy system cannot benefit from the implementation of PV. Furthermore, a TGC scheme will most likely promote the implementation of large ground mounted PV installations, as these are cheaper than roof mounted installations.

Table 27: Advantages and disadvantages of TGC

TGC	
Pros	**Cons**
Technology neutral	Does not provide a stable subsidy level
Market based pricing, where the electricity is sold on the electricity market, which is supplemented by a separate certificate market	Uncertainty for the investor as he does not have the certainty that all production will be purchased and at what price
Separates production and consumption	Risk that the implementation slows down or even stops as the desired capacity is closed to be reached
Incentivises electricity savings, as the PV production is sold to obligated buyers	Necessitates clear political targets
Total quantity of desired renewables on the market is better controlled	Risk of overcompensation for cheap technologies, as the certificate price is determined by the marginal unit
Can limit the total installed capacity	Only facilitating implementation of the cheapest alternatives (not PV)
	Can limit the total installed capacity

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