POTENTIAL OF PHOTOVOLTAIC TECHNOLOGY ON GREEK ISLANDS

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ABSTRACT: Photovoltaics (PV) is still a rather new technology in the Greek energy market, while the installed PV capacity is growing very fast as a result of the introduction of subsidy schemes in the year 2006. Deployment of PV on the many Greek islands presently is hampered by a maximum allowable limit of installed capacity, which differs per island. With the present combination of investment subsidy and feed-in-tariff, we show through several island case studies that this combined scheme can generate large profits. We therefore recommend a policy revision, reconsidering the present limits and lowering of the present financial support scheme.
Keywords: PV deployment; feed-in-tariff, Greece

1 INTRODUCTION

The global photovoltaics (PV) market has been growing for many years with average growth rates of 45% over the past 10 years [1, 2]. This has been demand-driven as a result of financial support schemes, in particular the introduction of feed-in-tariff (FiT) schemes in Germany and Spain [3]. For the Greek market, PV is a rather new renewable energy technology: presently about 10 MWp has been installed [4]. The potential of PV in Greece, like in other Mediterranean countries, is high due to the high insolation of >1800 kWh/m^2/year [5]. Greece is envisaged to be the first European country where so-called grid parity will be reached [6], meaning that cost of electricity from PV for consumers equals the cost of electricity as purchased from the utility.

Greece is a rather small country located in the South East of Europe; about 11 million people inhabit an area of 132,000 km^2 [7]. It is highly energy dependent, with 95% of the energy supplied by fossil fuels, which is mainly imported oil (60%) and domestic lignite (30%). Gas use is increasing to about 7% since its introduction in the mid 1990s. Also, the energy intensity of its economy is large, about 20% larger than the EU-15 average [8]. Nevertheless, the per capita energy consumption is lower than the EU-15 average, possibly due to the lack of heavy industry and the lower population density compared to other similar-sized or smaller countries, such as the Netherlands. Renewable energy potentials are high but their development is still in rather early stages. Recently, the Greek government has brought into force a set of policies that include rather generous subsidies and feed-in tariffs, to promote the use of renewable energy sources (RES). Regarding PV technology, subsidies such as 30-50% of the total investment costs and feed-in tariffs between 402.82 - 502.82 euro/MWh are provided [9]. This has lead to over 7000 applications for PV installations for a total of 2.6 GWp total capacity [10], which is enormous compared to the current status of about 10 MW total installed PV capacity [4].

The Regulatory Authority for Energy (RAE) is responsible for consulting the Greek government about decisions on energy policy [10]. The main challenge faced by policy makers in Greece is the large amount (about 2000) of islands that it embraces, where electricity is almost 100% generated with the use of Heavy Fuel Oil. This renders electricity generation rather expensive and environmentally unfriendly, due to the high amount of greenhouse gases emissions. The interconnection of the islands with the mainland, via submarine cables, has been proposed as a solution to this problem. Nevertheless, the maximum possible exploitation of renewable sources is of great importance. However, regarding PV, only a certain capacity is permitted for installation on each island, based on technical considerations [11, 12].

To address the possible profitability of PV deployment on Greek islands we have selected three different Greek islands, which are representative for most of the rest, and have performed an analysis using the simulation tool HOMER [13]. For each island an economically optimum electricity supply system is obtained. The most important variables used in HOMER are, among others, diesel price, PV capital costs, and the primary load of each island. The results include sensitivity of PV profitability to the increase of diesel price and decrease of PV capital costs.

We will show that the maximum PV capacity presently permitted for installation on each non-connected island is debatable. According to our modelling results, it is economically profitable to implement a several times larger PV capacity than the maximum permitted one. The Levelized Cost of Electricity (LCE) appears to be even lower than the present cost, if the current subsidies are taken into account. Furthermore, the LCE becomes much lower for increasing diesel prices. Despite the high capital costs, the payback periods of 5 and 7 years calculated for two of the three islands modelled, are rather short, as a result of the high feed-in tariff provided. It generally appears that, for a smaller island, the economic profitability of PV is higher and the payback period shorter. In all three cases, we will show that the cumulative cash flow, during the lifetime of the projects, is much more favourable with the use of PV than the current situation, due to the high fuel costs (oil).

2 PV DEVELOPMENT IN GREECE

2.1 Status, target, and subsidy

The current status for PV development can be briefly summarized as follows [14]: there is a satisfactory off-grid market development, but low on-grid development, a small national PV industry sector, cost reductions are according to EU trends, while a very high public acceptance is present. Further, PV modules generate electricity when costs are high due to peak demand, which is thus beneficial for large-scale implementation of PV. Due to local generation, costs and losses due to power transmission and distribution can be avoided. Note that these costs can amount to 50% of the generation costs on the mainland. On the islands these costs may even be a factor of two larger. Compared to other Renewable Energy Source (RES) technologies, PV is not well developed presently. The present capacity of 10 MW for PV is a factor of 100 lower than the wind power installed capacity [4].

The strengths of the national PV policy framework, as laid down in the law 3468 [15], which came into force in mid 2006, are (1) the high feed-in tariffs, (2) the monitoring system, and (3) the obligation for RES access to the grid. On the other hand, the weaknesses are: (1) the lack of systematic promotion of small-scale systems in households, (2) the time consuming licensing procedures even for small-scale applications, and (3) the complicated requirements for managing grid-connection.

The basic objective of the Greek government is the development and operation of a sustainable PV market and the growth of the PV industry in Greece. The Greek target is to have installed at least 500 MW_p and connected with the mainland grid by 2020 and a total PV capacity of at least 200 MW_p installed on the non-interconnected islands [15]. According to this law, though, "*This 200 MW_p, capacity may be allocated to the Non-Interconnected Islands' Autonomous Power Systems based on the capabilities of each Autonomous Power System, by means of decision of the Minister for Development, issued on a recommendation from the Non-Interconnected Islands Operator where RAE has first provided an opinion*" [15]. As RAE did apply a certain methodology in order to determine the maximum PV capacity permitted on each non-connected island [11, 12], only about 100 MW of PV capacity is permitted for installation on the non-connected islands; the remaining 100 MW are allocated to the mainland [16].

The law 3468 introduces a number of subsidies, which are particularly generous for PV technology, mainly due to the high solar potential all over the Greek country. The subsidies consist of two parts: a total investment subsidy and a feed-in tariff. The total investment subsidy varies between 30-50% of the total investment costs, according to the size of the PV system and the area on which it will be implemented. The feed-in subsidy varies from over 400 euro/MWh to over 500 euro/MWh, according, again, to the size and the area of the project's implementation and is provided for 20 years maximum for each PV installation [10]. These subsidies are very generous and give a strong belief to the policy makers that the PV market in Greece will expand within a few years [17].

2.2 Greek islands

A major impediment for PV deployment on Greek islands is the restriction of maximum allowed capacity set by RAE. The electrically autonomous Greek islands are characterized as electrically replete systems [12]. This implies that only a certain maximum of PV capacity is allowed to be installed, to avoid problems of over or under-charge of the electricity system, which would result in serious problems [12]. RAE applies this to all islands using the following main criteria: (1) safe and continuous functioning of the electricity system, (2) continuous electrification of the islands, (3) avoidance of implications on the already installed capacity of renewable energy technologies, and (4) continuous back-up function of the thermal power plants [12].

Restrictions applied by RAE are technical and economical. Technical restrictions have mainly to do with the solidity of the transmission network and the thermal power plants. A very important factor are the fluctuations in demand on most of the islands, due to tourism and cooling needs in summer [11]. Economic restrictions are probably linked to budget capability of the government in providing the subsidies. Implications of new RES installations on the already present ones, which are almost only wind turbines, should be avoided. Adding new RES installations would decrease the total net annual electricity generation from renewable sources, due to technical restrictions [11]. RAE estimates the capacity factor to be at least 27.5% in order for RES installations to be economically viable [11]. The capacity factor would decrease with additional RES installations, and depends on the hourly RES penetration. For PV the decrease is rather low (less than 1%) for hourly penetration of 15% of the average demand [11]. These rather vague and apparently unsubstantiated arguments have been used in assessments, which have shown that an electrically replete island is able to handle up to 30% RES penetration of its average load, in order not to violate the technical minimums of the existing electricity generating plants [11]. However, 35% would be acceptable. Thus, 15% or 35% of the average hourly demand is the maximum "safe" PV capacity to be installed, depending on whether already RES capacity is present on an island or not.

The maximum PV capacity per island is determined by RAE as follows [11]. First, the total demand for 2008 was estimated, using data from previous years, assuming that the average demand increase of the previous 5 years (2003-2007) could be applied for 2008. Second, the mean hourly demand was estimated from the annual demand. Third, for each autonomous island system, where already RES systems (except PV) were installed, the maximum capacity for PV installations was set at 15% of the calculated mean hourly demand. In case of already existing PV capacity, it was subtracted from the calculated one. Fourth, for each autonomous island system where no RES was installed, the maximum PV capacity was set at 35% of the calculated mean hourly demand. This resulted in an allowable total PV capacity for all islands together of 99 MW; the allowable small-scale wind capacity is 3.3 MW.

2.3 Other developments

The main fuel for producing electricity on the non-connected islands is Heavy Fuel Oil (HFO). This means that on many islands electricity generation plants that burn HFO are installed, which generate the total necessary electricity and fulfill the demand. In some cases "local" island grids, which connect different islands via submarine cables, have been constructed, in order to make electricity generation, especially on the very small islands, more economic. However, due to the high costs of HFO as a fuel, as well as the high costs of its transportation on each island, electricity generation on the islands is expensive. Furthermore, electricity generation from HFO results in high CO_2 emissions, equal to 880 g/kWh (including all life cycle emissions) [18]. It should be mentioned that, on some islands, a small wind capacity is also installed, in order to make use of the high wind potential there. However, this capacity is rather small. The total HFO-based generating capacity on the islands amounted to 1635 MW, while the total annual demand was 3140 GWh [10].

The inter-connection of the islands with the mainland grid is being discussed for a long time already. Islands close to the mainland have been inter-connected, by means of medium and high-voltage cables. For islands located further away the high cost of inter-connection is hampering its development, although plans have been formulated. Total interconnection cost would approach 2 billion euro [19].

3 MODELLING OF ELECTRICITY SUPPLY ON GREEK ISLANDS

The HOMER model is suited well for the simulation of island hybrid systems, as it is capable of analysing the optimization of the implementation of various RES technologies on an existing electricity supply system, as well as the sensitivity of the results on certain user-defined parameters [13]. It thus allows the user to evaluate technical and economic feasibility of a proposed hybrid system.

The vast number of islands did not allow for modelling of each one of them. Therefore we selected three case islands, which are representative for all others. Modelling was performed in two steps: first, the existing electricity supply system was modelled to compare with current cost of electricity, thereby indirectly validating the model and data used. Second, PV and storage capacity was added, and cost of electricity was calculated for several combinations, as illustrated in Fig. 1. The use of PV implies the addition of an inverter and batteries, as it may be profitable to store electricity. Thus, comparisons could be made for cost with and without PV capacity installed. These costs are also compared with the main generation cost of 123.58 Euro/MWh that RAE calculated for all islands.

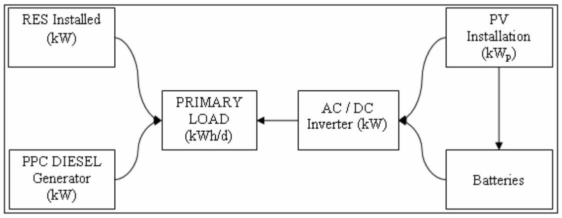

Figure 1: Overview of the model used in HOMER.

3.1 Necessary data and assumptions

The load profile of each island is an important input for the model. HOMER needs an hourly profile for each month of the year. We have tried various ways to gather the necessary data, however, this proved very difficult, as the Greek Power Producing Company (PPC) was not willing to provide the data. Luckily, during a visit to Greece, we managed to meet with some people that showed the monthly average demand for 2006, as well as the hourly profile of August 15, 2006. These data were written down in numerous books, and copied by hand, thus introducing perhaps some errors. We had to assume that the hourly profile was valid also for all other days, which is questionable, of course. Consequently, the load profiles used in HOMER are not completely accurate. Nevertheless, we consider them realistic and representative enough for running the model.

The installed diesel generator capacity per island is published by PPC [20]. The current diesel price was set at 0.4 $/liter, based on a combination of several sources [21, 22]. Solar irradiation on each island was taken from the NASA solar irradiation database [23], from within the HOMER model. Average wind speed is taken as 8 m/s, based on information from the Greek Center for Renewable Energy Sources (CRES) [24]. Capital and replacement costs and operation and maintenance (O&M) costs for the various components of the system are listed in Table 1, where we have used the experience of other HOMER models for island systems [25].

3.2 Choice of case islands

There are over 2000 islands in Greece and many of them are populated. The islands in the Aegean Sea are geographically divided in four major groups: Sporades, Cyclades, Dodecanese and East (and North East) Aegean islands (Fig. 2). Sporades are very close to the mainland and electrically connected with it (apart from Skyros island), these were not taken into account further. Cyclades and Dodecanese are rather small islands (with a few exceptions) with a few hundreds till a few thousands of inhabitants. Some of them are electrically connected with larger islands via submarine cables and are electrified from the power stations of these islands. The main characteristic of those islands is that they are very touristic and high fluctuations in population between summer and winter months occur. This also results in high fluctuations in electricity demand. East (and North East) Aegean islands are much larger, but the demand is rather constant throughout the year, or at least normal, due to the lack of tourism and lack of population fluctuations.

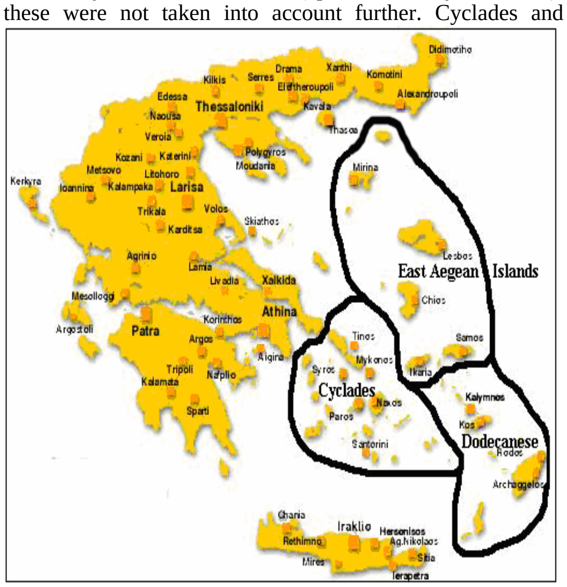

Figure 2: Overview of the three main geographic groups of Aegean Sea islands.

Taking into account the size, population and the fluctuations of population and electricity demand throughout the year, three categories of islands could be discerned: (1) small islands with high population density and high fluctuations, (2) small islands with low population density and low fluctuations, and (3) large islands with low population density and low fluctuations. Small islands are defined as islands with total size lower than 300 km^2 and low population density as density, i.e., below 75 people per km^2. Fluctuations were estimated taking into account the tourism data of previous years and the existing infrastructure for tourists. From each of the three categories, one island was chosen. For category 1 the island of Agathonisi is taken as representative; for category 2 the island of Kos, or rather the system of 9 islands connected together; for category 3 the island of Lesvos. Table I summarizes some relevant parameters. Average monthly demand is shown in Fig. 3. An example of the hourly demand of August 15th, 2006 is shown in Fig. 4.

Table I: Relevant parameters used in the simulation (sources: partly RAE and PPC). Data are from the year 2001 unless indicated otherwise. Note that thermal capacity has increased to 173 MW in 2008 for the Kos system. A=Agathonisi, K=Kos system, L=Lesvos

	A	K	L
Size (km^2)	14	614	1636
Population density (km^{-2})	10.9	94.3	55.4
Hotel beds (2006)	42	41294	6606
Thermal capacity (MW)	0.24	69.6	49.5
Max demand (MW)	0.095	57.3	45.7
Annual demand (GWh)	0.276	217.824	209.733
Max PV permitted (MW)	0.021	6.401	5.511
Existing wind capacity (MW)	-	8.4	1.8
Solar irr adiation ($kWh/m^2/day$)	5.16	5.37	4.47
Peak demand (MW)	0.229	131	141
Annual demand (GWh)	0.7986	384.345	531.075
Demand increase 2008/2001	2.89	1.76	2.53
Daily demand (MWh/day)	2.188	1053	1455

4. MODELLING RESULTS

After importing in HOMER all the data that were gathered for each one of the three case-islands, all simulations were performed. The results are shown below, separately for each case-island.

4.1 Small island (Agathonisi)

First of all the current status of the electrification of Agathonisi was modelled. The current Levelized Cost of Electricity (LCE) was calculated to be 0.180 $/kWh, for a diesel price of 0.4 $/lt. Of course, for higher diesel costs, the electricity generation costs increase. At a diesel price of 0.60 $/lt, the cost of electricity amounts to 0.266 $/kWh and at a diesel price of 0.75 $/lt it amounts to 0.33 $/kWh.

The next step was to import in HOMER different PV capacities, in order to run the model again and try to understand the effect of diesel price and PV capital costs on the optimization results: thus a sensitivity study is performed.

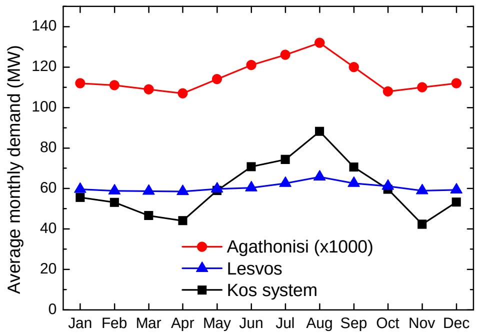

Figure 3: Average monthly demand of the three islands modelled for the year 2006.

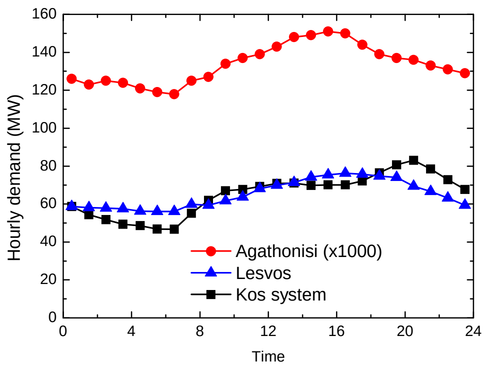

Figure 4: Hourly demand profile of the three islands modelled, data taken for 15 August 2006.

In HOMER, diesel price and capital costs were the two variables for the sensitivity analysis of the outcomes.

In Fig. 5 the average monthly calculated profile of the electricity generation sources (PV and diesel) in Agathonisi is shown. Even during winter months the share of PV in electricity generation is high and competitive with the one of the diesel generator. It can be seen that the use of the diesel generator is more or less stable throughout the year and PV is able to balance the small increase in demand during the summer months. The most important result to observe is that, even with quite low diesel price (0.4$/lt), the optimum system consists of, among others, 250 kW PV capacity. Note that this optimal PV capacity is much larger (nearly twelve times) than the maximum permitted capacity of 21 kW. These results include the 50% total investment subsidy provided.

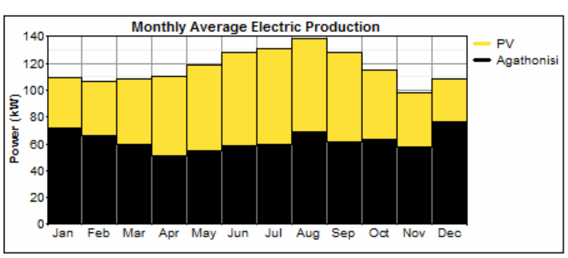

Figure 5: Monthly average generated power by installed PV and diesel generator capacity used for the electrification of the island of Agathonisi.

It can, therefore, be observed that PV technology does fit into the electricity system of Agathonisi. It would result into lower levelized cost of electricity than currently and much less use of diesel (about 42%), which, consequently, results in less fuel costs and a lower amount of CO_2 emissions.

Regarding the sensitivity of the model's results to the PV capital costs, two things should be stated. For the current costs and with no subsidy, the implementation of PV is still profitable and the optimum PV capacity is 50 kW (more than double the maximum permitted). If, the current policies and subsidies are taken into account, this becomes even better: if the PV capital costs decrease by 50%, which is the currently provided subsidy on the islands, the optimum PV capacity increases from 50 kW to 250 kW.

Furthermore, it should be noted that, for an island similar to Agathonisi, the current investment subsidy scheme is higher than necessary. Even without any subsidy the optimum PV capacity is 50 kW and the levelized cost of electricity at that point is 0.179 $/kWh, which is still lower than the current one.

At this point, it is interesting to run the model by including only the maximum permitted PV capacity and compare the results, which are rather different (Fig. 6). It has to be mentioned that in the case of Agathonisi, the option of 21 kW installed PV capacity is not the most profitable one, but the second best, even with the subsidy of 50% total investment cost. The LCE is higher than the previously modeled one and the fuel use and, consequently, the CO_2 emissions are much higher as well.

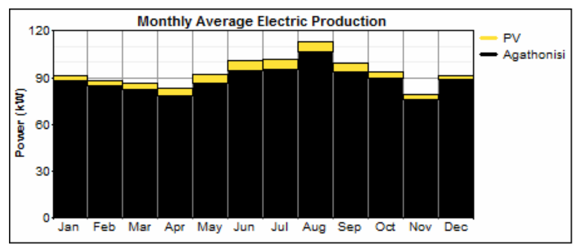

Figure 6: Monthly average generated power by installed PV and diesel generator capacity used for the electrification of the island of Agathonisi, taking into account the PV capacity limit.

Finally, the cash flow of the model for Agathonisi is investigated. For this particular case, the feed-in tariff seems very generous. PV implementation is not only feasible but provides profit as well. The feed-in tariff definitely overcomes the fuel costs. This is the case (with less revenue though) also for a 5% annual decrease of the feed-in tariff, alike the feed-in scheme currently implemented in Germany. Taking into account the PV capacity limits, the financial benefits of this system are much lower. Although the high feed-in tariff, the maximum permitted PV capacity is very small, in order to provide revenue for the fuel costs to be overcome. Figure 7 presents the cumulative cash flows of the current situation, the current maximum PV capacity permitted, the constant feed-in case and the decreasing feed-in case are compared. It is rather remarkable that the payback period of the modeled PV implementation, independently from the feed-in subsidy form, is about five years.

Table II presents an overview of the levelized cost of electricity in Agathonisi for the three situations for different diesel prices.

4.2. Small island system (Kos)

As was done in the case of Agathonisi, the current status was first modelled. For a diesel price of 0.4 $/lt, the electricity generation cost is 0.139 $/kWh. For higher diesel costs, the electricity generation costs increase. At a diesel price of 0.50 $/lt, the LCS amounts to 0.173 $/kWh and at a diesel price of 0.60 $/lt it amounts to 0.207 $/kWh.

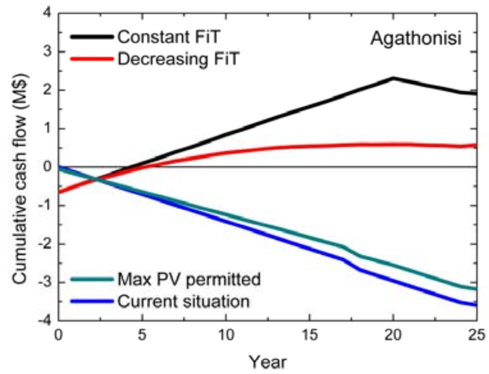

Figure 7: Cumulative cash flows outcomes of the model for Agathonisi for the current situation and the current maximum permitted amount of PV, as well the cash flows for constant and decreasing Feed-in-Tariffs for the island of Agathonisi.

Table II: Levelized cost of Electricity and diesel use of the current situation, for maximum possible and maximum permitted PV implementation of the case of Agathonisi.

Agathonisi	Diesel price ($/lt)		
	0.4	0.5	0.6
current LCE ($/kWh)	0.180	0.223	0.266
current diesel use (lt/yr)		342,963	
max perm PV LCE ($/kWh)	0.181	0.223	0.265
diesel use max perp PV (lt/yr)		334,934	
max impl PV LCE ($/kWh)	0.165	0.190	0.215
diesel use max impl PV (lt/yr)		201,511	

After running the model for different PV capacities, the average monthly calculated profile of the electricity generation sources in Kos system is obtained. It can be seen in Fig. 8 that the share of PV in electricity generation is significant throughout the whole year. The continuous function of the second generator is necessary, but PV decreases significantly the use of the second one. Only when the extremely high demand fluctuations occur during the summer, the first generator is used extensively.

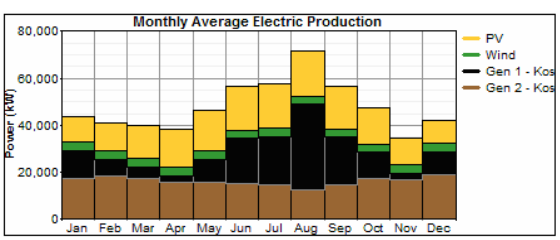

Figure 8: Monthly average generated power by installed PV and diesel generator capacity used for the electrification of the island of Kos.

It can, therefore, be observed that PV technology does fit into the electricity system of Kos as well. The levelized cost of electricity is, again, lower than currently and, additionally, the use of diesel is about 32% less, which, consequently, leads to about 32% less fuel costs and about 32% less CO_2 emissions.

Regarding the sensitivity of the model's results to the PV capital costs, two observations can be made. For the current costs and with no subsidy, the implementation of PV does not seem to be profitable, without, of course, taking into account any environmental restrictions. However, if the current policies and subsidies are taken into account, this changes drastically. It can be seen that if the PV capital costs decrease by 50%, which is the currently provided subsidy on the islands, the optimum PV capacity increases from 0 kW to 75 MW and can even reach 100 MW, for a diesel price larger than 0.50 $/lt.

Furthermore, one could even say that, also for an island similar to the Kos system, the current investment subsidy is higher than the necessary. It can be seen that even a subsidy of about 10% would be enough to render PV implementation profitable. Even with a 10% investment subsidy (PV capital multiplier 0.9), 10 MW is the optimum PV capacity for this system, which is again higher than the current limit. Furthermore, the levelized cost of electricity at that point is below 0.137 $/kWh, which is lower than the current one. Furthermore, for an investment subsidy of 30% (PV capital multiplier 0.7), the optimum PV capacity is 60 MW and the levelized cost of electricity at that point is 0.134 $/kWh.

If the current maximum PV capacity permitted is taken into account, the results are, again, rather different (see Fig. 9). It has to be mentioned that in the case of Kos system, the option of 6,401 kW installed PV capacity is the most profitable one. The levelized cost of electricity is higher than the previously modeled and the fuel use and, consequently, the CO_2 emissions are also much higher.

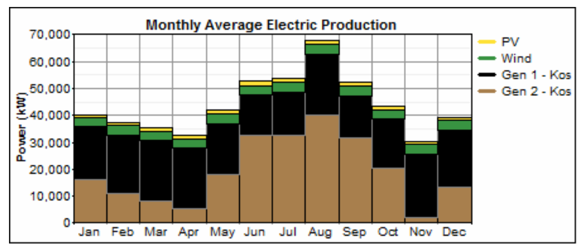

Figure 9: Monthly average generated power by installed PV and diesel generator capacity used for the electrification of the island of Kos, taking into account the PV capacity limits.

In Fig. 10, the cumulative cash flows of the current situation, of the constant feed-in case and of the decreasing feed-in case of Kos system are compared. It is rather remarkable that, in this case as well, the payback period of PV implementation, taking into account the current feed-in subsidy form, is about seven years. For a 5% annual decrease of this feed-in tariff though, the cumulative cash flow is always negative, but still much better than the current situation.

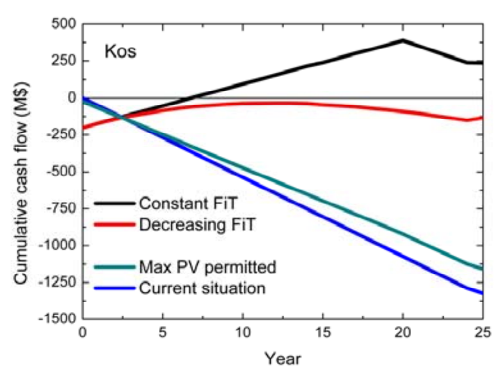

Figure 10: Cumulative cash flows outcomes of the model for Kos for the current situation and the current maximum permitted amount of PV, as well the cash flows for constant and decreasing Feed-in-Tariffs for the island of Kos.

Table III presents an overview of the levelized cost of electricity in Kos for the three situations for different diesel prices.

Table III: Levelized cost of Electricity and diesel use of the current situation, for maximum possible and maximum permitted PV implementation of the case of the Kos system.

Kos system	Diesel price ($/lt)		
	0.4	0.5	0.6
current LCE ($/kWh)	0.139	0.173	0.207
current diesel use (lt/yr)		130,885,100	
max perm PV LCE ($/kWh)	0.135	0.167	0.199
diesel use max perp PV (lt/yr)		132,200,056	
max impl PV LCE ($/kWh)	0.128	0.151	0.172
diesel use max impl PV (lt/yr)		88,173,364	

4.3. Large island (Lesvos*)*

In the case of Lesvos, for a diesel price of 0.4 $/lt, the current electricity generation cost is 0.144 $/kWh. For higher diesel costs, the electricity generation costs increase. At a diesel price of 0.50 $/lt, the cost of electricity amounts to 0.179 $/kWh and at a diesel price of 0.60 $/lt it amounts to 0.214 $/kWh.

In Fig. 11 the average monthly calculated profile of the electricity generation sources in Lesvos is shown. It can be seen that the share of PV in electricity generation is considerable throughout the whole year, but is lower (in terms of percentage) than in the previous two cases. PV, though, seems to be able to balance the small demand increase which occurs during the summer months.

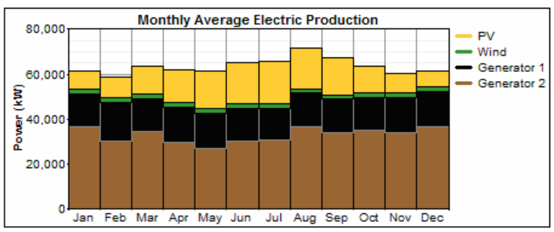

Figure 11: Monthly average generated power by installed PV and diesel generator capacity used for the electrification of the island of Lesvos.

It can, therefore, be observed that PV technology does fit into the electricity system of Lesvos as well. The levelized cost of electricity is, as for the other two cases, lower than currently and, additionally, the use of diesel is almost 26% less, which consequently leads to 26% less fuel costs and almost 26% less CO_2 emissions.

Regarding the sensitivity of the model's results to the PV capital cost, it can be observed that with the current costs and without any subsidy, the implementation of PV does not seem to be profitable, without, of course, taking into account any environmental restrictions. However, if the current policies and subsidies are taken into account, this changes. It can be seen that if the PV capital costs decrease by 50%, the optimum PV capacity increases from 0 kW to 80 MW and can even reach 130 MW, for a diesel price larger than 0.50 $/lt.

One could say that, for an island similar to Lesvos, the current investment subsidy is appropriate. It can be seen that even a subsidy of about 35% would be enough to render PV implementation profitable. Even with a 35% investment subsidy (PV capital multiplier 0.65), 14 MW is the optimum PV capacity for this system, which is again much higher than the maximum capacity permitted by RAE. Furthermore, the levelized cost of electricity at that point is lower than 0.139 $/kWh, which is lower than the current one. Furthermore, for an investment subsidy of 40% (PV capital multiplier 0.6), the optimum PV capacity is 28 MW and the levelized cost of electricity at that point is even lower than before, i.e., 0.137 $/kWh.

If, now, the current maximum PV capacity permitted is taken into account, the results are, similar to the above cases, rather different. The share of PV is minimal, as can be seen in Fig. 12. It has to be mentioned that in the case of Lesvos, the option of 5,511 kW installed PV capacity is not the most profitable one, but the second best, even with the subsidy of 50% total investment cost. The levelized cost of electricity is higher than the previously modeled and the fuel use and, consequently, the CO_2 emissions are also much higher.

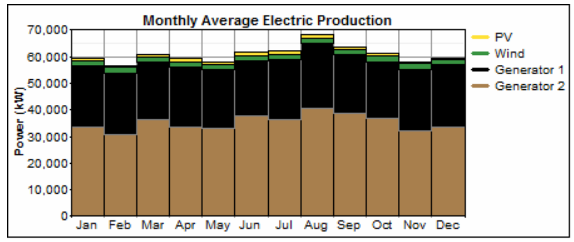

Figure 12: Monthly average generated power by installed PV and diesel generator capacity used for the electrification of the island of Lesvos, taking into account the PV capacity limits.

In Fig. 13, the cumulative cash flows of the current situation, of the constant feed-in case and of the decreasing feed-in case of Lesvos are compared. Contrarily with the other two cases, the modeled cash flow of Lesvos is always negative, but still better than the current situation.

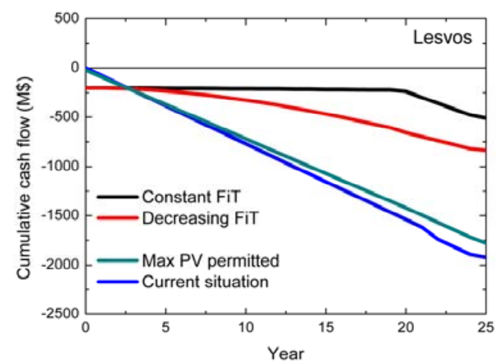

Figure 13: Cumulative cash flows outcomes of the model for Lesvos for the current situation and the current maximum permitted amount of PV, as well the cash flows for constant and decreasing Feed-in-Tariffs for the island of Lesvos.

Table IV presents an overview of the levelized cost of electricity in Lesvos for the three situations for different diesel prices.

Table IV: Levelized cost of Electricity and diesel use of the current situation, for maximum possible and maximum permitted PV implementation of the case of the Lesvos.

Kos system	Diesel price ($/lt)		
	0.4	0.5	0.6
current LCE ($/kWh)	0.144	0.179	0.214
current diesel use (lt/yr)		187,410,256	
max perm PV LCE ($/kWh)	0.141	0.175	0.209
diesel use max perp PV (lt/yr)		180,515,616	
max impl PV LCE ($/kWh)	0.136	0.162	0.186
diesel use max impl PV (lt/yr)		143,153,808	

4.4. Case study comparison

Even with a quick glimpse at all results, it can be easily concluded that the potential of PV on Greek Islands, from an economic perspective, is rather high, taking into account the current policies in force. This occurs due to three main reasons: first, because the solar irradiation that exists on each island is rather high, second because the only fuel used for electricity generation is diesel, which is rather expensive and third because the current subsidy provided for PV installations is rather generous. In the following the main observations are discussed and the three case studies are compared.

Population fluctuations, for example as a result of tourism, have a direct effect on the electricity demand fluctuations. Furthermore, electricity demand fluctuations lead to higher electricity costs, because of the high fuel costs. In addition, it generally appears that for small islands, with electricity demand of a few hundreds of kW, the current electricity generation costs are much higher than for larger islands.

At this point, it has to be mentioned that the categorization of the Greek islands, in order to choose case-studies, was made according to their size, their population density and their electricity demand fluctuations. The results showed that in the case of high electricity demand fluctuation, which is the case for Kos system, PV's share in electricity generation does not have the tendency to be larger, in order for this fluctuation to be balanced, but remains rather constant. This is not the case, though, for islands with low electricity demand fluctuations. In islands with such fluctuations, like Lesvos and Agathonisi, PV implementation seems to be able to balance this demand and their share in electricity generation increases, when the diesel generator's share remains rather constant.

An important objective of this research was to look deeper into the subsidy scheme that is currently applied in Greece. For Agathonisi, even with the current PV capital costs, PV implementation is profitable, which means that the subsidy, if not unnecessary, is too high. It can also be concluded that the provided subsidy is higher than necessary for the case of Kos. It was calculated that, for this case, even a subsidy of 10% of the investment costs would be sufficient. In contrast, for the case of Lesvos, i.e. a large island, the PV implementation subsidy provided is appropriate.

For the Kos system and Lesvos PV implementation seems unprofitable, without any decrease of PV capital costs, which means without the provision of any subsidy. However, this does change for increasing oil prices, which is a global trend nowadays. In islands with high electricity demand, independently of their size, PV implementation becomes profitable with an at least 25% increase of oil prices, without the provision of any subsidy. Contrarily, in islands with low electricity demand, similar to Agathonisi, no further increase of the oil prices is necessary in order for PV implementation to be profitable.

The most important parts of this analysis are the obtained results regarding the most profitable PV capacity on each island. This capacity, in all three cases is much larger than the maximum permitted one by 12-14 times. The model showed that PV capacity of 250 kW on Agathonisi, 75 MW on the Kos system and 80 MW on Lesvos would be the most appropriate in order for the lowest electricity generation costs to be achieved on those islands. Even if the space requirement parameter is taken into consideration, the installation of these capacities is still feasible there. It would respectively require 2,500 m^2 in Agathonisi, 750,000 m^2 in the Kos system and 800,000 m^2 in Lesvos, assuming a conservative 10% PV module efficiency (yielding 10 m^2 of area required per kW). Thus, the space availability does not seem to be a restriction, considering the size of those islands (14,000,000 - 614,000,000 - 1,636,000,000 m^2 respectively), as well as the rather arid morphology in large parts of them. The amount of PV in terms of area constitutes about 0.02, 0.12, and 0.05 % of the land area of these islands, respectively. The most significant effects of the installation of the calculated PV capacity on those islands would be the following two: first, the low cost of electricity generation. If these PV capacities are installed, the costs of electricity generation are even lower than currently, in all three cases, due to the large decrease in diesel usage. The second effect would be the large decrease of CO_2 emissions. The use of PV implies the decrease of fuel usage, which means decrease in CO_2 emissions. The percentage of CO_2 emissions decrease varies for each case between 42% and 26% and generally seems that, on islands with low annual electricity consumption, the percentage of the emissions decrease is higher.

Finally, the cumulative cash flow is more positive than currently in all three cases, because of the high feed-in tariff provided and the decrease in fuel usage. However, in case of Agathonisi, the feed-in tariff overcomes the fuel costs and provides high profits, with a rather short investment payback period. The same stands for the Kos system as well, but with lower profits and consequently slightly longer payback period. However, on islands with high and constant demand the cash flow is negative, especially due to the high constant usage of diesel, but remains still better than the current situation.

5 CONCLUSION

This paper shows that implementation of PV technology on Greek islands appears to be profitable from an economic perspective. Deploying PV leads to several advantages such as lower electricity costs, lower oil dependency, higher security of supply, and decrease of greenhouse gases emissions. The outcomes and the conclusions of this research showed that a few points in the Greek PV promotion scheme are debatable. First, the maximum permitted capacity on each island should be reconsidered, as these limitations are an important barrier for PV technology penetration on Greek islands. It is clear that, from an economic perspective, implementation of a much larger PV capacity is profitable. If technical restrictions of the grid are the main barrier, it is recommended that investments are made towards the improvement of the grid, which should have high priority.

On the other hand, the main driving force of the PV market expansion in Greece is the subsidies provided; especially the high feed-in tariff, which transforms PV installation into profitable business. This poses a great risk as this support system might collapse, under the burden of the extremely high and abrupt interest in PV implementation and possible incapability for subsidies to be provided. Since the provided feed-in tariff has proved to be too high for many cases, it is advisable to introduce an annually decreasing scheme, such as in Germany.

Furthermore, in almost all the reports where the plans for the future development of the Greek electricity system and, moreover, the electricity system of the islands, are discussed, the environmental point of view does not seem to be taken into much consideration. There can hardly be found any comments on the CO_2 emissions decrease necessity. Generally, it seems that the only reason that PV policies (and RES policies in general) are being applied in Greece, is the necessity to follow the EU policy and to abide by the obligations set by EU. An important point of view should be generally adopted in Greece: RES implementation implies many significant advantages, which Greece needs to utilize.

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