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# Draft Final Report

Submitted June 13th, 2017

Edited version (2) of June 25th, 2017

# Economic Analysis to Facilitate the Establishment of a Stable Price for Electricity from Renewable Sources

ME 36_1_2 T54

Prepared for: Division of Energy and Telecommunications, Prime Minister's Office, Government of Barbados

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June 25th, 2017

# TABLE OF CONTENTS

# DETAILED TABLE OF CONTENTS

# TECHNICAL SUMMARY

This summary reports on the main results of all work packages of the project with the exception of WP 12, which was the drafting of the interim report delivered in March 2017.

## WORK PACKAGE 1: STAKEHOLDER CONSULTATIONS

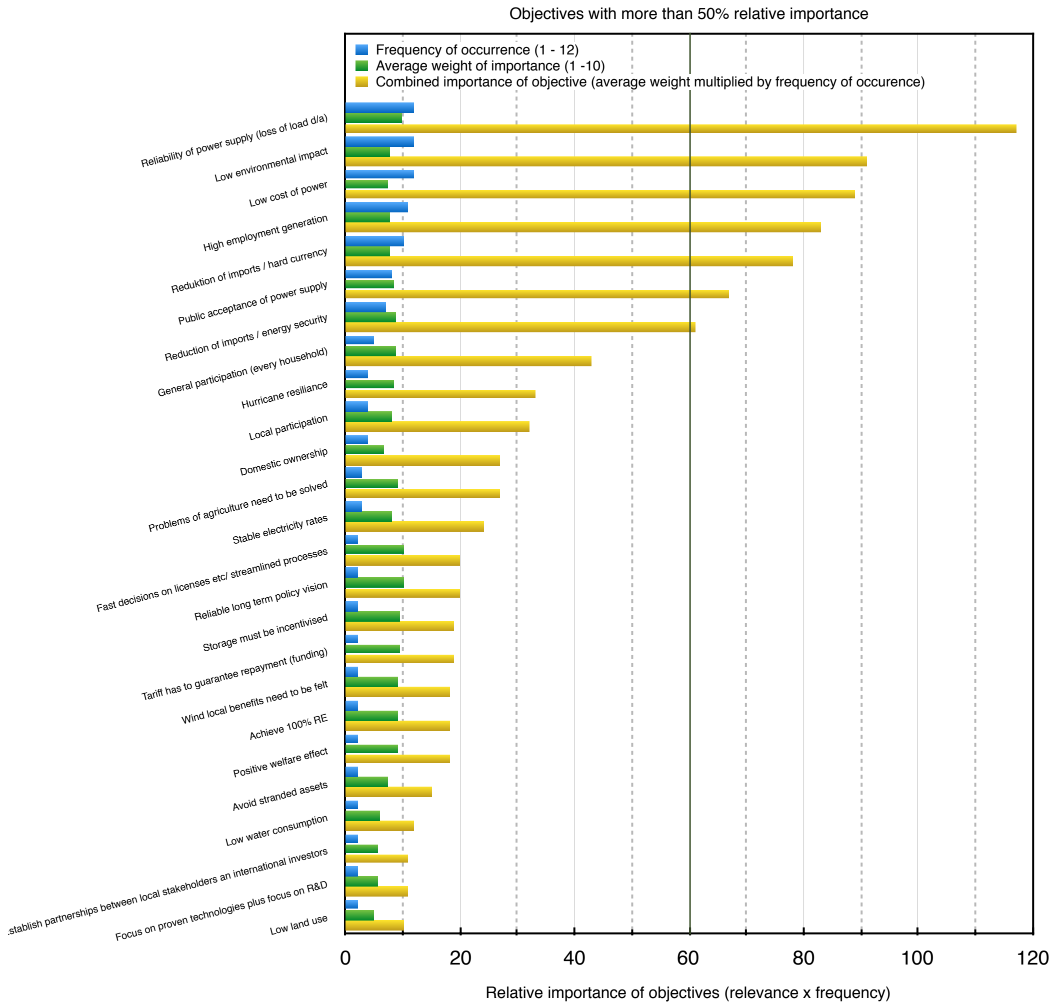
As the report has to recommend the most appropriate market structure, support mechanisms and policy measures for a sustainable development and stable prices of renewable electricity in Barbados it was necessary to find out the most important objectives of the introduction of renewable energy held by important stakeholders in the energy sector in Barbados. Interviews with twelve key stakeholders in power generation and renewable energy were conducted asking for the important objectives seen and their relative importance. The interviews produced 56 different objectives, out of which 30 objectives were only mentioned by one stakeholder. Combining the results of all interviews (average weight times the frequency at which an objective was mentioned) lead to an ordered set of objectives by relative importance. The results are shown in Figure IR1 below. Besides the *reliability of the power supply* a *low environmental impact, low cost of power, high employment generation,* and *reduction of imports* to reduce *the outflow of hard currency* and to *increase energy security* are objectives of high importance to the interviewed stakeholders. *Local participation* and *domestic ownership were* mentioned as other important objectives. The *public acceptance of the power supply* was an other important objective relating to public involvement. One group of stakeholders with an agricultural background stressed the objective p*roblems of agriculture need to be solved.*

These important objectives can give orientation beyond the often used *low cost of power* and *reliability of power supply* for the design of energy policies and support mechanisms as well as for the discussion on the most appropriate market structure.

## WORK PACKAGE 2: UPDATED ESTIMATES ON RENEWABLE ENERGY POTENTIALS AND COSTS

In work package 2 the available information on international cost developments for wind and solar PV were brought together with information on local cost and potentials. As a result it can be concluded that especially in the case of solar PV Barbados has made substantial progress in reducing the cost differences of systems installed in Barbados and in the world market. By early 2017 PV systems were installed at cost as low as 2.13 BBD/$W_p$. Nevertheless, very expensive systems are being installed at up to 20 BBD/$kW_p$, which strongly influence average investment cost to between 5.9 and 11.4 BBD/$W_p$ depending on system size. At the same time international PV prices are in the range of 2.8 to 5.8 BBD/Wp depending on system size.

Figure ES1: Frequency of occurrence, average weight of importance and relative importance of the twenty five objectives mentioned by at least two key stakeholders




For wind no reliable data exist for Barbados, but experts involved in the first two larger wind development projects suggest that the cost are about 20-25% higher in Barbados as compared to the world market due to market size and transport cost. At the end of 2016 world market prices for wind turbines including all investment and financing cost are in the range of 3,400 BBD/kW, with very similar costs in Europe (Germany as European lead market) and in the US.

Costs of biomass are highly project specific and no cost figures can be quoted from international markets, which could be directly compared to the two major biomass activities in Barbados for which cost estimates are available. The investment costs for the bagasse combustion plant are quoted at 18,400 BBD/kW (230 million USD for 25 MW capacity), while the first estimates for the gasification and power production from King Grass are at 10,000 BBD/kW.

Concerning the potential of of renewable energy resources in Barbados specifically wind seems to be critical. A new assessment by Rogers (2015) shows a good potential of about 450 MW as a result of a detailed study of the local wind resource. The potential of bioenergy depends highly on the agricultural land available and the type of use (energy crops only like King Grass or energy as a byproduct of an other crop utilisation like bagasse). In the case of King Grass 20,000 acres could produce about 400 GWh of electricity per year, while the use of bagasse from 18,000 acres of sugar cane plus river tamarind from additional 5,000 acres could produce about 169 GWh/a (net) in the biomass combustion planned by the cane industry.

## Work Package 3: Updated discussion of the applicability of pump storage hydro systems and their costs in Barbados

Latest studies have shown that pump storage installations in the range of 1 to 5 GWh of storage are feasible in Barbados (Stantec 2016) and that the costs will most likely be in the range of about 3,000 BBD/kW. Pump storage experts visiting the island in late 2016 came to the conclusion that the cost should be close to the average of present pump storage facilities build around the world. As the system will play a central role in controlling the frequency and voltage of the power system the specific technology used will allow a very fast and continuous operation shifting from 100% pumping to 100% generation within less than 180 seconds.

Battery storage, although becoming cheaper in the last years is still far away from being competitive with pump storage at the necessary scale for Barbados. The concentration on battery storage mislead the authors of the IRENA road map for Barbados to ignoring the potential of their own scenario. As shown in new model simulations included in this report the inclusion of a sizeable pump storage plant (3 GWh storage) instead of the assumed battery storage of 150 MWh would have lead to 94% of renewable energy production with the same installed renewable energy capacity instead of the 84% reached by the battery based scenario. Nevertheless, battery storage will play an important role in the short term stabilisation of local distribution grids with high renewable energy penetration.

## Work package 4: Extension and update of hourly power system simulation model for Barbados

The analysis of the most appropriate market structure, support mechanisms and policies for a sustainable development of renewable electricity generation in Barbados needs to be tested against the target to be reached and the transition pathway to the renewable energy based target system. To analyse different possible target systems for a 100% renewable electricity supply for Barbados the existing hourly simulation model developed by the author and applied to 100% renewable energy solutions was extended to accommodate the use of flexible bioenergy from King Grass gasification. This extension allows to model seasonal harvesting and flexible hour of day production based on a day ahead prognosis of the production from wind and solar energy. At the same time the model was extended to handle power production from waste gasification on the same basis.

In addition the model was extended by a discounted cash flow subprogram, which allows to account for the hourly income from residual load dependent feed-in tariffs for example for electricity from King Grass or solid waste gasification. This can be used to assess the impact of load dependent tariffs on flexible production units as a precondition to the setting of such tariffs.

## WORK PACKAGE 5: SIMULATION OF ALTERNATIVE 100% RE TARGET SYSTEMS AND ANALYSIS OF THEIR PROSPECTIVE COSTS

A set of 18 different target systems were simulated to analyse all relevant combinations of the renewable power technologies available to Barbados. These technologies are wind turbines, solar PV systems, solid biomass combustion, biomass gasification, solid waste combustion and waste gasification. The comparison of the power costs of all alternative target systems showed that a combination of wind, PV and solid waste combustion can produce 100% renewable power at the lowest cost (0.39 BBD/kWh in a year of low winds).

Table ES1: Electricity cost per kWh of simulated target systems for 100% RE power for Barbados

| Scenario | | LCOE |
|---|---|---|
| **No.** | **Name** | **BBD/ kWh** |
| **11** | 100% RE / Wind / PV / Solid waste combustion | 0.3883 |
| **7** | 100% RE Wind and PV plus storage | 0.3999 |
| **13** | 100% RE / Wind / PV / King Grass / WTE combustion | 0.4004 |
| **6** | 100% RE Wind and storage alone | 0.4013 |
| **17** | 100% RE / Wind / PV / King Grass / Bagasse / WTE combustion | 0.4128 |
| **14** | 100% RE / Wind / PV / Bagasse / WTE combustion | 0.4143 |
| **12** | 100% RE / Wind / PV / King Grass / WTE gasification | 0.4209 |
| **8** | 100% RE / Wind / PV / King Grass | 0.4212 |
| **9** | 100% RE / Wind / PV / Bagasse | 0.4233 |
| **10** | 100% RE / Wind / PV / WTE gasification | 0.4356 |
| **18** | 100% RE / Wind / PV / King Grass / Bagasse / WTE gasification /WTE combustion | 0.4361 |
| **13a** | 100% RE / Wind / PV / King Grass / WTE combustion | 0.4386 |
| **1** | New diesel only (base line) | 0.4495 |
| **16** | 100% RE / Wind / PV / King Grass / Bagasse / WTE gasification | 0.4584 |
| **15** | 100% RE / Wind / PV / Bagasse / WTE gasification | 0.4614 |
| **2** | Bagasse and river tamarind only | 0.4810 |
| **3** | King grass gasification only | 0.4886 |
| **5** | 100% RE PV and storage alone | 0.5100 |
| **4** | Waste to energy gasification only | 0.5126 |

The target system addressing the agricultural problem still having relatively low costs is the combination of wind, PV, solid waste combustion and the gasification of King Grass from about 6,000 acres leading to costs of 0.4 BBD/kWh. Table IR1 shows the costs of each simulated scenario in the sequence of the cost per kWh.

## Work package 6: Discussion of the Alternative 100% RE Target systems with the relevant stakeholders and the energy division

As all reasonable alternatives have been covered by the scenarios calculated and as it has become clear that only one option can be dismissed right away, while all other decisions will need to be made by policymakers, it was decided that a stakeholder workshop could not decide on the final technology choices. Only if a decision on the solution of the agricultural problem is taken by policymakers, the decision on the final target system can be made.

Policymakers will need to decide how to complement the basic mixture of wind, PV and solid waste combustion with a biomass technology for securing the future of intercropping agriculture in Barbados. As the King Grass gasification is right know entering the demonstration phase, it might be wise to postpone this decision until the results of the first demonstration project on Barbados will be available about 2020. In the meantime the expansion of wind and solar PV can be pursued without the need for such a decision for the energy system before 2025.

Instead of holding the planned stakeholder workshop on the modelling results there will be a broader workshop at the end of the project for the discussion of all results of phase one and phase two of the project. From recent discussions it has become clear that, while most stakeholders see the advantages of a differentiated dynamic feed-in tariff system, the first price points to be suggested in the report and the assumptions going into their calculation will meet far greater interest as some details of the final target scenario.

## Work package 7: analysis of the present power supply system as the starting point of the necessary transition to A 100% RE target system

The analysis of the present power supply system shows that this is dominated still by oil based power production (96%), although the installation of solar PV has increased significantly during the last years. With respect to the necessary back-up of future renewable power systems the present generating equipment with the exemption of the steam turbines (2 x 20 MW out of 239 MW total generating capacity) can be used as flexible back-up capacity, if the necessary maintenance is done and the generators are kept operating. The target system simulations show that a back-up capacity between 160 and 200 MW will be need. Therefore, the flexible part of the present generators of BL&P will be a sufficient back up capacity for the target systems. As the equipment will be fully written off by the time when it will go into back-up operation, these generators will be the cheapest back-up capacity available to the system.

For the IRP (integrated resource plan) of Barbados Light and Power (2012), filed in 2012 the power demand for 2035 is estimated to be around 1,350 GWh/a in the base case. In a low case it is estimated at about 950 and in a high demand case at about 2,000 GWh/a. For the simulations of the 100% RE target system a demand of 1,350 GWh/a has been assumed based on the numbers of the IRP.

## Work package 8: Design of an appropriate transition pathway from the present electricity system to the 100% RE target system

As a result of the eighteen 100% RE target systems simulated in WP5 four different target scenarios have been selected for the design of four alternative transition pathways. These systems are the combination of wind, PV and solid waste combustion (scenario 11) as the lowest cost alternative. The combination of these three technologies with a modest use of King Grass gasification (scenario 13), or with an extensive use of King Grass (scenario 13a) and with the combustion of solid biomass (scenario 14). All scenarios employ between 200 and 260 MW of wind and PV and 11 MW of solid waste combustion. They only differ in the extent of biomass utilisation and the technology used for the biomass utilisation.

All scenarios start faster on PV, because the ramping up of wind energy requires more preconditions to be set appropriately, while the power cost will benefit substantially from the use of wind energy. A substantial share of renewable energy will decrease cost as compared to the starting system, while power cost will increase again as the full 100% are finally approached. By 2020 the share of RE electricity is between 22% and 41%, where the main difference is due to the assumed commissioning of the solid biomass combustion plant (25 MW) before 2020 in scenario 14 bringing the share of RE in this scenario to 41% in 2020 already. The other scenarios show shares close to 25% (see Table IR3 below). By 2030 the RE share increases to between 59% and 75%, with the lowest share in scenario 13a including a massive use of King Grass gasification, while the scenario 14 still has the highest share of RE due to the operation of the solid biomass combustion. By 2030 all scenarios have shares of RE between 86% and 91% with the shares of RE moving closer together. In 2035 all scenarios reach 96.3% of RE based on the selected renewable technologies. The rest of 4.7% is based on bio fuels used in the back-up units. Tables IR2 and IR3 show the development of the four transition pathways.

Table ES2: Four target scenarios for 100% RE power supply in 2035 and transition pathways to these target scenarios

| Scenario / Wind year 2011 | | Year | Annual power demand | LCOE | Installed capacities and annual generation | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Wind | | PV | | King Grass | | Bagasse and river tamarind combustion | | Solid wate combustion | |
| No. | Name | | | BBD/ kWh | MW | GWh/ a | MW | GWh/ a | MW | GWh/ a | MW | GWh/ a | MW | GWh/a |
| 11 | 100% RE / Wind / PV / WTE combustion | 2015 | 950 | | 0 | | 10 | 19 | | | | | 0 | |
| | | 2020 | 1050 | 0.3664 | 25 | 114 | 55 | 113 | | | | | 5 | 34 |
| | | 2025 | 1150 | 0.3002 | 105 | 481 | 125 | 258 | | | | | 11 | 74 |
| | | 2030 | 1250 | 0.3123 | 185 | 847 | 195 | 403 | | | | | 11 | 74 |
| | | 2035 | 1350 | 0.3883 | 265 | 1213 | 265 | 547 | | | | | 11 | 74 |
| 13 | 100% RE / Wind / PV / King Grass / WTE combustion | 2015 | 950 | | 0 | 0 | 10 | 19 | 0 | 0 | | | 0 | 0 |
| | | 2020 | 1050 | 0.3696 | 20 | 92 | 65 | 134 | 2 | 5 | | | 5 | 34 |
| | | 2025 | 1150 | 0.3253 | 90 | 412 | 120 | 248 | 10 | 30 | | | 11 | 74 |
| | | 2030 | 1250 | 0.3161 | 160 | 733 | 175 | 361 | 18 | 75 | | | 11 | 74 |
| | | 2035 | 1350 | 0.4004 | 232 | 1062 | 232 | 479 | 26 | 120 | | | 11 | 74 |
| 13 a | 100% RE / Wind / PV / King Grass / WTE combustion | 2015 | 950 | | 0 | | 10 | 19 | 0 | 0 | | | 0 | |
| | | 2020 | 1050 | 0.3749 | 20 | 92 | 50 | 103 | 2 | 5 | | | 5 | 34 |
| | | 2025 | 1150 | 0.3354 | 80 | 366 | 100 | 206 | 14 | 45 | | | 11 | 74 |
| | | 2030 | 1250 | 0.3451 | 140 | 641 | 150 | 310 | 27 | 150 | | | 11 | 74 |
| | | 2035 | 1350 | 0.4331 | 200 | 916 | 200 | 413 | 40 | 300 | | | 11 | 74 |
| 14 | 100% RE / Wind / PV / Bagasse / WTE combustion | 2015 | 950 | | 0 | 0 | 10 | 19 | | | 0 | 0 | 0 | 0 |
| | | 2020 | 1050 | 0.3807 | 20 | 92 | 65 | 134 | | | 25 | 169 | 5 | 34 |
| | | 2025 | 1150 | 0.3452 | 85 | 389 | 120 | 248 | | | 25 | 169 | 11 | 74 |
| | | 2030 | 1250 | 0.3609 | 170 | 778 | 175 | 361 | | | 25 | 169 | 11 | 74 |
| | | 2035 | 1350 | 0.4143 | 219 | 1003 | 219 | 452 | | | 25 | 169 | 11 | 74 |

Table ES3: Four target scenarios for 100% RE power supply in 2035 and transition pathways to these target scenarios. The development of the need for storage during the transition period.

| Scenario / Wind year 2011 | | Year | Annual power demand | LCOE | Installed capacities and annual generation: Diesel/ Biodiesel | | Storage volume | Storage generation | | Storage pumping | | Share of RE | Total overproduction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | Name | | | BBD/ kWh | MW | GWh/ a | MWh | MW | GWh/ a | MW | GWh/ a | % | GWh/a |
| 11 | 100% RE / Wind / PV / WTE combustion | 2015 | 950 | | 239 | 950 | | | | | | | |
| | | 2020 | 1050 | 0.3664 | 140.9 | 789 | | | | | | 24.9 % | 0 |
| | | 2025 | 1150 | 0.3002 | 148.8 | 354 | 3000 | 150.5 | 60 | 90 | 80 | 69.2 % | 17 |
| | | 2030 | 1250 | 0.3123 | 162.2 | 118 | 5000 | 186.3 | 176 | 220.7 | 202 | 90.6 % | 192 |
| | | 2035 | 1350 | 0.3883 | 166.7 | 50 | 5000 | 196.8 | 205 | 307 | 238 | 96.3 % | 400 |
| 13 | 100% RE / Wind / PV / King Grass / WTE combustion | 2015 | 950 | | 239 | 950 | 0 | 0 | 0 | 0 | 0 | 0.0 % | 0 |
| | | 2020 | 1050 | 0.3696 | 140.2 | 785 | | | | | | 25.2 % | 0 |
| | | 2025 | 1150 | 0.3253 | 148 | 422 | | | | | | 63.3 % | 36 |
| | | 2030 | 1250 | 0.3161 | 155.6 | 164.4 | 5000 | 178 | 142 | 162.8 | 163 | 86.8 % | 157.4 |
| | | 2035 | 1350 | 0.4004 | 144.8 | 50 | 5000 | 172.9 | 163 | 253.4 | 190 | 96.3 % | 435 |
| 13 a | 100% RE / Wind / PV / King Grass / WTE combustion | 2015 | 950 | | 239 | 950 | | | | | | 0.0 % | |
| | | 2020 | 1050 | 0.3749 | 140.2 | 816 | | | | | | 22.3 % | 0 |
| | | 2025 | 1150 | 0.3354 | 140.5 | 469 | | | | | | 59.2 % | 10 |
| | | 2030 | 1250 | 0.3451 | 135.3 | 168 | 5000 | 156 | 97 | 131.5 | 110 | 86.6 % | 93 |
| | | 2035 | 1350 | 0.4331 | 131.6 | 50 | 5000 | 156.8 | 129 | 199.8 | 151 | 96.3 % | 403 |
| 14 | 100% RE / Wind / PV / Bagasse / WTE combustion | 2015 | 950 | | 239 | 950 | 0 | 0 | 0 | 0 | 0 | 0.0 % | 0 |
| | | 2020 | 1050 | 0.3807 | 121.7 | 621 | | | | | | 40.9 % | 0 |
| | | 2025 | 1150 | 0.3452 | 129.9 | 286 | 5000 | 138.4 | 56 | 85.3 | 75 | 75.1 % | 16 |
| | | 2030 | 1250 | 0.3609 | 139.4 | 133 | 5000 | 165 | 157 | 181.4 | 181 | 89.4 % | 265 |
| | | 2035 | 1350 | 0.4143 | 151.9 | 50 | 5000 | 180.6 | 176 | 248.3 | 205 | 96.3 % | 398 |

## Work package 9: Discussion of possible market mechanisms and policies for the successful introduction of renewables in Barbados

Basically four main market or support mechanisms for the introduction of renewable energy sources into electricity production are used world wide. These are net metering, feed-in tariffs (FIT), renewable portfolio standards (RPS) and auctioning. All are used widely throughout the world, while net metering is seen only as an early mechanism of limited applicability, as it shifts the other power system costs to the customers not producing renewable electricity, which can become overwhelming, if large shares of RE are produced based on net metering. Like net metering FITs approach the target of inducing higher RE shares from the side of the pricing of energy and the quantity installed is determined by the market players, while RPS and auctioning set quantity targets and the final price for the quantity of RE installed is set by market processes.

While pay-as-bid auctions allow to approximate the cost curve for the supply of renewable power RPS combined with the trading of green certificates price the renewable energy according to the last unit of

RE supplied. Thus, in the case of RPS all other producers with lower costs can benefit from a substantial producer surplus. Therefore, by tendency the cost of renewable electricity supplied under RPS will be higher than under an auctioning system. Both approaches have the serious disadvantage that they require sophisticated well informed market players in sufficient numbers for a competitive market. Thus, most likely they are either not applicable to small island states or may require a substantial number of international investors to reach the necessary level of competition.

FITs rely heavily on an informed administration and well informed policy makers setting differentiated tariffs according to the cost structure of the different RE technologies. If FITs are differentiated for different system sizes and different conditions under which the RE are deployed (e.g. the quality of a wind site) it is possible to approximate the cost curve of a technology similar to the auction process. If FITs are applied in a dynamic way, reducing the rates for new installations every year according to the cost digression of a technology seen in the market, they can result in lower RE cost than auctioning and RPS, as historic experience shows in the comparison between the cost development of RE in Germany (FIT), the UK (auctioning and RPS) and the USA (RPS). At the same time FITs don't need competitive markets to find the tariff to be paid. As RE technologies are traded internationally national FITs can be informed by the international cost structures and developments as long as the local specifics are taken into account.

Empirical evidence has shown that specifically a wide participation of all citizens in RE investments is best accommodated by FITs and that these can induce a very rapid market diffusion of RE.

A review of experiences with different support mechanisms for the market diffusion of renewable energy sources in five island systems with high RE penetration and the experiences of the Dominican Republic, which is the only Caribbean country with a FIT system legislated, showed that FITs and net metering systems had very effectively promoted RE market diffusion. RPS and auctioning or tendering have been used only in rare cases (Hawaii uses RPS and Crete and Reunion are presently forced to move to tendering by EU law) with limited success. In the case of Hawaii non dynamic FITs had to be capped for maximum capacity and lead to speculative project queuing. In Crete and Reunion dynamic FIT tariffs were able to calm down very fast developments of PV in the years after 2008. The examples show that FIT systems have to be very well tailored to the circumstances of an island country and have to follow the cost trends of renewable energy technologies for new investments.

## WORK PACKAGE 10: ANALYSIS OF THE PRESENT MARKET SITUATION OF RENEWABLES IN BARBADOS

Presently only solar PV has been installed in sizeable numbers as RE electricity technology in Barbados. As Table IR4 shows the installation of PV capacity has started in significant numbers in 2012 with 910 $kW_p$ of capacity installed and annual installation has been increasing ever since. The main driver of the installation of PV has been the renewable energy rider (RER) first introduced in 2010 for a trial period of two years and allowed as a permanent support mechanism in August 2013. The RER was directly linked to the fuel cost adjustment clause and thereby to the world market price of oil. In 2016 the variable rate of the RER based on the Fuel Clause Adjustment was temporarily converted to a fixed feed-in tariff of 0.416 BBD/kWh for PV and 0.315 BBD/kWh for wind energy. This change was due to the fact that the world market crude oil price had gone down to below 40 USD/bbl while it was at more than 100 USD/bbl in the years when the RER was originally designed. This massive drop in oil prices led to many solar installations becoming economically endangered. As the 2016 RER ruling is only temporary investors are waiting for the further development of the Barbados support mechanism.

As the RER initially only applied to installations up to 150 kW, a limit that was later raised to 250 and then to 500 kW, larger installations are not seen in Barbados except the 10 MW PV plant built by BL&P, which does not come under the support mechanisms applied to all other investors

Besides the unclear future of the renewable energy support mechanism the development of RE is slowed down by relatively unclear and lengthy licensing and permitting processes. The new requirement of an ELPA license and the financial burdens posed by it on investors is seen by many as one of the main obstacles to a faster development of RE. The situation that every project over 500 kW is treated as an independent power producer (IPP) under the Electric Light and Power Act (ELPA) puts investors into a very difficult negotiating position with the vertically integrated monopoly of BL&P, as this is a totally asymmetrical negotiating position.

Table ES4: Development of PV capacity in Barbados since 2010 (sources: UNDP no year, p.19, IDB 2016, p.12 and application data for ELPA licenses)

| Year | No. of PV Systems | Annually Installed Capacity (kW) | Cumulative Installed Capacity (kW) |
|---|---|---|---|
| 2010 | 4 | 7 | 7 |
| 2011 | 8 | 7 | 14 |
| 2012 | 63 | 896 | 910 |
| 2013 | 350 | 1990 | 2900 |
| 2014 | 710 | 2600 | 5500 |
| 2015 | ? | 4900 | 10400 |
| 2016 | 850 | 12455 | 22855 |

In addition the frequent demand for additional information from investors in unclear licensing and permitting processes are a main obstacle to substantial RE investments in Barbados. Some wind energy projects have been in the licensing and permitting process for more than five years with the end of the process still pending. As compared to international standards this is absolutely not acceptable.

One special problem of the permitting of wind power installations are the distance rulings applied by Town and Country Planning. As different from the international standard rules Town and Country Planning requires minimum distances from the perimeter of the property on which a wind turbine is placed, while the international standard is based on the distance to an object to be protected from the direct impact of wind energy. As the Barbados ruling does not allow to locate wind turbines in the middle of uninhabited agricultural land owned by a several land owners it only allows a small fraction of the wind energy capacity which could be placed on such land as compared to international standards. If Barbados wants to benefit from its superb wind energy resource and the low cost of wind energy this rule needs to be brought up to international standards.

## WORK PACKAGE 11: COMPARISON OF PRESENT MARKET SITUATION AND INSTRUMENTS TO POSSIBLE ALTERNATIVE CHOICES

In WP11 the present support situation and the alternative support mechanisms discussed in WP9 are analysed with respect to the important objectives that they should fulfil according to the interviews with key stakeholders (see WP1). In addition to the 13 most important objectives two additional criteria were introduced into the discussion, the *applicability of* such *a support mechanism* and the *necessary administrative effort* to handle a support mechanism. Table ES5 shows the results of the comparison of the support mechanisms with the objectives. Green colour showing that a support mechanism can fulfil an objective and red colour showing that it does not fulfil the objective.

As pointed out before, net metering should not be applied at a large scale, as it drives up the cost for the poorest ratepayers and benefits richer investors. The same applies to the original renewable energy riders system, which, in addition to favouring RE investors at the expense of ratepayers, prohibits that power prices are stabilised in times of high oil prices, as it could be achieved by constant cost based tariffs for renewable energy sources. Thus, both systems, net metering and the original RER, should be ruled out for a large scale application in Barbados.

Renewable portfolio standards (RPS) require functioning markets for green certificates based on the production of renewable electricity. In addition they require spot and futures markets for electricity to fully function. Both types of large anonymous markets can not be established with the small number of market participants in Barbados and with the monopoly generator of conventional electricity. Thus, RPS are not applicable for Barbados and are therefore dismissed.

The final discussion boils down to a comparison of auctioning and feed-in tariffs (FITs) with respect to the important objectives. As measured against all thirteen objectives and the two additional criteria FITs do well on all of them. ***There is not a single objective which could not be met by a well tailored differentiated dynamic FIT system***.

While auctioning does best on *low cost of electricity* and by tendency even better than an FIT system, if there is enough competition in the auctions, it does badly on *high employment generation, reduction of imports/hard currency, public acceptance of power supply, general participation, local participation* and *domestic ownership*, while it necessitates a large *administrative effort* for the regular auctions and the setting of multiple quantity targets at short time intervals. It can do well on *reduction of imports/energy security* and *solving agricultural problems*.

The detailed discussion of all different aspects in WP11 has shown that ***a differentiated dynamic FIT system tailored to the needs of Barbados is clearly the most adequate support mechanism for a sustainable long term diffusion and stable prices of renewable energy in Barbados***.

Table ES5: Summary of the scores of all support mechanisms on thirteen objectives for the renewable energy policy of Barbados and two additional criteria

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Applicable to Barbados | | | | | | | | |
| Administrative effort necessary | | | | | | | | |
| Reliability of power supply (loss of load d/a) | 117.0 | | | | | | | |
| Low environmental impact | 91.0 | | | | | | | |
| Low cost of power | 89.0 | | | | | | | |
| High employment generation | 83.0 | | | | | | | |
| Reduktion of imports / hard currency | 78.0 | | | | | | | |
| Public acceptance of power supply | 67.0 | | | | | | | |
| Reduction of imports / energy security | 61.0 | | | | | | | |
| General participation (every household) | 43.0 | | | | | | | |
| Hurricane resiliance | 33.0 | | | | | | | |
| Local participation | 32.0 | | | | | | | |
| Domestic ownership | 27.0 | | | | | | | |
| Problems of agriculture need to be solved | 27.0 | | | | | | | |

## WORK PACKAGE 12: INTERIM REPORT

## WORK PACKAGE 13: DEVELOPMENT OF THE MOST PROMISING MARKET DESIGN AND POLICIES FOR THE PROMOTION OF RE TECHNOLOGIES AND STORAGE UP TO A SHARE OF 100% RENEWABLE POWER

Work Package 13 develops the details of an Feed-in Tariff (FIT) system suggested to be implemented in Barbados. It discusses more than 30 different design choices and selects the most appropriate configuration for Barbados. Table ES6 and ES 7 show the most important choices considered and the suggestions made for the FIT system implementation for Barbados. The main features of the FIT system are:

- **Cost based price setting** using the cost of renewable energy generation plus a fair return for the investor to guarantee stable long term prices for ratepayers and to guarantee stable long term cash flows for investors
- **Tariff differentiation** by technology, type of fuel (in the case of biomass), resource quality, project size, and location (roof top or ground mounted PV) to enable the best mix of RE technologies and possible sites at low cost
- **Dynamic degressive tariffs** with pre-established tariff degression for future installations to capture reductions in investment costs due to technical progress
- **Responsive tariffs** with automatic tariff adjustment for the following year to meet target capacity corridors
- **Inflation adjustment** for variable cost components, to increase investor security
- **Front-end loading** with a higher tariff during the first ten years to enable a positive cash flow from the first year of operation
- **Time of delivery sensitive** for dispatchable renewable energy technologies to incentivise operation during time of greatest need
- **Bonus payments for community ownership** to encourage broad citizen participation (e.g. in community wind parks)
- **Guaranteed priority grid access for renewable energy** to increase investor security
- **Guaranteed 20 year FIT rates** to increase investor security through stable Feed-in Tariff payments
- **Payment in Barbados Dollars** to encourage domestic and discourage international investors by putting the exchange rate risk on the returns of international investors and not on ratepayers
- **Broadest possible eligibility** of all relevant RE technologies of all sizes and of all domestic investors to encourage broad participation in the new energy system
- **Ownership by impact** granting a share of up to 10% additional ownership to people living very close to new wind turbines to increase local acceptance of wind energy
- **Temporary capacity caps** for grid subsections to ensure grid and system stability
- **Low stable renewable energy cost** through minimising investor and financing risks to allow for low risk debt financing and low risk returns on invested equity
- **Tax neutral** by levying all costs onto the electricity rates by a FIT levy, to avoid additional burdens on taxpayers
- **Agriculture friendly** by including special FIT rates for solid biomass combustion from bagasse and King-Grass gasification for power production to help to solve the key agricultural problem of Barbados.

Table ES6: Suggested FIT design for Barbados: 1. FIT payment choices

| | Design options | Possible choices | Choice for Barbados |
|---|---|---|---|
| | | FIT Payment choices | |
| 1 | **Prices setting based on** | - Cost of generation<br>- Value of generation / avoided cost<br>- Fixed price incentive<br>- Auction based price discovery | Cost of generation |
| 2 | **Payment differentiation by** | Technology | Yes (wind, biomass, waste to energy, storage) |
| 3 | | Fuel type (biomass) | Yes (biomass: bagasse, syngas from gasification, biogas from manure and agricultural waste) |
| 4 | | Project size | Yes (PV, biomass) |
| 5 | | Resource quality | Yes (wind, PV) |
| 6 | | Location (roof top, facade, ground mounted) | Yes (PV: roof top or ground mounted) |
| 7 | **Ancillary design elements** | Pre-established tariff degression | Yes (wind, PV, biomass) |
| 8 | | Indexed tariff degression (international cost development) | Yes (PV, wind, storage) |
| 9 | | Responsive tariff degression | Yes (PV, wind, biomass, storage) |
| 10 | | Inflation adjustment (O&M and fuel costs) | Yes (O&M for wind, PV, storage and waste to energy; fuel costs for biomass) |
| 11 | | Front-end loading | Yes (PV, wind, biomass, storage) |
| 12 | | Time of delivery (dispatchable production) | Yes, eventually (for biomass and waste to energy) |
| 13 | **Further differentiation (bonus)** | Bonus for community ownership | Yes (wind, PV?) |
| 14 | | Ownership by impact (proximity to wind turbines) | Yes (wind energy, up to 10% of investment cost) |
| 15 | **Payment duration** | Short, medium and long term | Long term (20 years plus x) |
| 16 | **Payment currency** | BBD / USD | BBD |
| 17 | **Net metering** | Yes / No. Capacity limits are possible. Limitation to certain customer groups is possible. | Yes (PV with a capacity limit of 1 kWp and and a limit to 25% of all households (lowest income quarter) |

Table ES7: Suggested FIT design for Barbados: 2. Implementation options

| | Design options | Possible choices | Choice for Barbados |
|---|---|---|---|
| | | **Implementation options** | |
| **18** | **Eligibility** | All technologies, possible operators, sizes and locations can be eligible or eligibility can be restricted. | All RE technologies, all owners, all sizes, all locations (based on location specific caps) |
| **19** | **Purchase obligation / Interconnection guarantee** | Yes/No | Yes, within the technical limits BL&P has to buy |
| **20** | **Purchasing entity** | Utility company, grid operator, government | Grid operator (BL&P) |
| **21** | **FIT policy adjustment** | Yes / No. Adjustment of FIT payment levels or of FIT program | Adjustment of payment levels (every two or three years) in addition to automatic degression After five years a revision of the overall policy should be considered in the light of the lessons learned (without endangering investor trust in the policy). |
| **22** | **Caps** | Capacity cap, project size cap, cap to program cost | Technical caps for every grid section. Grid operator has to remove technical limits as planned and agreed with the Energy Division. In the planning of the transition pathway the cost to the ratepayer should be analyzed in advance in order to limit rate increases above the average rate development under conventional electricity production. |
| **23** | **Interconnection priority for RE** | Yes / No | Yes (within the limits set by the caps, otherwise queuing until technical limit has been removed) |
| **24** | **Dispatch priority for RE** | Yes / No | Yes, to the extent possible |
| **25** | **Obligation for production forecast** | Yes / No (for larger installations) | No, much cheaper to do for entire system |
| **26** | **Transmission and interconnection cost allocation** | - Super shallow (no connection cost)<br>- Shallow (connection cost to the nearest transmission point)<br>- Deep (All cost for grid connection including transmission and substation upgrades)<br>- Mixed (connection cost plus some share of transmission and substation upgrade) | Super shallow for systems up to 100kW. (No connection cost paid by RE operator.)<br>and<br>shallow for system larger than 100kW. (Connection cost to the nearest transmission point paid by RE operator.) |

| | Design options | Possible choices | Choice for Barbados |
|---|---|---|---|
| **27** | **Funding option** | - Ratepayer funded (electricity tariff)<br>- Taxpayer funded (specific allocation from the treasury)<br>- Supplementary options (e.g. carbon auction revenues | Ratepayer funded by RE levy on every kWh. without any exemption. |

The suggested structure of the FIT system for Barbados is given in Table ES8, which specifies the different technologies, size ranges, the duration of the guarantee period of the FIT payments, the duration of the higher FIT payments due to front-end loading, first suggestions of capacity corridors and possible response rates for over or under achieving capacity target corridors. First price points are given in Table ES9 under WP 14. Due to the very early stage of development the tariff structure for storage should be discussed later.

Table ES8: Structure of the proposed Barbados FIT system not including initial price points for FIT payments (net metering for small PV 0-1 $kW_p$ restricted to low income households)

| Technology | Size range in kW | Initial FIT rates Phase I | Initial FIT rates Phase II | Guarantee period | Annual reduction | Capacity target corridor | Increase by under-achievement | Decrease by over-achievement |
|---|---|---|---|---|---|---|---|---|
| | | Duration in years for reference site | Duration in years for reference site | in years | in % | in MW/a | in % per 10% | in % per 10% |
| **PV roof** | 1-10 | 10 | 10 | 20 | 2.4 % | 5 - 10 | 1 % | 1 % |
| | 10-100 | 10 | 10 | 20 | 2.4 % | | 1 % | 1 % |
| | 100-1,000 | 10 | 10 | 20 | 2.4 % | | 1 % | 1 % |
| | > 1,000 | 10 | 10 | 20 | 2.4 % | | 1 % | 1 % |
| **PV ground mounted** | | 10 | 10 | 20 | 2.4 % | 5 - 10 | 1 % | 1 % |
| **Wind** | Investor owned | 10 | 10 | 20 | 0 % | 0 - 20 | ? | ? |
| | Community owned | 10 | 10 | 20 | 0 % | | ? | ? |
| **Biogas from manure** | 0-75 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| | 75-150 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| | 150-500 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| | 500-5,000 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| | > 5000 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| **Biomass gasification** | | 10 | 10 | 20 | 0 % | ? | ? | ? |
| **Solid biomass combustion** | | 10 | 10 | 20 | 0 % | none | none | none |
| **Solid waste combustion** | | 10 | 10 | 20 | 0 % | ? | ? | ? |

In addition to the overall Feed-in Tariff system developed for Barbados it is suggested by the consultant to use net metering for very small PV installations (up to 1 $kW_p$) owned by households, who are part of the lowest income quarter of Barbados. Such net metering provision would allow the broadest possible participation of all households in Barbados, but it would avoid an overburdening of the average ratepayer with general system costs not paid for by the net metering customers.

## WORK PACKAGE 14: DEVELOPMENT OF FIRST PRICE POINTS FOR PRICING MECHANISMS/POLICIES

Based on the structure of the suggested FIT system for Barbados (derived in WP 13) and the best available national and international cost information Work Package 14 derives some first price point suggestions as starting points for Barbados' first FIT rates. Table ES8 shows the rates developed, which are given for reference locations in the case of solar and wind energy. The rates for solar PV and wind energy are front-loaded, with a payment ratio of 1:0.55 in the first ten and the second ten years of the twenty year tariff guarantee period. If a location has a higher or lower output the payment of the higher up front rate is shortened or extended in order to be paid for the same number of kilowatt hours as for the reference plant.

The rates for PV are differentiated by system size according to average US cost ratios. Depending on system size the average FIT rate ranges from 0.28 for very large to 0.49 BBD/kWh for very small PV systems.

In the case of wind energy up to 10% additional ownership by impact (noise exposition) can be granted to people living very close to the turbines. For community owned wind parks an adder of 10% is calculated into the FIT rate for assumed higher investment costs. The basic average FIT rate for investor owned wind turbines (with no ownership by impact) is 0.198 BBD/kWh. The rate increases to 0.208 BBD/kWh for 10% additional ownership by impact and to 0.212 BBD/kWh for community wind parks.

The price points for PV are based on cost data for Barbados as well as international cost data, while the price points for wind energy are based on international data plus a 25% adder for estimated higher costs in Barbados. The price points for both technologies can be considered as reasonably sound starting points for Barbados.

In the case of biomass different FIT rates are suggested for the anaerobic digestion of manure and agricultural residues, for the combustion of bagasse combined with river tamarind and for the gasification of King-Grass for power production. In the case of anaerobic digestion a strong differentiation over size is suggested based on experiences in Germany and the UK. The price points and the differentiation are based on early FIT payments in Germany (2004-2009) plus an adder of 25% for higher costs in Barbados. The price point for bagasse combustion (0.28 BBD/kWh) is taken directly from the costs quoted for the Barbados Cane Industry project, which has been under development for a number of years. In the case of King-Grass gasification extremely preliminary cost data from a feasibility study for the gasifier at ARMAG Farms have been used as very first cost orientation. Investment cost estimates differ by up to factor three for this technology. Thus, the average estimate given has to be treated with extreme care. Both FIT rates for bagasse combustion and for King-Grass gasification are not differentiated over time (no front-end loading) due to a lack of detailed data.

In the case of waste to energy international FIT rates from Indonesia, Vietnam and Uganda (0.2 BBD/kWh) have been used for a first orientation, as there are hardly any FIT rates for waste combustion in industrialised countries. The suggested price point for Barbados is a rounded average rate for these three countries plus an adder of 25% for higher costs in Barbados.

The price points given can be used as starting points for the FIT system in Barbados, but it will be absolutely essential for the further development of the FIT rates to closely monitor the cost development of each technology under the specific circumstances in Barbados. International experience has shown that this can easily be done by a legal requirement for cost, output and performance reporting for each installation receiving FIT payments.

No price points have been developed for FIT rates for storage, as the available data are far to preliminary. The FIT structure and rates for storage will need to be subject to an intensive discussion with international storage experts and the key local stakeholders.

Table ES9: Summary of suggested first price points for all technologies considered for possible FIT rates for Barbados (net metering for small PV 0-1 $kW_p$ restricted to low income households)

| **Techno logy** | **Size range in kW** | FIT rates | | | | | Guarantee period | Annual reduction |
|---|---|---|---|---|---|---|---|---|
| | | Average FIT rate in BBD/ kWh | Phase I | | Phase II | | | |
| | | | Rate in BBD/ kWh | Duration in years | Rate in BBD/ kWh | Duration in years | in years | in % |
| **PV roof** | 1-10 | 0.491 | 0.634 | 10 | 0.348 | 10 | 20 | 2.4 % |
| | 10-100 | 0.443 | 0.571 | 10 | 0.314 | 10 | 20 | 2.4 % |
| | 100-1,000 | 0.334 | 0.431 | 10 | 0.237 | 10 | 20 | 2.4 % |
| | > 1,000 | 0.281 | 0.363 | 10 | 0.200 | 10 | 20 | 2.4 % |
| **PV ground mounted** | | 0.281 | 0.363 | 10 | 0.200 | 10 | 20 | 2.4 % |
| **Wind** | Investor owned | 0.198 | 0.255 | 10 | 0.140 | 10 | 20 | 0 % |
| | Community owned | 0.212 | 0.273 | 10 | 0.150 | 10 | 20 | 0 % |
| | Investor owned plus 10% ownership for proximity | 0.208 | 0.268 | 10 | 0.147 | 10 | 20 | 0 % |
| **Biogas from manure** | 0-75 | 0.826 | 0.826 | 20 | 0.826 | 0 | 20 | 0 % |
| | 75-150 | 0.678 | 0.678 | 20 | 0.678 | 0 | 20 | 0 % |
| | 150-500 | 0.623 | 0.623 | 20 | 0.623 | 0 | 20 | 0 % |
| | 500-5,000 | 0.519 | 0.519 | 20 | 0.519 | 0 | 20 | 0 % |
| | > 5,000 | 0.373 | 0.373 | 20 | 0.373 | 0 | 20 | 0 % |
| **Biomass gasification** | | 0.824 | 1.061 | 20 | 0.587 | 0 | 20 | 0 % |
| **Solid biomass combustion (bagasse)** | | 0.280 | 0.280 | 25 | 0.280 | 0 | 20 | 0 % |
| **Solid waste combustion** | | 0.250 | 0.250 | 20 | 0.250 | 0 | 20 | 0 % |

## WORK PACKAGE 15: DISCUSSION OF FUTURE PRICING OF SYSTEM SERVICES AND GRID OPERATION

Work Package 15 looked at the necessities of future pricing of system services and grid operation. It can be concluded that the lump sum pricing structure used in Barbados today, which only differentiates between fixed capital costs, fixed operation and maintenance costs (O&M), variable O&M costs and fuel costs, will not be sufficient for a fair pricing of all system components of the electricity system of the future, as it only covers one dimension of the necessary differentiation. As shown in Table ES10 a fair pricing system will need to differentiate between the costs for basic power generation, the costs for transmission and distribution of electricity and the cost for system services eventually including the costs of storage. For each of these parts of the electricity system fixed and variable costs have to be differentiated. Such differentiation will be a necessary precondition for the further liberalisation of Barbados' electricity market as discussed below. The work package flags the need for such reform, but it is beyond the scope of this study to develop actual proposals, how such cost and price differentiation can be carried out in practice.

Table ES10: The different cost elements of supplying electric power

| | Fixed capital cost | Fixed O&M cost | Variable O&M cost | Fuel cost |
|---|---|---|---|---|
| Basic power generation | x | x | x | x |
| Transmission and distribution | x | x | x | - |
| System services | x | x | x | x |

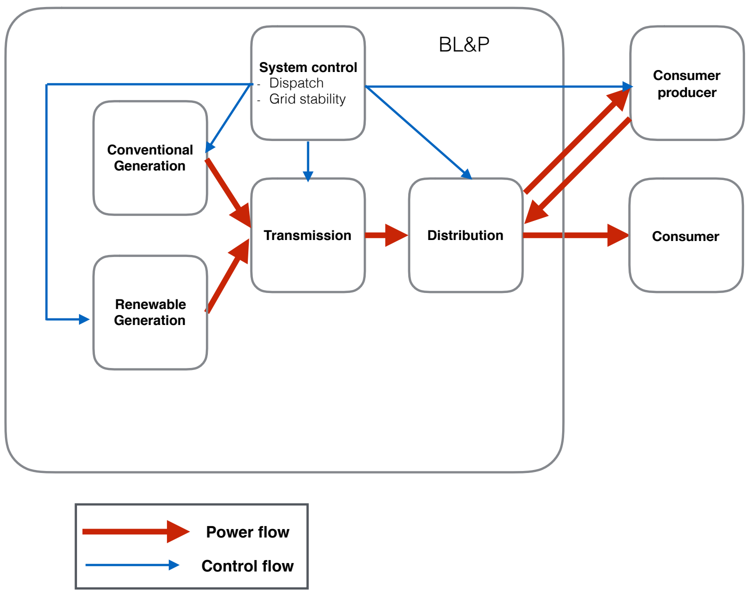
## WORK PACKAGE 16: DISCUSSION OF MOST APPROPRIATE SUPPLY MODE FOR RENEWABLE POWER

Work Package 16 discusses the possible supply mode for renewable power. After a discussion of wheeling and banking approaches used in some countries the Work Package concludes that in the Barbados situation the most appropriate supply mode for renewable power is to guarantee priority grid access and operation for all renewable energy sources within the technical limits of the electricity system and to combine this with the guaranteed right to sell all renewable power to the grid operator and the obligation for every grid connected customer to buy every kilowatt hour used from the public grid. By this combination of a comprehensive sales guarantee with the ‚buy all, sell all' rule all producers of renewable electricity are treated equal and all electricity costs are born equally by all ratepayers, not withstanding the existing social differentiation of household tariffs. Provisions for wheeling or banking of renewable electricity are rejected as they would constitute an unreasonable burden on the average ratepayer while granting undue advantages for the operators of renewable energy systems. The only exemption from the rule is the net metering for very small PV installations of up to 1 $kW_p$, which is a social component of the framework suggested for renewable energy.

## WORK PACKAGE 17: SUGGESTION OF POWER MARKET STRUCTURE

In Work Package 17 the present and possible future structure of Barbados' power market is discussed. Although, the legal situation allows for independent power producers (IPPs) of conventional and renewable electricity, the present situation is characterised by a monopoly of conventional electricity generation combined with the grid and system operation in the hands of Barbados Light and Power. The only independent power production is done by hundreds of households and commercial customers operating solar PV systems under the renewable energy rider (RER). This situation is depicted in Figure ES2.

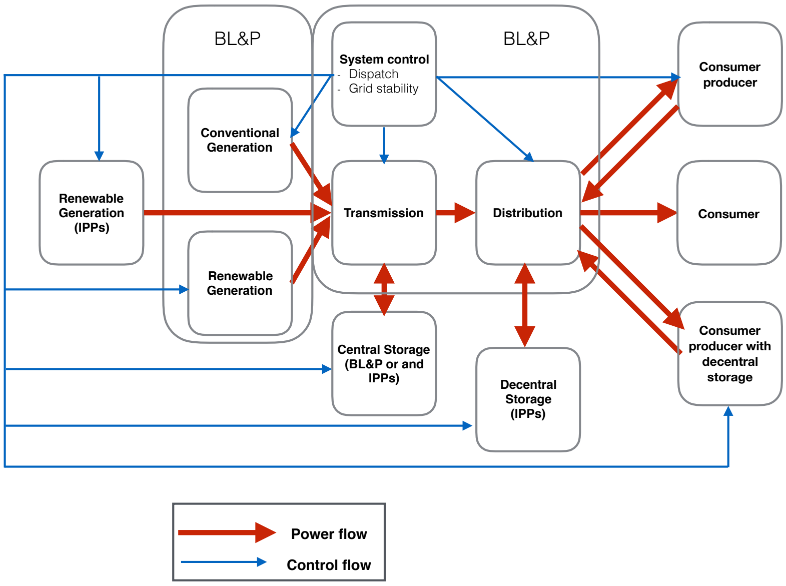
Figure ES2: Actual (not legal) present structure of Barbados' electricity system




As the small electricity system size does not allow the market entry of IPPs based on competitive conventional power generation and as storage will start to play an important role in every power market with high shares of solar and wind energy the future electricity market structure of Barbados will see seven different functions on the supply side (as pictured in Figure ES3 below):

- conventional generation (in the hands of Barbados Light and Power)
- renewable generation (in the hands of many IPPs and thousands of consumers as well as generation by Barbados Light and Power)
- central storage (in the hands of Barbados Light and Power, independent IPPs or joint ventures)
- decentralised storage (in the hands of many households and commercial customers)
- control of the entire system including all system services (in the hands of the central system operator)
- transmission of electricity at higher voltage levels (in the hands of the grid operator) and
- distribution of electricity to customers (in the hands of the grid operator).

Figure ES3: Possible future electricity system structure for Barbados including the establishment of central and decentralised storage




## WORK PACKAGE 19: DISCUSSION OF A POSSIBLE LIBERALISATION OF THE BARBADOS POWER MARKET

Work Package 19 shows that Barbados has already reached a very high level of power market liberalisation leaving only two out of nine possible steps not taken as shown in Table ES11.

Table ES11: The nine stages of electricity market liberalisation and the market situation in Barbados

| | State of liberalisation | Short characterisation | Status in Barbados |
|---|---|---|---|
| 1 | Corporatisation | Transformation of the utility into a separate legal entity | Achieved |
| 2 | Commercialisation | Cost recovering prices etc. | Achieved |
| 3 | Passage of requisite legislation | Provides legal framework for restructuring and private ownership | Achieved |
| 4 | Establishment of independent regulator | Aims to introduce transparency, efficiency and fairness in the management of the sector | Achieved |
| 5 | Independent power producers (IPPs) | Introduce new private investment in generation with long-term power purchase agreements (PPAs) | Legally achieved |
| 6 | Restructuring | Involves horizontal and/or vertical unbundling of the incumbent (state-owned) utility as preparation for privatisation | Not achieved |
| 7 | Divesture of generation assets | Divests state ownership of generation assets to the private sector | Achieved |
| 8 | Divesture of distribution assets | Divests state ownership of distribution assets to the private sector | Achieved |
| 9 | Competition | Introduces wholesale and retail markets for electricity | Not achieved |

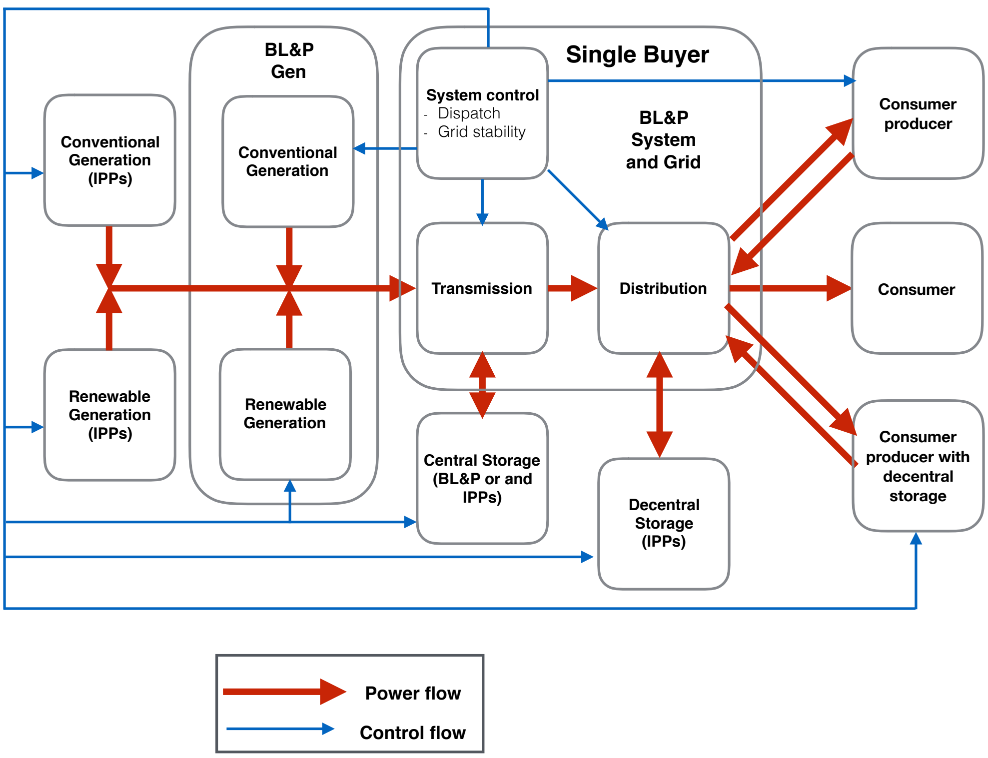
What is more, the present level of liberalisation has achieved a very high level of system reliability and system efficiency. As discussed in Work Package 19 the horizontal unbundling of conventional power generation is not reasonably possible in Barbados due to the small size of the overall system. Thus, horizontal unbundling of production will only occur through the broad ownership of renewable energy systems with guaranteed grid access and guaranteed long term FIT rates.

In Barbados only a vertical unbundling of Barbados Light and Power into two separate legal entities ‚*Barbados Light and Power Generation*' and ‚*Barbados Light and Power Grid and System Operation*' seems to be feasible. To avoid high additional coordination costs between generation and grid extension it seems to be advisable to only legally unbundle Barbados Light and Power into these two units, which still need to cooperate closely.

## WORK PACKAGE 20: SUGGESTION OF A SUITABLE LIBERALISATION STRATEGY FOR BARBADOS' POWER MARKET

Work package 20 builds upon the discussion of Work Package 19 and suggests the legal vertical unbundling of Barbados Light and Power and the establishment of *Barbados Light and Power Generation* and *Barbados Light and Power Grid and System Operation* as the single buyer and system controller of Barbados' future electricity system as pictured in Figure ES4.

Figure ES4: Resulting future electricity market structure of Barbados




The suggested structure will allow the broadest possible ownership of renewable electricity generation, central and decentralised storage and a neutral system control and coordination by the combined grid and system operator. Should any independent power producer want to enter into conventional generation at his own risk, the Electric Light and Power Act already provides the legal framework for such economic activity. Given the small system size the suggested level of liberalisation and the suggested future system structure will allow a maximum of independent power production and the best possible balance between Barbados Light and Power and all other possible power producers.

## WORK PACKAGE 18: RECOMMENDATIONS FOR THE IMPLEMENTATION OF POLICIES, REGULATION AND LEGISLATION

For the implementation of the suggested Feed-in tariff system a number of recommendations for the implementation of relevant policies, regulations and legislation can be made on the basis of the work done in the different work packages of this consultancy assignment:

- The national energy policy needs to set the framework for the future expansion of the electricity production from renewable energy sources by deciding on the approximate **structure of the target energy system** reaching the envisaged goal of a 100% renewable power supply.
- The national energy policy should indicate as well the **share of green e-mobility** envisaged in the target energy system, as this will require adequate additional renewable power generation capacities.
- The national energy policy needs to set a **target year**, when the envisaged 100% renewable energy system should be reached and by which year the additional switch to green e-mobility should be achieved.
- Once the target system and the target year are chosen the **transition pathway** to the target system can be designed.
- The national energy policy will need to **adopt the suggested Feed-in Tariff** (FIT) system in order to set the framework for a continuous and solid development of the use of renewable energy sources for power generation in Barbados.
- Barbados' national energy policy will need to **decide whether** it wants **to adopt net metering for very small PV systems** (up to 1 $kW_p$) **in low income households** as suggested by the consultant.
- The national energy policy will need to **decide** together with Barbados' agricultural policy **whether** it wants **to pursue** the plans for the combined **bagasse and river tamarind combustion** for electricity production or whether it considers the future prospects of Barbados' cane industry as to uncertain as to base a 460 million BBD investment on it.
- Barbados' national energy policy should **set** the necessary **framework conditions for the demonstration** and further development **of King-Grass gasification** for electricity production in Barbados, as this technical option can be a back-up solution for Barbados' agricultural problems connected to the decline of the sugar industry.
- To allow the full development of Barbados' very low cost wind resource the **identified seven regions** with very good preconditions **for the development of wind energy** in Barbados **need to be earmarked** as **preferential wind areas as soon as possible** in the revised physical development plan for Barbados, which is in development at the time of writing of these recommendations.
- To allow for a broad participation in wind energy citizen wind turbines and wind parks should be supported. One necessary precondition for the economically successful implementation of wind

energy are bankable wind time series data, which need to be available at the time of application for the necessary debt funding part of the financing. Thus, it is suggested that the government of Barbados finances a **wind measuring campaign** at all seven preferential wind energy areas and that the results of this measuring campaign will be made publicly available to all interested investors free of charge.

- In preparation of the broad citizen participation in the investment in new renewable energy system of Barbados it will be necessary to start a **broad information campaign for Barbados' citizens** on the new FIT system, its conditions and the opportunities for citizen investment.
- It is highly recommended on the basis of decades of international experiences to **involve the local population** in the seven preferential areas for wind energy **in the development of the wind energy planning and the actual investment** in wind energy in each location.
- For the implementation of the FIT system it will be essential to **follow the basic rules for a good FIT design**.
- With respect to **legislation** it is recommended to **amend PART III of the Electric Light and Power Act** (ELPA) by inserting a **new section on ‚Pricing of renewable energy sources'**.
- With respect to **regulations** it will be absolutely necessary to **change from the present distance rule for wind energy** used in Town and Country Planning and wind energy licensing, which refers to minimum distances from the perimeter of property on which the turbine is located, **to the international standard of distance rulings**, which refer to the effective distance from dwellings, settlements, streets, nature preservation areas and other objects to be protected from excessive impacts of wind turbines.
- It is highly recommended to establish the necessary rules and procedures to **achieve the highest level of information transparency for the general public and all possible investors**.

## WORK PACKAGE 21: DETAILED POLICY RECOMMENDATIONS

In addition to the recommendations given in WP 18 additional policy recommendations are given in WP 21 on two areas, first there are recommendations of the possible liberalisation of Barbados' power market based upon WP 19 and WP 20, second there are some more detailed policy recommendations on the FIT system to be adopted, which go beyond WP 18.

Recommendations on the possible **further liberalisation of Barbados' power market:**

- **Stabilise the high technical reliability of Barbados' present power supply** achieved by the present level of liberalisation and by the very good performance of Barbados Light and Power.
- **Strengthen the FTC as effective independent regulator** by increasing the number of highly qualified staff employed for the regulation of the power sector.
- **Prepare for the legal unbundling of Barbados Light and Power into ‚Light and Power Generation' and ‚Light and Power Grid and System Operation'**.
- **Reduce political interventions into the power system** to a minimum, but **concentrate on setting a clear policy framework** for its future development.

Recommendations for the Feed-in Tariff system to be adopted (details can be found in WP 13 and 14):

- For the implantation of the FIT system **follow the basic rules for a good FIT design**.
- **The FIT system** implemented should have the following qualities. It **should be**:
  - **Differentiated**
  - **Reliable**
  - **Investment friendly**
  - **Dynamic**
  - **Responsive**
  - **Capped**
  - **Transparent**
  - **Low cost**
  - **Tax neutral**
  - **Without license fees**
  - **Citizen centred**
  - **Domestic ownership based**
  - **Acceptance oriented** and
  - **Agriculture friendly**

Before the suggested FIT system can be fully implemented a number of **decisions on the basic settings for the Feed-in Tariff** have to be made:

- Decide on the **rate of return on equity**, which can be considered a fair rate of return on low risk investments
- Decide on the basic assumptions on debt financing:
  - which **share of debt**/equity shall be assumed for low risk debt finance of renewable energy systems under the guaranteed FIT rates
  - which **interest rate for debt** financing shall be assumed for low risk debt finance of renewable energy systems under the guaranteed FIT rates.
- **Set** the **target corridors for each renewable energy technology** under the FIT system in accordance with the transition pathway, the target energy system and the target year for a 100% renewable energy system for Barbados.
- **Set the response rates for under- or overachieving the target** quantity for a given year as basis for the automatic FIT rate correction.
- **Decide on the adder for citizens wind parks** to the FIT rate paid for wind energy.

- Decide on the distance rules for wind energy and the distribution of **ownership by impact of wind turbines** and develop rules and procedures for ownership by impact.
- **Decide on the initial FIT rates** for the different renewable energy technologies based on the suggestions made in WP14.
- **Develop rules and procedures for grid area specific RE caps** and possible queuing of applications.

*Barbados has all the necessary preconditions for the transition to a low cost 100% renewable energy supply for all sectors. The success of the possible transition will depend mainly on the setting of an appropriate policy framework.*

*The policy framework developed in this report is based on a modern Feed-in Tariff system, taking into account the main objectives of the major stakeholders, it meets the challenge of guaranteeing a stable price for electricity from renewable energy sources allowing low risk investments at low (risk free) interest rates, it guarantees fair returns for investors and low prices for the average ratepayer. At the same time the suggested policy framework will foster a vast reduction of fuel imports and the leakage of hard currency from the country, thereby increasing domestic economic growth and employment, which in turn will boost the countries tax income and help to substantially reduce its public deficit.*

*This report has tried to supply some of the necessary information to the Energy Division, policy makers and stakeholders to set an appropriate policy framework for a development, which can benefit the people of Barbados in many ways. While it has painted the broad picture of an appropriate policy framework a number implementation details still need to be discussed, as pointed out in the report.*

# FULL REPORT

## WORK PACKAGE 1: STAKEHOLDER CONSULTATIONS

As Barbados is embarking on a process to convert its entire energy system from the basis of fossil fuels, namely mineral oil products, to a green energy supply based on domestic renewable energy sources, it is embarking on a transition process of the economy which will have very substantial impacts on many walks of life. Besides a massive reduction of Barbados' green house gas emissions this transition can have positive impacts on environmental pollution and human health in Barbados through the reduction of sulphur dioxide, nitrous oxide, VOC (volatile organic compounds) and particulate emissions from power generation, transportation including the energy consumption of cruise liners berthed at Barbados' harbour and other energy uses like cooking. These emissions can virtually be reduced to zero. At the same time the switch to domestic renewable energy sources can reduce Barbados' exposure to the risk of fast changing oil prices and it can reduce the high burden of fossil fuel imports on Barbados' balance of payments by eventually reducing the imports of mineral oil products for energy to zero.

Although, some equipment for the generation of green energy will need to be imported, a first analysis shows that the transition to a domestic 100% renewable energy supply can reduce net energy related imports by about 80% (based on fuel costs of 2013) (see Hohmeyer 2015, p.27). By the virtue of import reductions GDP (gross domestic product) will rise accordingly leaving hundreds of millions of dollars in the hands of Barbadians, which are presently spend on energy imports. This will result in a creation of substantial additional employment. By the same mechanism the tax income of Barbados' government will rise due to the fact that much more taxable income stays in Barbados' economy. Nevertheless, it has to be pointed out that most of the possible positive economic effects for Barbados' economy will only occur to the extend that the new energy system will be owned and operated by Barbadian nationals or by international investors keeping the money earned with renewable energy production in Barbados' economy.

At the same time it will be essential that the reliability of Barbados' energy supply, especially the supply of electricity, will remain at its present high level and that the energy costs to the consumer will be substantially below the extremely high levels of some of the past years and that they will be stabilised at such a lower level for the future.

It follows from the different possible impacts of Barbados' transition to a green energy supply that the energy policy enabling this transition has to take into account a number of different objectives. Depending on the emphasis on different objectives eg. lowest costs (which may require large foreign investors to come into play) versus greatest positive impact on the domestic economy (which may preclude higher levels of foreign investment), the market structure and policy measures designed to facilitate and guide the transition process need to take into account how these different objectives are weighted by the major players in the field of power generation, especially those stakeholders concerned about the introduction of renewable energy.

Although the new draft energy policy for Barbados spells out over a hundred different objectives it is not possible to use this large array of objectives to guide the shaping of the market structure for renewable energy sources and policy measures to guide the transition process, as there seems to be no clear ranking of the importance of all the different objectives mentioned in the draft energy policy (see Ince 2016). Therefore, the consultant conducted a short survey amongst key stakeholders in Barbados' electricity sector to find out which of the different possible objectives are seen as relevant for the electricity sector (which is the focus of this report) and how these are weighed with respect to each other. This survey was conducted in coordination with the Division of Energy and Telecommunications (Mr. Bryan Haynes) in as much as the selection of stakeholders to be interviewed was done as a joint exercise. Fifteen key stakeholders have been interviewed during the time available. The interviews were conducted as structured interviews with open questions. Thus, the interviewees were not given a list of objectives to choose from, but they voiced their own choices without much external influence. The only exemption from this rule was that the reliability of the power system mentioned by the interviewer, which is unquestionably a central objective of each power supply system in the world. Power system reliability was used in the second part of the interviews, when the interviewees were asked to rank the mentioned objectives on a scale from 1 to 10 (least important to most important). To allow the interviewed persons to calibrate their answers, they were asked, how important the reliability of the electricity supply was to them. Then all other objectives were ranked by the interviewees.

As four of the persons were interviewed in one meeting at Barbados Light and Power and as these persons were representing BL&P as well as EMERA Caribbean their answers, which were given collectively, were weighed by factor two. This was done as they were representing the Barbados power company entrusted with all of the public fossil fuel based power generation, the transmission and distribution of electricity in Barbados as well as the control of the system, and EMERA Caribbean, the Canadian owned holding company of BL&P. Thus, the interviewees can rightfully be considered the key players of the electricity sector most heavily affected by the envisaged transition away from fossil fuel based power generation.

In total the interviewees mentioned 56 different objectives. Three objectives (*Reliability of power supply*, *Low environmental impact* and *Low cost of power*) were mentioned by all interviewees. Four further objectives were mentioned by eleven (*Employment generation*), ten (*Reduction of imports/outflow of hard currency*), eight (*Public acceptance of source of power supply*) and seven stakeholders (*Reduction of imports to increase energy security*).

All other objectives were mentioned by clearly less than 50% of the interviewees, although the three objectives mentioned either by five (*General participation in the new energy system/all households*) or by four stakeholders (*Local participation*) (*Domestic ownership*) are all pointing into the direction of a necessary increase of public participation in and domestic ownership of the new energy supply system. A trend often discussed as ‚democratisation of power production‘.

Four stakeholders mentioned the necessary *resilience* of the new energy system *against* the risks of *hurricanes*, while three stakeholders mentioned *Stable electricity rates,* and the necessity that the new energy system needs to *contribute to the solution of the agricultural problems of Barbados.*

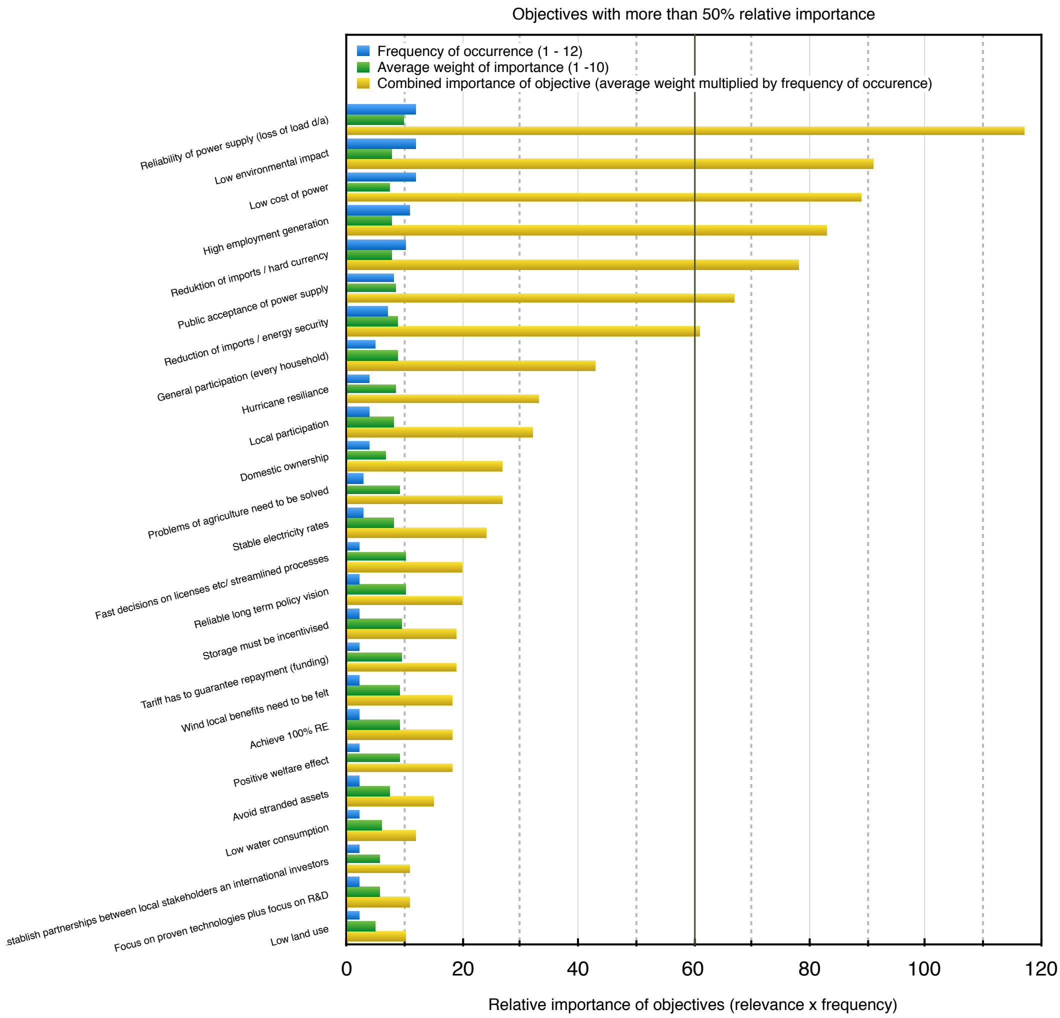
Twelve objectives were mentioned by two stakeholders, while another thirty objectives were just mentioned by one interviewee. It can certainly be assumed that objectives mentioned only by one or two stakeholders would be relatively low on the priority scale if many more stakeholders would be interviewed.

In a review of the *Visionary goals,* the *Core Values,* the *Overall objectives,* the *Objectives for renewable energy sources,* the *Objectives for Electricity* as well as the suggested *Policy Measures for the renewable energy sector* and the *Objectives for the Electricity Sector* of the draft new energy policy for Barbados (Ince 2016), about 140 different *Values*, *Objectives* and *Measures* were counted. The review showed that there is strong overlap between the objectives raised by the stakeholders in the interviews and the objectives given in the Draft National Energy Policy. While all three objectives raised by all stakeholders are put forward in the Draft Energy Policy, three objectives mentioned by the majority of the stakeholders

(*High employment generation*, *Reduction of outflow of hard currency*, *Public acceptance of sources of power supply*) were not found in the draft available to the consultant, although due to the sheer number of objectives and the short time available for the review, it may have escaped the attention that these objectives are mentioned in the Draft Energy Policy in different locations of the document not reviewed in detail.

For all objectives, which were at least mentioned by two different stakeholders, the number of stakeholders, who had mentioned a given objective (frequency) was multiplied by the average weight (importance) attached to an objective by all stakeholders, who had mentioned it. The resulting value is called the relative importance (RI) of an objective in the following text. The objectives were than ordered in the sequence of the resulting relative importance value on a scale between 0 and 120. Across the twenty five ranked objectives, which were mentioned by at least two stakeholders, relative importance values from 10 (Low land use) to 117 (Reliability of power supply) were reached. Figure 1 shows the graphed values for the the *Frequency* at which an objective was mentioned (blue), the *Average importance* attached to an objective (green) and the *Relative importance* (yellow) of an objective.

Figure 1: Frequency of occurrence, average weight of importance and relative importance of the twenty five objectives mentioned by at least to key stakeholders (Table with data in Annex 1)



The graphing of the relative importance (RI) values shows that there is a group of four objectives, which follows the outstanding criterion of *Reliability of power supply* (RI=117) at a high level of importance with RI values between 78 and 91 (*Low environmental impact (91), Low cost of power (89), High employment (83)* and *Reduction of imports (78))*. Within the group the distance between every pair of neighbouring objectives is less than 7 points. Thus, this can be seen as a group of objectives with similar high importance. The next group of objectives is constituted by just two objectives, which have a distance of more than ten points to the lowest ranking objective of the top group and a distance of almost twenty points to the next objective. At the same time both objectives (*Public acceptance of sources of power supply (67)* and *Reduction of imports for energy security (61)*) are the only remaining objectives achieving at least 50% of the maximum RI score. Of the remaining objectives only three reach at least 25% of the maximum possible IR score (*General participation (41)*, *Hurricane resilience (33)* and *Local participation (32)*) forming the next group of objectives by importance. Three further objectives reach at least 20% of the maximum possible score (*Domestic ownership (27)*, *Solving the problems of the agricultural sector (27)* and *Stable electricity rates (24)*), while the other ten objectives, which were mentioned by at least two stakeholders reached RI scores between 11 and 20.

While the results of the survey clearly point to the fact that energy policy has to address substantially more objectives than just the short term low cost energy for the ratepayers, the number of important objectives seems to be quite manageable. Although a *low cost of electricity* is among the most important objectives *low environmental impacts* or *high employment generation* and the net *reduction of energy imports* for balance of payment and energy security reasons were seen to be of similar or even higher importance by the interviewees.

Besides these core objectives public participation in the new energy system in its different forms all the way from domestic to local ownership seems to be a strong concern of the key stakeholders interviewed.

If a new energy policy will be able to make substantial contributions to these objectives and to the solution of Barbados' agricultural problem connected to the decline of the sugar industry and if it can deliver a very high reliability of the future electricity supply including a substantial hurricane resilience, it will be able to address the prime concerns voiced by the interviewees.

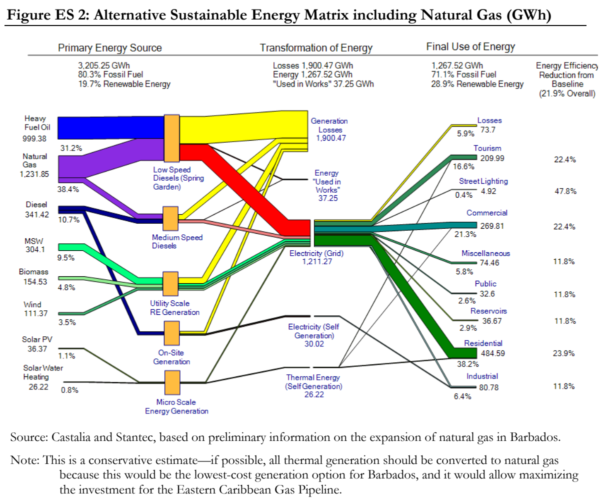
# WORK PACKAGE 2: UPDATED ESTIMATES ON RENEWABLE ENERGY POTENTIALS AND COSTS

## 2.1 ANALYSES ON THE COST OR POTENTIAL OF RENEWABLES IN BARBADOS PRESENTED SO FAR

### 2.1.1 Castalia and Stantec (2010)

In the past there have been a number of discussions on the possible contributions of renewable energy sources to the electricity production of Barbados and to the overall energy supply. The first extensive treatment was in the Sustainable Energy Framework for Barbados developed by Castalia and Stantec in 2010. In this study an *alternative sustainable energy matrix* was developed, which included 10.2% of renewable energy sources (4.8% of biomass, 3.5% wind, 1.1% solar PV and 0.8% solar hot water).

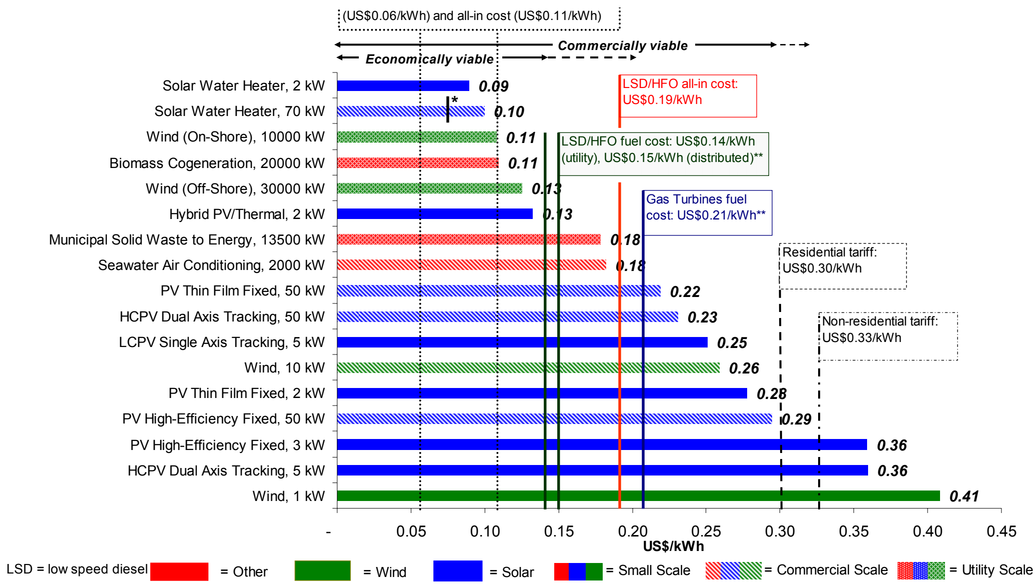
Figure 2: Alternative Sustainable Energy Matrix by Castalia and Stantec (2010, p. iii)




A share of 9.5% energy input from municipal solid waste (waste-to-energy) was included in the matrix as well, which ended up with a share of more than 80% of fossil fuels in the ‚sustainable' energy mix.

The study of Castalia and Stantec formed the basis for the decision of the Barbados government to set its indicative renewable energy target for electricity production to 29% to be reached by 2029 (Government of Barbados, National Sustainable Energy Policy (no year), p. 8), which explicitly contains the *Sustainable Energy Matrix* developed by Castalia on page 10 of the policy. Furthermore, the study gave a cost comparison of the different energy technologies in 2009/10 showing generation costs of 0.11 USD/kWh for large on-shore wind (10 MW), 0.11 USD/kWh for biomass cogeneration, 0.13 USD/ kWh for off-shore wind, 0.18 USD/kWh for municipal solid waste, 22 USD/kWh for larger PV installations (50 kW) and 0.36 USD/kWh for small solar PV systems (2 kW) (see Figure 3 below).

Figure 3: Cost of renewable energy generation according to Castalia and Stantec (2010, p. 6)




Source: Castalia and Stantec estimates

Note: * For "Solar water heater, 70kW" the comparator is fuel oil boiler heating (US$0.08 per kWh). ** 'Fuel costs' also include variable O&M costs; and are grossed up for losses (6.6%) for distributed technologies, but *not* for utility scale technologies. Generation costs and tariffs estimated based on oil prices of US$100 per barrel, and natural gas prices of US$7 per MMBTU. All-in cost of LSD with natural gas contingent on availability from the planned Eastern Caribbean Gas Pipeline.

### 2.1.2 Hohmeyer (2015)

In fall 2014 a first analysis of the possibility to convert Barbados entire electricity supply to 100% renewable energy was introduce to key Barbados stakeholders and later published by Hohmeyer (2015). This study assumed that Barbados has a sufficient potential to install 452 MW of wind turbines, 376 MW of solar PV, to produce 25 GWh of liquid biofuels and that it had the potential to install a pump storage hydro power scheme with a storage capacity of 3 GWh (see Figure 4 below). For the calculations it was assumed that all passenger cars would be converted to green electricity, which would be supplied by the simulated power system on top of the basic electricity demand for all other purposes.

Based on an hourly system simulation the study could show that a 100% renewable energy supply for Barbados is possible, could supply all power needs in every hour of the year and would lead to substantially lower costs than the costs of the substituted fossil fuels of the conventional power production of 2013. Figure 5 shows the cost of the electricity produced from the 100% renewable power system in comparison to the cost of the conventional electricity produced in 2013. Furthermore, the graph shows production costs of wind energy, solar PV and the pump storage costs per average kilowatt hour sold.

These results were based upon assumed investment costs of 1,500 Euro/kWp for PV systems and 1,050 Euro/kW for wind turbines (for all assumptions see Hohmeyer 2105, p.25). The prices assumed were 2014 prices and converted into BBD by the factor of 2.53. Thus, the cost were equal to 3,795 BBD/kWp for PV and 2,657 BBD/kW for large wind turbines. Based on 6% interest rate for financing, a solar radiation (GHI/Global Horizontal Irradiation) of 2025 kWh/m$^2$/a, an average wind speed of 4.97 m/sec at 10 meter measuring hight, which translates to an average wind speed of 8.44 at an assumed hub hight of 66m with an assumed roughness (shear coefficient) at the measuring site of 0.28. Assuming annual operating costs of 5% of the initial investment costs the calculations resulted in production costs of 0.07 BBD/kWh for wind energy and 0.252/kWh for PV.

The study was based on international system prices of 2014 and on the assumption that Barbados would have sufficient space available for the deployment of the wind and solar capacities assumed. While this assumption is not critical for solar PV, as it requires rather limited space per MW installed, this assumption is critical for wind energy, as the possible area for the deployment for wind turbines is largely restricted by the minimum distances of wind turbines from dwellings and protected areas and by the minimum distance of wind turbines in a wind park. At the time of the study the necessary information of a detailed assessment of the wind potential of Barbados was not available.

A second shortcoming of the study was the assumption of prevailing world market prices for wind, PV and pump storage installations, as the market size for these technologies is limited in Barbados, which could lead to substantially higher costs than the costs realised in the world lead markets like Germany or the United States.

A third shortcoming was that the wind data used in the first calculations were data from the Caribbean region (Dominica), but not from Barbados. What is more, the assumed surface roughness of 0.28 was most likely to high, producing to high calculated wind speeds at hub hight.

Figure 4: Basic configuration of Barbados' electricity system supplying the regular electricity demand plus the demand for electrical mobility 100% by renewable energy sources (Source: Hohmeyer 2015, p. 32)

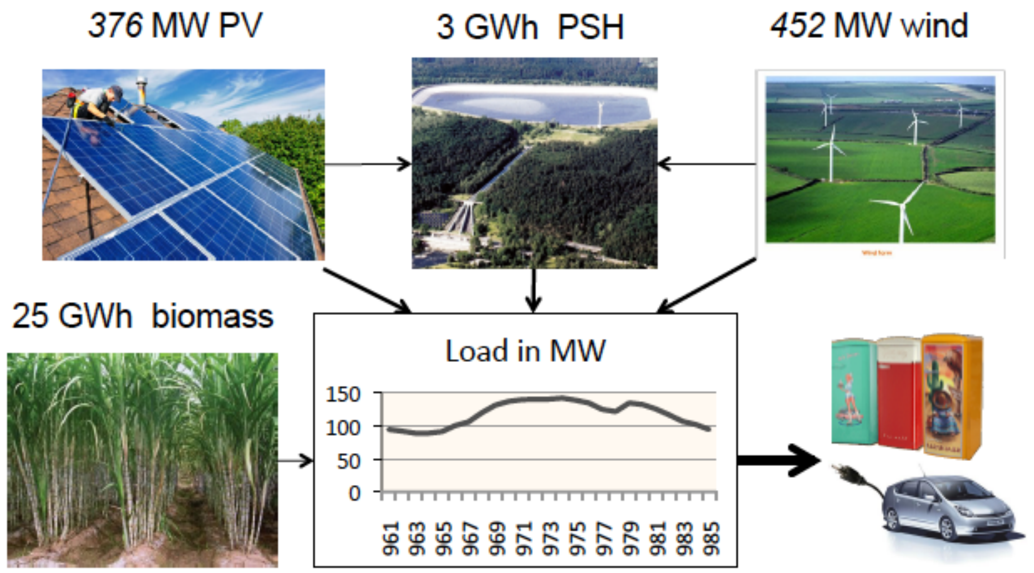
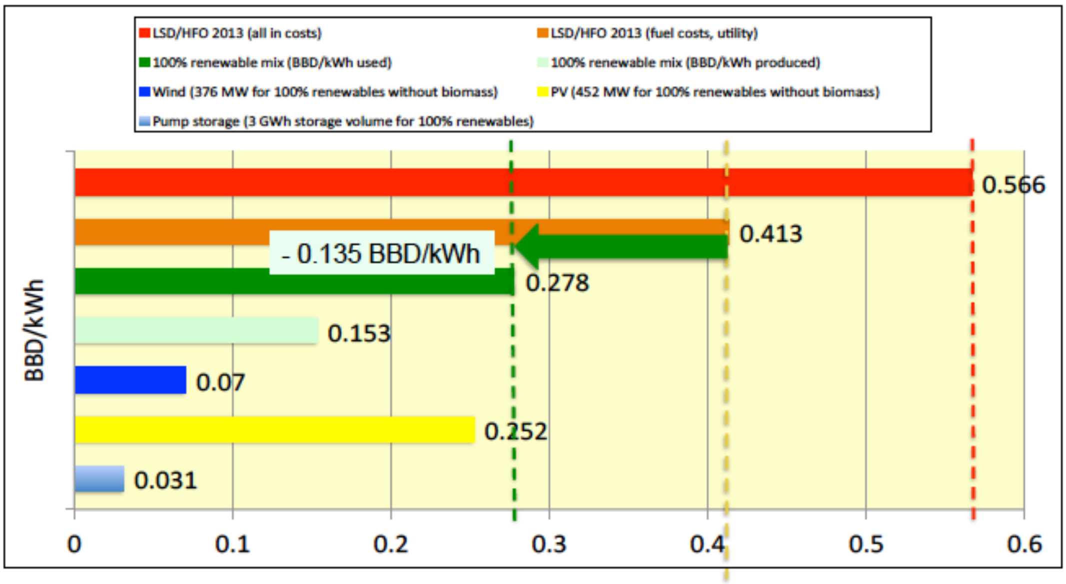


Figure 5: Costs of a 100% renewable power supply for Barbados including electrical mobility compared to present generation costs (2013) based on present prices for renewable energy technologies (Source: Hohmeyer 2015, p.33)




### 2.1.3 GE grid integration Study (2015)

In March 2015 a grid integration study commissioned by Barbados Light and Power suggested that 55 MW of solar and wind energy can be taken up by the existing system without any mitigation measure and 80 MW could be integrated with modest mitigation measures (GE 2015, p. 127). The report does not give information on higher renewables penetration, as no such scenarios were commissioned for the analysis. Presently a follow up study is underway, which is supposed to look at up to 150 MW of renewable generation capacity in a power system with a peak load of a little more than 150 MW.

The GE study did not look at the potential for the different renewable energy sources, as the capacities considered for inclusion were seen as easily available in Barbados and it did not look at investment and operation costs of renewable energy sources, as the focus was on the impact of the inclusion of wind and PV on the operation of the conventional units and on the system reliability.

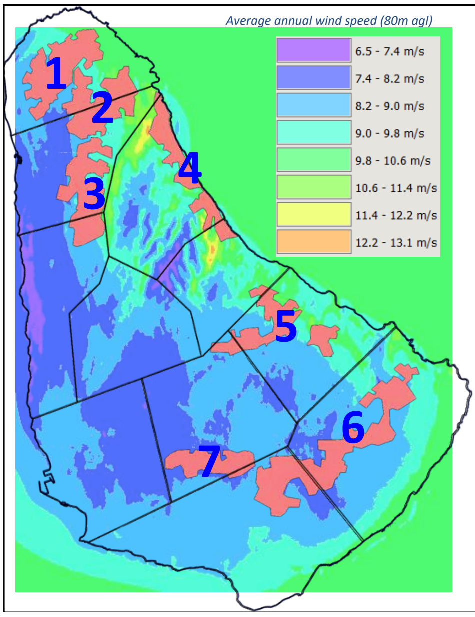
### 2.1.4 Rogers (2015)

In November 2015 Rogers (2015) introduced the first more detailed wind energy assessment of Barbados at a workshop of the Barbados Renewable Energy Association held at the Central Bank of Barbados on November 7$^{th}$ 2015. He identified seven zones with good wind speeds and enough distance to dwellings with a total area of about 64 km$^2$ available to locate a substantial number of wind turbines. Figure 6 below shows the distribution of wind speed in Barbados and the location of the seven wind siting areas.

Rogers showed that 317 to 456 MW of wind capacity can be located in these zones depending on the use of 1 or 3 MW wind turbines reaching capacity factors between 30.9 and 51.8%. In an average wind year the capacities, once installed, could translate into a total production of 1,144 GWh/a (1 MW turbines) or 1,594 GWh/a (3 MW turbines). The detailed results are shown in Figure 7 below.

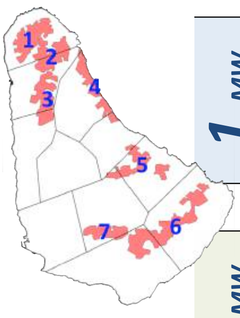
One interesting result of a stakeholder discussion at the workshop was an unanimous agreement on the choice of the larger turbine size based on realistic foto images of the turbines put in their actual locations on some selected sites in the wind zones. The images showed that an increase in turbine size from 1 to 3 MW can substantially reduce the clutter of the landscape as Pictures 1 and 2 show for locations in St. Lucy and a location on the east coast of Barbados.

Figure 6: Average annual wind speeds at 80m and possible zones for locating wind turbines on Barbados (Rogers 2015)




| Zone | Area (km²) |
|---|---|
| 1 | 9.4 |
| 2 | 9.2 |
| 3 | 9.4 |
| 4 | 7.0 |
| 5 | 7.9 |
| 6 | 16.2 |
| 7 | 5.2 |
| | **64.2** |

Figure 7: Possible wind energy production on Barbados in seven wind zones with preferential conditions (Rogers 2015)




| | Zone | Area (km²) | No. turbines | Installed capacity (MW) | Capacity density (MW/km²) | Energy yield (GWh/year) | Capacity factor | Yield per turbine (GWh) |
|---|---|---|---|---|---|---|---|---|
| 1 MW | 1 | 9.4 | 48 | 48 | 5.1 | 174.3 | 41.5% | 3,632 |
| | 2 | 9.2 | 42 | 42 | 4.6 | 166.0 | 45.1% | 3,953 |
| | 3 | 9.4 | 35 | 35 | 3.7 | 135.3 | 44.1% | 3,864 |
| | 4 | 7.0 | 51 | 51 | 7.3 | 231.4 | 51.8% | 4,537 |
| | 5 | 7.9 | 38 | 38 | 4.8 | 138.7 | 41.7% | 3,651 |
| | 6 | 16.2 | 76 | 76 | 4.7 | 224.7 | 33.7% | 2,956 |
| | 7 | 5.2 | 27 | 27 | 5.2 | 73.2 | 30.9% | 2,710 |
| | | **64.2** | **317** | **317** | **5.1** | **1,143.6** | **41.2%** | **3,607** |
| 3 MW | 1 | 9.4 | 19 | 57 | 6.1 | 226.0 | 45.3% | 11,895 |
| | 2 | 9.2 | 24 | 72 | 7.9 | 270.4 | 42.9% | 11,267 |
| | 3 | 9.4 | 24 | 72 | 7.7 | 262.3 | 41.6% | 10,930 |
| | 4 | 7.0 | 16 | 48 | 6.9 | 196.3 | 46.7% | 12,267 |
| | 5 | 7.9 | 16 | 48 | 6.1 | 170.2 | 40.5% | 10,634 |
| | 6 | 16.2 | 40 | 120 | 7.4 | 361.0 | 34.3% | 9,026 |
| | 7 | 5.2 | 13 | 39 | 7.5 | 107.5 | 31.5% | 8,268 |
| | | **64.2** | **152** | **456** | **7.1** | **1,593.7** | **39.9%** | **10,485** |

Picture 1: Realistic foto image of the location of 1 and 3 MW wind turbines at St. Lucy (Rogers 2015)


Picture 2: Realistic foto image of the location of 1 and 3 MW wind turbines on the east coast of Barbados (Rogers 2015)


Rogers' assessment showed that the assumptions made by Hohmeyer (2015) that Barbados could actually install about 450 MW of wind had not been far from the real potential, although, it would stretch the potential analysed by Rogers to the full.

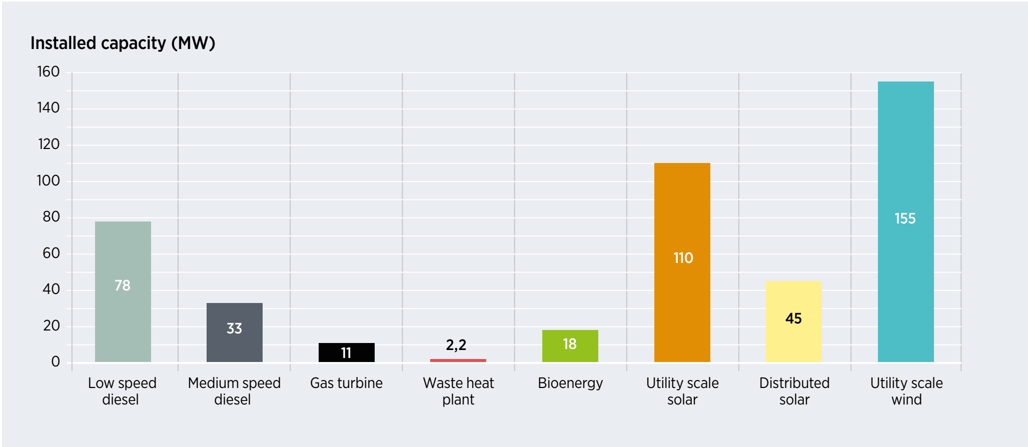
### 2.1.5 Irena (2016)

In 2016 the International Renewable Energy Agency (IRENA) introduced the draft of a Barbados Energy Roadmap, which looked at a least cost scenario of electricity production plus a change of up to 50% of the individual cars to green electricity. As the road map did not include the possibility of pump storage hydro installations as system back-up (IRENA 2016, p.37), the scenarios produced for 2030 and the path from the present to the 2030 power system resulted in a renewable share of 76% of the total electricity production in 2030 (IRENA 2016, p.42). Table 1 shows the power production in the minimal cost reference scenario for 2030. These production shares are a result of about 330 MW of renewable capacity installed, which is shown in Figure 8 below.

Table 1: 2030 generation by power plant type: IRENA Reference Scenario (Source: IRENA 2016, p. 42)

| **Generator type** | **Generation (GWh)** |
|---|---|
| Low-speed diesel | 221.12 |
| Medium-speed diesel | 8.03 |
| Gas turbine | 0.72 |
| Waste heat plant | 10.57 |
| Bioenergy | 120.08 |
| Utility-scale PV | 205.83 |
| Distributed PV | 70.45 |
| Utility-scale wind | 365.8 |
| **Total** | **1 002.6** |
| **Renewable energy total** | 762.17 |
| **Renewable energy share** | 76% |
| **Variable renewable energy total** | 642.08 |
| **Variable renewable energy share** | 64% |

Figure 8: 2030 installed capacities per generation technology in the IRENA Reference Scenario




The IRENA calculations are based on a few central cost assumptions, like the 2030 oil price, which is assume to reach 113 USD/bbl in the ‚new policies oil price scenario' (see Figure 9 below), PV investment cost of 3,800 to 5,200 BBD/kWp and wind energy investment costs of 3,450 BBD/kW in 2014. Table 2 below gives the central assumptions of the Road Map for wind and PV and Figure 10 below shows how these are assumed to decline until 2030. Table 3 gives the investment cost assumptions used in the Road Map for new diesel generators, bioenergy and battery storage.

Figure 9: Oil price developments assumed in the IRENA Road Map (source: IRENA 2016, p.31

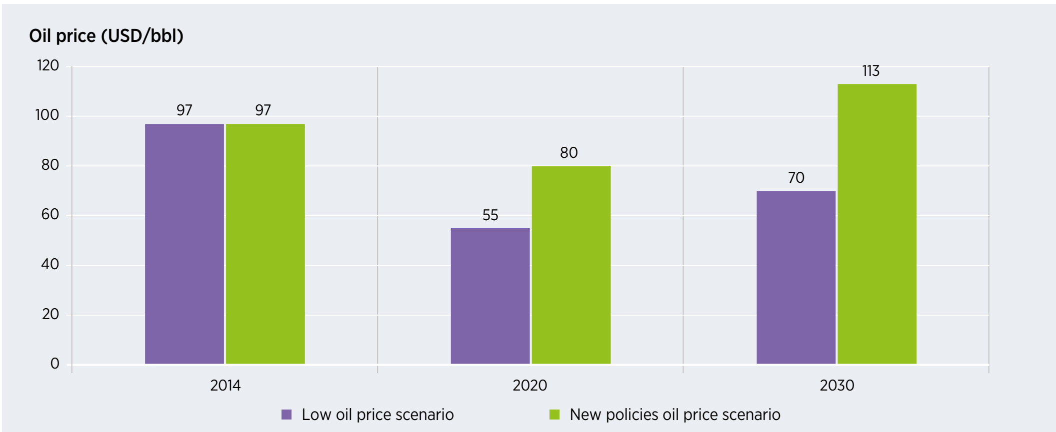



Table 2: IRENA assumptions made for PV and wind (source: IRENA 2016, p.30)

| Assumption | Units | Technology | | |
|---|---|---|---|---|
| | | **Residential and commercial PV** | **Utility-scale PV** | **Utility-scale wind** |
| CAPEX | $BBD/MW_{AC}$ | 5 200 000 | 3 800 000 | 3 450 000 |
| OPEX | BBD/MW/year | 52 000 | 38 000 | 138 000 |
| cost of capital | % | 10 | 10 | 10 |
| lifetime | years | 30 | 30 | 30 |

Figure 10: In the IRENA Road Map assumed cost digression of wind and PV over time (source: IRENA 2016, p.31)

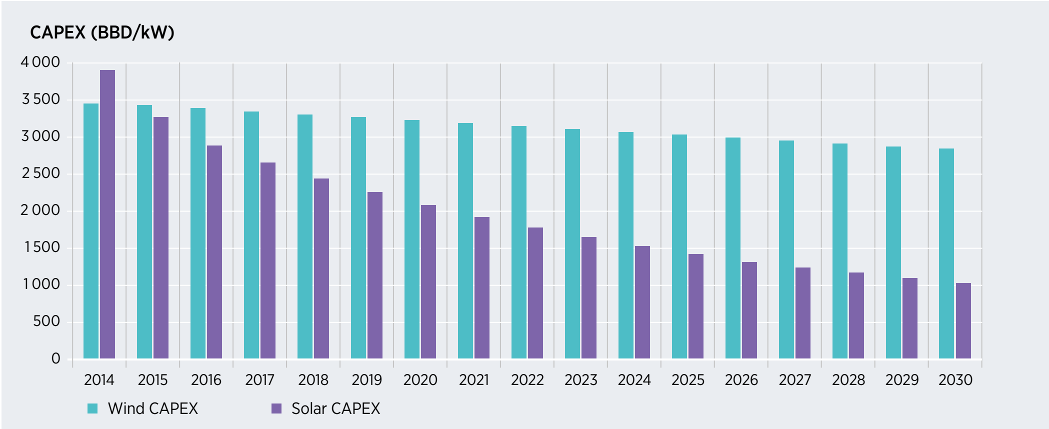



Table 3: Investment costs for new diesel generators, biomass and battery storage used in the IRENA Road Map (source: IRENA 2016, p.30)

| Generation expansion candidate | CAPEX (BBD/kW) |
|---|---|
| Medium-speed diesel | 2 344 |
| Low-speed diesel | 2 853 |
| Bioenergy | 7 000 |
| Battery energy storage system* | 1 400 |

** Assumes lithium-ion batteries with 1 MWh of energy storage capacity per MW of AC power and price in 2020.*

For biomass IRENA is assuming that the planned 18 MW bagasse combustion will go into operation in 2017. It looks like this is assumed as a given, although it is pointed out in the Road Map that solid fuel combustion will not fit into the future power system with a very high share of wind and solar power. It actually urges to convert to either biogas or liquid biofuels ‚*Given the large shares of solar and wind in the system, it will be essential that this (biomass) plant is as flexible and as efficient as possible, considering a feedstock conversion process from solid biomass to liquid or gas. Direct combustion of solid bioenergy feedstock to feed a steam turbine is not advisable, as these plants lack the necessary flexibility.‘ (IRENA 2016, p.29).*

The Road Map briefly discusses the possibility of a 100% renewable energy supply (IRNEA 2016, p.37), which is introduced by an outright rejection of the option of pump storage for Barbados ‚*One of the solutions* (for a 100% renewable energy scenario) *discussed was to built a large pump hydropower storage facility; however, this option has been considered as non realistic for Barbados.‘* Unfortunately, not a single reason or argument is given for this outright dismissal of pump storage. This is even more astounding, as the authors of the Road Map acknowledge in the same box (p.37) that a 100% renewable power supply ‚*would require a major increase in battery storage capacity, with a substantial increase in system cost‘.* Instead of seriously discussing the extension of low cost storage (pump storage) the Road Map reverts to the suggestion of expanding the biomass combustion from 18 to 54 MW. At the same time the authors realise that this would require about 20,000 hectares of sugar cane production, while the present production is done on approximately 5,000 hectares. At the end the Road Map does not offer any solution for going to higher shares of renewables than the 76% realised in the reference scenario.

Considering the available evidence on the possible implementation of pump storage in Barbados (see WP 3 below), it is quite striking that the International Renewable Energy Agency does give this kind of advice. It may just be that the models available to the authors did not include the pump storage option and by that virtue limited the scope of the study or that the authors simply assumed Barbados not to have the necessary elevation differences, which they could easily have checked by looking at google maps.

The Road Map is not explicitly considering any resource constraints on the availability of wind or solar energy. Looking at the analysis by Rogers (2015) the installed capacities of wind energy (155 MW in the Reference Scenario) will most likely not meet with space constraints in Barbados, if the areas identified by Rogers will be earmarked for wind energy in the new Physical Development Plan for Barbados to be amended in 2017, which is in the drafting stages at the time of writing of this document.

## 2.2 International cost assessment for solar PV

### 2.2.1 IPCC SRREN (2012)

In 2012 the Intergovernmental Panel on Climate Change (IPCC) published a special report on ‚Renewable Energy Sources and Climate Change Mitigation‘, which gave a very thorough state of the art review of the possible use of renewable energy sources to reduce green house gas emissions, mainly carbon dioxide from the use of fossil fuels to supply energy. Among other questions the report gave an in depth treatment of the costs of different renewable energy sources as of 2010.

For PV the report documents the vast cost reduction of PV systems between 1990 and 2010, starting out at about 24 $USD_{2005}/W_p$ in 1990 reducing to less than 5 $USD_{2005}/Wp$ in 2010 as can be seen in Figure 11 below. The same figure shows that PV system costs have constantly been higher in the US than in Europe. This points to the fact that the European market, specifically the German market, which was the largest PV market until 2015 (see Figure 12), has been more competitive than the US market.

Figure 11: Installed system costs for smaller PV systems up to 100 kW (source: IPCC 2012, p.382)

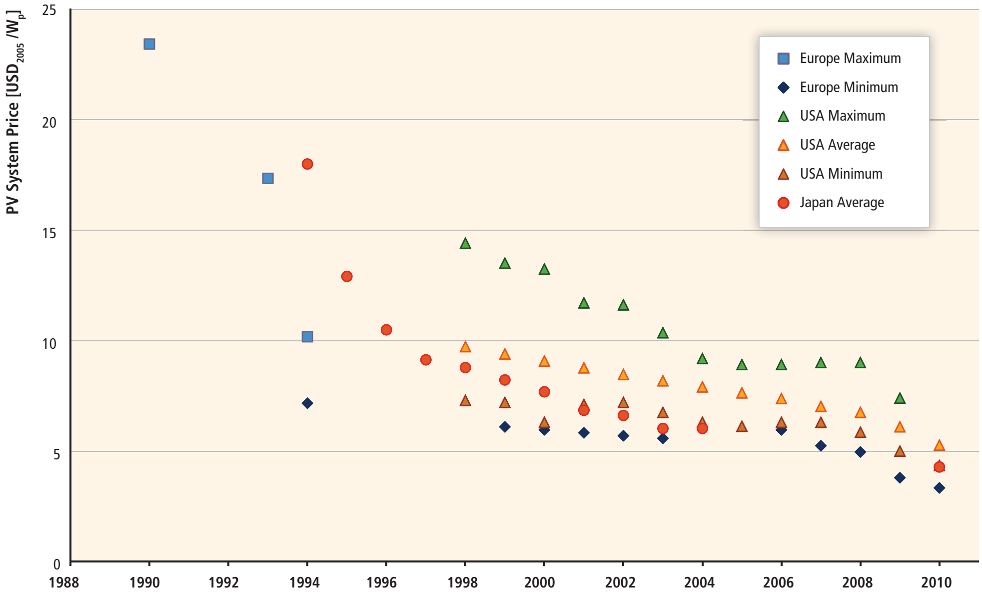
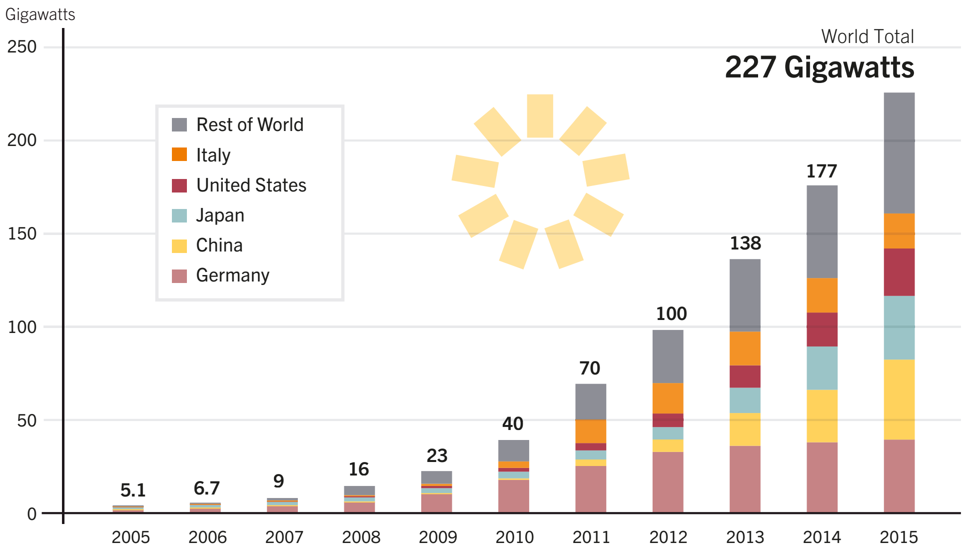



**Figure 3.18 |** Installed cost of PV systems smaller than 100 $kW_p$ in Europe, Japan and the USA. Data sources: Urbschat et al. (2002); Jäger-Waldau (2005); Wiser et al. (2009); Bundesverband Solarwirtschaft e.V. (2010); SEIA (2010a,b).

Figure 12: Installed solar PV capacity by country/region 2005-2015 (source: REN 21 2016, p.62)




Much of the system cost reduction has been driven by the learning curve for the production of PV modules, which is shown for silicon modules in Figure 13. The graph shows that with increasing installed capacity there has been a cost reduction by 20% for each doubling of the global PV capacity starting at 65 USD/$W_p$ in 1976 the module cost had been reduced to 1.4 USD/$W_p$ in 2010.

Figure 13: Solar price experience or learning curve for silicon PV modules (source: IPCC 2012, p. 393)

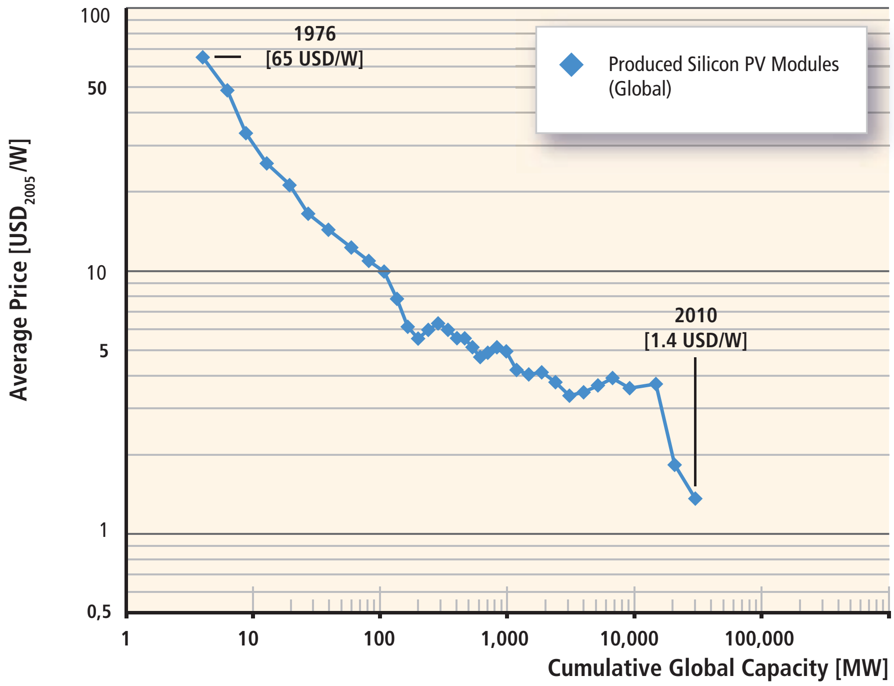



**Figure 3.17 |** Solar price experience or learning curve for silicon PV modules. Data displayed follow the supply and demand fluctuations. Data source: Maycock (1976-2003); Bloomberg (2010).

At the same time the cost reduction for the so called Balance of Systems (BOS) costs showed learning rates in the range of 19 to 22% (IPCC 2011, p.380).

Depending on the solar radiation at the installation site the Levelized Costs of Electricity (LCOE) generation of PV systems were anywhere between 0.1 and 0.78 USD/kWh in 2009. The differences in the levelized costs are due to different solar radiation (reflected in the capacity factor), the investment cost of the system, the size of the system and the interest rate applied in the calculations. Thus, the lowest costs were seen with large utility scale systems (larger than 2 MW) with low system prices (2700 USD/kWp) and low interest rates (3%). Fixed systems were seen with maximum capacity factors of 21% in very good locations (similar to or better than the radiation in Barbados), whereas systems tracking the sun over two axes, which can always point the solar array directly towards the sun, were seen with maximum capacity factors of 27%. The impact of the different factors on LCOEs are shown in Figure 14 below. The capacity factor used can be translated into a system output equivalent to a certain number of operation hours at full load. A capacity factor of 10% for example translates into a full load operation of 876 hours. Thus, a system with a rated power of 1 kW will produce 876 kWh/a. At a different location with higher solar radiation the system may reach a capacity factor of 20% producing 1752 kWh/a.

Figure 14: Levelized costs of PV electricity generation in 2009 as a function of different parameters (source: IPCC 2012, p383)

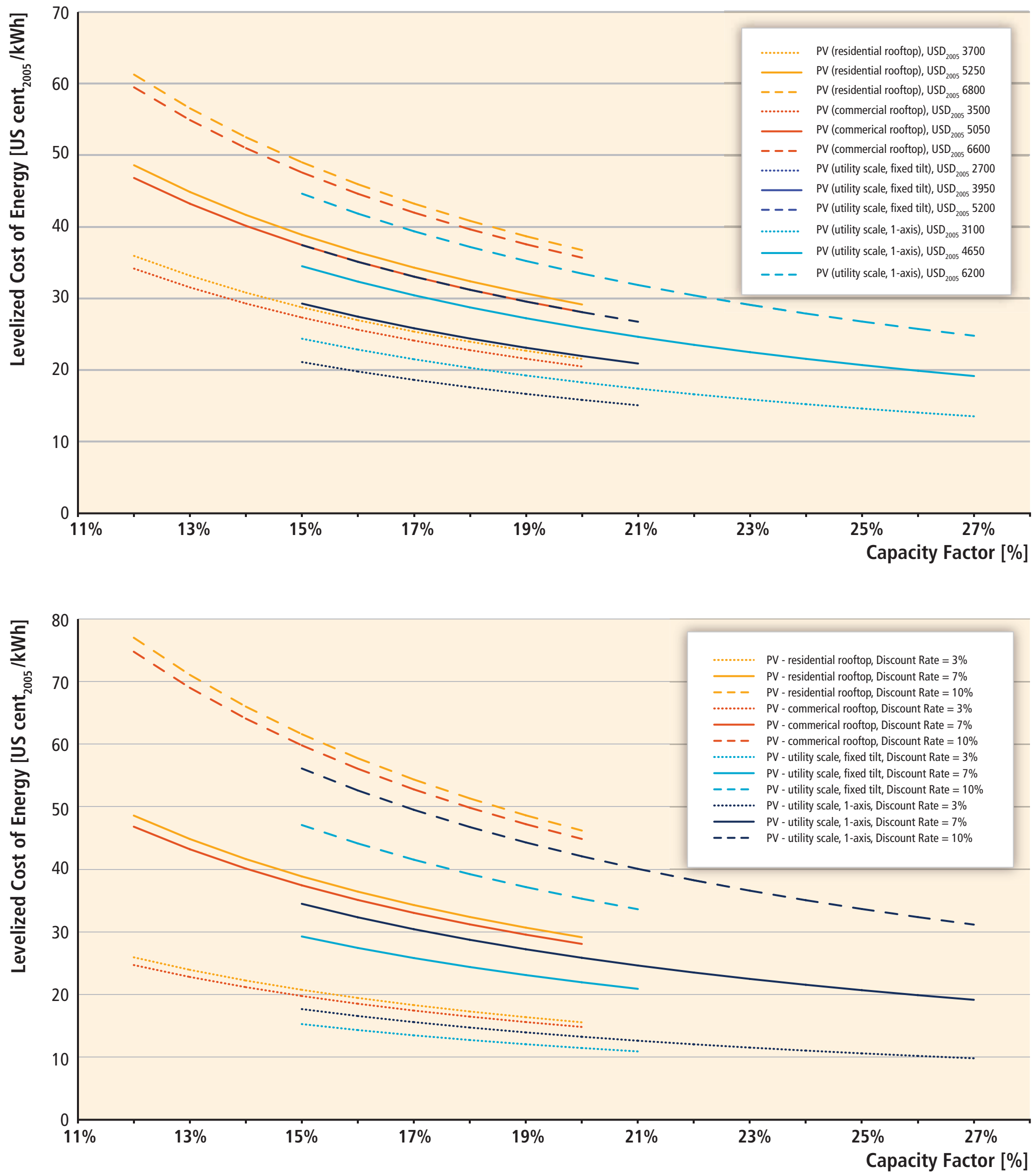



**Figure 3.19 |** Levelized cost of PV electricity generation, 2009. Upper panel: Cost of PV electricity generation as a function of capacity factor and investment cost[1,3]. Lower panel: Cost of PV electricity generation as a function of capacity factor and discount rate[2,3]. Source: (Annex III).

Notes: 1. Discount rate assumed to equal 7%. 2. Investment cost for residential rooftop systems assumed at $USD_{2005}$ 5,250/kW, for commercial rooftop systems at $USD_{2005}$ 5,050/kW, for utility-scale fixed tilt projects at $USD_{2005}$ 3,950/kW and for utility-scale one-axis projects at $USD_{2005}$ 4,650/kW. 3. Annual O&M cost assumed at $USD_{2005}$ 41 to 64/kW, lifetime at 25 years.

Different studies showed LCOEs of 0.145 to 0.363 $USD_{2005}$/kWh for 2009 (IPCC 2012, p.381), which are well in line with the cost functions shown in Figure 14. At the time the US DOE targeted 8 to 10 US $cents_{2005}$/kWh for residential, 6 to 8 US $cents_{2005}$/kWh for commercial and 5 to 7 cents UD $_{2005}$/kWh for utility scale installations (US DOE, 2008 according to IPCC 2012, p.381f).

### 2.2.2 FHG-ISE (2017)

In January 2017 the German Fraunhofer-Institute for Solar Energy (FhG-ISE) published updated facts on the quarterly investment cost development of roof top PV installations of 10-100 kW capacity for the time of 2006 to 2015. These investment costs developed from 5,000 Euro/kW$_p$ in the first quarter of 2006 to 1,270 in the last quarter of 2015 as shown in Figure 15. These costs are equivalent to a decrease from 6,278 USD/kW$_p$ in 2006 to 1,409 USD/kW$_p$ in 2015 for readily installed roof top PV systems or a drop from about 3,500 USD in 2010 (see Figure 11) to 1409 USD/kW$_p$ in 2015, a further investment cost reduction by 60% in five years following the period documented in the IPCC report cited above.

Figure 15: Average consumer system price (net VAT) for installed roof top PV systems with a capacity of 10-100 kWp (FhG-ISE 2017, p.8)

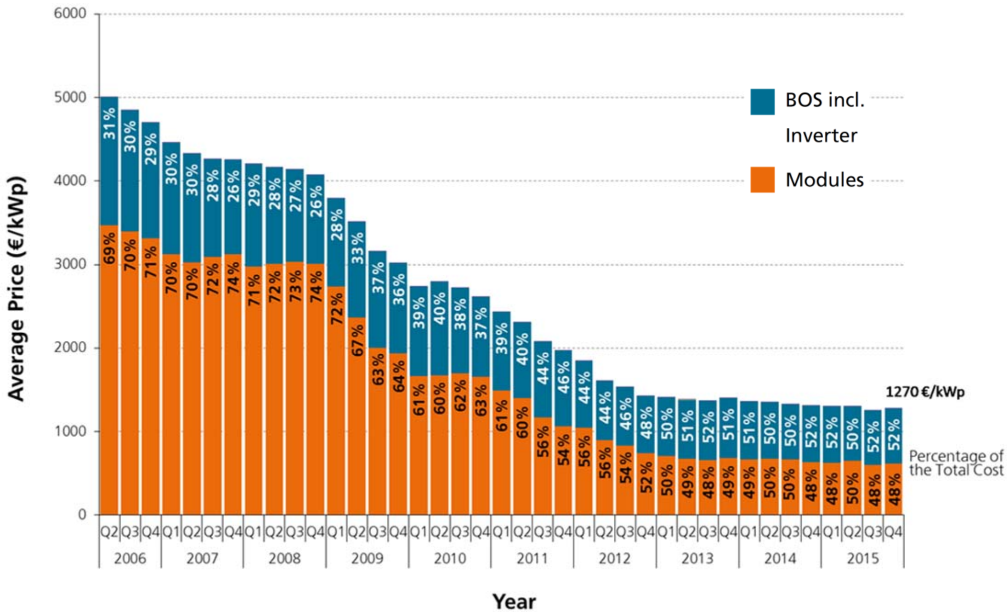



Abbildung 3: Durchschnittlicher Endkundenpreis (Systempreis, netto) für fertig installierte Aufdachanlagen von 10-100 kW$_p$, Daten von BSW, Darstellung PSE AG

The same publication takes the learning or experience curve for PV modules five years further (see Figure 16 below) as compared to the IPCC reports (see Figure 13). It actually shows how the module prices fluctuate around the trend line of the learning curve (the straight line in the double logarithmic system) reaching about 0.6 Euro$_{2015}$/kWp or about 0.67 USD$_{2015}$/kWp in 2015.

Figure 16: Price development of PV-modules between 1980 and 2015 (source: FhG-ISE 2017, p.9)

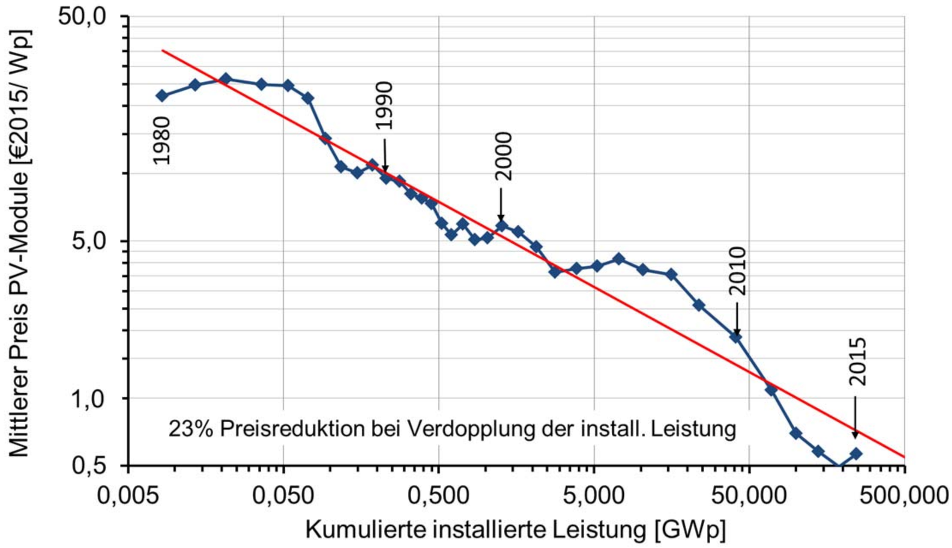



Abbildung 4: Historische Entwicklung der Preise für PV-Module (PSE AG/Fraunhofer ISE, Datenquelle: Strategies Unlimited/Navigant Consulting/EuPD). Die Gerade zeigt den Trend der Preisentwicklung.

### 2.2.3 NREL 2016

In September 2016 NREL, the US National Renewable Energy Laboratory, published US benchmark figures for PV systems (NREL 2016). These are detailed model calculations on the benchmark costs for PV systems in the United States. The report shows the development for an average installed residential PV system of 5.6 $kW_p$, a commercial system of 200 $kW_p$ and a utility scale system of 100 $MW_p$ from the fourth quarter of 2009 until the first quarter 2016 (NREL 2016, p. V). By that time the costs for residential roof top systems came down from 7.06 $USD_{2016}/kW_p$ in Q4 2009 to 2.93 $USD_{2016}/kW_p$ in Q1 2016. At the same time commercial scale installations went down from 5.23 USD2016/kWp to 2.13 USD2016/ kWp and very large utility scale systems came down from 4.46 to 1.42 USD2016/kWp. These cost developments and the cost structures of the different systems are shown in Figure 17 below. The report shows that the modelled benchmark results are quite realistic using a comparison to the reported costs of three relevant solar system integrators (NREL 2016, p.17). This comparison is reproduced in Figure 18 below.

The same report shows quite nicely how the model can be used for the calculation of cost reduction effects reached trough economies of scale and how the different components of such cost reduction can be analysed (see NREL 2016, p.28). The results of such decomposition and the distribution of the scale effects across different system costs are shown in Figure 19 below.

Figure 17: NREL PV system cost benchmark results Q4 2009 until Q1 2016 (source: NREL 2016, p. V)

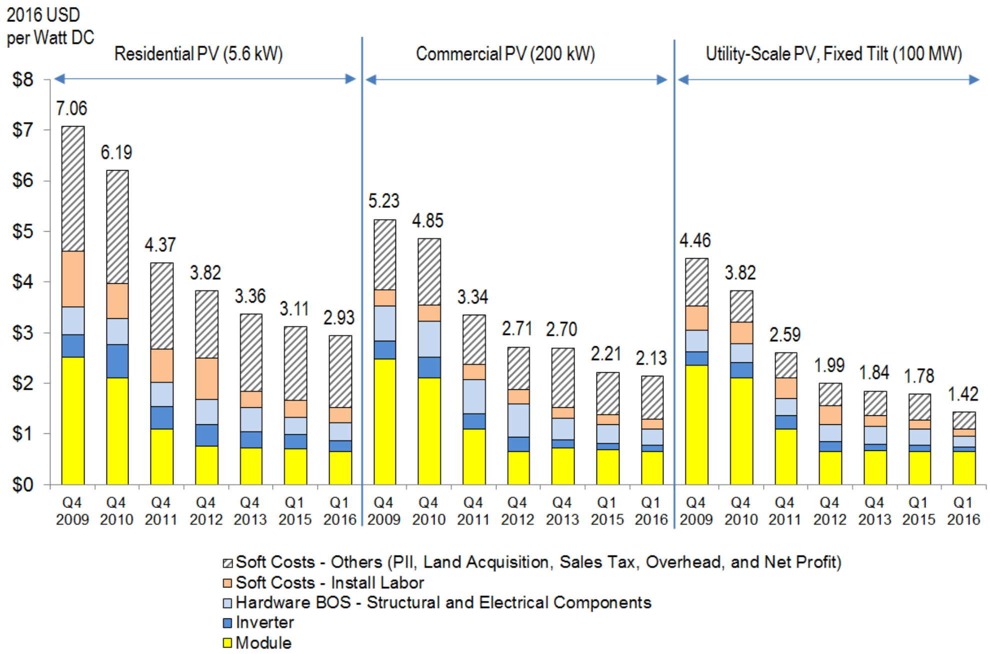



**Figure ES-1. NREL PV system cost benchmark summary (inflation adjusted), Q4 2009–Q1 2016**

Figure 18: Comparison of NREL benchmark results vs. company reported costs (source: NREL 2016, p. 17)

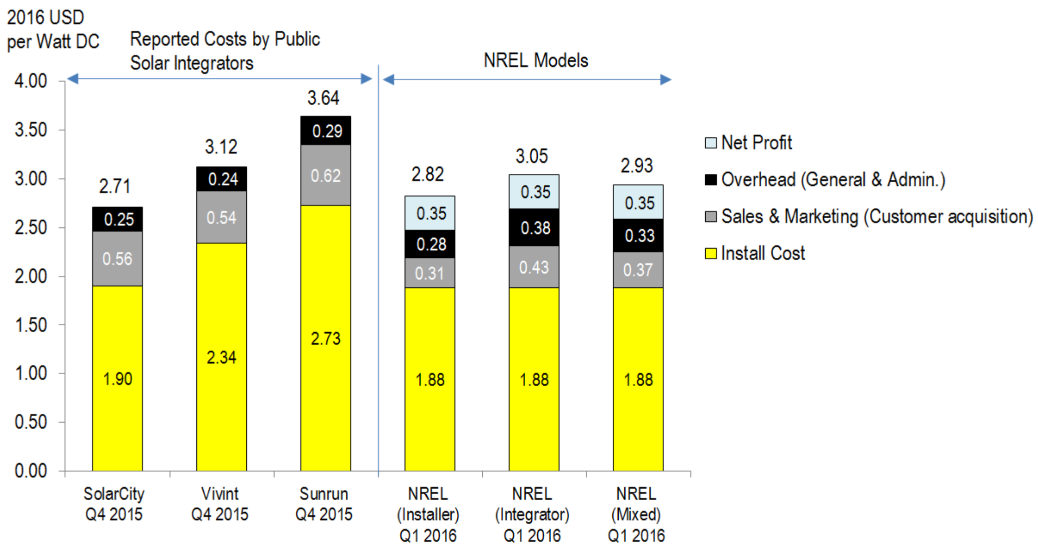



**Figure 14. Q1 2016 NREL modeled cost benchmark (2016 USD/Wdc) vs. Q4 2015 company-reported costs**

Figure 19: NREL results on economies of scale for increasing system size from 10 to 100 $MW_p$ (source: NREL 2016, p.28)

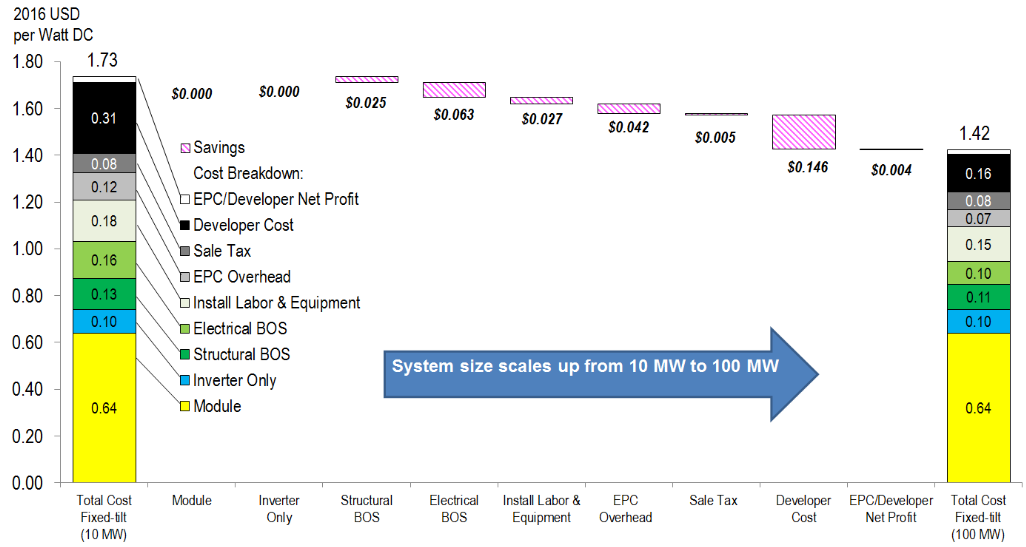
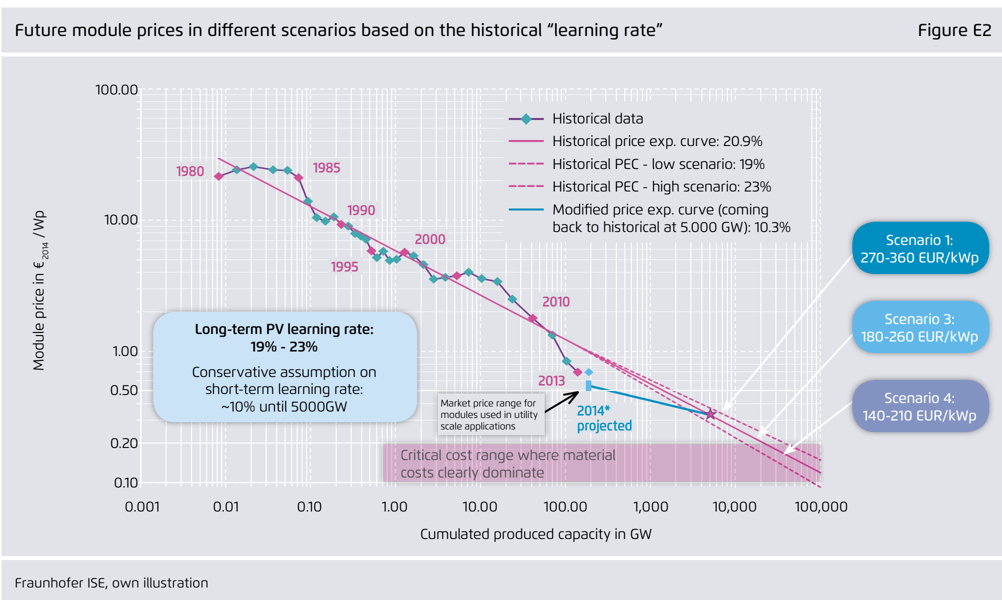



**Figure 22. Model application: U.S. utility-scale fixed-tilt PV system cost reduction from economies of scale (2016 USD/Wdc)**

## 2.2.4 AGORA (2015)

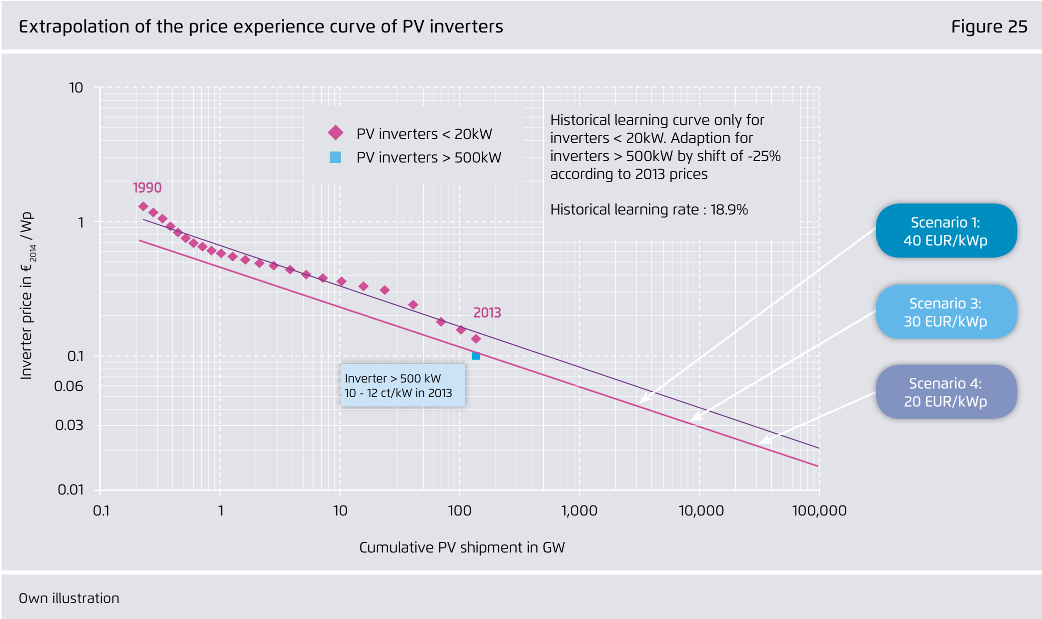
An other German study published in 2015 takes a look at the current and future costs of PV systems until 2050 (AGORA 2015). It is based on a detailed expert assessment of the learning/experience curves of PV modules and inverters and it discusses in detail the cost reduction potentials of other important parts of the BOS (Balance of System Costs). Depending on the future installation volume of PV the study derives module costs between 0.14 and 0.36 $Euro_{2015}/W_p$, which translates into 0.155 to 0,399 $USD_{2015}/W_p$ (AGORA 2015, p.6). Figure 20 below shows the future costs and the learning curve approach used.

Figure 20: Future module prices based on installed quantities by 2050 and historical ‚learning rate' (source: AGORA 2015, p.6)



The same type of analysis is done for the inverter of the solar PV system. Based on the ‚learning curve' approach and the estimated installed volumes a cost reduction from 1 - 1.2 $Euro_{2015}/W_p$ down to 0.2 to 0.4 $Euro_{2015}/kW_p$ is estimated for the inverters (AGORA 2015, p.35). This is equal to a price decrease from 1.11 - 1.33 $USD_{2015}/Wp$ to 0.22 - 0.44 USD2015/Wp. Figure 21 below shows the development of the inverter costs over time.

Figure 21: Future price scenarios for PV inverters by 2050 (source: AGORA 2015, p. 45)




Starting from the cost composition (system integrator costs) of an installed ground mounted PV system of about 1000 $Euro_{2015}/kW_p$, which are made up of about 550 Euro for the module, 110 Euro for the inverter and about 340 Euro for all other (BOS) costs (see Figure 22), the study further details the BOS costs into seven major components of which the five most important components are then analysed separately for their cost depression potential (compare Figures 23 and 24 below). Figure 21: Future price scenarios for PV inverters by 2050 (source: AGORA 2015, p. 35)

Figure 22: Present structure of PV system costs for Germany (source: AGORA 2015, p. 40)

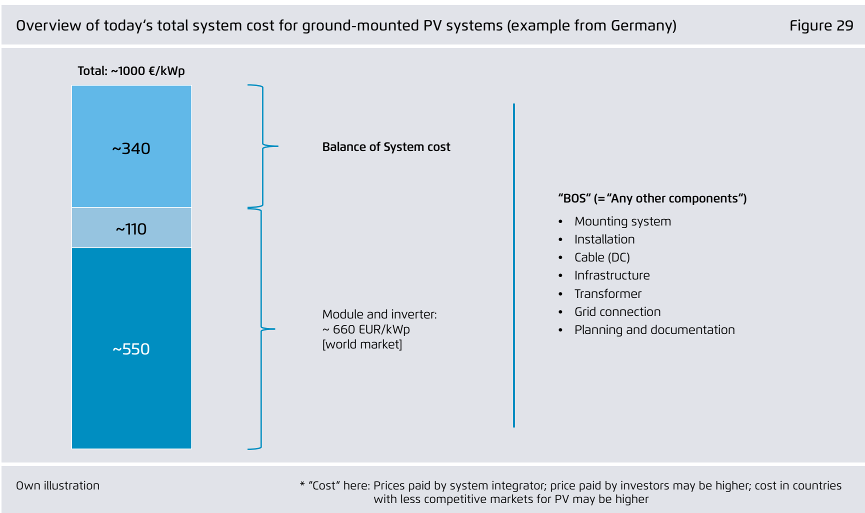


Figure 23: Split of present BOS costs (without inverter) of PV systems in Germany (source: AGORA 2015, p.40)

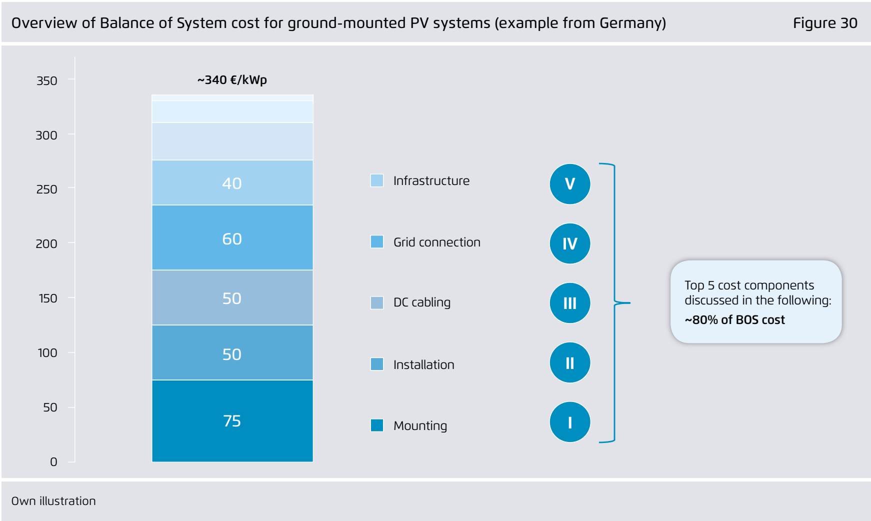
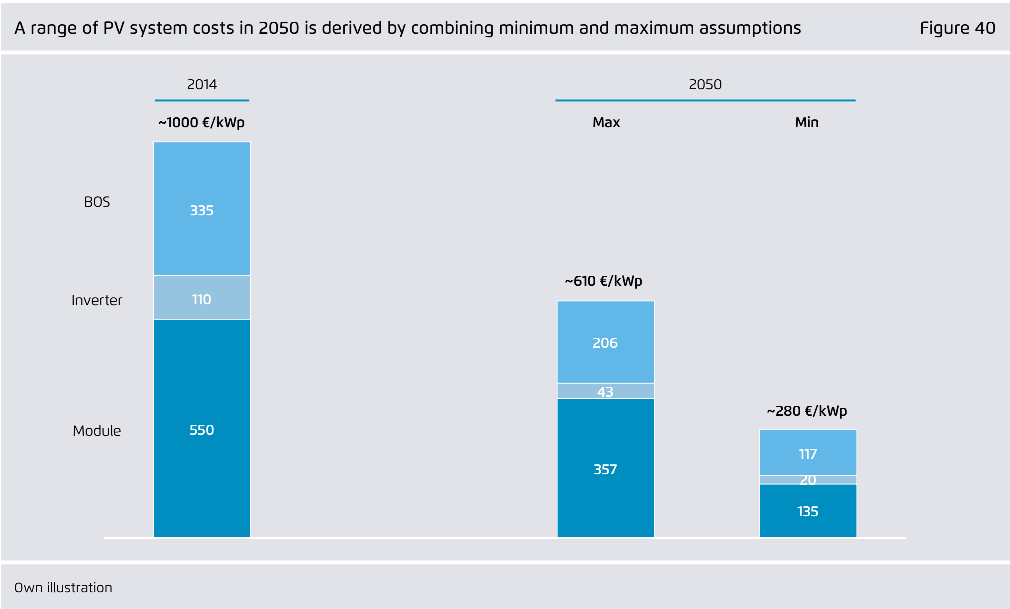
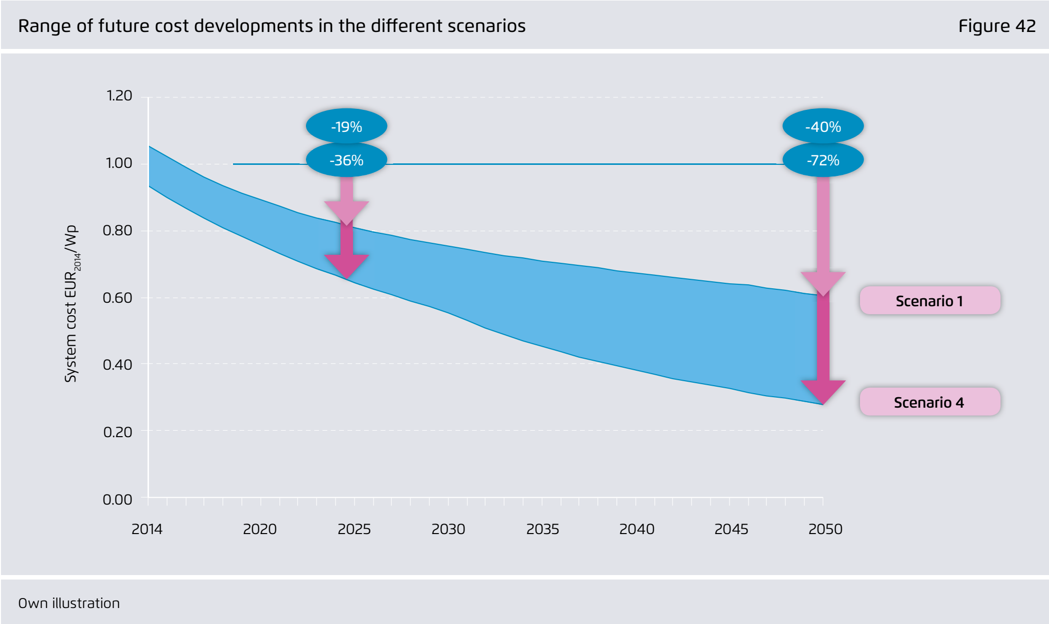



Figure 24: Cost reduction for PV systems by 2050 divided by major cost component (source: AGORA 2015, p. 50)




The study concludes that PV costs can be reduced by 19-36% by 2025 (as compared to 2015) and by 40 to 72% by 2050 (AGORA 2015, p.52). The extent of the cost reduction depends mainly on the volumes installed and the system efficiencies reached, as higher efficiencies lower many of the BOS cost components, as the systems become smaller producing the same output. Figure 25 shows the derived cost reduction corridor.

Figure 25: Range of future PV system cost developments (AGORA 2015, p.52)




## 2.3 Present PV costs in Barbados

In Barbados some first information on the costs of installed PV systems has become available since the operator of the system has to apply for a licence under the Barbados Electric Light and Power Act (ELPA). About 500 PV systems have applied for a licence under the ELPA by January 2017 representing a total installed capacity 9.9 MWp and system sizes from 0.5 to 350 kW. As the applications for seven larger systems with capacities between 180 and 350 kWp had not been finalised at the time of writing, the maximum size of systems included in the cost overview given in Table 4 is about 200 kW.

A first overview of the average, minimum and maximum costs of PV systems installed in Barbados shows that these reflect approximately world market prices in the case of the minimum cost systems installed, but that a fair share of outrageously overpriced systems is sold in almost every system size segment. This observation speaks to an asymmetrical market, where a substantial number of customers are not well informed about the prevailing market prices. A situation which seems to be capitalised upon by some PV system installers in Barbados. On average systems are installed at about 6 BBD/$W_p$, while low cost systems are installed for prices between 2 and 3 BBD/$W_p$. On the high end systems in the range of up to 10 $kW_p$ have been installed at up to 20 BBD/$W_p$, which is eight to nine times the price (800 - 900%) paid for the lowest cost systems in the same size range. The bolded size ranges (0.5-3 $kW_p$, 3-10 $kW_p$ and 10$kW_p$ - 2 $MW_p$) have been introduced to increase direct comparability with international PV prices used for example in the NREL cost assessments.

Table 4: PV system costs in Barbados 2015 and 2016 according to ELPA license applications

PV system costs in Barbados 2015 and 2016

| System size range | Average cost in BBD/$W_p$ | Minimum cost in BBD/$W_p$ | Maximum cost in BBD/Wp |
|---|---|---|---|
| 0.5 $kW_p$ | 11.42 | 9.20 | 12.00 |
| 1 $kW_p$ | 9.73 | 5.10 | 19.20 |
| 1,5 - 2,99 $kW_p$ | 7.54 | 3.10 | 20.00 |
| ***0,5 - 3 $KW_p$*** | ***8.13*** | ***3.10*** | ***20.00*** |
| 3 - 4,9 $kW_p$ | 7.16 | 2.50 | 20.00 |
| 5 - 9,9 $kW_p$ | 6.16 | 2.13 | 11.80 |
| **3 - 10 $kW_p$** | **6.47** | **2.13** | **20.00** |
| **0.5 - 10$kW_p$** | **7.30** | **2.13** | **20.00** |
| 10 - 19,9 $kW_p$ | 6.65 | 4.11 | 16.72 |
| 20 - 49 $kW_p$ | 5.87 | 2.50 | 10.21 |
| 50 - 99 $kW_p$ | 6.17 | 4.00 | 16.58 |
| 99 - 200 $kW_p$ | 6.05 | 3.02 | 9.15 |
| **10 $kW_p$ - 2 $MW_p$** | **6.25** | **2.50** | **9.15** |

## 2.4 INTERNATIONAL COST ASSESSMENT FOR WIND ENERGY

### 2.4.1 NREL 2012

The cost development for wind energy looks back on a considerably longer period of commercial applications as compared to solar PV. The commercial basis for the predominating three bladed horizontal axis wind turbines, which are installed at an average size of 2 to 3 MW per machine today, was laid in the late 1970ties in Denmark with the first series production of such types of wind turbines in the size range of about 20 kW per machine. With the help of different wind turbine markets developing internationally over time (in the US in the early 1980ties, in Germany in the 1990ties, in Spain in the late 1990ties) it was possible to scale up the turbines through numerous size steps to a maximum of about 8 MW per turbine build for offshore applications today. Thus, most of the historic cost digression took place between 1980 and 2005 bringing down the levelized costs of wind energy from 0.25 USD/kWh in 1980 to 0.05 USD/kWh in 2005, as can be seen in Figure 26 below. Due to increased steel prices and due to a very substantial increase in international demand for wind turbines the levelized costs increased substantially till 2009 to a level of 0.075 USD/kWh (see NREL 2012, p. iv). It can be observed that the historic LCOEs have been considerably lower in Europe (mainly Denmark, Germany and Spain) as compared to the United States.

Figure 26: Estimated levelized costs of energy (LCOE) for wind energy between 1980 and 2009 for the United States and Europe (excluding incentives) (Source: NREL 2012, p. iv)

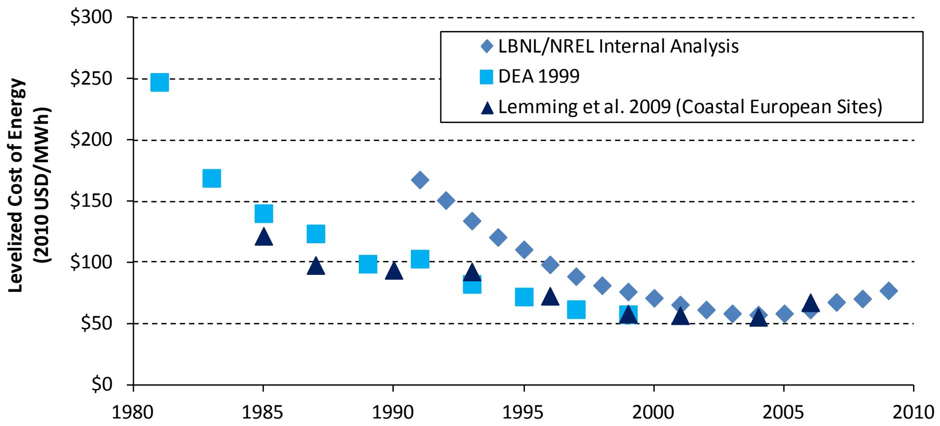



**Figure ES-1. Estimated LCOE for wind energy between 1980 and 2009 for the United States and Europe (excluding incentives)**

Sources: LBNL/NREL (internal analysis), Lemming et al. 2009, and DEA 1999

### 2.4.2 IPCC SRREN (2012)

The IPCC Special Report on ‚Renewable Energy Sources and Climate Change Mitigation' shows a very similar development of the investment costs of wind energy projects as the results given by NREL 2012 for the levelized costs of electricity shown above. According to the IPCC the US investment costs decreased from about 4,000 $USD_{2005}$/kW in 1982 to about 1,300 $USD_{2005}$/kW in the year 2000. Subsequently the investment costs increased to about 1,950 $USD_{2005}$/kW in 2009 (see Figure 27 lower part). At the same time a similar but less pronounced development can be seen for Denmark (see upper part of Figure 27) where investment costs of wind projects declined from about 2,600 $USD_{2005}$/kW in 1983 to about 1,000 $USD_{2005}$/kW in 2003. In the following years investment costs increased to slightly less than 1,500 $USD_{2005}$/kW in 2007 and 2008 and started to decline again in 2009 (see IPCC 2012 p. 585). The results allow the conclusion that the European wind turbine market has been substantially more competitive than the US market with cost levels 10 to 25% under the costs experienced in the United States. This is quite surprising from a theoretical perspective, as the policy instruments used in the United States (renewable portfolio standards) are putting high emphasis on competitive pricing and the better cost information available to market participants as compared to policymakers. At the same time the leading European wind energy countries (Denmark, Germany and Spain) were heavily relying on policy controlled price setting through Feed-in tariffs (FITs), which rely exclusively on the cost information available to policy makers (mostly compiled by wind energy research institutes).

Figure 27: Wind energy investment cost development in Denmark and the United States between 1982 and 2009 (source: IPCC 2012, p.585)

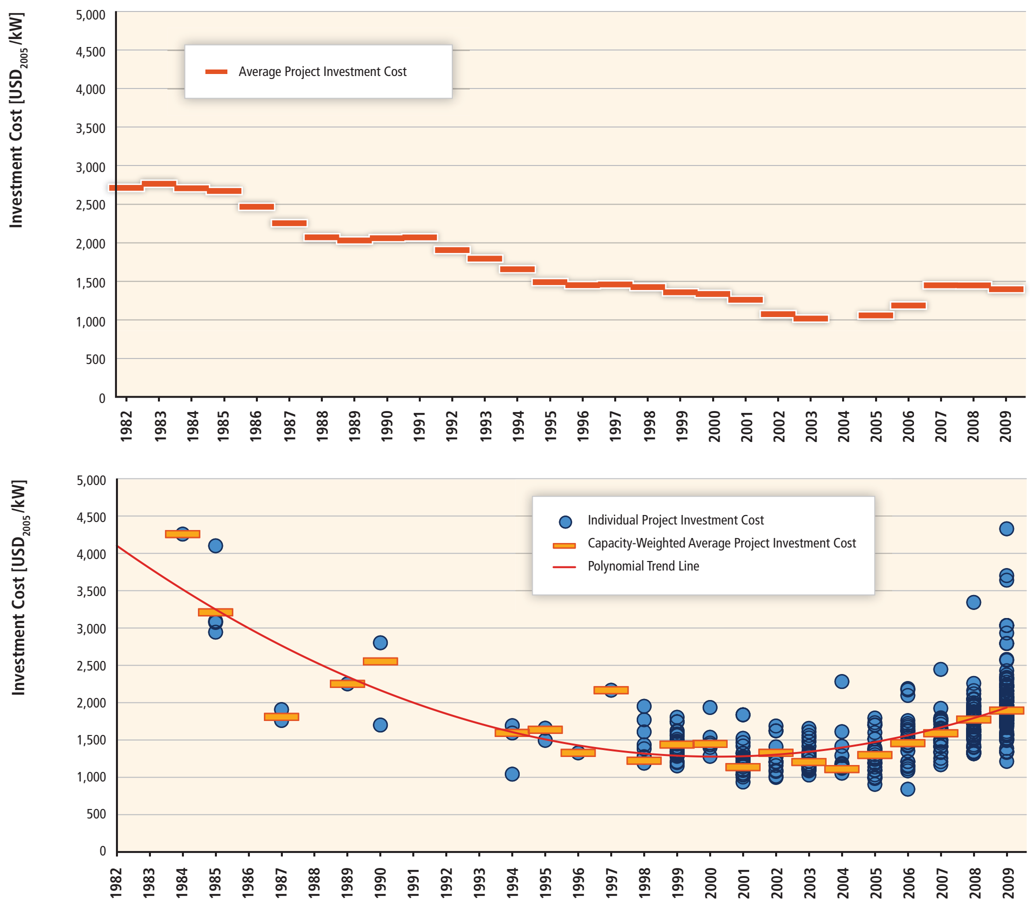



**Figure 7.20.** Investment cost of onshore wind power plants in (upper panel) Denmark (Data source: Nielson et al., 2010) and (lower panel) the USA (Wiser and Bolinger, 2010).

The IPCC report shows the very strong influence of the available wind speeds (expressed as capacity factor) on the levelized costs of wind energy. Depending on the capacity factor (varied between 50 and 15%) and other circumstances (investment costs, interest rate) held constant, the same wind turbine can produce levelized costs of electricity between 5.5 and 14 US $cent_{2005}$/kWh depending on the wind regime. A capacity factor of 15% represents a very marginal location allowing just about 1300 hours of full load (equivalent) operation per year, while a capacity factor of 50% represents an exceptionally good offshore wind site with more than 4300 full load hours of operation. Wind sites at the German and Danish coast have capacity factors in the range of 20 to 30%, which are considered favourable onshore wind energy locations in the two countries, which have been leading the technical wind energy development over the last 35 years. Figure 28 shows the impacts of three central parameters on the costs of wind energy, which are the achieved capacity factor, the investment costs per kW and the interest rate available for financing the investment.

Figure 28: Estimated levelized cost of on- and offshore wind energy in 2009 as function of capacity factor and investment cost (left) and as function of capacity factor and discount rate (source: IPCC 2012, p.588)

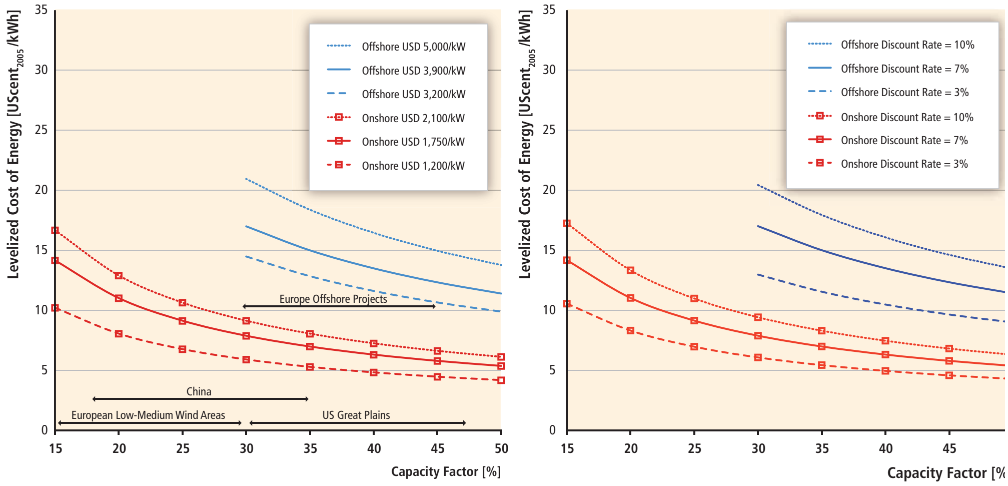



**Figure 7.23 |** Estimated levelized cost of on- and offshore wind energy, 2009: (left) as a function of capacity factor and investment cost* and (right) as a function of capacity fact and discount rate**.

Notes: * Discount rate assumed to equal 7%. ** Onshore investment cost assumed at $USD_{2005}$ 1,750/kW, and offshore at $USD_{2005}$ 3,900/kW.

### 2.4.3 NREL 2015

In a more recent study the US National Renewable Energy Laboratory (NREL) has published rather detailed cost estimates for a typical wind energy project based on a standard 2 MW turbine design. In prices of 2014 the investment costs are 1,710 $USD_{2014}$/kW (NREL 2015, p. vi), which is equivalent to 1,410 $USD_{2005}$/kW, if the inflation of 17.5% (for the entire period 2005 to 2014) is considered. Thus, the cost of wind turbines has come down again from the high levels in 2009, but it has not quite reached the lowest point on the cost curve given by IPCC 2012 for the year 2000 (see Figure 27 above).

On the basis of a net capacity factor of 39.6% NREL arrives at 6.5 US $cent_{2014}$/kWh for a very good on shore site (see Table 5 below). What is more, the study gives a very good breakdown of the cost structure for a wind energy development (see Figure 30 below) as well as a sensitivity analysis of the levelized cost of electricity (LCOE) with respect to the most important parameters (see Figure 29 below).

As Table 5 shows, there are substantial additional costs beyond the costs of the turbine, these are the so called balance of system costs (e.g. development, electrical infrastructure, assembly and installation) as well as the financial cost (e.g. insurance and construction financing). On average the other costs constitute roughly 30% of the onshore wind energy costs (NREL 2015, p. vii). Operation and maintenance cost constitute between 20 and 25% of the overall LCOE.

Table 5: Cost structure of land based wind energy reference projects in 2014 (source: NREL 2015, p. VI)

**Table ES1. Summary of the Land-Based Reference Project Using 1.94-MW Turbines**

| Data Source[a] | | 1.94-MW Land-Based Turbine ($/kilowatt [kW]) | 1.94-MW Land-Based Turbine ($/MWh) |
|---|---|---|---|
| Model | Turbine capital cost | 1,221 | 35 |
| Model | Balance of system | 345 | 10 |
| Model | Financial costs | 154 | 3 |
| Market | Market price adjustment[b] | –10 | 0 |
| Market | Capital expenditures (CapEx) | 1,710 | 49 |
| | | | |
| Market | Operational expenditures (OpEx; $/kW/yr) | 51 | 15 |
| Market | Fixed charge rate (%) | 10.3 | |
| Model | Net annual energy production (MWh/MW/yr) | 3,466 | |
| Model | Net capacity factor (%) | 39.6 | |
| **Calculated** | **TOTAL LCOE ($/MWh)** | **65** | |

[a] Sources are listed in the relevant sections of this report related to the specific cost components.
[b] The market price adjustment is the difference between the modeled cost and the average market price paid for the typical project in 2014.

A sensitivity analysis (see Figure 29 below) shows that the LCOE of wind are extremely sensitive to the prevailing wind speeds of a site. An net capacity factor of 51% brings down the LCOE from 6.5 to approximately 5 US $cent_{2014}$/kWh, while a reduction of the capacity factor to 18% can increase the same LCOE to more than 14 US $cent_{2014}$/kWh. At the same time a variation in investment costs can increase or decrease LCOE considerably as well, while a variation of operating costs (OPEX) has a substantially lower impact. Although the variation of the discount rate (interest rate for financing) seems to have a low impact, it has to be taken into account that the NREL calculations vary the discount rate only over a small range (8.0 to 9.4%), while German experience shows financing at far lower interest rates (as low as 2-3%). Such strong variation would reduce LCOE as much as the variations in capacity factor (wind speed).

NREL (2015) shows a very clear cost breakdown of the capital expenditure cost (CAPEX) for onshore wind energy in the case of the standard 2 MW wind turbine (see Figure 30 below). While the turbine constitutes 71% of CAPEX, the nacelle, containing the generator and the drive train, makes up over 40% of the entire CAPEX followed by the cost of the rotor (17%) and the cost of the tower (13%). The electrical infrastructure (9%) makes up almost 50% of the balance of system cost (20%). The detailed cost figures for the CAPEX break down are given in Table 6 below, while Table 7 gives a breakdown of the operating cost (OPEX).

Figure 29: Sensitivity analysis for on shore wind energy LCOE with respect to key parameters (source: NREL 2015, p. IX)

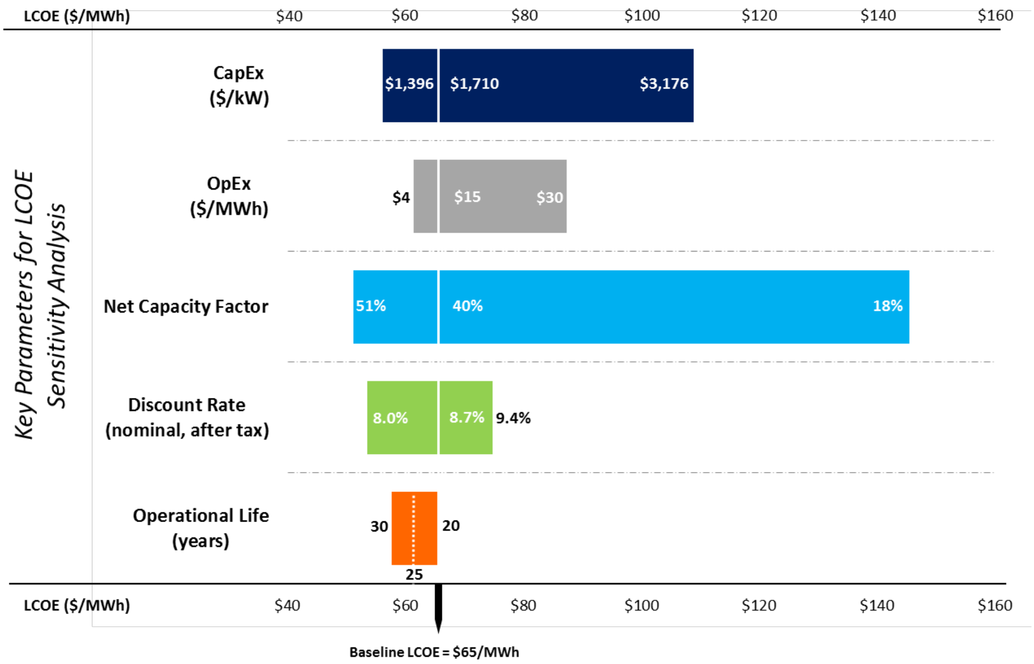



**Figure ES3. Land-based wind plant assumptions and ranges for key LCOE input parameters**

Source: NREL

Figure 30: Structure of capital expenditure (CAPEX) for a typical 2 MW on shore wind turbine in the United States in 2014 (source: NREL 2015, p.11)

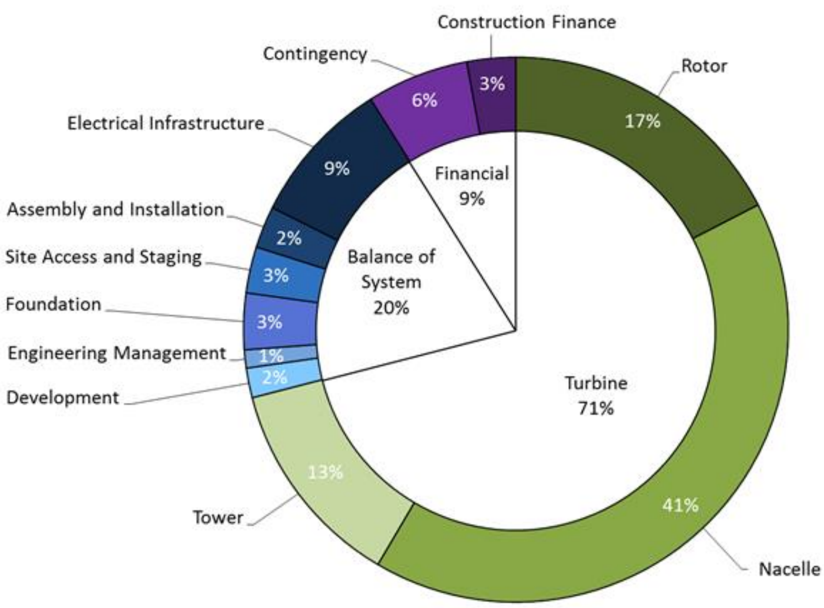



**Figure 5. Capital expenditures for the land-based wind reference project**

Source: NREL

Table 6: CAPEX cost break down of on shore wind energy in the United States in 2014 based on a standard 2 MW wind turbine (source: NREL 2015. p.12)

**Table 2. Land-Based LCOE and CapEx Breakdown**

| | 1.94-MW Land-Based Turbine ($/kW) | 1.94-MW Land-Based Turbine ($/MWh) |
|---|---|---|
| **Rotor Module** | **300** | **9** |
| Blades | 182 | 5 |
| Pitch assembly | 68 | 2 |
| Hub assembly | 50 | 1 |
| | | |
| **Nacelle Module** | **706** | **20** |
| Nacelle structural assembly | 153 | 4 |
| Drivetrain assembly | 240 | 7 |
| Nacelle electrical assembly | 282 | 8 |
| Yaw assembly | 40 | 1 |
| **Tower Module** | **215** | **6** |
| **TURBINE CAPITAL COST** | **1,221** | **35** |
| | | |
| **Development Cost** | 30 | 1 |
| **Engineering Management** | 19 | 1 |
| **Foundation** | 58 | 2 |
| **Site Access and Staging** | 47 | 1 |
| **Assembly and Installation** | 43 | 1 |
| **Electrical Infrastructure** | 149 | 4 |
| **BALANCE OF SYSTEM** | **345** | **10** |
| | | |
| **Market Price Adjustment** | -10 | 0 |
| **Construction Financing Cost** | 50 | 1 |
| **Contingency Fund** | 104 | 3 |
| **FINANCIAL COSTS** | **144** | **4** |
| | | |
| **TOTAL CAPITAL EXPENDITURES** | **1,710** | **49** |

Table 7: OPEX cost break down of on shore wind energy in the United States in 2014 based on a standard 2 MW wind turbine (source: NREL 2015. p.12)

**Table 3. Land-Based Wind Reference Project OpEx**

| | 1.94-MW Land-Based Turbine | 1.94-MW Land-Based Turbine |
|---|---|---|
| Operations (OPER) | $15/kW/yr | $5/MWh |
| Land lease cost | $8/kW/yr | $2/MWh |
| Maintenance (MAIN) | $28/kW/yr | $8/MWh |
| **OpEx** | **$51/kW/yr** | **$15/MWh** |

### 2.4.4 Deutsche Wind Guard 2015

A study on the cost structure of wind power in Germany has been published by Deutsche Wind Guard in 2015. This study is based on industry surveys among six wind turbine manufacturers holding a joint market share of 97% in the German market, which constituted about 50% of the entire European wind energy market in 2015 (REN 21 2016, p.76) with newly installed wind energy capacities of about 6 000 MW bringing the total installed German wind energy capacity to 45 GW. Deutsche Wind Gard has been one of the consultants helping the German government to find appropriate Feed-in tariffs (FITs) for wind energy in the past.

For onshore wind park developments planned for 2016/17 Wind Guard derived main investment costs (consisting of turbine cost, transportation cost and installation cost) of 980 - 1,380 $€_{2015}$/kW and other investment costs (consisting of all on site cost like foundations, connection to the power grid and site preparation plus planing and financing cost) of 387 $€_{2015}$/kW. Taking the average annual exchange rate of 1.0672 USD/Euro in 2015 and an inflation rate of 0.1% from 2014 to 2015 into account gives a range of 1,045-1,471 $USD_{2014}$/kW for the main investment costs and 413 $USD_{2014}$/kW for the other investment cost. The total CAPEX resulting are 1457 to 1884 $USD_{2014}$/kW or an average CAPEX value of 1671 $USD_{2014}$/kW. As Wind Guard and NREL have reached their results totally independently of each other the results show that wind energy costs seem to be converging substantially in the leading international markets. What is more, it looks like the capital cost of wind energy are not decreasing any more as compared to the market prices paid between 2000 and 2005 in Europe.

As onshore wind energy is a mature technology by now, which is mainly based on electrical and mechanical components, it seems highly unlikely that very substantial cost reductions will be reached in the future. Nevertheless, wind energy is one of the cheapest options to generate renewable power in locations with good average wind speeds and it will remain to be that for decades to come. For policy makers and regulators like the FTC this fact will make it easier to stay on top of future wind energy cost developments for the design of appropriate pricing policies.

At the same time offshore wind energy is just approaching the status of mature technology with numerous lessons still to be learned. At present the costs for offshore wind energy in shallow waters (up to 50m water depth) are well established and estimated for the United States at about 19.3 US $cent_{2014}$/kWh roughly three times as expensive as the cost of onshore wind (6.5 US cent2014/kWh) (NREL 2015, p. vi), but major cost reductions are still possible. For Barbados offshore wind turbines would need to be deployed at very large water depth of several hundred or more meters. The necessary deep water offshore wind technology is in a first full scale testing phase. Figures quoted by Norwegian developers in 2016 on the first offshore wind park off the coast of Great Britain are in the range of 8,000 Euro/kW. Nevertheless, these figures have only been quoted during a discussion at a wind energy conference in Norway and have not surfaced in the literature thus far.

## 2.5 COST ASSESSMENT FOR BIOMASS TO POWER

### 2.5.1 General use of biomass for energy

The assessment of the cost of power production from biomass is substantially more complex than for the cost of PV or wind energy. As shown in Figure 31 below there are many possible combinations of biomass feedstocks with numerous conversion technologies to produce different kinds of energy outputs. In the case of this study we concentrate on power as the energy output and possibly heat as a by-product of the process. Feedstocks can be oil crops, sugar crops, lignocellulosic biomass and biodegradable waste. Depending on the form of feedstock the biomass can be combusted, hydrogenated, fermented, gasified, pyrolysed or digested. Due to the multitude of possible permutations the cost of the energy produced can vary across a very large range. Thus, it is not possible to give similar cost figures from the international literature relevant for Barbados as for wind and solar PV. Therefore, the following text will concentrate on the developments seen in Barbados and try to give cost figures for these developments as far as possible.

Figure 31: Different routes of converting biomass feedstocks to different forms of energy (source: IPCC SRREN 2012, p.235)

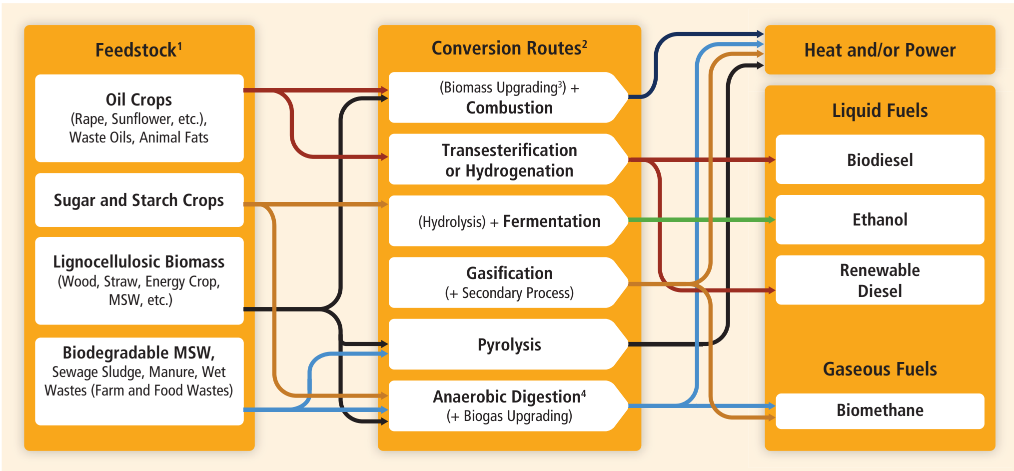



**Figure 2.6** | Schematic view of commercial bioenergy routes (modified from IEA, Bioenergy, 2009).

Notes: 1. Parts of each feedstock, for example, crop residues, could also be used in other routes. 2. Each route also gives co-products. 3. Biomass upgrading includes any one of the densification processes (pelletization, pyrolysis, etc.). 4. Anaerobic digestion processes release methane and $CO_2$ and removal of $CO_2$ provides essentially methane, the main component of natural gas; the upgraded gas is called biomethane.

### 2.5.2 Two proposed Biomass to energy projects for Barbados

In Barbados two possible routes for the conversion of biomass to power seem to be of interest. The combustion of bagasse from sugar production has long been favoured by the sugar cane industry and the government of Barbados. A project for the combustion of bagasse plus some additional biomass from river tamarind has been in the planning stages for a number of years. Recently, an alternative biomass utilisation route has been researched. This approach is trying to use King Grass grown on former sugar cane land, to produce synthetic gas through pyrolysis and to use this gas in combustion engines to produce electricity.

Both projects address a major problem of Barbados' agriculture, the necessity to keep up some form of agricultural grass cultivation in order to preserve the rather thin top soil of Barbados. Due to its very young age of just about 100,000 years, there has been a very limited formation of fertile topsoil on the

limestone basis of the island. For agriculture in the tropics with its frequent heavy rainfalls such thin topsoil is very prone to water erosion in every major rainfall event. Only in the case that the topsoil is either fully covered by a plant cover or held together with a tight mesh of roots, the topsoil will withstand erosion from heavy rainfall and fast run off. For Barbados this has lead to a rotation agriculture intercropping non grass plants (e.g. beans or sweat potatoes) with sugar cane, which belongs to the family of grasses and supplies the tight mesh of roots holding together the topsoil during the intercropping period.
Since the sugar industry has lost its international competitiveness and its preferential status for sugar sales into the European Union, Barbados' sugar industry is in decline. Besides the negative impacts on the industry itself and the extent of sugar cane farming, the reduction of acreage used for the production of sugar cane means a reduction of intercropping possibilities for other vegetables on the island, as the intercropping partner (sugar cane) is loosing ground.

The two approaches pursued to produce biomass for energy in Barbados, the use of bagasse and the use of King Grass both aim at retaining sugar cane or (King) grass cultivation to enable intercropping of other vegetables. Without any such approach it is foreseen by many farmers that Barbados will not just loose its sugar cane production, but that it will loose virtually all of its normal agricultural production except green house based agriculture.

### Combustion of bagasse and river tamarind

In the case of the bagasse utilisation a project has been designed, which would use the bagasse and trimmings from 18,000 acres of sugar cane (7,285 ha or 72.8 $km^2$) (personal communication with Mr. Charles Simpson, January 2017) during the sugar campaign and 2,900 ha (29 $km^2$) of river tamarind production (assuming a yield of 28 tons of dry solids per ha and year) to fill in the rest of the year (see Barbados Draft NAMA 2013, p. 139). The project has been in planning stages since at least 2007. It is planned by the Barbados Cane Industry Association and is supported by the Barbados government.

Considering a base load operation of a steam turbine process the planned volume of biomass would suffice to operate a 22 to 24 $MW_{el}$ generator. During the cane season this plant could produce about 18.5 MW of electricity due to the process use of some of the steam produce and 22.3 MW during the rest of the season assuming a 90% load factor (equivalent to 7,884 hours of full load operation per year) (see Barbados Draft NAMA 2013, p. 40). The investment costs are estimated between 240 Million USD (see Barbados Draft NAMA 2013, p. 39) and 230 Million USD (personal communication with Mr. Charles Simpson, January 2017). The estimated output is 169 GWh/a of electricity. Fuel costs are estimated at 40 BBD/t of (dry) bagasse or 5 - 5.6 BBD/GJ and 7.49 BBD/GJ of leucina (river tamarind). With 71% of the input energy from river tamarind and 29% from bagasse the levelized cost of electricity are estimated at 0.28 BBD/kWh (personal communication with Mr. Charles Simpson, January 2017).

Although the project compares favourably with the avoided average fuel costs of the last ten years, it may run into problems in a changing future energy system due to two reasons. First, the economics of the project are built on the assumption that the plant will run approximately 8,000 hours per year at full load, which is a fair assumption, if it would be running against the present diesel fired power production. With power production costs of 0.28 BBD/kWh it could outcompete diesel generation on the basis of marginal costs virtually every hour of the year. Unfortunately, the project, once completed, will have to compete with a power production based more and more on wind and solar energy, both of which have virtually no marginal costs for power production, as they are not depending on any kind of fuel. Thus, whenever the new solid biomass combustion has to compete against wind and solar energy, it will not be chosen, as it has substantial positive marginal (fuel) costs.

Such development has been experienced by thermal power plants all around the world in countries with increasing shares of wind and solar energy in power production like in Germany. The new situation will result in gradually declining operation hours per year eventually leaving the plant with a few thousand hours of full load operation per year. As the hours of operation decrease the cost of power production will increase. Thus, a plant operating only 4,000 full load hours a year will need an average price of 0.56 BBD/kWh to recover its cost at the pace originally planed. Whenever the hours of full load operation drop further, the average price has to go up even further to fully recover costs.

The second problem a solid biomass combustion will face in the future is the fact that it can not be operated continuously at a constant load factor, but that it has to be ramped up and down quite frequently and to operate in partial load to adjust to the new market situation with growing shares of wind and solar power production. Such partial load operation will lead to seriously reduced generation efficiencies, while frequent ramping and cold starts of the plant will increase fuel and maintenance costs. Thus, the necessary changed mode of operation will increase generation costs more than proportionately.

Both problems point to the fact that the planned solid biomass combustion will encounter serious economic problems during its expected 25 years of operation. Thus, it might not be the best choice to stabilise the production of sugar cane in Barbados. What is more, the present calculations are assuming that the sugar from 18,000 acres of cane production can still be sold in the world market with the additional income from the solid biomass combustion plant (5 - 5.6 BBD/GJ of bagasse), which may not be sufficient across the lifetime of the plant.

### Gasification of king grass

The second project is far more recent. It assumes that the production of sugar will not be economically viable in Barbados in the long run. Therefore, the farmers initiating the project have been looking for a grass type which can be used in crop rotation like sugar cane in order to stabilise the top soil in crop rotation, which yields a relatively high biomass output per acre and which can be planted and harvested more continuously around the year.

After a first pre selection successful field trials have been conducted with King Grass. The biomass yield has been 19 t of biomass at 10% moisture per acre and year with an energy content of 18 GJ/t of biomass at 10% moisture. To allow a flexible production of electricity from this biomass source, a gasification process is chosen which produces 1,897.4 $Nm^3$ of syngas per ton of biomass at 10% moisture with an assumed gasifier conversion efficiency of 70% (see Fichtner 2016, p.10). The produced syngas has an energy content of 5.5 $MJ/Nm^3$(see Fichtner 2016, p.10). A gasifier with a feed throughput of 575 kg biomass/hr will produce 1,091 $Nm^3$ of syngas per hour, which would be sufficient to operate a 600 $kW_{el}$ gas engine for power production (see Fichtner 2016, p.10). Assuming a load factor of 80% and a biomass yield of 60 green t/acre equivalent to 19 t/acre at 10% moisture) about 216 acres of King Grass are needed to operate a 600 kW gas engine 7,008 hours per year producing 4.204 GWh of electricity per year. Gasifiers in the required size range come at about 6 Million USD (see Fichtner 2016, p.17). Gas engines combined with generators will most likely cost between 2 and 3 Million USD/MW. So far the exact costs of growing and harvesting King Grass as well as the operation and maintenance costs of the gasifier and the power production unit have not been analysed in detail, as a first pilot plant will be built in 2017. But the farmers involved in the project calculate that 3 t of wet King Grass needed to produce 1 t of dry King Grass (at 10% moisture) will cost about 120 BBD/t or 6.67 BBD/GJ.

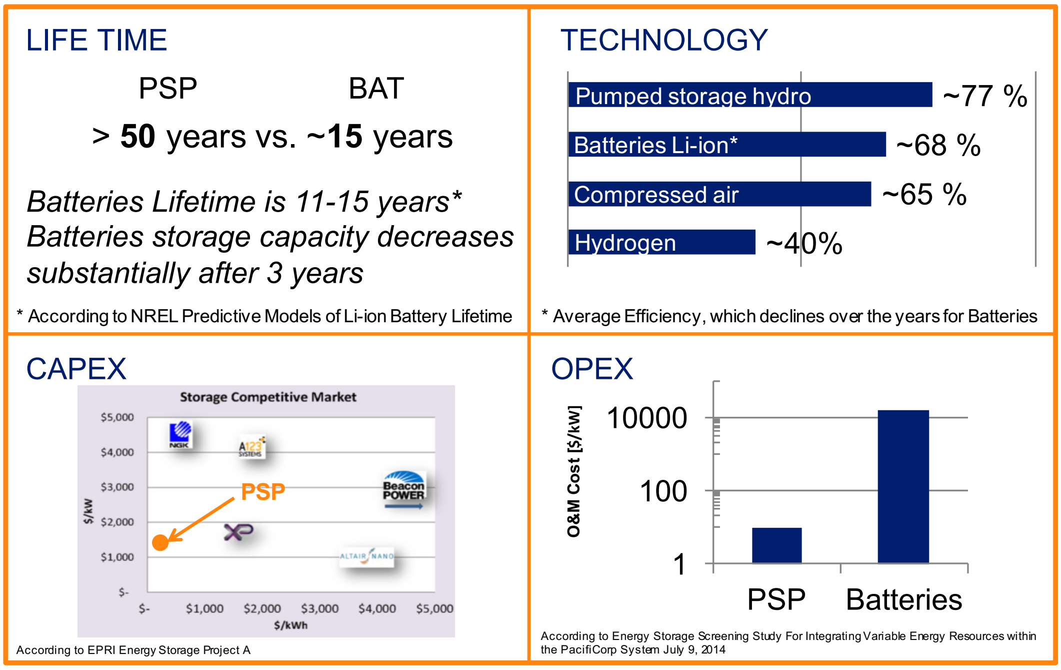
The King Grass approach has a number of systemic advantages over solid biomass combustion in the future energy system build mainly on the variable renewable energy sources wind and solar energy. The combustion engine allows a ramping of the system from no operation to full operation within less than 15 minutes, which allows to follow the residual load of the power system (the load remaining after wind and solar power production have been deducted from the total load or power demand of any given hour). Thus, the system can supply the flexibility needed in the future power system to complement wind and solar energy. What is more, the flexible planting and cropping of King Grass across the year allows to adjust the harvest of the biomass to the expected seasonal output from wind and solar energy. Additionally, the produced syngas can be stored for a number of hours or days allowing a high flexibility in the operation of the gas engine for power production, while the gasifier can be in constant operation. The relatively small size of single systems (about 0.6 $MW_{el}$) allows the adjustment of the operated production capacity to the residual load in every hour of the year. Thus, from a systems perspective the more flexible second option for the energetic use of biomass in Barbados seems to fit Barbados' future power production better than the large scale solid biomass combustions based on bagasse and river tamarind. Nevertheless, it still has to prove its economic viability, which can only be judged after the planning and demonstration phases have been left.

# WORK PACKAGE 3: UPDATED DISCUSSION OF THE APPLICABILITY OF PUMP STORAGE HYDRO SYSTEMS AND THEIR COSTS IN BARBADOS

Substantial storage will only be needed whenever the production from variable renewable energy sources like wind and solar energy are installed at capacities large enough to cause substantial overproduction. As both energy sources have virtually no variable costs the overproduction of electricity comes at no additional cost to the system. Thus, the cost of utilising this overproduction is equal to the cost of storage necessary to make it available in times when wind and solar energy can not cover the full system load and the energy saved can substitute other forms of power production with substantial variable cost.

As discussed in detail in Annex 2, pump storage hydro facilities seem to offer the lowest cost solution for the necessary large scale storage of the future electricity supply of Barbados mostly supplied by wind and solar energy. Although, batteries will play an important role in local grid stabilisation, they are far more expensive than pump storage given the positive preconditions found on Barbados for pump storage with achievable altitude drops of up to 300m. Figure 32 summarises the major aspects pertaining to the costs of different storage systems.

Figure 32: Comparison of pump storage and battery storage systems (source: Stoebich 2016)




Details on the assessment of a promising pump storage location can be found in Annex 2. It is worth mentioning that the water collection facilities for the pump storage can be used to collect far more water from the water shed for drinking water and irrigation purposes. The outflow of the watershed is about 12 million cubic meters per year, which are presently flowing out into the Atlantic without any use for Barbados. The pump storage facility will need 4 million cubic meters of cleaned water from this watershed only once for the initial filling of the system and about 30,000 $m^2$/a once the system is filled in order to compensate evaporation losses. All other water collected could be cleaned and feed into the public water system.

# WORK PACKAGE 5: SIMULATION OF ALTERNATIVE 100% RE TARGET SYSTEMS AND ANALYSIS OF THEIR PROSPECTIVE COSTS

Based on an extended version of the energy system simulation model used in the former 100% scenario calculations for Barbados (see Annex 4 for the extensions implemented) and the updated results on the costs and potentials of different renewable energy sources and storage options for Barbados and interviews with investors in wind and bio energy 19 different possible 100% RE target systems were simulated for a target year taken as 2035. From international experience it is quite clear that based on available renewable energy technologies and available international know how, a transition to a 100% renewable power supply can be achieved by 2035 without any major problem, as soon as the policy and the administrative framework are set to facilitate such transition. For 2035 the annual power demand projected by Barbados Light and Power in their IRP of 2012 for 2035 was taken from the graph on page 9 of the IRP (Barbados Light and Power 2012, p.9). This is approximately 1,350 GWh/a.

As a basic reference case a power supply exclusively based on new large diesel engines was calculated in scenario 1. The other scenarios look at the possibilities to supply 100% RE power from four different sources (wind, solar PV, biomass and municipal solid waste) using six different technologies. In the case of biomass the combustion of solid biomass (bagasse and river tamarind) and the gasification of King Grass were analysed. Both are relevant options to solve part of the agricultural problem created by the international competitive situation of sugar produced from sugar cane in Barbados. For municipal solid waste the widely used technology of solid waste combustion was used as one option and the proposed plasma gasification as a second option. Thus, in total six different technologies can be combined to produce a 100% renewable power supply for Barbados. As in earlier simulations (Hohmeyer 2015) a small residual power production is done by the existing diesel generators and gas turbines to allow to limit storage to an economic and manageable size for Barbados. This back-up production is limited to 50 GWh/a, which is less than 4% of the total electricity demand.

In a first set of scenarios (scenario 2 to 6, see Table 8 below) each technology was used on its own. If the potential allowed (e.g. in the case of PV) it was attempted to supply the 100% RE power just based on this source and storage. In the case of biomass and municipal waste this in not possible, therefore, in these cases the production was limited to the resource potential. As municipal solid waste is far from such a potential only an extreme case of a 13 MW for plasma gasification was taken into account assuming high system efficiencies. For solid waste combustion the contribution would be limited to a 11 MW plant due to lower system efficiencies, which is even smaller. Therefore, solid waste combustion was not calculated as a separate scenario. In the case of bagasse and river tamarind the limit was set by the constant full load operation of the planned 25 MW plant. In the case of King Grass a limit of 300 GWh/a ,which is equivalent to 15,000 acres of land used for King Grass production, was used as a limit.

With the exemption of a pure wind scenario (which requires about 10% more area than the 456 MW production possible on the sites proposed by Rogers (2015), which has a cost of just about 0.4 BBD/kWh all single resource scenarios have cost close to 0.5 BBD/kWh.

In scenario 7 wind and PV, the renewable energy technologies with the largest potential were combined to see, whether the combination of the two can bring down cost and solve the capacity problem of wind (only 450 MW of good sites). The combination of wind and PV actually turns out to have slightly lower cost than wind energy alone, again very close to 0.4 BBD/kWh.

In scenario 8 to 11 wind and PV are combined with each of the other options, one at a time to see the best fit. Only the combination with municipal solid waste (MSW) combustion leads to lower cost than the combination of wind and PV alone. It actually can bring down cost for the 100% RE power supply to slightly less than 0.39 BBD/kWh. The assumed MSW capacity appropriate for Barbados is taken to be 11 MW for constant firing. All other combinations increase costs. The use of biomass leads to costs of about 0.42 BBD/kWh for both bagasse and river tamarind combustion as well as for King Grass gasification. The most expensive combination results from the use of waste plasma gasification.

In scenario 12 and 13 wind, PV and King Grass gasification were combined with the two waste to power technologies one at a time. The combination with King Grass results in a slight cost increase from 0.39 to 0.4 BBD/kWh, while again the combination with waste plasma gasification results in a more significant increase to 0.42 BBD/kWh.

In scenario 14 and 15 wind, PV and solid biomass combustion (bagasse and river tamarind) were combined with the two waste to energy technologies. In the case of solid waste combustion this increases the cost as compared to the use of King Grass from 0.4 to about 0.42 BBD/kWh, while in the case of waste plasma gasification the costs increase from 0.42 to 0.46 BBD/kWh. Thus, it seems that a combination with King Grass gasification is the more attractive solution for the agricultural problem of Barbados.

As the lowest cost solution with a substantial use of King Grass is only 120 GWh/a from King Grass, which is equivalent to about 6,000 acres of land planted with King Grass, an additional scenario (13a) has been calculated to show the impact of extensive use of King Grass equivalent to 15 000 acres, which translates into an annual electricity production of 300 GWh from King Grass gasification. This scenario leads to cost of about 0.44 BBD/kWh. Thus, if a very large acreage is supposed to be kept in agricultural production and if sugar production will be viable at that scale the solid biomass combustion based on bagasse and river tamarind may have a cost advantage over a very large scale use of King Grass. On the other side it will be risky to follow such strategy as the world market for sugar does not show any signs that such a strategy can be sustained on the side of the sugar production, which is the very basis for the bagasse concept. River tamarind alone will not solve the agricultural problem of loosing the sugar cane crop for intercropping as explained above.

Scenario 16 and 17 combine wind, PV, King Grass and solid biomass combustion with either municipal waste combustion or waste plasma gasification. Again the combination with the simple waste combustion leads to substantially lower cost at about 0.41 BBD/kWh, while the inclusion of waste plasma gasification brings up the cost to about 0.46 BBD/kWh.

In the last scenario (18) all technologies were combined for a 100% RE power supply. In this case the capacities for waste combustion and waste gasification were cut in half, as they are limited by the available municipal and commercial waste in Barbados. As could be expected this combination of all available technologies leads to relatively high costs of about 0.44 BBD/kWh.

To complete the overview of the nineteen basic scenarios calculated Table 9 gives the additional information on the use of back-up power and storage as well as the overproduction in the 100% scenarios, which is necessary to meet the 100% goal. This excess production will actually be down regulated in reality.

To give a clear impression of the relative costs of the different scenarios they are ordered by cost per kWh in Table 10 below. It becomes quite clear that a combination of wind, PV and the standard combustion of solid waste has the lowest average levelized cost of electricity. The second cheapest scenario is the simple combination of wind and PV like it was used by Hohmeyer (2015) in his first calculations on a 100% RE scenario for Barbados. Third is the first combination with King Grass gasification at the level of 120 GWh/a or 6,000 acres. The most expensive option is waste to energy plasma gasification.

Table 8: Composition and electricity costs of 19 basic scenarios analysed (pleas note that in this table the comma is used as decimal point

| Scenario | | LCOE | Installed capacities and annual generation | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Wind | | PV | | King Grass | | Bagasse and river tamarind combustion | | Wast gasification | | Solid wate combustion | |
| No. | Name | BBD/ kWh | MW | GW h/a | MW | GW h/a | MW | GW h/a | MW | GW h/a | MW | GW h/a | MW | GW h/a |
| 1 | New diesel only (base line) | 0.4495 | | | | | | | | | | | | |
| 2 | Bagasse and river tamarind only | 0.4810 | | | | | | | 25 | 169 | | | | |
| 3 | King grass gasification only | 0.4886 | | | | | 40 | 300 | | | | | | |
| 4 | Waste to energy gasification only | 0.5126 | | | | | | | | | 25 | 200 | | |
| 5 | 100% RE PV and storage alone | 0.5100 | | | 755 | 1559 | | | | | | | | |
| 6 | 100% RE Wind and storage alone | 0.4013 | 505 | 2312 | | | | | | | | | | |
| 7 | 100% RE Wind and PV plus storage | 0.3999 | 286 | 1309 | 286 | 589 | | | | | | | | |
| 8 | 100% RE / Wind / PV / King Grass | 0.4212 | 224 | 1026 | 224 | 463 | 26 | 200 | | | | | | |
| 9 | 100% RE / Wind / PV / Bagasse | 0.4233 | 240 | 1099 | 237 | 485 | | | 25 | 169 | | | | |
| 10 | 100% RE / Wind / PV / WTE gas | 0.4356 | 265 | 1213 | 265 | 547 | | | | | 13 | 100 | | |
| 11 | 100% RE / Wind / PV / Solid waste combustion | 0.3883 | 265 | 1213 | 265 | 547 | | | | | | | 11 | 74 |
| 12 | 100% RE / Wind / PV / King Grass / WTE gas | 0.4209 | 234 | 1071 | 234 | 483 | 25 | 110 | 10 | 67.6 | | | | |
| 13 | 100% RE / Wind / PV / King Grass / WTE combustion | 0.4004 | 232 | 1062 | 232 | 479 | 26 | 120 | | | | | 11 | 74 |
| 13a | 100% RE / Wind / PV / King Grass / WTE combustion | 0.4386 | 200 | 916 | 200 | 413 | 40 | 300 | | | | | 11 | 74 |
| 14 | 100% RE / Wind / PV / Bagasse / WTE combustion | 0.4143 | 219 | 1002 | 219 | 425 | | | 25 | 169 | | | 11 | 74 |
| 15 | 100% RE / Wind / PV / Bagasse / WTE gas | 0.4614 | 219 | 1002 | 219 | 425 | | | 25 | 169 | 13 | 100 | | |
| 16 | 100% RE / Wind / PV / King Grass / Bagasse / WTE gasification | 0.4584 | 212 | 971 | 212 | 438 | 25 | 120 | 10 | 68 | 13 | 100 | | |
| 17 | 100% RE / Wind / PV / King Grass / Bagasse / WTE combustion | 0.4128 | 213 | 975 | 213 | 440 | 25 | 120 | 10 | 68 | | | 11 | 74 |
| 18 | 100% RE / Wind / PV / King Grass / Bagasse / WTE gasification /WTE combustion | 0.4361 | 213 | 975 | 213 | 440 | 25 | 120 | 10 | 68 | 6.5 | 50 | 5.5 | 37 |

Table 9: Cost, conventional power production, storage and overproduction in 19 basic scenarios analysed

| Scenario | | LCOE | Installed capacities and annual generation: Diesel/Biodiesel | | Storage volume | Storage generation | | Storage pumping | | Total overproduction |
|---|---|---|---|---|---|---|---|---|---|---|
| No. | Name | BBD/kWh | MW | GWh/a | MWh | MW | GWh/a | MW | GWh/a | GWh/a |
| 1 | New diesel only (base line) | 0.4495 | 196.8 | 1350 | | | | | | 0 |
| 2 | Bagasse and river tamarind only | 0.4810 | 177.5 | 1181 | | | | | | 0 |
| 3 | King grass gasification only | 0.4886 | 156.8 | 1050 | | | | | | 0 |
| 4 | Waste to energy gasification only | 0.5126 | 171.8 | 1154 | | | | | | 0 |
| 5 | 100% RE PV and storage alone | 0.5100 | 177.9 | 50 | 10000 | 196.8 | 661 | 558.8 | 758 | 259 |
| 6 | 100% RE Wind and storage alone | 0.4013 | 177.3 | 50 | 10000 | 196.8 | 197 | 320.1 | 197 | 1012 |
| 7 | 100% RE Wind and PV plus storage | 0.3999 | 175.1 | 50 | 5000 | 196.8 | 218 | 335.6 | 252 | 598 |
| 8 | 100% RE / Wind / PV / King Grass | 0.4212 | 152.4 | 50 | 5000 | 182.7 | 184 | 232.7 | 217 | 389 |
| 9 | 100% RE / Wind / PV / Bagasse | 0.4233 | 159.8 | 50 | 5000 | 190.4 | 188 | 272.2 | 218 | 453 |
| 10 | 100% RE / Wind / PV / WTE gas | 0.4356 | 165.5 | 50 | 5000 | 196.8 | 193 | 299.7 | 225 | 560 |
| 11 | 100% RE / Wind / PV / Solid waste combustion | 0.3883 | 166.7 | 50 | 5000 | 196.8 | 205 | 307 | 238 | 400 |
| 12 | 100% RE / Wind / PV / King Grass / WTE gas | 0.4209 | 146.6 | 50 | 5000 | 174.9 | 165 | 256.1 | 192 | 431.6 |
| 13 | 100% RE / Wind / PV / King Grass / WTE combustion | 0.4004 | 144.8 | 50 | 5000 | 172.9 | 163 | 253.4 | 190 | 435 |
| 13a | 100% RE / Wind / PV / King Grass / WTE combustion | 0.4386 | 131.6 | 50 | 5000 | 156.8 | 129 | 199.8 | 151 | 403 |
| 14 | 100% RE / Wind / PV / Bagasse / WTE combustion | 0.4143 | 151.9 | 50 | 5000 | 180.6 | 176 | 248.3 | 205 | 370 |
| 15 | 100% RE / Wind / PV / Bagasse / WTE gas | 0.4614 | 147.3 | 50 | 5000 | 175.4 | 164 | 241.0 | 191 | 396 |
| 16 | 100% RE / Wind / PV / King Grass / Bagasse / WTE gasification | 0.4584 | 134.1 | 50 | 5000 | 160.0 | 139 | 219.3 | 162 | 397 |
| 17 | 100% RE / Wind / PV / King Grass / Bagasse / WTE combustion | 0.4128 | 138.6 | 50 | 5000 | 165.2 | 151 | 228.3 | 176 | 377 |
| 18 | 100% RE / Wind / PV / King Grass / Bagasse / WTE gasification / WTE combustion | 0.4361 | 136.3 | 50 | 5000 | 162.6 | 145 | 224.6 | 169 | 390 |

Table 10: Scenarios ordered by cost per kilowatt-hour

| Scenario | | LCOE |
|---|---|---|
| **No.** | **Name** | **BBD/ kWh** |
| **11** | 100% RE / Wind / PV / Solid waste combustion | 0.3883 |
| **7** | 100% RE Wind and PV plus storage | 0.3999 |
| **13** | 100% RE / Wind / PV / King Grass / WTE combustion | 0.4004 |
| **6** | 100% RE Wind and storage alone | 0.4013 |
| **17** | 100% RE / Wind / PV / King Grass / Bagasse / WTE combustion | 0.4128 |
| **14** | 100% RE / Wind / PV / Bagasse / WTE combustion | 0.4143 |
| **12** | 100% RE / Wind / PV / King Grass / WTE gas | 0.4209 |
| **8** | 100% RE / Wind / PV / King Grass | 0.4212 |
| **9** | 100% RE / Wind / PV / Bagasse | 0.4233 |
| **10** | 100% RE / Wind / PV / WTE gas | 0.4356 |
| **18** | 100% RE / Wind / PV / King Grass / Bagasse / WTE gasification / WTE combustion | 0.4361 |
| **13a** | 100% RE / Wind / PV / King Grass / WTE combustion | 0.4386 |
| **1** | New diesel only (base line) | 0.4495 |
| **16** | 100% RE / Wind / PV / King Grass / Bagasse / WTE gasification | 0.4584 |
| **15** | 100% RE / Wind / PV / Bagasse / WTE gas | 0.4614 |
| **2** | Bagasse and river tamarind only | 0.4810 |
| **3** | King grass gasification only | 0.4886 |
| **5** | 100% RE PV and storage alone | 0.5100 |
| **4** | Waste to energy gasification only | 0.5126 |

Finally the scenario assumptions of the IRENA reference scenario for 2030 were put into the model to see how this scenario performs in comparison to the 100% scenarios analysed. There are two main differences between the scenario assumptions used by IRENA and the ones used in this analysis. First, IRENA denies the possibility of pump storage for Barbados (without any evidence) and second IRENA has a far lower electricity demand, namely 1,002.6 GWh/a in 2030. Using the assumed capacities of 155 MW wind, 155 MW PV and 18 MW of solid biomass combustion the scenario was run with all other assumptions as set for the 19 scenarios above.

The first result of the calculation is that the IRENA scenario has lower costs than all the other scenarios, but this is mostly due to the fact that only 1,002 and not 1,350 GWh/a need to be produced.

The most interesting result is that the inclusion of realistic data on pump storage, easily allowing 3,000 MWh of storage, 20 times as much as the 150 MWh battery capacity used in the IRENA road map, allows a far better utilisation of the renewable energy produced. This leads to an increase of the RE power share from 84 to 94% without any additional generating capacity. If the back-up is covered by bio diesel this scenario can easily qualify as a 100% RE scenario for Barbados. As the use of large storage capacities in the form of pump storage reduces the conventional generation by 100 GWh/a it allows to reduce the cost per kWh from 0.31 to 0.29 BBD/kWh using the assumptions applied to all other scenarios and using, as in all other calculations the low wind speeds of 2011. The results point to the fact that a substantial increase in energy efficiency could help reduce specific electricity cost. At the same time the results produced with the specific wind energy data for 2011 point to the fact that IRENA may have been using rather low wind speeds for Barbados as suspected by Dr. Rogers in a personal communication before.

Table 11: Scenarios based on IRENA road map for Barbados

| Scenario | | LCOE | Installed capacities and annual generation | | | | | | | | | | | RE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Wind | | PV | | Bagasse and river tamarind combustion | | Diesel/ Biodiesel | | Storage volume | Storage generation | | |
| No. | Name | BBD/ kWh | MW | GWh/ a | MW | GWh/ a | MW | GWh/ a | MW | GWh/ a | MWh | MW | GWh/ a | % |
| IRENA 2030 | 85% RE / Wind / PV / Solid biomass / 150 MWh battery storage | 0.3057 | 155 | 710 | 155 | 320 | 18 | 122 | 123.0 | 156 | 150 | 126.4 | 51 | 84.4 % |
| IRENA 2030 mit 3 GWh PSH | 95% RE / Wind / PV / Solid biomass / 3 GWh PSH | 0.2884 | 155 | 710 | 155 | 320 | 18 | 122 | 119.7 | 56 | 3000 | 142 | 143 | 94.4 % |

# WORK PACKAGE 6: DISCUSSION OF THE ALTERNATIVE 100% RE TARGET SYSTEMS WITH THE RELEVANT STAKEHOLDERS AND THE ENERGY DIVISION

As all reasonable alternatives have been covered by the scenarios calculated and as it has become clear from the simulations that only one option can be dismissed right away, which is the plasma gasification of waste, as plasma gasification is the most expensive option and at the same time not a proven technology. Besides taking plasma gasification out of the target scenarios all other decisions will need to be made by policymakers based on their perspective regarding the solution for the agricultural sector and the future of the Barbados sugar industry. Therefore, it was decided that a stakeholder workshop could not decide on the final technology choices.

Policymakers will need to decide how to complement the basic mixture of wind, PV and solid waste combustion with a biomass technology for securing the future of intercropping agriculture in Barbados. As the King Grass gasification is right know entering the demonstration phase, it might be wise to postpone this decision until the results of the first demonstration project on Barbados will be available in 2020. In the meantime the expansion of wind and solar PV can be pursued without the need for such a decision before 2025. The combustion of solid waste can be pursued whenever this is advisable for the municipal waste handling in Barbados.

Instead of the stakeholder workshop on the modelling results there will be a broader workshop at the end of the project for the discussion of all results of phase one and phase two of the project. From recent discussions it has become clear that, while most stakeholders see the advantages of a differentiated dynamic feed-in tariff system, the first price points to be suggested in the report and the assumptions going into their calculation will meet far greater interest as some details of the final target scenario.

As the lowest cost scenario including a solution of the agricultural intercropping problem was the combination of wind, PV and solid waste combustion with a modest volume of King Grass gasification (120 GWh/a) and as the gasification of biomass can be far better integrated with the other renewables than solid biomass combustion, scenario 13 was selected as the first target scenario for 2035. In addition three further target scenarios were selected for the transition pathway analysis, which are scenario 13a (300 GWh/a from King Grass gasification), as this covers a far larger share (15 000 acres) of the land under sugar cane cultivation compared to scenario 13. Scenario 14 (wind, PV, solid waste combustion and solid biomass combustion) was selected as well, as this scenario covers 18 000 acres of sugar cane and has lower costs than scenario 13a. Scenario 11 (wind, PV and solid waste combustion) was selected as well, having the lowest cost of all 2035 scenarios analysed.

# WORK PACKAGE 7: ANALYSIS OF THE PRESENT POWER SUPPLY SYSTEM AS THE STARTING POINT OF THE NECESSARY TRANSITION TO THE 100% RE TARGET SYSTEM

## 7.1 THE PRESENT POWER DEMAND AND SUPPLY IN BARBADOS AND THE DEVELOPMENT OF POWER DEMAND UNTIL 2036

Power is publicly supplied by Barbados Light and Power to about 126,000 customers, which had a power consumption of about 900 GWh/a in 2014 (see EMERA Caribbean 2015, p. 7) and 915 GWh/a in 2015 (IDB 2016, p. 14) as well as a maximum load of about 155.2 MW in 2015 (IDB 2016, p. 10). The installed conventional generation capacity is about 239 MW (see IDB 2016, p. 10). The Barbados power supply is characterised by comparatively low system losses between 5 and 7.5% (IDB 2016, p.33).

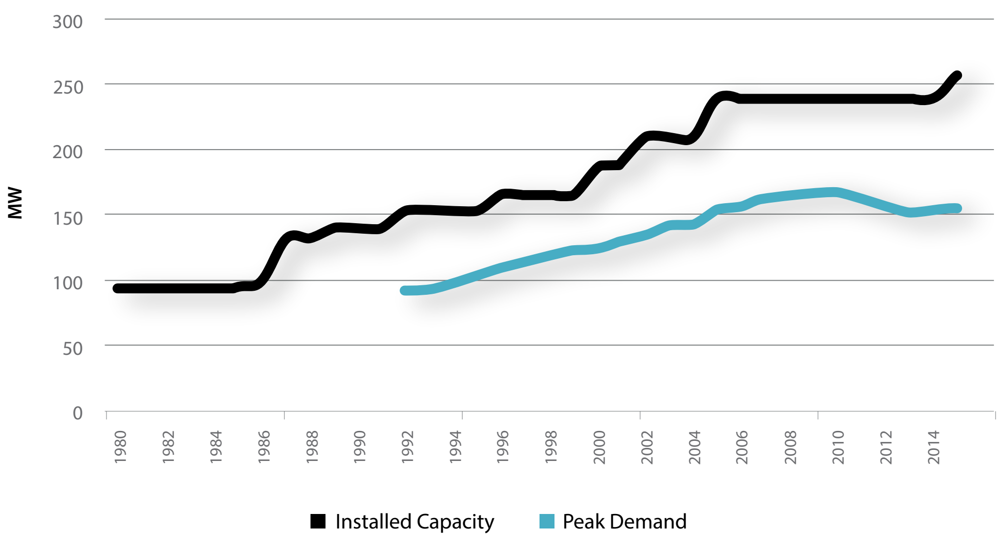
Table 12: Barbados Power and Light generating capacities as of 2014 (source: IDB 2016, p.10)

| Power Stations | Fuel | Capacity | Details | Heat Rate kJ/kWh | Year of PPA |
|---|---|---|---|---|---|
| BL&P | | 256.6MW | | | |
| Spring Garden | | 153.1MW | Opened 1967 | | |
| S1 | HFO | 20MW | Steam Turbine Generator | 14,377 | 2017/01 |
| S2 | HFO | 20MW | Steam Turbine Generator | 14,377 | 2017/01 |
| S10 | HFO | 12.5MW | Low Speed Diesel Generator | 8,063 | 2019/01 |
| S11 | HFO | 12.5MW | Low Speed Diesel Generator | 8,063 | 2019/01 |
| S12 | HFO | 12.5MW | Low Speed Diesel Generator | 8,063 | 2019/01 |
| S13 | HFO | 12.5MW | Low Speed Diesel Generator | 8,063 | 2019/01 |
| CG01 | | 1.5MW | Co-generating unit connected to D10-13 | | 2019/01 |
| CG02 | | 2.2MW | Co-generating unit connected to D10-13 | | 2036/01 |
| DA14 | HFO | 29.7MW | 2005, Low Speed Diesel Generator | 7,456 | 2036/01 |
| DA15 | HFO | 29.7MW | 2005, Low Speed Diesel Generator | 7,456 | 2036/01 |
| GT01 | | | Retired | | |
| Seawell | | 73MW | | | |
| GT03 | Diesel | 13MW | 1996, Gas Turbine Generator | 13,276 | 2022/01 |
| GT04 | Diesel | 20MW | 1999, Gas Turbine Generator | 11,134 | 2025/01 |
| GT05 | Av-Jet | 20MW | 2001, Gas Turbine Generator | 11,134 | 2027/01 |
| GT06 | Diesel | 20MW | 2002, Gas Turbine Generator | 11,134 | 2028/01 |
| Garrison Hill | | 13MW | | | |
| GT02 | Diesel | 13MW | 1990, Gas Turbine Generator | 13,276 | 2017/01 |

Since 2009 the installed capacity of solar PV installations connected to the public grid has increased to about 10.4 MW by the end of 2015 and an additional 10 MW PV plant has been installed by BL&P in 2016 (see IDB 2016 p. 12f). BL&P reported payments for 18.7 GWh for the renewable energy capacity installed in 2015 (see IDB 2016, p. 17), which would be equal to about 2% of the annual gross power production by BL&P, which amounted to 969.4 GWh/a in 2015 (see IDB 2016, p. 14). Even if this renewable power production can be doubled by the new capacities installed in 2016, Barbados is still supplied to more than 95% by electricity generated from mineral oil products.

While the power production capacity has increased from about 100 MW in 1980 to about 260 MW in 2016 (including about 19 MW of solar PV capacity) the peak demand has risen from just a little below 100 MW in 1980 to about 160 MW in 2010 and has declined afterwards due to high power prices. In 2014 the peak demand was about 150 MW (see Figure 33 below).

Figure 33: Development of peak demand and installed capacity in Barbados (source: IDB 2016, p. 11)




The hourly load curve for Barbados is not publicly available, but it has been reconstructed by Hohmeyer (2015, p.11) and by IRENA (2016, p.18). The annual hourly load curve derived by IRENA is virtually identical with the curve derived by Hohmeyer. The load curve derived by IRENA is given in Figure 34 below.

In its Integrated Resource Plan of 2012, which shows the possible future development of the electricity demand for Barbados until 2036, Barbados Power and Light has developed three scenarios, a low, a base and a high scenario, which are based on detailed analyses of the power demand of the different sectors. As Figure 35 shows, the peak demand may increase to about 300 MW in the high scenario, to about 210 MW in the Base scenario and may even decline to about 140 MW in the low scenario. BL&P foresees a total power demand of about 2,000 GWh/a in the high scenario, about 1,360 GWh/a in the base scenario and a decline to about 900 GWh/a in the low scenario (see BL&P 2012 Table 1, p.9). This development will mostly depend on the overall economic development of Barbados, but it will certainly depend upon the future price of electricity and the efficiency measures as well, which will be taken to reduce the power demand of different uses.

Figure 34: Reconstructed annual load curve of Barbados for 2014 (source: IRENA 2016, p.18)

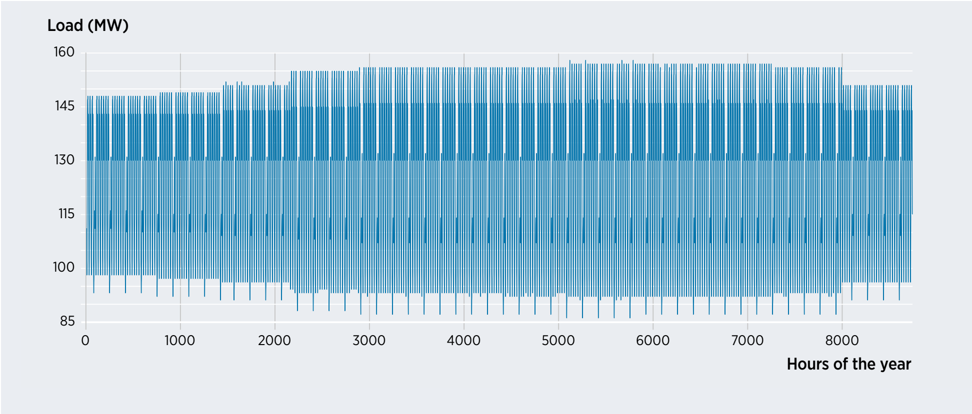



Figure 35: Three possible scenarios for the development of Barbados' future maximum electrical load (source: BL&P 2012, p.26)

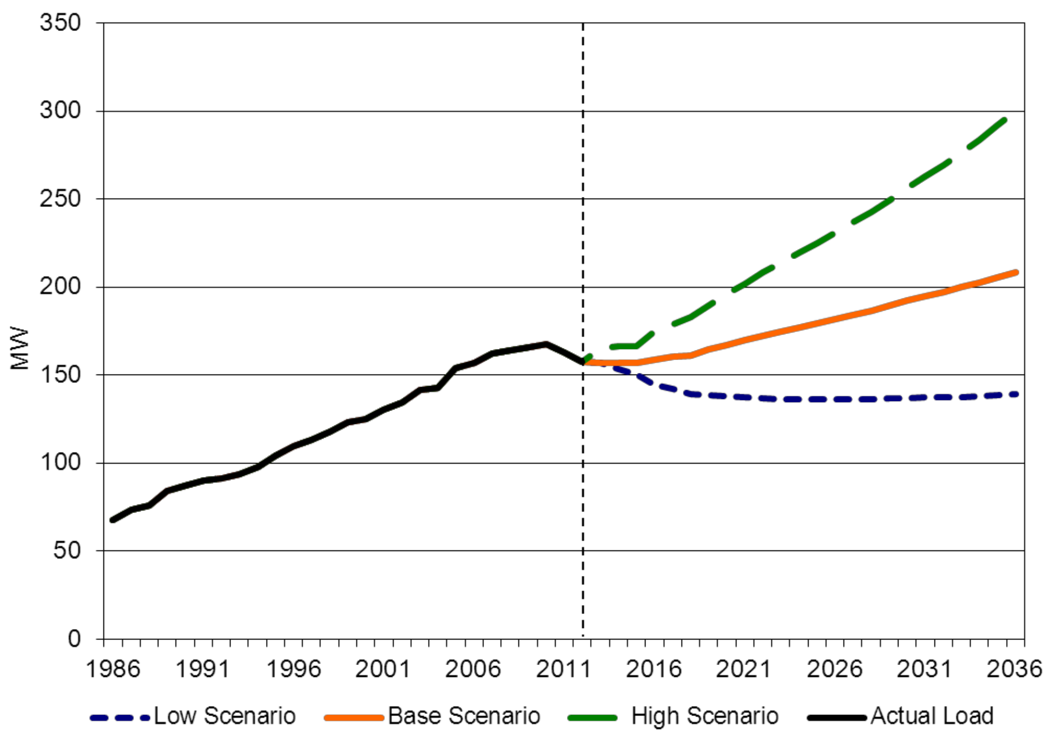
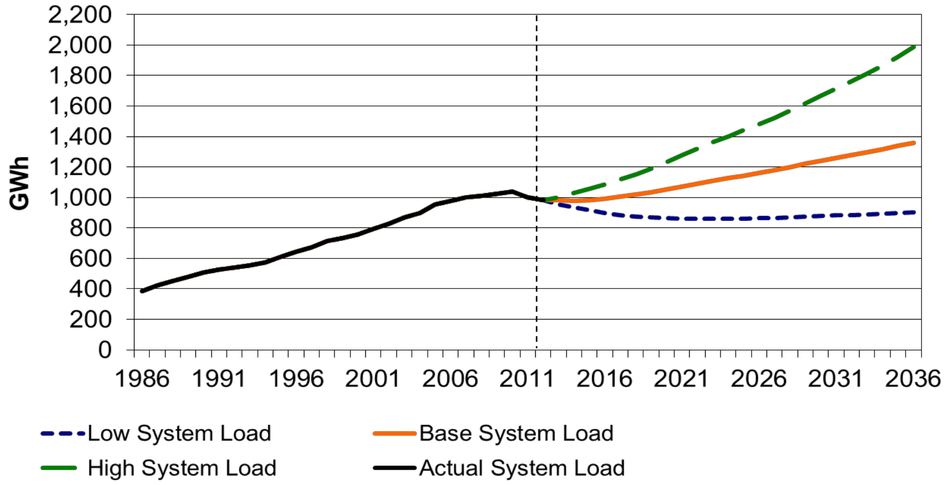


Figure 36: Three possible scenarios for the development of Barbados' future annual electricity demand (source: BL&P 2012, p.9)




It becomes quite clear from the Integrated Resource Plan of BL&P that the build up of the future power supply of Barbados needs to be quite flexible in order not to risk too low capacities and an unstable power supply and not to risk stranded investment into additional supply capacities, which will sit idle due to a lack of power demand in the case of the lower scenarios. As the present installed firm capacity in conventional equipment is at about 240 MW and most of this equipment is already written off, one of the cheapest strategies to keep enough firm capacity would be to maintain the existing generators as long as possible.

## 7.2 Barbados' present power market structure and regulatory regime

The electricity market of Barbados is characterised by the dominant position of BL&P, which is a vertically integrated utility company responsible for the generation, supply, and distribution of electricity (see IDB 2016, p. 28). Since 2014 BL&P is owned by EMERA Caribbean, which in turn is owned by EMERA, a Canadian-based company (80%), the National Insurance Board and approximately 1700 other shareholders (see IDB 2016, p. 29).

The power market is regulated by the Barbados Fair Trading Commission (FTC), which was established in 2001 under the Fair Trading Commission Act (see IDB 2016, p.31). With the passing of the Electric Light and Power Act (ELPA) in 2013 the power sector was opened to independent power producers (IPPs). As of 2016 no IPP has entered the market for either conventional generation, transmission or distribution (see IDB 2016, p. 28). Despite the market opening to IPPs BL&P still holds an official mandate for the generation, transmission and distribution of electricity under its current license, which runs until 2028 (see IDB 2016, p. 29). Thus, the present electricity market of Barbados is dominated by a vertically integrated privately owned utility producing about 98% of the traded electricity acting as a single buyer for all other power producers.

According to the nomenclature of the World Bank developed for the full liberalisation of power markets (see Gratwick and Eberhard 2008, p. 3952) Barbados has adopted seven of nine reform steps (corporisation, commercialisation, passage of requisite energy legislation, establishment of an independent regulator, introduction of IPPs, divestiture of generation assets, divestiture of distribution assets). Only the two steps of restructuring (unbundling the vertically integrated utility) and the introduction of competition through the introduction of wholesale and retail markets have not been taken (compare Gratwick and Eberhard 2008, p. 3952). According to Gratwick and Eberhard (2008, p. 3954) the Barbados situation resembles the single buyer model, which can be seen as one of the standard hybrid forms of power market liberalisation, which have evolved during the last two decades in the power market liberalisation of developing countries. It can well be argued that the power market in Barbados is too small to allow retail or wholesale competition or horizontal unbundling (see e.g. Bacon 1995, p.4 or Weiser 2004, p. 108f). Bohun, Terway and Chander (2001) *‚have emphasised that developing countries with capacities below approximately 1000 MW would not attract sufficient numbers of participants in generation and distribution to introduce sustained competition*‘ (cited in Wiser 2004, p. 109). Only five out of 54 SIDS have installed capacities over 1000 MW (Cuba, Dominican Republic, Jamaica, Trinidad and Tobago and Singapore) (see Wiser 2004, p. 110). The minimum market size of 1000 MW compares to just about 150 MW of peak load in Barbados. Thus, taking into account this limited market size the liberalisation of the Barbados power sector has already reached a comparatively high level, where unbundling could be discussed but may well have high transaction and coordination costs and little positive effect, while it seems to be extremely unlikely that wholesale and retail competition could generate any positive returns.

## 7.3 BARBADOS’ PAST AND PRESENT RENEWABLE ENERGY POLICY

Presently the use of renewable energy sources to increase the share of domestic power production and to reduce the drainage of foreign exchange earnings for imported fossil fuels for power production remains at the very low level of less than 4% in 2016, while other islands and SIDS have already reached very substantial shares of renewable power production e.g. Fiji with 59.3% Reunion with 31.2%, Crete with 26%, and Cape Verde with 21% (see Kuang et al. 2016, p. 506) to name a few prominent examples.

In 2015 the goals for the renewable energy policy of Barbados have been (nominally) increased from the 2012 target of 29% for renewable power by 2029 (AOSIS 2012, p.6 and Revised National Sustainable Energy Policy, 3.3, first bullet) to 65% of the maximum electrical load in 2030 (Barbados Intended Nationally Determined Contribution 2015, p.5). Depending on the composition of the renewable energy sources used in 2030 to reach this share of 65%, this might just be the same target as the 29% for 2029, which referred to the total electricity produced by renewables per year. In the likely case that the renewable power production of 2030 will be mostly based upon wind and photovoltaic solar energy (PV) the share of 65% of the maximum electrical load of 192 MW in 2030 (derived from the IRP of Barbados Light and Power 2014, p.10) would equal 125 MW of installed wind and PV capacity. This would produce just about 350 GWh/a (assuming 50% PV and 50% wind), which would be equal to 28.2% of the annual system load of 2030 projected by BL&P (interpolated figure based on BL&P 2014, p.9). Thus, the nominal change of the target from 29% of annual electricity produced to 65% of the maximum capacity might hardly result in an increase of renewable electricity being produced in 2029.

Recently the Barbados Government declared a 100% renewable power target to be reached by 2066 (declared by the Prime Minister of Barbados at the BREA Sustainable Energy Conference on November 10th, 2016). The proclaimed target of 100% renewable power by *2066* can hardly be seen to be in line with the claim to reach 100% renewable domestic energy supply ‚*as rapidly as possible*‘ as made by the CVF at COP 22, of which Barbados is a member.

What is more, the new ‚ambitious’ 100% target is nothing else than the 29% target for 2029. Assuming a linear distribution of the market diffusion of renewable energy over the 50 year period from 2017 to 2066 the new policy target implies a growth of 25.48% from 2017 to 2029. If this is added to a renewables share of roughly 4% by the end of 2016 the set policy target for 2029 remains virtually unchanged as compared to the target set in 2012. It seems that some policy makers try to leave the impression with the public in Barbados and the world that Barbados is speeding up its pace in the introduction of renewable electricity, while they are still just pursuing the old, rather unambitious, target of 2012.

# WORK PACKAGE 8: DESIGN OF AN APPROPRIATE TRANSITION PATHWAY FROM THE PRESENT ELECTRICITY SYSTEM TO A 100% RENEWABLE TARGET SYSTEM

Different from the original idea to select one target scenario in a stakeholder workshop by consensus, it was decided, based on the results of a complete set of scenarios, to go ahead with four different target scenarios and to develop transition pathways for all of them. These four target scenarios were selected on the basis of their power costs and their possible contribution to the solution of the agricultural problem of Barbados connected to the decline of the sugar industry and sugar cane farming.

As the lowest cost scenario including a solution of the agricultural intercropping problem was the combination of wind, PV and solid waste combustion with a modest volume of King Grass gasification (120 GWh/a) and as the gasification of biomass can be far better integrated with the other renewables than solid biomass combustion, scenario13 combining wind, PV, solid waste combustion and King Grass gasification (120 GWh/a) was selected as the first target scenario for 2035. In addition three further target scenarios were selected for the transition pathway analysis, which are scenario 13a (300 GWh/a from King Grass gasification), as this covers a far larger share of the land (15 000 acres) under sugar cane cultivation as scenario 13. Scenario 14 (wind, PV, solid waste combustion and solid biomass combustion) was selected as well, as this scenario covers bagasse from 18 000 acres of sugar cane and has lower costs than scenario 13a. Scenario 11 (wind, PV and solid waste combustion) was selected as well, having the lowest cost of all 2035 scenarios analysed.

The different target scenarios diverge, based on the renewable energy sources utilised, on the following criteria:

- low cost of power
- employment generation
- public acceptance of power supply
- general participation (every household)
- solving the problems of agriculture.

On the other criteria of significant importance to the stakeholders interviewed the different target scenarios don't differ. With respect to the *cost of power*, the target scenario without any biomass performs best, but at the same time it does not contribute to the *solution of the agricultural problem*, while the two target scenarios performing best on the solution of the agriculture problem (lack of grass crop to continue intercropping agriculture), scenario 13a and 14, are the most expensive scenarios of the four (see Table 13 and 14 below). The cost differences of 0.02 to 0.04 BBD/kWh (as compared to a cost level of about 0.4 BBD/kWh) are in the range of 5 - 10% of the total generation cost. With a total electricity demand of 1,350 GWh/a this difference translates into additional costs of 27 to 54 million BBD/a. This figure needs to be compared to the subsidies necessary to keep the sugar cane based agriculture going without any help from the future power generation.

On the objective of *employment generation* the target scenarios including the substantial use of biomass will have the greatest positive impact, as the employment in agriculture will have the largest domestic employment effect of all renewable energy technologies. This employment will either be secured through the continuous farming of sugar cane with the help of bagasse utilisation (if successful) or through the farming of King Grass for gasification on the same agricultural land, if the sugar production does not survive. Nevertheless, all 100% renewable energy scenarios will have far higher employment effects than the use of imported fossil fuels for power generation, as a far larger share of the cost of electricity will stay in Barbados' economy.

*Public acceptance* is critical for all four target scenarios as there are only gradual differences in the use of wind energy (at least 200 MW and 260 MW in the maximum case). As compared to solar PV wind energy is highly visible. This has lead to situations of low public acceptance in cases where the local population was not seriously involved in the development as well as in the investment. As shown by Mitchell (2004, p.1937) a badly planned introduction of wind energy combined with a lack of local involvement can lead to very strong and lasting public opposition to wind energy, while at the same time wind energy can reach very high diffusion rates (up to 5% of the total land area used for wind parks in parts of Schleswig-Holstein, Germany), when the investment is done in the form of citizen wind parks, with local farmers driving the process allowing for very broad local participation in the investment. As all scenarios without wind energy are substantially more expensive in Barbados, all target scenarios include a substantial share of wind energy. To achieve such a penetration of wind energy in Barbados a high degree of local ownership and participation in the development of wind energy will be necessary.

With respect to the objective of *general participation*, which means  a chance for every household to actively participate in the new energy system, solar PV performs well, as the smallest systems of a kilowatt or less can be installed by many households on their roofs. In the case of wind energy the threshold for participation as a single investor is far higher and starts in the range of about 1 million BBD. Nevertheless, as the international examples of citizen wind parks show, it is quite well possible to join in such an investment, if it is done by a large group of citizen investors. An other possibility is the investment by credit unions in wind parks, which allows a very widespread participation. Both approaches are applicable to larger solar PV installations as well. In the case of a waste combustion plant it is highly unlikely that this will be done in such form. In this case it is more likely that a large investor either from the waste handling industry or a utility company will invest in a plant of 5 to 15 MW capacity. In the case of the 25 MW solid biomass combustion plant based on bagasse it is clear that this is an investment project of the Barbados cane industry. Thus, this is not a project for broad citizen participation. In the case of King Grass gasification a substantial number of farmers, eventually more than 50, can participate in this investment due to the modular size of the single installations of about 500 to 1000 kW each. So solar and wind can do very well on this objective, while the large single projects (waste and biomass combustion) are not performing well on this objective.

Concerning the four target scenarios it boils down to  weighing the cost on one side and employment and solving the agricultural problem on the other. The target scenario with a modest share of biomass and still very low cost can be seen as a compromise with respect to meeting all criteria.

During the first years of the transition up to 2020 the main difference between the different transition pathways is the decisions whether or not to pursue the planned bagasse combustion. As this carries a substantial risk of ending up as stranded investment, if the sugar production does not survive, it may not be the best choice to take this decision based on the present knowledge about the future development of the sugar industry in Barbados. At the same time the gasification of King Grass may provide an interesting alternative, which is independent of the production of sugar in Barbados and can solve the intercropping problem just as well as the farming of sugar cane. What is more, a gradual shift to the farming of King Grass for energy production can be done gradually, depending on the development of the international sugar markets and Barbados' sugar industry. At the same time it can be tailored to the need for agricultural land for intercropping other crops. Nevertheless, the final costs of this technology are still quite unsure as the technology is just entering its demonstration phase in Barbados.

Dependent upon the decision concerning the future use of biomass for power production the market diffusion of wind and solar energy is somewhat different over time. Nevertheless, as the maximum difference between the scenarios is just 30% of the lowest market diffusion (200 MW wind and PV each in 2035), the diffusion paths don't differ very much. A late decision for a low share of biomass in the energy mix can always be compensated by a somewhat faster diffusion of wind and PV in the later years of the transition period.

In the following work packages all four target scenarios will be used in the discussion of policies and support instruments.

With respect to storage it can be seen in Table 14 below that the scenarios including King Grass gasification don't need storage in 2025, while the other two scenarios, scenario 11 without biomass and scenario 14 with the solid biomass combustion, benefit of substantial storage as early as 2025. Thus, a decision for the 25 MW bagasse combustion plant implies a relatively early construction of a substantial pump storage facility just as a development not using biomass at all. The scenario based exclusively on wind and solar PV with some additional waste combustion, will need substantial storage by 2025 due to the faster growth of wind and solar PV. As large pump storage plants have a lead time from the beginning of a pre feasibility study to commercial operation of five to eight years, it may be necessary to seriously advance such plans within the next years in order to have sufficient storage available at the time needed during the transition.

Besides the needed storage capacities Table 14 shows  that the target scenarios for 2035 with a demand of 1,350 GWh/a will have the lowest electricity costs if the storage is as large as 5 GWh. This is substantially larger than the storage volumes discussed so far (see Hohmeyer 2015), where 3 GWh were seen as sufficient for a target system of about 1,050 GWh/a.

The four pathways developed will be used in later work packages for the evaluation of different market mechanisms and policies to introduce and steadily diffuse the different renewal energy technologies into the power generation of Barbados

Table 13: Four target scenarios for 100% RE power supply in 2035 and transition pathways to these target scenarios

| Scenario / Wind year 2011 | | Year | Annual power demand | LCOE | Installed capacities and annual generation | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Wind | | PV | | King Grass | | Bagasse and river tamarind combustion | | Solid wate combustion | |
| **No.** | **Name** | | | **BBD/ kWh** | **MW** | **GWh/ a** | **MW** | **GWh/ a** | **MW** | **GWh/ a** | **MW** | **GWh/ a** | **MW** | **GWh/a** |
| 11 | 100% RE / Wind / PV / WTE combustion | 2015 | 950 | | 0 | | 10 | 19 | | | | | 0 | |
| | | 2020 | 1050 | 0.3664 | 25 | 114 | 55 | 113 | | | | | 5 | 34 |
| | | 2025 | 1150 | 0.3002 | 105 | 481 | 125 | 258 | | | | | 11 | 74 |
| | | 2030 | 1250 | 0.3123 | 185 | 847 | 195 | 403 | | | | | 11 | 74 |
| | | 2035 | 1350 | 0.3883 | 265 | 1213 | 265 | 547 | | | | | 11 | 74 |
| 13 | 100% RE / Wind / PV / King Grass / WTE combustion | 2015 | 950 | | 0 | 0 | 10 | 19 | 0 | 0 | | | 0 | 0 |
| | | 2020 | 1050 | 0.3696 | 20 | 92 | 65 | 134 | 2 | 5 | | | 5 | 34 |
| | | 2025 | 1150 | 0.3253 | 90 | 412 | 120 | 248 | 10 | 30 | | | 11 | 74 |
| | | 2030 | 1250 | 0.3161 | 160 | 733 | 175 | 361 | 18 | 75 | | | 11 | 74 |
| | | 2035 | 1350 | 0.4004 | 232 | 1062 | 232 | 479 | 26 | 120 | | | 11 | 74 |
| 13 a | 100% RE / Wind / PV / King Grass / WTE combustion | 2015 | 950 | | 0 | | 10 | 19 | 0 | 0 | | | 0 | |
| | | 2020 | 1050 | 0.3749 | 20 | 92 | 50 | 103 | 2 | 5 | | | 5 | 34 |
| | | 2025 | 1150 | 0.3354 | 80 | 366 | 100 | 206 | 14 | 45 | | | 11 | 74 |
| | | 2030 | 1250 | 0.3451 | 140 | 641 | 150 | 310 | 27 | 150 | | | 11 | 74 |
| | | 2035 | 1350 | 0.4331 | 200 | 916 | 200 | 413 | 40 | 300 | | | 11 | 74 |
| 14 | 100% RE / Wind / PV / Bagasse / WTE combustion | 2015 | 950 | | 0 | 0 | 10 | 19 | | | 0 | 0 | 0 | 0 |
| | | 2020 | 1050 | 0.3807 | 20 | 92 | 65 | 134 | | | 25 | 169 | 5 | 34 |
| | | 2025 | 1150 | 0.3452 | 85 | 389 | 120 | 248 | | | 25 | 169 | 11 | 74 |
| | | 2030 | 1250 | 0.3609 | 170 | 778 | 175 | 361 | | | 25 | 169 | 11 | 74 |
| | | 2035 | 1350 | 0.4143 | 219 | 1003 | 219 | 452 | | | 25 | 169 | 11 | 74 |

Table 14: Four target scenarios for 100% RE power supply in 2035 and transition pathways to these target scenarios. The development of the need for storage during the transition period.

| Scenario / Wind year 2011 | | Year | Annual power demand | LCOE | Installed capacities and annual generation | | | | | | | Total overproduction |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Diesel/ Biodiesel | | Storage volume | Storage generation | | Storage pumping | | |
| No. | Name | | | BBD/ kWh | MW | GWh/ a | MWh | MW | GWh/ a | MW | GWh/ a | GWh/a |
| 11 | 100% RE / Wind / PV / WTE combustion | 2015 | 950 | | 239 | 950 | | | | | | |
| | | 2020 | 1050 | 0.3664 | 140.9 | 789 | | | | | | 0 |
| | | 2025 | 1150 | 0.3002 | 148.8 | 354 | 3000 | 150.5 | 60 | 90 | 80 | 17 |
| | | 2030 | 1250 | 0.3123 | 162.2 | 118 | 5000 | 186.3 | 176 | 220.7 | 202 | 192 |
| | | 2035 | 1350 | 0.3883 | 166.7 | 50 | 5000 | 196.8 | 205 | 307 | 238 | 400 |
| 13 | 100% RE / Wind / PV / King Grass / WTE combustion | 2015 | 950 | | 239 | 950 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | 2020 | 1050 | 0.3696 | 140.2 | 785 | | | | | | 0 |
| | | 2025 | 1150 | 0.3253 | 148 | 422 | | | | | | 36 |
| | | 2030 | 1250 | 0.3161 | 155.6 | 164.4 | 5000 | 178 | 142 | 162.8 | 163 | 157.4 |
| | | 2035 | 1350 | 0.4004 | 144.8 | 50 | 5000 | 172.9 | 163 | 253.4 | 190 | 435 |
| 13 a | 100% RE / Wind / PV / King Grass / WTE combustion | 2015 | 950 | | 239 | 950 | | | | | | |
| | | 2020 | 1050 | 0.3749 | 140.2 | 816 | | | | | | 0 |
| | | 2025 | 1150 | 0.3354 | 140.5 | 469 | | | | | | 10 |
| | | 2030 | 1250 | 0.3451 | 135.3 | 168 | 5000 | 156 | 97 | 131.5 | 110 | 93 |
| | | 2035 | 1350 | 0.4331 | 131.6 | 50 | 5000 | 156.8 | 129 | 199.8 | 151 | 403 |
| 14 | 100% RE / Wind / PV / Bagasse / WTE combustion | 2015 | 950 | | 239 | 950 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | 2020 | 1050 | 0.3807 | 121.7 | 621 | | | | | | 0 |
| | | 2025 | 1150 | 0.3452 | 129.9 | 286 | 5000 | 138.4 | 56 | 85.3 | 75 | 16 |
| | | 2030 | 1250 | 0.3609 | 139.4 | 133 | 5000 | 165 | 157 | 181.4 | 181 | 265 |
| | | 2035 | 1350 | 0.4143 | 151.9 | 50 | 5000 | 180.6 | 176 | 248.3 | 205 | 398 |

# WORK PACKAGE 9: DISCUSSION OF POSSIBLE MARKET MECHANISMS AND POLICIES FOR THE SUCCESSFUL INTRODUCTION OF RENEWABLE ELECTRICITY IN BARBADOS

Due to the fact that most of the environmental and health benefits of renewable energy technologies as well as some economic benefits like the reduction of necessary fuel imports for power production are external to the market process, the cost savings to society don't show up in market prices (see e.g. Hohmeyer 1988, Ottinger et al. 1990). Thus, although the use of renewable energy sources may be highly beneficial to a country like Barbados, market prices alone will not bring about the implementation of renewable energy technologies for power production. This fact has lead many countries of the world to enact policies to support the market introduction of technologies utilising renewable energy sources. As early as 1990 Germany introduced the first so called Feed-in tariff (FIT), while the United Kingdom introduced an auctioning system for all non fossil fuels (NFFO) in 1989/90, which was succeeded by renewables obligations in 2002 after the auctioning under NFFO had failed to reach the set quantity targets. Many federal states of the US introduced so called renewable portfolio standards (RPS) mostly between 1997 and 2010. In the early stages of renewable energy policies many countries have introduced net metering for limited volumes of renewable energy capacity as a simple first measure for the promotion of renewable energy sources.

Before such preferential policies were established some utility companies offered to pay the variable costs of power production replaced by the renewable electricity for each kilowatt-hour feed into the grid, but many times utilities, possessing regional monopoly status, even refused to buy any renewable electricity from independent power producers. Most of the time there were no laws to mandate the buying of such electricity by utility companies. Such was the situation in Germany until the first FIT was established in 1990.

All of these policies for the promotion of renewable energy production have in common that they establish separate markets or market conditions for renewable energy sources, but they approach the problem in different ways. Net metering pays the full consumer price for the renewable electricity produced. Net billing pays a lower fixed price for renewable electricity produced by consumers, while it charges the full consumer tariff for the electricity consumed. FITs (feed-in tariffs) establish separate tariffs for renewables, at which these can be sold to the grid. By doing so, they set a price, which is considered a fair and appropriate price for electricity produced from renewable energy sources taking into account differences between the external costs of conventional and renewable power production. As the quantification of external costs is difficult and sometimes depending on value judgements (see Hohmeyer 2002), FITs are seen as incorporating external costs in a very rough manner (see Lipp 2007, p.5488). Under an FIT regime the tariffs are set by a public authority, most of the time based on a scientific assessment of the cost of the technologies in question. In auctioning the policy sets a certain quantity target for the market share of renewable energy sources to be met at a certain point in time. This longer term quantity target is then broken down into single rounds of auctioning/tendering, where the price is either set by the final bid necessary to achieve the volume auctioned (marginal bid price) or each successful bidder is paid the price he has bid for in the auction (pay as bid). In a renewable portfolio standard (RPS) longer term targets for the share of renewables are set (e.g. 15% by the year 2020) and all companies selling electricity to final consumers have to prove that their power production portfolio contains the necessary share of renewable energy. Thus, auctioning as well as renewable portfolio standards are quantity based policies while net-metering and FITs are price based policies. If there is full information by all market participants on the marginal cost curve of a given renewable energy technology quantity and price policies, targeting a certain quantity of renewable energy to be produced, will theoretically lead to the same result (see e.g. Lamy et al. no year, p.5). Nevertheless, such situation of full information is hardly ever given.

By 2016 net metering was used in 52 countries (see REN 21 2016, p.114), FITs were established in 75 countries plus 35 federal states (see REN 21 2016, p. 109), while auctioning, referred to as competitive bidding or tendering as well, has been established in 65 countries (see REN 21 2016, p.111). Renewable portfolio standards (RPS) were in place in 26 countries and in 74 federal states or provinces (see REN 21 2016, p.114). In total 114 countries throughout all parts of the world had one or the other policy for the support of renewable energy technologies in place by the end of 2015 (see REN 21 2016, p.112).

In order to understand the advantages and disadvantages of the different policies one has to go into some details of each policy.

## 9.1 NET METERING AND NET BILLING

Net metering and net billing are policies normally offered to electricity consumers, who operate a renewable energy plant mostly to cover their own consumption. Net metering is a very simple policy as the electricity produced by e.g. a solar PV installation on the roof of a private household substitutes the electricity which would normally by bought by that household from the grid. As this principle is applied to the annual sum of all electricity produced, even if at times the PV installation produces more electricity than the household consumes in a given hour, the household is only charged with the price for the net number of kilowatt-hours supplied from the grid (number of total kilowatt-hours supplied from the grid minus number of kilowatt-hours fed into the grid from the solar installation). For small installations and small shares of renewable power in the system this is a very simple and straight forward policy, as it does not need any additional price or quantity setting by policy makers or public authorities. As Hughes and Bell (2006, p.1536) have pointed out, there are about eight different ways to set up a net metering system depending on the way excess production is treated (not paid for, banked or bought at a certain buy-back rate). The renewable energy rider (RER) established in Barbados in July 2010 on a two year trial basis (see Fair Trade Commission 2010, p.7) was a mixture of net metering and a bonus payment for the excess electricity feed into the grid, which was originally set at 1.8 times the fuel adjustment clause, which is basically representing the avoided fuel costs of BL&P, or at a minimum of 31.5 cents/kWh (see Fair Trade Commission 2010, p.22). Such premium payments are rare cases, but there were good arguments concerning the value of the energy for Barbados' power supply, which led to the premium payment.

The main disadvantage of net metering is the fact that the producer of renewable electricity is relieved from the payment of all power system costs for each kilowatt-hour he is producing for his own consumption, although, he is still fully relying on all grid services to supply his electricity whenever his own production is not sufficient to meet his power consumption. These system costs are e.g. the cost for the grid, the cost for the full back-up capacity and the cost for all grid services like frequency and voltage stabilisation. As more and more renewable energy installations are connected to the grid, these system costs are concentrated more and more on the bills of customers not operating any form of renewable power production if net metering is applied (see Hunter 2015). Eventually, the poorest households will have to shoulder most of these costs, while the richer households enjoy the benefits of the system. It is obvious that net metering can not be used for any substantial share of a country's power production.

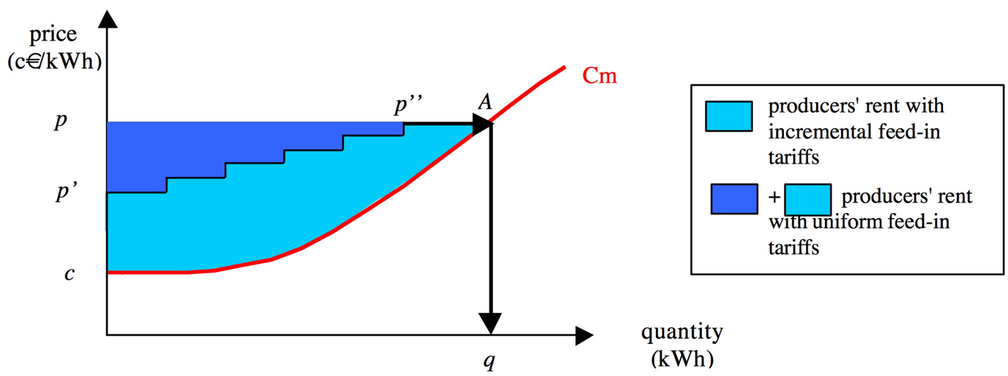
Net billing is avoiding this disadvantage of net metering as it separates the payments for the electricity produced by the renewable energy installation, which is bought at a fixed buy-back rate, from the energy consumed, which is charged the full consumer rate (see Hughes and Bell 2006, p. 1535). Depending on the compensation arrangement eight sub-types are described by Hughes and Bell (2006, p. 1536), which differ in the buy-back policy, the banking policy and the buy-back rate. Blechinger et al. (2012, p. 1) describe net billing as a feed-in tariff below retail price. Like net metering net billing aims at smaller installations, which are predominantly operated to supply the own consumption of a private or small commercial electricity consumer (customer generators), which are distinct from independent power producers (IPPs), who are primarily in the business of electricity generation (see Hughes and Bell, 2006, p. 1533).

## 9.2 Feed-in Tariffs

Feed-In Tariffs have started as an attempt to increase the payment for electricity produced from renewable energy sources to a level at which they can enter into the power market at a reasonable return to the operator of any such technology. FITs are always combined with a mandate for the utility company to buy all renewable electricity produced from any renewable energy source delivered to the grid. Sometimes they are combined with the obligation to extend and improve power lines to enable the uptake of all electricity produced from renewable energy sources in the area of a grid operator.

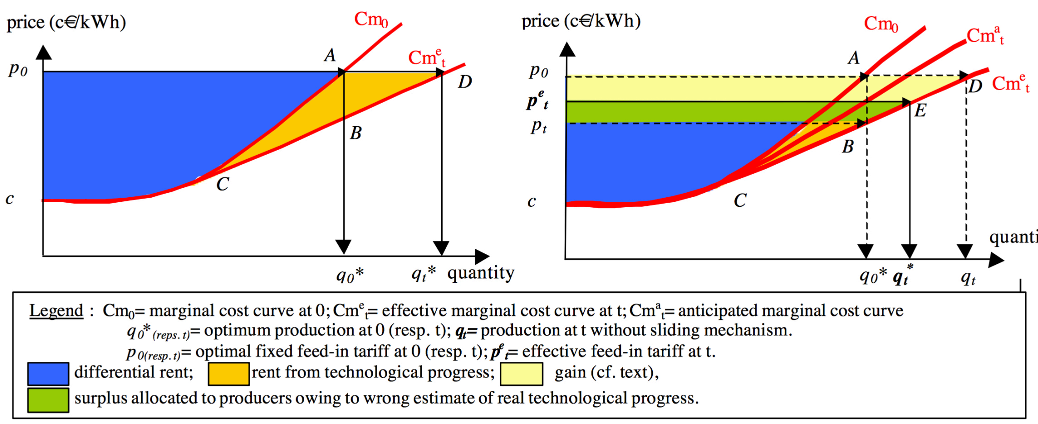
Feed-in tariffs are normally differentiated by the renewable energy source used, by the size of the system and by the conditions at a given site (incremental feed in tariff). The later is important for wind energy, as the output from a given turbine can vary extremely with the prevailing wind speeds, as the output from the system increases with the third power of the wind speed ($v^3$). Even in a relatively small country like Barbados the output of a wind turbine can easily differ by factor 2 to 3 depending on the very location of the turbine. Considering just the best areas for wind energy in Barbados the output from the same turbine can be about 70% higher in the best location as compared to the least favourable of the good locations (see Rogers 2015). Figure 37 shows how a fixed and an incremental Feed-in tariff work and how an incremental Feed-in tariff can limit excessive producers' rents on very good sites. The differentiation between different sites or different installation sizes allows the incremental FIT to follow the shape of the marginal cost curve and the producer surplus can be limited to a reasonable amount.

Figure 37: Producers' rents under uniform and incremental FITs (source: Lamy, no year, Graph 1)



Feed-in tariffs are normally guaranteed for fifteen or twenty years from the day of the first production in order to secure high bankability of the investment leading to low financing cost. In order to assure that the tariffs capitalise on the reduction of technology cost over time (see e.g. Chapter 2 for the development of PV cost over time), the tariff is reduced every year by a given percentage and is reviewed at a given interval (two to four years). Figure 38 shows how a sliding FIT can capture at least some part of the future cost reductions due to technological progress.

Figure 38: Technological progress and fixed (left) versus sliding (right) FIT to capture technological progress (source: Lamy, no year, Graph 7)



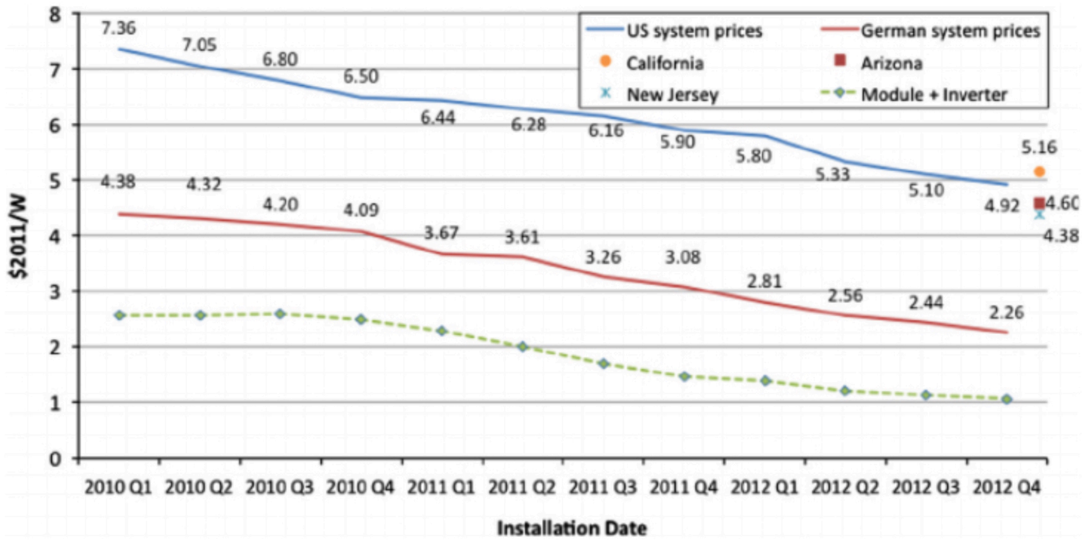

The payments for the FIT are made by the grid operator, who collects the money as part of the electricity bill from every customer as FIT levy. If there is a power exchange the grid operator sells the renewable electricity at the prevailing hourly prices at the power exchange and collects the remaining difference through an FIT levy charged to each customer. Thus, no public funding or taxpayers money is involved in the financing of FITs. With increasing shares of renewables the FIT levy may become a major part of the consumer electricity rate. Simultaneously the cost for conventional generation will constitute a decreasing share of the consumer rate.

It has been argued that FITs will by tendency be set too high, as the public authority setting the tariff does not have the full information of all market participants. Thus, an incentive system utilising the full market information (like auctioning or renewable portfolio standards) should be able to produce lower cost. So far this advantage has not materialised in reality, as can be seen in the market prices for PV installations in Germany (FIT system) as compared to the United States (RPS system). Both countries are large PV markets, but historically the prices for PV systems and the payments for PV electricity have been considerably lower in Germany than in the US (see Figure 39 below and Chapter 2.2 above).

Seel et al. (2014, p.216) show that the lower system costs in Germany have a multitude of reasons. Experience shows that lower financing costs due to the very good bankability under a FIT system enable the investment even further by better bankability and lower interest rates for loans. Thus, the claimed advantage of strongly market based policies have not materialised during the last 25 years.

A disadvantage of FIT systems can be the reaction time to fast market developments. This can be seen in the past development in Germany, where the FIT rates for PV were evaluated by parliament every two years after 2004. Due to a scarcity of solar grade silicon production capacities in the market between 2003 and 2006 module prices actually did not decrease according to the cost digression reached (see Figure 20 in Chapter 2), but they slightly increased during these years leading to a constantly high FIT for

Figure 39: Median installed price of customer owned PV systems <= 10 kW in Germany and the US (source: Seel et al. 2014, p.219)

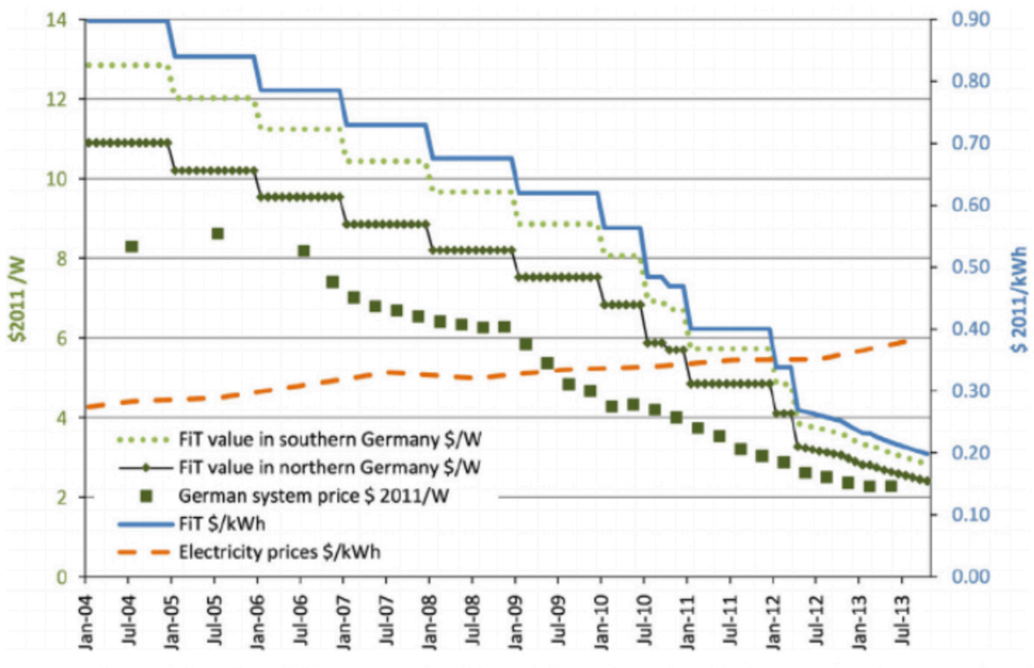



PV. In the years 2007 and 2008 module prices decreased only a little. After substantial additional production capacity entered the market in 2009 module prices dropped sharply for five years making up more than the expected cost decrease. As prices dropped substantially every month and as this development was not foreseen in the FIT digression structure, the possible margins to be earned with PV investments increased tremendously. This led to an increase of the annual installation from less than 2 GW/a in 2008 to about 4.5 GW/a in 2009 and more than 7 GW/a in 2010, 2011 and 2012. The installed capacity increased from 6.1 GW in 2008 to more than 33 GW PV in 2012 (see Quaschning 2017). During these years many institutional investors discovered PV as a very safe investment with exceptionally high returns. Investment fonds rating different types of investments for their customers rated PV investments as save as German government bonds, while they rated their return as high as very risky investments in shipping or airplanes, yielding a return in the range of 10%, while German government bonds where yielding negative returns of about -0.15%. This return structure explains, why the investment in PV boomed during the years 2009 to 2012. Finally the government switched to lowering the FIT for PV on a quarterly and even monthly basis to follow the fast drop in PV prices and to lower the margin of investors to a reasonable rate again. The FIT rate for rooftop-mounted PV installations up to 30 kW decreased from 0.574 Euro/kWh in 2004 to 0.4675 Euro/kWh in 2008 and 0.3914 Euro cent by the first half of 2010. Due to the sharp drop in PV system prices the adjustment cycle of the tariff was shortened to three month by mid 2010. Thus, the rate was dropped to 0.3405 Euro/kWh by July 2010 and to 0.3303 Euro/kWh by October 2010. It was further dropped to 0.2874 Euro/kWh in 2011 and 0.2443 Euro/kWh by January 2012. From May 2012 to October 2012 a monthly reduction by 1% was introduced. This monthly reduction was kept until 2014, but the percentage of reduction was actually varied. Details can be seen in Table 15a and 15b below. Seel et al. (2014, p.224) show how well the adjustment of the FIT worked reducing the gap between the FIT and the system cost drastically between January 2010 and July 2012 (see Figure 40 below). Although, this adjustment process did not go very smoothly and left rather substantial returns to be earned until 2012, a tremendous reduction in solar PV cost was induced allowing a reduction from 0.54 to 0.13 Euro/kWh or to less than 25% within ten years.

This extreme situation shows the main disadvantage of FITs, if there is a very fast and continuous drop in investment costs in the market, which policy can only follow with substantial delay. Nevertheless, once the trend becomes clear it is quite possible to adjust the mechanism to such development. Until policy is on top of the development the payment for the renewable electricity fed into the grid will be too high.

In export intensive economies, like in Germany, policy makers may decide to exempt energy intensive businesses from the payment of the FIT levy. As long as the total sum of the FIT payments is low, this does not cause a problem, but with increasing shares of renewables in the energy mix this can lead to relatively high FIT levies for the rest of the electricity customers. If such situation is combined with an open power market, at which the grid operator sells the renewable electricity bought from the producers of renewable electricity, this may lead to a situation where average power prices drop whenever there is

Figure 40: German residential PV system prices and value of FIT payments in high and low solar regions in Germany (source: Seel et al. 2014, p.224)




much PV or wind energy production. This has lead to substantially decreasing power prices at the German power exchange during the last years. So energy intensive businesses, not paying the FIT levy, are actually enjoying substantially lower power prices than in a situation without renewable energy production, while all other customers, paying the FIT levy are confronted with significantly higher power prices, subsidising the reduced power prices for the energy intensive industries. This development and the early installation of large volumes of very expensive PV systems have lead to a rather significant FIT levy in Germany, which is subsidising vastly increased power exports, as these are exempted from the FIT levy as well. Such developments could easily be counteracted if policymakers would decide to act on the problem (see Hohmeyer 2014). Considering the necessary FIT levy for countries switching to renewable power today the necessary FIT levy will in most cases be lower than the possible reductions of the conventional power production cost achieved by the introduction of a growing share of renewable energy sources, as Hohmeyer has shown for Barbados (Hohmeyer 2015) and the Seychelles (Hohmeyer 2016, 2016a).

Table 15: Development of the German FITs for solar PV 2004 to 2014 (source: Wikipedia 2017, Feed-in tariffs in Germany)

Table 15a: 2004 to 2012

| Type | | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | July 2010 | October 2010 | 2011 | January 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Rooftop-mounted** | up to 30 $kW_p$ | 57.40 | 54.53 | 51.80 | 49.21 | 46.75 | 43.01 | 39.14 | 34.05 | 33.03 | 28.74 | 24.43 |
| | above 30 $kW_p$ | 54.60 | 51.87 | 49.28 | 46.82 | 44.48 | 40.91 | 37.23 | 32.39 | 31.42 | 27.33 | 23.23 |
| | above 100 $kW_p$ | 54.00 | 51.30 | 48.74 | 46.30 | 43.99 | 39.58 | 35.23 | 30.65 | 29.73 | 25.86 | 21.98 |
| | above 1000 $kW_p$ | 54.00 | 51.30 | 48.74 | 46.30 | 43.99 | 33.00 | 29.37 | 25.55 | 24.79 | 21.56 | 18.33 |
| **Ground-mounted** | conversion areas | 45.70 | 43.40 | 40.60 | 37.96 | 35.49 | 31.94 | 28.43 | 26.16 | 25.37 | 22.07 | 18.76 |
| | agricultural fields | 45.70 | 43.40 | 40.60 | 37.96 | 35.49 | 31.94 | 28.43 | — | — | — | — |
| | other | 45.70 | 43.40 | 40.60 | 37.96 | 35.49 | 31.94 | 28.43 | 25.02 | 24.26 | 21.11 | 17.94 |
| Installations on agricultural fields were removed under the PV Act (2010). | | | | | | | | | | | | |

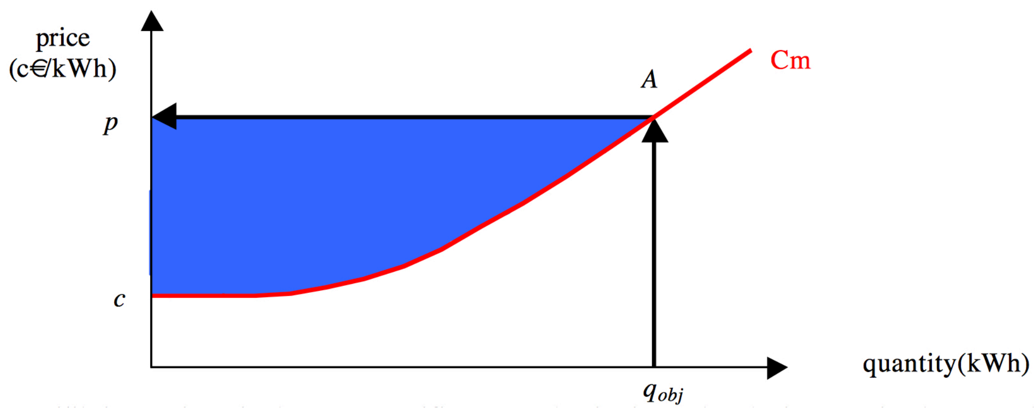
Table 15b: 2012 to 2014

| Year | Month | Degression | Rooftop mounted | | | | Ground mounted |
|---|---|---|---|---|---|---|---|
| | | | up to 10 $kW_p$ | up to 40 $kW_p$ | up to 1 $MW_p$ | up to 10 $MW_p$ | up to 10 $MW_p$ |
| **2012** | April | — | 19.50 | 18.50 | 16.50 | 13.50 | 13.50 |
| | May | 1.0% | 19.31 | 18.32 | 16.34 | 13.37 | 13.37 |
| | June | | 19.11 | 18.13 | 16.17 | 13.23 | 13.23 |
| | July | | 18.92 | 17.95 | 16.01 | 13.10 | 13.10 |
| | August | | 18.73 | 17.77 | 15.85 | 12.97 | 12.97 |
| | September | | 18.54 | 17.59 | 15.69 | 12.84 | 12.84 |
| | October | | 18.36 | 17.42 | 15.53 | 12.71 | 12.71 |
| | November | 2.5% | 17.90 | 16.98 | 15.15 | 12.39 | 12.39 |
| | December | | 17.45 | 16.56 | 14.77 | 12.08 | 12.08 |
| **2013** | January | | 17.02 | 16.14 | 14.40 | 11.78 | 11.78 |
| | February | 2.2% | 16.64 | 15.79 | 14.08 | 11.52 | 11.52 |
| | March | | 16.28 | 15.44 | 13.77 | 11.27 | 11.27 |
| | April | | 15.92 | 15.10 | 13.47 | 11.02 | 11.02 |
| | May | 1.8% | 15.63 | 14.83 | 13.23 | 10.82 | 10.82 |
| | June | | 15.35 | 14.56 | 12.99 | 10.63 | 10.63 |
| | July | | 15.07 | 14.30 | 12.75 | 10.44 | 10.44 |
| | August | 1.8% | 14.80 | 14.04 | 12.52 | 10.25 | 10.25 |
| | September | | 14.54 | 13.79 | 12.30 | 10.06 | 10.06 |
| | October | | 14.27 | 13.54 | 12.08 | 9.88 | 9.88 |
| | November | 1.4% | 14.07 | 13.35 | 11.91 | 9.74 | 9.74 |
| | December | | 13.88 | 13.17 | 11.74 | 9.61 | 9.61 |
| **2014** | January | | 13.68 | 12.98 | 11.58 | 9.47 | 9.47 |
| | February | 1.0% | 13.55 | 12.85 | 11.46 | 9.38 | 9.38 |
| | March | | 13.41 | 12.72 | 11.35 | 9.28 | 9.28 |
| | April | | 13.28 | 12.60 | 11.23 | 9.19 | 9.19 |
| | May | | 13.14 | 12.47 | 11.12 | 9.10 | 9.10 |
| | June | | 13.01 | 12.34 | 11.01 | 9.01 | 9.01 |

## 9.3 Renewable Portfolio Standards

Renewable Portfolio Standards try to avoid the pitfalls of FITs as they simply set a quantity target to be fulfilled by every company selling electricity to final customers. To enable the lowest cost to be realised in the market the tradable certificates for every kilowatt-hour of renewable electricity produced are given to the producers of renewable electricity. Sometimes differentiated for large and small installations like in the case of Australia, where Large-scale Generation Certificates (LGC) and Small-scale Generation Certificates (SGC) are traded as different commodities. As the certificates are standardised they can be traded freely in the market. Thus, the company selling electricity to final consumers can buy or produce any kind of electricity, it just needs to buy enough renewable energy certificates (or produce renewable electricity) to meet the set standard. On the other hand the producers of renewable electricity sell their electricity in the normal power market at the prevailing price of each hour. Theoretically, these mechanisms should lead to a situation in which the producers with the lowest costs will produce renewable electricity and the set quantity target will be reached at minimum cost. Nevertheless, RPS allocate the total producer surplus to the producers as they can not differentiate between good and not so good sites or between large and small installations. Figure 41 shows the basic principle of the function of an RPS and its impact on producer rents.

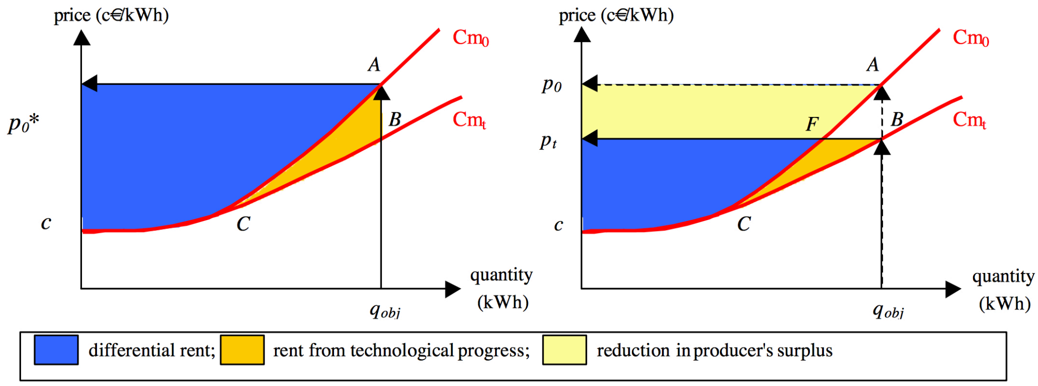
Figure 41: Operation of renewable portfolio standards and green certificates and the allocation of the producers rent (source: Lamy, no year, Graph 3)




In the case of technical progress cost reductions are easily captured by RPS, as the certificate prices is set by the market progress which has the information on eventual cost reductions due to technological progress. Figure 42 shows how the price adjustment follows the cost reduction and how the producer surplus in reduced.

Unfortunately, the theoretical consideration, asserting that RPS should produce lower cost solutions than FITs, misses out on the high risk that investors in technologies for power production from renewable energy sources are subject to. Different from the payments under an FIT system, which guarantee a discounted cash flow for twenty years, if a reliable technical system is installed, the investor (under RPS) does not know his future income neither from the sale of electricity in the power market nor from the sale of renewable energy certificates. As Figure 43 shows the price for renewable certificates (in this case LGCs

Figure 42: RPS/green certificates markets and the impact of technological progress on prices and producers rent (source: Lamy, no year, Graph 5)




in Australia) can fluctuate vastly. In the case of LGCs the monthly average price starting at about 31 AUSD fluctuated anywhere between 11 and 54 AUSD over the period of fifteen years. If the sales of certificates are combined with the electricity sales in power markets a similar picture remains as Figure 44 shows. Between 2003 and 2012 the average annual return in Australian dollars per Megwatt hour fluctuated between 60 and 120 AUSD/MWh. Even elections can have very significant impacts on the total revenues earned by a given renewable energy installation.

Figure 43: Price fluctuations of spot price for Large-scale Generation Certificates for renewable electricity in Australia between June 2001 and June 2015 (source: Parkinson, 2015)

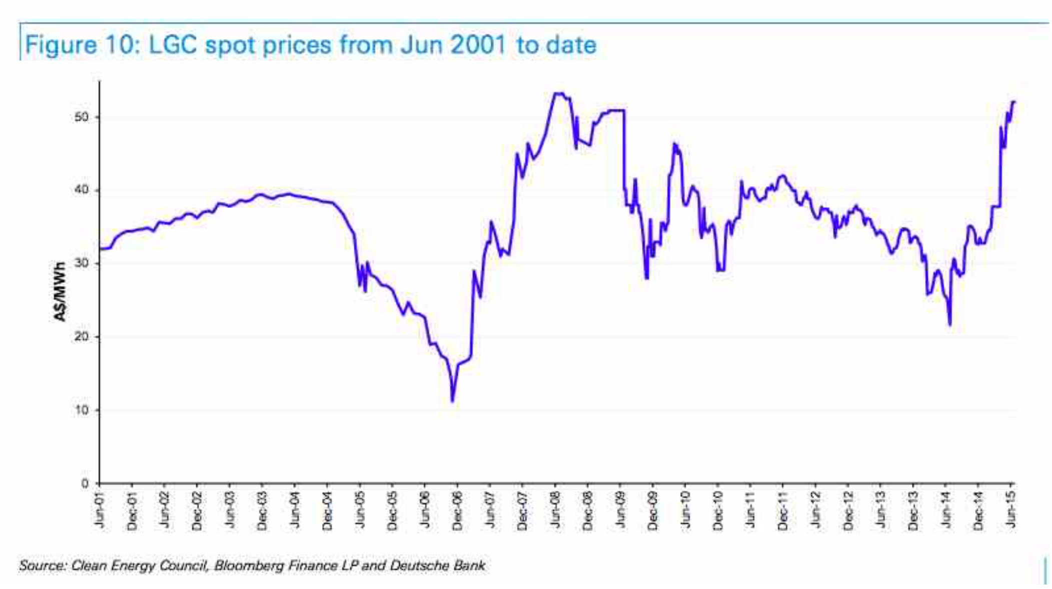
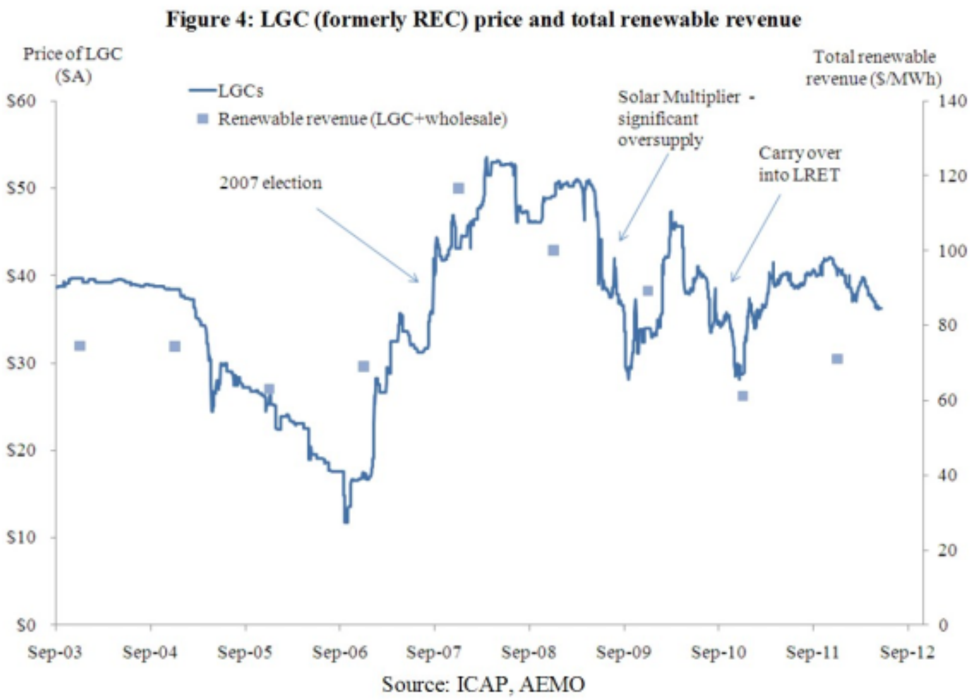


Figure 44: Price fluctuations of spot price for Large-scale Generation Certificates (LGC) and total revenue for renewable electricity including revenues from electricity sold a the spot market for renewable electricity in Australia from September 2003 to September 2012 (source: Morton 2017, Figure 4)



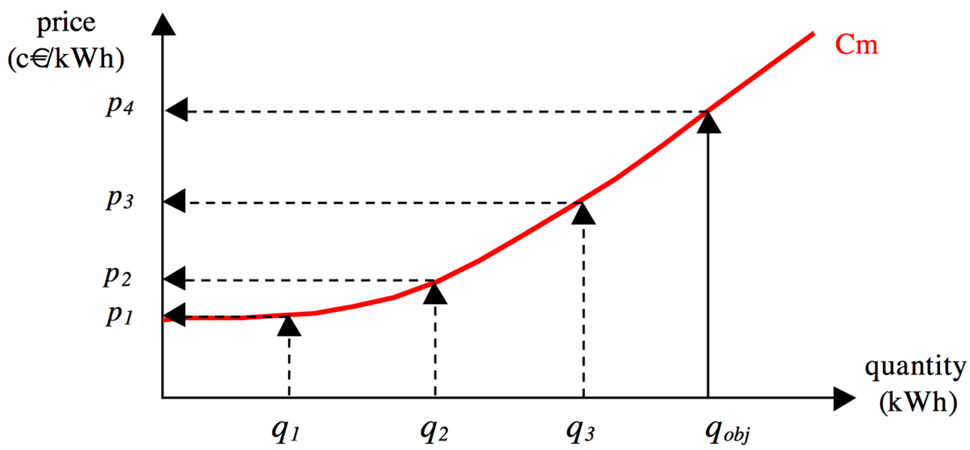

It is obvious that the income flow for a renewable energy investment can not be predicted with any sufficient degree of reliability. Thus, banks financing renewable energy investments under such regime will need to ask for a high risk margin in order to secure their loans. For the investor a renewable energy investment becomes highly speculative, thus, every investor will ask for a very high return to compensate him for the possible risk of bankruptcy. He is actually faced with the opposite situation of the investment under a guaranteed FIT regime. Reuter et al. (2012) show that risk perception can increase the levelized cost of electricity (LCOE) for the same wind site from 79 to 102 Euro/MWh, if uncertainty about future payments increases (Reuter et al. 2012, p.253). Although, the calculation is carried out for the risk perception of a set FIT to be changed in the future, this can be seen as a good indication for the impact of the uncertainty in the returns on green certificates. As Langniß (2003) has shown this structural property of RPS systems leads to a concentration of the renewable investments in the hands of large investors with a substantial capacity to absorb the risk of single investments and a strong enough capitalisation to reap the benefits of speculation gains. In a small island state like Barbados an RPS system would either lead to the concentration of all renewable energy investments in the hands of a few very large domestic investors or it would need to invite international investors to create a sufficiently wide investor basis. In any case an RPS system would lead to very high renewable power production costs, as these would need to absorb all necessary risk premiums. What is more, the market for renewable electricity certificates would certainly lack the necessary level of volatility with only a few sales being made and only one power company being obliged to adhere to the quantity targets set by the RPS policy.

It is fair to conclude that RPS systems are not suitable for any small isolated power market like in the case of most SIDS and especially in the case of Barbados.

## 9.4 AUCTIONING

Auctioning (called tendering or bidding as well) of renewable production capacities is trying to combine a lower risk about future payments for renewable electricity produced, similar to FITs, with a market mechanism to find the lowest possible rate necessary to be paid for a kilowatt-hour of renewable electricity. If there are enough bidders to create a highly competitive bidding process in the auction, auctioning should lead to lower renewable energy costs than FITs, as the bidders know their production cost structures better than any state agency could ever estimate such costs. There are two main types of actions, strike price auctions and pay-as bid auctions. In a strike price auction every successful bidder gets the price of the marginal bid reaching the auctioned quantity. In this case the producer rent is allocated like in the case of RPS with green certificates (see Figure 54 above). In a pay-as-bid auction every bidder receives the price for which he has been bidding. In this way the auction can actually pay exactly according to the underlying cost curve, if perfect competition can be realised. Figure 45 shows the prices payed as a result of a pay-as-bid auction.

Figure 45: Prices according to a pay-as-bid auction (source: Lamy, no year, Graph 2)

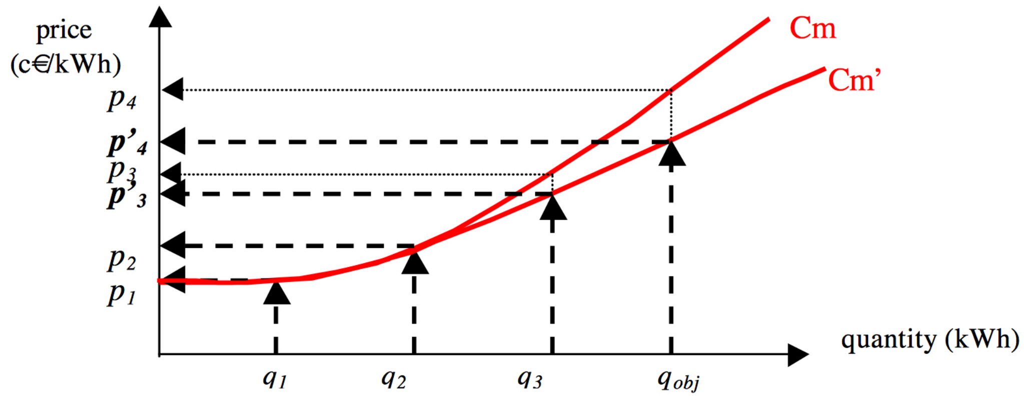



Auctioning can accommodate cost reductions due to technological learning as easily as RPS with green certificates, as the information on technological progress can be incorporated into the bids directly, as Figure 46 shows. Nevertheless, NFFO 4 and 5 have shown in the UK that this may turn out to be a trap for optimistic bidders under the circumstances of a substantial grace period until the capacity has to be installed (see below).

Furthermore, both forms of auctioning can lead to lower costs as compared to renewable portfolio standards (RPS), as auctioning can avoid the high risk premiums necessary for the economic survival of renewable energy projects under RPS (see above). In an auctioning system the rates, once granted after the auction, are fixed for a given time frame just like in an FIT system.

The first auctioning framework for renewables was created in 1989 in the United Kingdom as part of the NFFO (Non Fossil Fuel Obligation) system and it made up the core of the UK renewable energy policy for

Figure 46: Auctioning and the accommodation of cost reductions due to technological progress (source: Lamy, no year, Graph 6)




about ten years (see Agnolucci 2005, p.1). It was created as a side aspects of the attempt of the British government to privatise nuclear power plants, which proved not to be competitive to coal based power production in the liberalised UK power market (see Mitchell 2004, p.1936). Therefore, NFFO was designed to create an additional payment for new nuclear capacity, which in the times of power market liberalisation would not have been built. As Mitchell (2004, p.1936) reports, there was actually no policy target for the implementation on renewable energy sources at the time of the first round (NFFO 1), although this was set at 600 MW, when the NFFO contracts were announced. What is more, two thirds of the contracts were with renewable power plants already generating and the payments per kWh were agreed between the civil servants and the operators before these entered their bids (see Mitchell 2004, p.1936). Thus, NFFO 1 was not a real auction process. This changed with NFFO 2. The auction was geared towards new capacity and competition occurred to a limited degree (see Mitchell 2004, p.1936). But there was a major pitfall in the NFFO process, as this was originally designed to support nuclear energy. Due to this fact the whole scheme had to be sanctioned by the EU Commission, which allowed the support only to last until 1998. Thus, in the early rounds NFFO 1 and NFFO 2 the bidders were confronted with a very short time frame for the recovery of their investments. As Mitchell points out (Mitchell 2004, p.1936f) investors were rushing to the best sites in similar locations. This in turn lead to a well organise campaign against wind farms. The *‚creation of anxiety about the ‚wind rush‘ was wholly unnecessary and a direct result of NFFO contracts ending in 1998.. The anti-wind feelings engendered in 1990 and 1991 are still felt in some parts of the UK and is an important reason why onshore wind developments have been so slow*.‘ (Mitchell 2004, p.1937).

As the history of NFFO shows there are numerous pitfalls, which can be encountered in the design and execution of an auctioning system. At first it was unclear to the potential bidders for how long a period the payment would be guaranteed (see Mitchell 1995, p.1079), making it very difficult to calculate bids allowing to recover cost. Then, the payment period in NFFO 1 and 2 was extremely short, leading to an unnecessary rush for the best sites (see above). Furthermore, it was not clear when and how further rounds of auctioning would be performed after the first round was completed. Additionally, the differentiation of auctioned capacities between different renewable energy technologies only developed between the first and second round of auctioning (see Mitchell 1995, p.1082). The pitfalls of NFFO and the inherent structure of auction processes lead to the crowding out of smaller developers. Mitchell (1995, p. 1082) finds that *‚Small-scale projects and independent generators (whether individuals or communities) found it particularly hard to obtain contracts; the smaller scale projects because they were* *on the whole more expensive than the larger-scale projects and independent generators found it hard to obtain finance. .. In fact, not one project within NFFO2 was developed by an independent developer who did not have their own equity. All such projects initially developed by independent companies were forced to accept equity from companies (either the RECs (Regional Electricity Companies), generators or water companies or venture capitalists) at very high capital cost, ..'.* An other pitfall was the imposition of a total cost cap for the total enumerations payed under a NFFO bidding round combined with the lack of a penalty for companies which did not take up their contract (see Mitchell 2004, p.1937). As NFFO 3 to 5 allowed a 5 year grace period and the fact that planning permission did not have to be granted at the time of bidding, bidders speculated on the best sites and future cost reductions of the technology (see Mitchell 2005, p.1937). This structure lead to the situation that extremely low bids were entered, which later proved t be uneconomic and resulted in lower and lower completion rates of the contracts as Figure 47 shows. Only the use of land-fill-gas did not decline to a completion rate of 10% or lower in NFFO 5 pulling up the average completion rate of all NFFO projects substantially. The completion rate of wind energy dropped drastically from over 50% in NFFO 3 to below 5% in NFFO 4 and 5.

Figure 47: Project completion rates under NFFO in the UK (source: Mitchell 2004, p. 1938) (LFG: land-fill-gas, MIW: municipal and industrial waste combustion)

As can be seen in the example of wind energy, the NFFO auctioning process lead to very low costs on paper with 4.43 p/kWh in NFFO 3, 3.56 p/kWh in NFFO 4 and 2.88 p/kWh in NFFO 5. Unfortunately, these extremely low costs did virtually not support any real project, as can be seen in the completion rates for wind in NFFO 4 and 5 (see Figure 60).

Table 16 summaries the most important information on the different NFFO rounds. It shows quite clearly

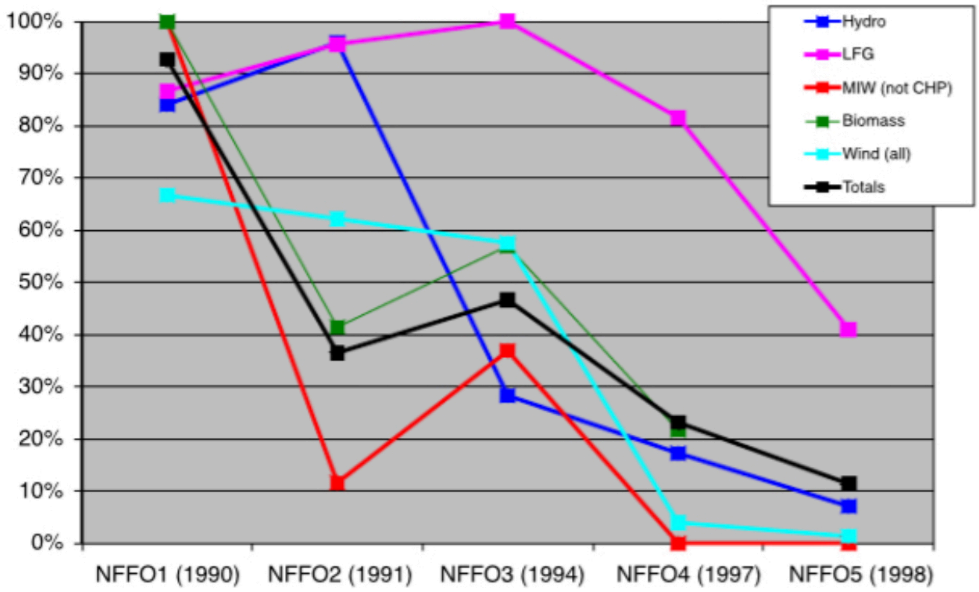


Fig. 1. Overall completion rates for NFFO contracts in 2003. Hartnell (2003).

how badly the auctioned quantities were missed. Even in NFFO 2 only 36% of the auctioned capacity was finally built, with the share of build capacity dropping to just 5% in NFFO 5. At the same time the preoccupation with the lowest possible cost for renewable energy sources led to a situation, where the UK fell far behind the developments in other European countries employing FIT systems as Table 17 below shows. While the installed German wind capacity rose from 68 MW in 1990 to 13,184 MW in 2003, the installed wind capacity in the UK rose from 10 MW in 1990 to just 588 MW in 2003. Lamy et al. (no year, p.9) point out that the three leading countries in Europe using FITs had installed 20 times the capacity of wind energy in 2000 as the European countries using competitive bidding schemes.

Table 16: Average price results (listed in GBP) for NFFO rounds (1 to 5) in UK (source: Wiser, 2002)

| | NFFO-1 | NFFO-2 | NFFO-3 | NFFO-4 | NFFO-5 |
|---|---|---|---|---|---|
| Period of guaranteed contract | 1990-1998 | 1991-1998 | 1994-2009 | 1997-2012 | 1998-2013 |
| Capacity of winning bids (MW, DNC) | 152 | 472 | 627 | 843 | 1 177 |
| Installed capacity (MW, DNC) | 145 | 172 | 293 | 156 | 55 |
| Average price (GBP/kWh) | 0.065 | 0.066 | 0.044 | 0.035 | 0.027 |
| Average price (USD2011/kWh) | 0.093 | 0.092 | 0.055 | 0.045 | 0.034 |

Table 17: The deployment of wind energy in Europe between 1990 and 2003 (source: Mitchell 2004, p. 1936)

Table 1
The deployment of wind energy in Europe (MW)

| | 1990 | End 1995 | End 1999 | End 2001 | End 2002 | Late 2003 |
|---|---|---|---|---|---|---|
| Germany | 68 | 1136 | 4445 | 8753 | 12001 | 13184 |
| Spain | 7.2 | 145 | 1530 | 3335 | 4830 | 5198 |
| Denmark | 343 | 619 | 1742 | 2556 | 2880 | 2927 |
| Italy | 2.9 | 25 | 211 | 697 | 785 | 800 |
| Netherlands | 49 | 236 | 410 | 483 | 688 | 829 |
| UK | 9.9 | 200 | 356 | 485 | 552 | 588 |
| Sweden | 8 | 67 | 220 | 280 | 325 | 364 |
| Greece | 1.8 | 28 | 87 | 272 | 276 | 354 |
| Portugal | 0.5 | 13 | 60 | 127 | 194 | 217 |
| France | 0.3 | 7 | 23 | 85 | 145 | 219 |

*Source*: WPM (1999, 2001, 2003).

Lamy et al. stress the point that competitive bidding schemes have left to little producers' surplus to the manufacturers of renewable energy technologies to invest in sufficient research and development necessary for the technology development. Although the UK government wanted to incentivise the formation of a national renewable energy industry, the bidding scheme did not facilitate such national industry formation. Virtually all contracts for wind energy were taken by projects based on Danish wind turbines (see Lamy et al. no year, p.6) and in the year 2000 eight of the ten biggest wind manufacturers in the world were located in Germany, Denmark and Spain, all three countries relying on FITs granting relatively high shares of producer surplus to the manufacturers (see Lamy et al. no year, p.6).

As Mitchell (2004, p.1937) has pointed out competitive bidding can lead to substantial problems with project acceptance. This point is underscored by Lamy et al. (see Lamy et al. no year, p.6) as well, who stress that FITs have an undeniable advantage with respect to the criteria ‚Stimulation of renewables', ‚Positive industrial impact' and ‚Project acceptability' (see Lamy et al. no year, p.6). Nevertheless, in the early years of renewable energy technology development this came at a substantial cost to electricity consumers, as the high uptake rates of renewable energy technologies, which were still considerably more expensive than conventional power generation had to be paid for. This holds although intelligent FIT systems were able to push down the costs and to limit the extent of producer surplus, as can be seen in the comparison of the US RPS and the German FIT systems (see Barbos and Wyser 2013).

It is fair to summarise that all systems have their advantages and disadvantages, which make it necessary to consider the specific policy goals and market structures of any given country to be able to design the best market structure and renewable energy policy framework to achieve the given goals as far as possible.

## 9.5 Small island experiences with different support mechanisms for the integration of renewable energy sources

Due to their system size and insularity small island power systems like in Barbados may have special circumstances impacting on the applicability of different support mechanisms for renewable energy sources just as they may have special circumstances for power market reform and liberalisation. As there are a number of island countries or isolated larger islands, which seem to have been quite successful in the adaptation of renewable energy sources for power generation, it is interesting to see whether there are any lessons to be learnt from these successful examples applicable to Barbados. Islands with major grid connections to a mainland don't qualify as useful examples, as they can use the grid of the mainland as back-up making it much easier to reach high shares of renewables. This condition, grid connection to the mainland, applies for example in the much discussed case of the Danish island Samsoe, which has virtually reached a 100% renewable power supply measured as the sum of all RE power produced throughout the year, but which is still heavily relying on imports and exports of electricity from and to the Danish mainland.

As mentioned above Kuang et al. (2016, p. 506) have identified a number of such examples of SIDS or large islands with high RE penetration. The island countries or isolated islands with the highest shares of RE power production according to Kuang et al. are Fiji with 59.3%, Reunion with 31.2%, Crete with 26%, and Cape Verde with 21% of renewable power production. A thorough literature review has revealed that Hawaii should be added to the list due to its relatively high share of renewable power production (25.8%) and due to the multitude of support mechanisms used. These five SIDS or isolated islands will be looked at in the following in some detail to find out whether there are lessons to be learnt for Barbados. In addition the Dominican Republic will be looked at as it is the only Caribbean country with feed-in tariffs legislated.

### 9.5.1 The case of Fiji

As compared to Barbados Fiji is relatively large in land mass with 18,274 km$^2$ divided into 322 islands. Nevertheless, the majority of its 909,000 inhabitants (about 600,000) live on the main island Viti Levu, which has more than half of Fiji's land mass (10,388km2). In a number of publications Fiji, reaching about 60% of renewable power, has been mentioned as a prime example for the successful introduction of high shares of renewable electricity production (e.g. Kuang et al. 2016). Fiji has set very ambitious renewable power targets of 81% for 2020 and 99% for 2030 (see Table 18 below). Thus, it should be expected that such a high penetration of renewable power reached already and such extremely ambitious policy goals are backed up by effective support mechanisms for the further market diffusion of renewable energy.

While Fiji has achieved 59.3% of renewable power production (see Kuang et al. 2016, p. 506), this is mostly due to a very high share of large hydropower, with hydropower producing about 55% of Fiji's electricity (see Table 19 below). As large hydropower has historically been pursued by incumbent utility companies, a high share of large hydropower production does not require a special renewable energy support policy. Prime examples for large hydropower development by large public utility companies can be found in Norway or Switzerland, where hydropower has developed over the last 100 years without any special renewable energy policy support mechanism. In the case of Norway almost 100% of the countries electricity is supplied by large hydropower installations (Norwegian Ministry of Petroleum and Energy 2016).

In Fiji the state owned Fiji Electrical Authority (FEA) has build up Fiji's power supply around large hydropower with the completion of the Monasavu hydropower scheme on the main island. In 1982 this single dam with a capacity of 83 MW was able to supply the entire electricity demand of the main island (Dorman and Jotzo 2011, no page number). This hydropower scheme was build with the help of the World Bank and other international donors (see Dorman and Jotzo 2011). With the expanding electricity demand the share of fossil fuel generation has grown again leading to attempts of the FEA to build more hydropower schemes resulting in a total installed hydropower capacity of 134 MW (see Table 20 below).

Table 18: Fiji's renewable energy targets 2015 to 2030 (Source: IRENA 2015, p. 20)

| Indicator | Baseline | Targets | | |
|---|---|---|---|---|
| | | 2015 | 2020 | 2030 |
| Access to modern energy services | | | | |
| Percentage of population with electricity access | 89%[a] (2007) | 90% | 100% | 100% |
| Percentage of population with primary reliance on wood fuels for cooking | 20%[b] (2004) | 18% | 12% | <1% |
| Improving energy efficiency[c] | | | | |
| Energy intensity (consumption of imported fuel per unit of GDP in megajoules (MJ)/FJD) | 28.9[d] (2011) | 2.89 (-0%) | 2.86 (-1%) | 2.73 (-5.5%) |
| Energy intensity (power consumption per unit of GDP in kWh/FJD) | 0.23[d] (2011) | 0.219 (-4.7%) | 0.215 (-6.5%) | 0.209 (-9.1%) |
| Share of renewable energy | | | | |
| Renewable energy share in electricity generation | 56%[e] (2011) | 67% | 81% | 99% |
| Renewable energy share in total energy consumption | 13%[f] (2011) | 15% | 18% | 25%[g] |

[a] Preliminary data from 2007 Census, Fiji Islands Bureau of Statistics 2012b
[b] 2002-2003 Household Income and Expenditure Survey, Fiji Islands Bureau of Statistics,(2004). Reliance on wood fuels alone for cooking.
[c] Based on 15% fuel substitution to local fuels and a 3% annual efficiency improvement.
[d] Fiji Islands Bureau of Statistics based on average 36 MJ per litre of fuel.
[e] Annual report 2011, FEA
[f] Based on total energy consumption of 16,500 terajoules (TJ) (Fiji Islands Bureau of Statistics, 2011) and 55% power generation from renewables (FEA).
[g] Based on 99% renewable power and 25,000 kL of biofuel.

Source: SE4ALL Rapid Assessment and Gap Analysis Report, 2014

Table 19: Installed capacities and electricity generation from renewable energy sources in Fiji in 2012 (Source: IRENA 2014, p. 16)

| | |
|---|---|
| Electricity Access in 2012 | 92 percent |
| Installed Capacity in 2012 | 263 megawatts |
| Renewable Capacity in 2012<br>• Hydro<br>• Wind<br>• Biomass | 164 megawatts (62% of all capacity)<br>• 129 megawatts (49%)<br>• 10 megawatts (4%)<br>• 25 megawatts (9%) |
| Electricity Generation in 2012 | 823 gigawatt-hours |
| Renewable Generation in 2012<br>• Hydro<br>• Wind<br>• Biomass | 493 gigawatt-hours (60% of generation)<br>• 452 gigawatt-hours (55%)<br>• 33 gigawatt-hours (4%)<br>• 8 gigawatt-hours (1%) |
| Electricity Tariff (residential) in 2012 | Subsidised: 8 U.S. cents per kilowatt-hour<br>Unsubsidised: 17 U.S. cents per kWh |

Table 20: Detailed installed generation capacity in Fiji by plant (Source: Source: IRENA 2015, p. 20)

| Location/site | Installed Capacity (MW) | Energy Source | Nameplate Output | Year of Commission |
|---|---|---|---|---|
| **Viti Levu Island** | | | | |
| Monasavu Wailoa | 83 | Hydro | 60% of the electricity in Viti Levu | 1983 |
| Nadarivatu | 42 | Hydro | 101 GWh[19] | 2012 |
| Wainikasou | 6.6 | Hydro | 18 GWh | 2004 |
| Nagado/Vaturu | 2.3 | Hydro | 10 GWh | 2006 |
| Buton | 10 | Wind | - | 2007 |
| Multi-locations | 72 (total) | Industrial Diesel Oil | - | |
| Kinoya | 20.6 | Heavy Fuel Oil | - | 2007 |
| **Vanua Levu Island** | | | | |
| Labasa | 13.5 | Industrial Diesel Oil | - | - |
| Savusavu | 5.2 | Industrial Diesel Oil | - | - |
| Wainiqeu | 0.8 | Micro-hydro | - | - |
| **Ovalau Island** | | | | |
| Levuka | 2.9 | Industrial Diesel Oil | Distribution network 11 kV and below | - |
| **Total Installed Generation Capacity** | | | | |
| **258.9 MW** | | | | |

Source: FEA Power Development Plan, FEA Presentation Energy Forum 2013

Figure 61 shows the expansion of Fiji's renewable energy capacities. Mainly hydropower and solid biomass combustion have grown, while wind has had a single expansion in 2007, when 10.2 MW of wind capacity were installed. PV has expanded from 0.2 MW in 2010 to 3.9 MW in 2016 contributing just about 1.1 GWh form 2.2 MW of PV in 2014 (no data on the PV production is available from the IRENA database for 2015 and 2016 at the moment). As Table 21 shows, the share of Fiji's renewable power production has varied widely over the years between 92% in 2002 and 56% in 2014 and the trend is a decline not an increase of the share of renewables in Fiji's power production due to increasing consumption and very limited additions of new renewable power capacities since 2012 when the last big hydropower plant was commissioned.

Figure 61: Installed RE capacities in Fiji in MW from 2000 to 2016 (Source: IRENA 2017) (Large hydro: dark blue, medium sized hydro: lighter blue, wind energy: light blue, PV: orange and solid biomass: dark green)

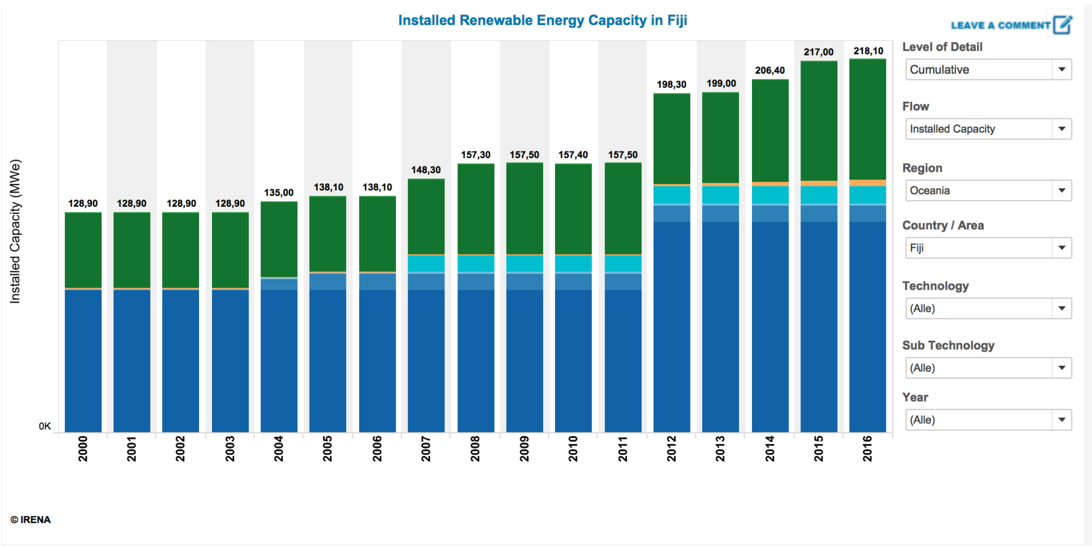



Figure 62: Installed wind (light blue) and PV (orange) capacities in Fiji in MW from 2000 to 2016 (Source: IRENA 2017)

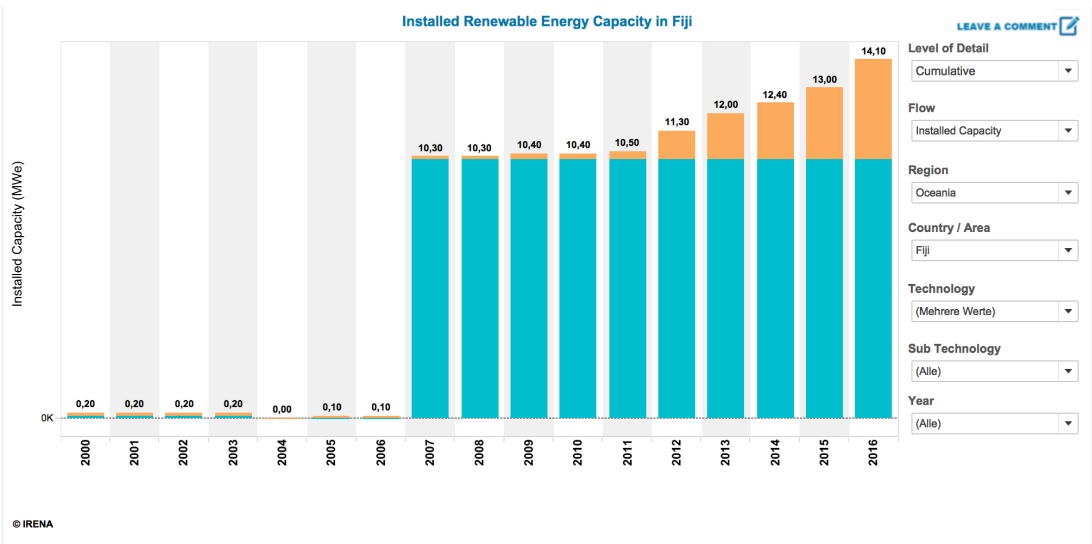


Table 21: Development of electricity production and capacities in Fiji from 2000 to 2016 (data sources: IRENA 2017 and US EIA 2017)

| Fiji | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation capacity in MW | 200 | 200 | 200 | 200 | 200 | 260 | 260 | 280 | 291 | 291 | 291 | 291 | 305 | 306 | 321 | | |
| Total RE capacity in MW | 83.26 | 83.06 | 83.06 | 83.06 | 84.06 | 140 | 140 | 160 | 171 | 171 | 171 | 171 | 185 | 186 | 201 | | |
| Wind | 0.1 | 0.1 | 0.1 | 0.1 | 0 | 0 | 0 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 | 10.2 |
| PV | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.3 | 1.1 | 1.8 | 2.2 | 2.8 | 3.9 |
| Solid Biomass | 44.5 | 44.5 | 44.5 | 44.5 | 44.3 | 44.3 | 44.3 | 44.3 | 53.3 | 53.3 | 53.3 | 53.3 | 53.3 | 53.3 | 60.3 | 70.3 | 70.3 |
| Hydropower, large | 83.2 | 83.2 | 83.2 | 83.2 | 83.2 | 83.2 | 83.2 | 83.2 | 83.2 | 83.2 | 83.2 | 83.2 | 123.2 | 123.2 | 123.2 | 123.2 | 123.2 |
| Hydropower, medium size | 6.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 | 9.5 |
| Hydropower, small size | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.1 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 |
| | | | | | | | | | | | | | | | | | |
| Total electricity production in GWh/a | 600 | 600 | 600 | 600 | 700 | 705.1 | 756.1 | 794.1 | 785.1 | 790.1 | 835.1 | 801.1 | 803 | 857 | 859 | | |
| Share of RE | 84.7 % | 90.6 % | 92.9 % | 73.0 % | 67.4 % | 62.6 % | 60.0 % | 75.2 % | 75.0 % | 68.2 % | 58.3 % | 66.8 % | 74.0 % | 69.0 % | 56.0 % | | |
| Share of non hydro RE | 15.6 % | 13.4 % | 17.9 % | 15.7 % | 14.9 % | 14.5 % | 14.9 % | 11.1 % | 11.9 % | 10.0 % | 8.8 % | 9.9 % | 8.5 % | 7.5 % | 9.4 % | | |
| Share of non hydro and non large biomass RE | 0.0 % | 0.0 % | 0.0 % | 0.0 % | 0.0 % | 0.0 % | 0.0 % | 0.5 % | 0.6 % | 0.9 % | 0.8 % | 0.7 % | 0.9 % | 0.7 % | 0.6 % | | |
| Total RE electricity production in GWh/a | 508 | 543.5 | 557.3 | 438.1 | 471.7 | 441.1 | 453.6 | 596.8 | 588.5 | 539.1 | 487.2 | 535.5 | 593.9 | 591.7 | 481.4 | | |
| Non hydro RE production in GWh/a | 93.6 | 80.6 | 107.1 | 94.3 | 104.3 | 102.3 | 112.3 | 88.3 | 93.4 | 78.9 | 73.5 | 79 | 68.6 | 64.3 | 80.4 | | |
| Non hydro and non large biomass RE | 0.2 | 0.2 | 0.2 | 0.2 | 0 | 0.1 | 0.1 | 3.6 | 4.8 | 7.5 | 6.7 | 5.5 | 7.5 | 6.2 | 5.4 | | |
| Wind | 0.1 | 0.1 | 0.1 | 0.1 | 0 | 0 | 0 | 3.4 | 4.6 | 7.2 | 6.4 | 5 | 6.8 | 5.3 | 4.3 | | |
| PV | 0.1 | 0.1 | 0.1 | 0.1 | 0 | 0.1 | 0.1 | 0.2 | 0.2 | 0.3 | 0.3 | 0.5 | 0.7 | 0.9 | 1.1 | | |
| Solid Biomass | 93.4 | 80.4 | 106.9 | 94.1 | 104.3 | 102.2 | 112.2 | 84.7 | 88.6 | 71.4 | 66.8 | 73.5 | 61.1 | 58.1 | 75 | | |
| Hydropower, large | 412.1 | 460.6 | 448.3 | 343.7 | 357.3 | 322.5 | 315.6 | 481.1 | 463 | 436.1 | 383 | 424.8 | 496.7 | 518.8 | 381.9 | | |
| Hydropower, medium size | 0 | 0 | 0 | 0 | 8.9 | 15.2 | 24.4 | 26 | 31.4 | 24 | 29.8 | 29.7 | 27.6 | 6.5 | 18.1 | | |
| Hydropower, small size | 2.3 | 2.3 | 1.9 | 0.1 | 1.2 | 1.1 | 1.3 | 1.4 | 0.7 | 0.1 | 0.9 | 2 | 1 | 2.1 | 1 | | |

In spite of its ambitious policy targets Fiji has virtually no support mechanisms like net metering, feed-in tariffs, auctions or renewable portfolio standards. The only exemption from this is a minimum feed-in tariff for independent power producers, which was established by the Fiji Commerce Commission in 2010 (see Dornan 2014, p. 707) but this was generally deemed to be too low to attract private investment. In 2014 this minimum tariff was increased from 0.2565 FJD/kWh to 0.3308 FJD/kWh (IRENA 2015, p.26). As the future development of this minimum tariff is not clear, it is considered to be a major obstacle to IPP investment in renewable energy sources in Fiji (IRENA 2015, p. 33).

In general the shaping of Fiji's energy policy since 1996 has been subject to numerous changes in government with a first government (SVT) trying to commercialise FEA in 1998. This was stopped by the following government (FLP) in 1999 reversing the process. The FLP government was overthrown by a coup in 2000. A newly appointed government (SDL) won the next elections and pursued some moderate reforms of the FEA, but did not go back to privatisation. This government was overthrown again in 2006 by the military, which remained in power until 2014 not pursuing major reforms of the energy sector (see Dorman 2011, p.706). In this general political situation the main influence on the actual development seemed to have remained with the Fiji Electricity Authority (FEA) operating as an integrated monopoly in the electricity market.

Thus, although Fiji has set very ambitious goals for the share of renewable electricity there seems to be only one lesson to be learned from this example, which is that a continued lack of support mechanisms for private investment in renewable energy technologies will most likely lead Fiji not to achieve the set targets unless all of the development will be done by FEA.

### 9.5.2 The case of Reunion

Although Reunion is an island in the southern hemisphere, it actually belongs to France and comes under French legislation and energy policy. Being part of the European Union EU rules apply, which have a strong impact on the present transition from a feed-in tariff system to a tendering mechanism.

Reunion presently has a population of 830,000 with a projected growth to about 1 million by 2030 (see Go 100% renewable energy, 2017). In 2008 electricity consumption was about 2,500 GWh (see Go 100% renewable energy, 2017). Thus, the electricity system has roughly three times the size of Barbados with a very similar per capita electricity consumption. In 2000 the share of renewable power production was about 43.2% (see Table 22), while all other power production was based on imported fossil fuels. The bulk of the renewable power production came from large hydropower plants producing 512 GWh in 2000, while medium sized hydropower plants produced 48.3 GWh and two bagasse power plants produced 261 GWh (see Table 22). In 2000 there was no electricity production from wind or solar energy, small hydropower plants or biogas (source: IRENA 2017 and US Energy Information Administration 2017).

As Figure 64 shows the electricity production from renewable energy sources has exclusively been based on hydropower (dark blue) and solid biomass combustion (dark green) until 2004. Even in 2014 hydropower and solid biomass supplied more than two thirds of Reunion's renewable power. The installation of first wind turbines started in 2004 and PV was first installed in 2005. Wind energy was built up to its present level of 14.8 MW in the years 2005 to 2007. PV expanded very fast after a slow introductory phase until 2008. The installed PV capacity increased from 10 MW in 2008 to 180.4 MW in 2015 reaching about 18.5% of the total installed generation capacity of 980 MW. It looks like the fast expansion came to a halt in 2016, when only 0.6 MW were added (all data excerpted from IRENA 2017). Despite the fast expansion of PV until 2016 the share of renewable electricity in Reunion has decreased from 43.2% in the year 2000 to just 35.5% in 2014 due to the strong growth in electricity demand from 1,900 to 2,650 GWh/a in 2014. At the same time the share of non hydro and non solid biomass based renewable power production has increased from 0 to 10% of the total electricity production of Reunion.

Figure 64: Electricity generated from renewable energy sources in Reunion in GWh/a in the years 2000 to 2014 (Source: IRENA 2017)

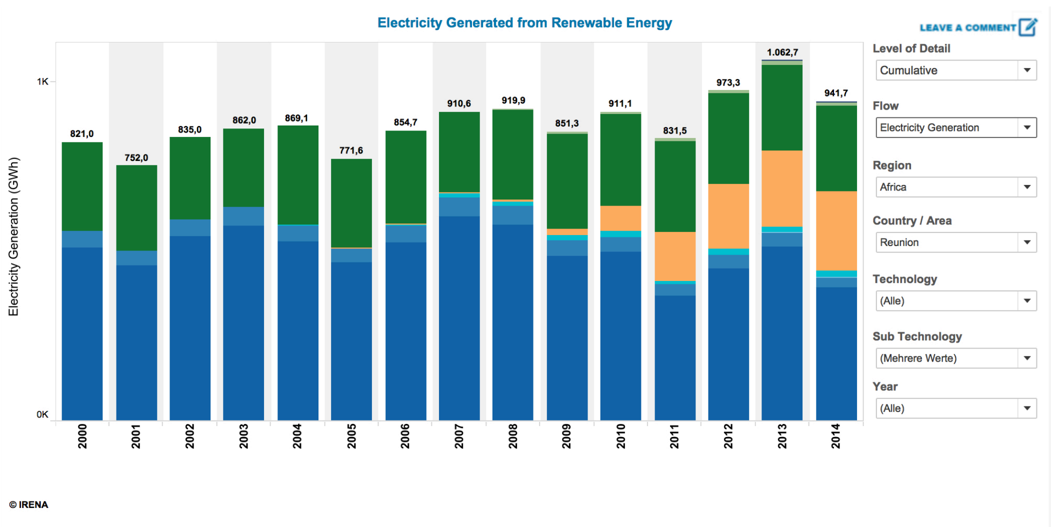


Figure 65: Installe RE capacities in MW in Reunion since 2000 (Source: IRENA 2017)

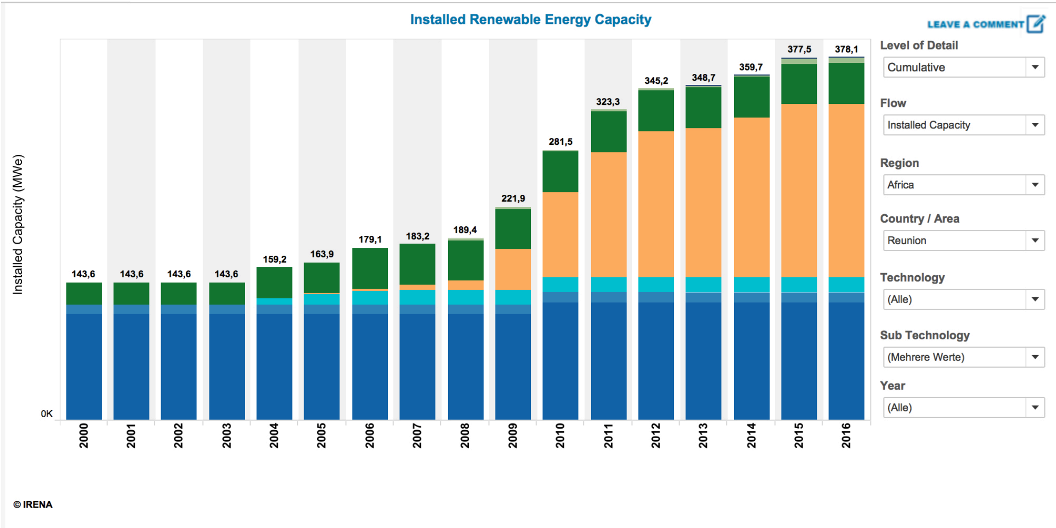



Table 22: Development of electricity production and capacities in Reunion from 2000 to 2016 (data sources: IRENA 2017 and US EIA 2017)

| Reunion | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation capacity in MW | 500 | 500 | 500 | 500 | 500 | 578 | 608 | 660 | 665 | 734 | 780 | 828 | 949 | 969 | 980 | | |
| Total RE capacity in MW | 143.6 | 143.6 | 143.6 | 143.6 | 159.2 | 163.9 | 179.1 | 183.2 | 189.4 | 221.9 | 281.5 | 323.3 | 345.2 | 348.7 | 359.7 | 377.5 | 378.1 |
| Wind | 0 | 0 | 0 | 0 | 6.6 | 10.5 | 13.5 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 | 14.8 |
| PV | | | | | | 0.8 | 3.0 | 5.8 | 10 | 42.5 | 89.3 | 131.1 | 153.0 | 156.0 | 167.0 | 180.4 | 181.0 |
| Solid Biomass | 23.0 | 23.0 | 23.0 | 23.0 | 32.0 | 32.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 | 42.0 |
| Biogas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 6.4 | 6.4 |
| Hydropower, large | 110.2 | 110.2 | 110.2 | 110.2 | 110.2 | 110.2 | 110.2 | 110.2 | 110.2 | 110.2 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 | 123.0 |
| Hydropower, medium size | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 | 10.4 |
| Hydropower, small size | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.2 | 0.2 | 0.2 | 0.2 |
| | | | | | | | | | | | | | | | | | |
| Total electricity production in GWh/a | 1900 | 2000 | 2000 | 2100 | 2300 | 2438 | 2461 | 2548 | 2425 | 2484 | 2507 | 2649 | 2620 | 2535 | 2650 | | |
| Share of RE | 43.2 % | 37.6 % | 41.8 % | 41.0 % | 37.8 % | 31.6 % | 34.7 % | 35.7 % | 37.9 % | 34.3 % | 36.3 % | 31.4 % | 37.1 % | 41.9 % | 35.5 % | | |
| Share of non hydro RE | 13.7 % | 12.6 % | 12.1 % | 11.0 % | 12.7 % | 10.7 % | 11.3 % | 9.9 % | 11.9 % | 12.9 % | 14.7 % | 16.2 % | 18.5 % | 19.9 % | 19.5 % | | |
| Share of non hydro and non large biomass RE | 0.0 % | 0.0 % | 0.0 % | 0.0 % | 0.0 % | 0.0 % | 0.2 % | 0.6 % | 1.0 % | 1.7 % | 4.0 % | 6.0 % | 8.3 % | 10.0 % | 10.0 % | | |
| Total RE electricity production in GWh/a | 821.0 | 752.0 | 835.0 | 862.0 | 869.1 | 771.6 | 854.7 | 910.6 | 919.9 | 851.3 | 911.1 | 831.5 | 973.3 | 1062.7 | 941.7 | | |
| Non hydro RE production in GWh/a | 261.0 | 252.0 | 241.0 | 232.0 | 292.1 | 261.6 | 278.7 | 252.6 | 287.9 | 320.3 | 369.6 | 429.8 | 485.3 | 505.6 | 515.9 | | |
| Non hydro and non large biomass RE | 0 | 0 | 0 | 0 | 0.1 | 0.6 | 5.7 | 14.6 | 24.9 | 42.8 | 100.6 | 159.9 | 218.2 | 254.2 | 264.7 | | |
| Wind | 0 | 0 | 0 | 0 | 0.1 | 0.3 | 4.3 | 11.8 | 15.0 | 15.5 | 16.9 | 11.7 | 18.2 | 15.1 | 15.7 | | |
| PV | 0 | 0 | 0 | 0 | 0 | 0.3 | 1.4 | 2.8 | 4.8 | 20.5 | 76.1 | 141.8 | 190.4 | 224.2 | 235.9 | | |
| Solid Biomass | 261.0 | 252.0 | 241.0 | 232.0 | 292.0 | 261.0 | 273.0 | 238.0 | 263.0 | 277.5 | 269.0 | 269.9 | 267.1 | 251.4 | 251.2 | | |
| Biogas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5.1 | 6.8 | 7.6 | 6.4 | 9.6 | 14.9 | 13.1 | | |
| Hydropower, large | 511.7 | 456.9 | 542.8 | 575.7 | 527.2 | 466.0 | 526.3 | 601.3 | 577.5 | 485.2 | 499.3 | 370.4 | 450.0 | 512.8 | 392.0 | | |
| Hydropower, medium size | 48.3 | 43.1 | 51.2 | 54.3 | 49.8 | 44.0 | 49.7 | 56.7 | 54.0 | 45.8 | 42.2 | 31.3 | 38.0 | 43.4 | 33.1 | | |
| Hydropower, small size | | | | | | | | | | | | | | 0.8 | 0.6 | | |

France has experimented with feed-in tariffs since 2001, when a first set of FITs was set, which were deemed not appropriate to induce much new renewable energy investment (see Lesieur, no year). In 2005 a new law introducing improved FITs was enacted and the FITs were reviewed on a two year basis. In 2006 FITs have been set according to the new law. In March 2011 the feed-in tariff system was adjusted for PV. For installations up to 100 kWp the feed in tariff was adjusted every trimester on the basis of a defined quarterly cap (50MW/quarter for residential and 200 MW/quarter for non-residential installations (for France). Tariffs were dropped by 2.6%/quarter when the cap was reached. If the cap was not reached the reduction was lower. For installations larger than 100 kWp and for all ground mounted installations a tendering procedure was introduced. By July 2016 building-integrated PV installations no larger than 9 kWp were entitled to an FIT rate of 0.246 EUR/kWh, systems no larger than 36 kWp received 0.133 EUR/kWp and plants between 36 and 100 kWp received 0.126 EUR/kWh (source IEA 2016). The tariffs guaranteed up to 2016 are given in Table 15d below.

Table 15d: French feed-in tariffs applicable in Reunion until 2015 (source: AGORA 2015, p.28)

Feed-in Tariff Levels for Selected Renewable Technologies — Table 6

| Technology | Orders governing the purchase of electricity | Duration of contracts | Sample tariffs for installations commissioned on the date that FiT order was issued |
|---|---|---|---|
| **Hydro** | 1 March 2007 | 20 years | **6.07 c€/kWh** + bonus **between 0.5 and 2.5** for small installations + premium between **0 and 1.68 c€/kWh** in winter depending on level of production<br>**15 c€/kWh** for offshore hydropower (wave, tidal, and hydrokinetic) |
| **Geothermal** | 23 July 2010 | 15 years | **Mainland France: 20 c€/kWh** + premium for energy efficiency of between **0 and 8 c€/kWh**<br>**Overseas France (DOM): 13 c€/kWh** + premium for energy efficiency between **0 and 3 c€/kWh** |
| **Wind** | 17 June 2014 | 15 years (onshore)<br>20 years (offshore) | **Onshore: 8.2 c€/kWh** for 10 years, then between **2.8 and 8.2 c€/kWh** for 5 years depending on site<br>**Offshore: 13 c€/kWh** for 10 years, then between **3 and 13 c€/kWh** for 10 years depending on site |
| **Solar** | 4 March 2011, amended 7 Jan. 2013 | 20 years | Tariff rates for solar power are set quarterly, based on the number of projects submitted over the previous quarter and compared to annual targets*. Tariffs are set for facilities under 100 kW, and tenders issued for facilities above 100 kW**. The FiT for the last quarter of 2014 are the following :<br>- Rooftop PV, 0-9kW: **26.96 c€/kWh**<br>- Simplified rooftop PV, 0-36 kW: **13.75 c€/kWh**<br>- Simplified rooftop PV, 36-100 kW: between **13.05 c€/kWh**<br>- All types of ground-mounted installations (from 0 to 12 MW): **6,80 c€/kWh** |

Ministère de l'Écologie, du Développement durable et de l'Énergie, 2013.; * As of the 7 January 2013, amendments to the FiT, the total annual target for solar power is 1000 MW for the next several years. This doubles the previous target. It is divided into targets for various sizes of rooftop and ground-based solar PV [Ministère de l'Écologie, du Développement durable et de l'Énergie, 2013a.]., ** Ministère de l'Écologie, du Développement durable et de l'Énergie, 2013b.

Due to the general shift of the EU renewable energy policy towards mandated tendering, feed-in tariffs have only survived for smaller installations and technologies in their early stages of development. As the latest changes in the support mechanism have had no direct impact on the past installations of renewable energy technologies in Reunion they will not be treated in detail here.

Figure 65 above shows that the feed-in tariffs granted in France have lead to a substantial expansion of solar PV installations in Reunion between 2006 and 2016. In 2009 a critical threshold seems to be have reached by the FIT rates granted spurring a fast development of PV installations in Reunion. The installation numbers of 2016 seem to reflect a situation were the automatic tariff reduction has dried out further market penetration. In the case of wind energy two wind farms of 8.4 and 6.3 MW have been built from 2004 to 2006. The exposition of Reunion to frequent cyclones with wind speeds of more than 200 km/h have lead to a rather slow development of wind energy based on smaller turbines (275 kW each), which can be taken down in a cyclone. Nevertheless, some of the machines have been damage in cyclones while on the ground (see Praene et al. 2012, p. 431). Praene et al. (2012, p. 431) argue that the best possible use of the remaining limited wind energy potential will require the use of larger turbines build for cyclone conditions to make better use of the rather limited potential.

Praene et al. (2012, p. 439) point out that in the island context transport cost and local taxes can increase investment costs for renewables by up to 30%, which presents a major disadvantage when the national FIT rates for France are applied to Reunion. Thus, although the French renewable energy policy has helped to boost the expansion of PV on Reunion it simultaneously has put investors in Reunion, faced with higher investment costs, at a systematic disadvantage as compared to investors in the mainland of France with the same FIT rates being applied. It has to be mentioned though, that the solar irradiance in Reunion is most likely substantially higher than in most parts of France, offsetting this disadvantage at least partially.

In 2012 Praene et al. (p. 439) were already foreseeing difficulties for a sustained market penetration of PV due to the drastic reductions in FIT rates and market size limitations introduced by the French government in 2011. Nevertheless, it took until 2016 that the reductions in FIT rates outpaced the cost reductions for PV systems to bring the market diffusion of PV in Reunion to a halt.

The lesson, which can be learnt from Reunion is that a well administered and reliable FIT system with long term guaranteed FIT rates for PV systems, once installed, can induce a very strong market diffusion of PV systems and that a reduction of the tariff level below the threshold of economic viability can reduce market diffusion almost instantaneously. As no net metering was applied in France the FIT tariffs for small solar installations have the same effect as net billing with full buy-back at the guaranteed FIT rate. As there are no statistics available on the different size ranges of PV systems installed in Reunion it can not be judged how successful this part of the policy has been.

A general policy lesson which was derived by Praene et al. (2012, p. 440) was that the lack of high quality information on support measures hampered the development of renewable energy sources in Reunion, just as a lack of coordination between authorities has lead to long administrative procedures. Furthermore the lack of competent technical and administrative support for projects has lead to delays in processing projects (see Praene et al. 2012, p. 440).

### 9.5.3 The case of Crete

Crete is the largest non grid connected island of Greece. It has a size of 8336 km$^2$ and is inhabited by approximately 650,000 inhabitants (Executive Agency for Competitiveness and Innovation, no year, p.23). The total electricity demand is 3,000 GWh/a, which is supplied by about 600 MW of conventional power plants mostly based on diesel, about 200 MW of wind energy, about 78 MW of PV and some 5 MW of biomass and small hydropower systems with about 1.25 MW (see Antoniakis 2005, p. 24 and Greek TSO 2017). Unfortunately, energy data specific to Crete are very rare, as most information on the Greek electricity system is reported at the national level. Although, there are special reports on the non grid connected Greek islands by the new Greek transmission system operator, these reports have only been published since August 2012. The circumstance that these reports are in Greek language makes the bulk of the information rather inaccessible to non native speakers, as it is the case with many recent publications on the Greek regulatory system and its details.

As Crete is part of Greece, which again is part of the European Union, the regulations of the power sector in Crete are controlled by the Greek legislation pertaining to the power sector. In some respects, like the transition from feed-in tariffs to tendering, the Greek legislation has to follow the EU policy framework, just like we have seen this in the case of Reunion, following the French legislation, which in turn has to apply the EU rules.

Different from Reunion there are no separate data sets on Crete in the IRENA renewable energy database. All available information is aggregated on the national level of Greece. As the national renewable energy legislation applies, the trends in the market diffusion of renewable energy sources relying on support mechanisms like wind and PV, should be similar for Crete as for Greece as a whole. Thus, a first look is taken at the development of renewable energy sources in Greece since the year 2000, while the scant available information for Crete is used in a second step to see in how far the market diffusion of renewable energy sources has differed in Crete from the Greek mainland. As only wind energy and PV play a significant role in Crete, the other renewable energy sources playing a role in Greece, like large hydropower, are not treated explicitly.

Greece has a very old tradition in using wind energy. Based on a generally positive attitude of the population towards the usefulness of wind energy, modern wind energy started to develop as early as 1991, but it only took off in 1999 when the installed capacity more than doubled from 40 to more than 100 MW in just one year (Figure 66). Since 2000 wind energy has grown almost continuously until 2016 (see Figure 67) from about 200 MW to almost 2,400 MW in an electricity system with about 19,000 MW total installed capacity (see Table 22). By 2014 renewable energy sources contributed about 25% to the Greek electricity production. Non hydropower renewables contributed about 16%, while wind energy as well as PV contributed 8% each to the Greek electricity production. Thus, the renewable energy contribution to the Greek power production was about equally shared between wind, PV and hydropower in 2014.

Compared to wind energy PV developed very late in Greece experiencing a very fast development between 2009 and 2013 (see Table 22 and Figure 68). The years of fast PV expansion coincide with the international cost trends. As shown above (see Figure 15) the costs of PV systems decreased from more than 4000 EUR/kWp in the fourth quarter of 2008 to below 1500 EUR/kWp in the lead market Germany. As in the case of Germany the existing feed-in tariffs opened up highly profitable investment opportunities for PV in these years, as the FIT adjustments could not quite keep pace with the fast decline in prices. In 2014 the FIT level was obviously reduced so much that only minor investments were realised after 2013 (19 MW in 2014, 8 MW in 2015 and 7 MW in 2016) after 1,043 MW in 2013.

Figure 66: Early development of wind energy in Greece between 1990 and 2004 (source: Antoniakis 2005, p. 17)

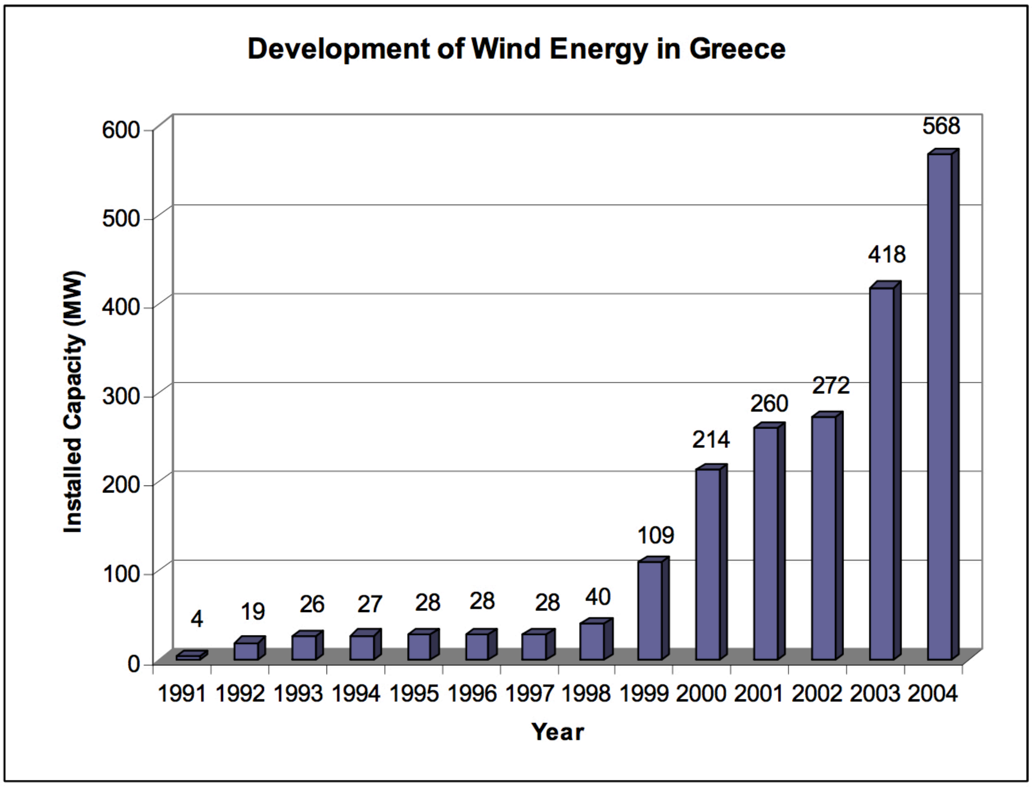



Figure 67: Development of installed wind energy capacity in Greece from 2000 to 2016 (data source: IRENA 2017)

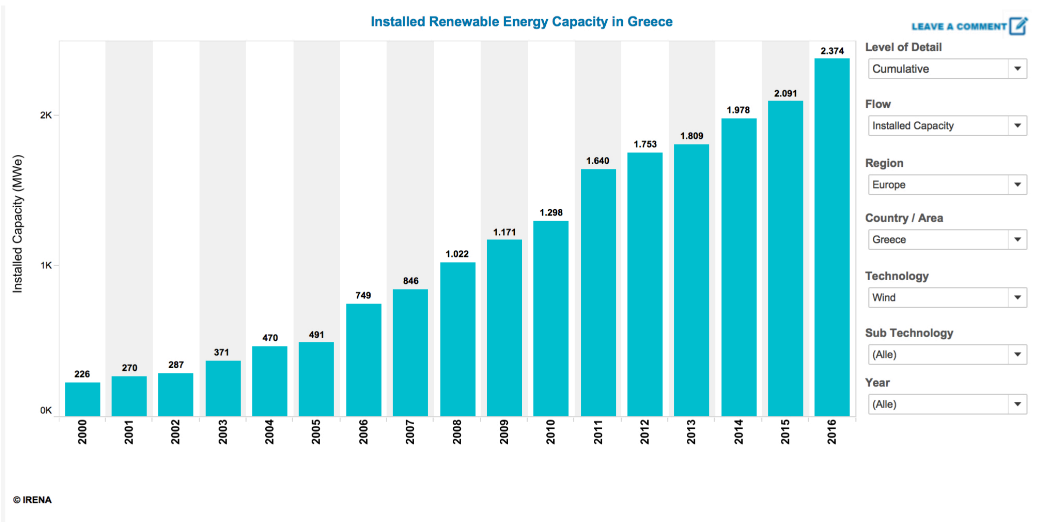
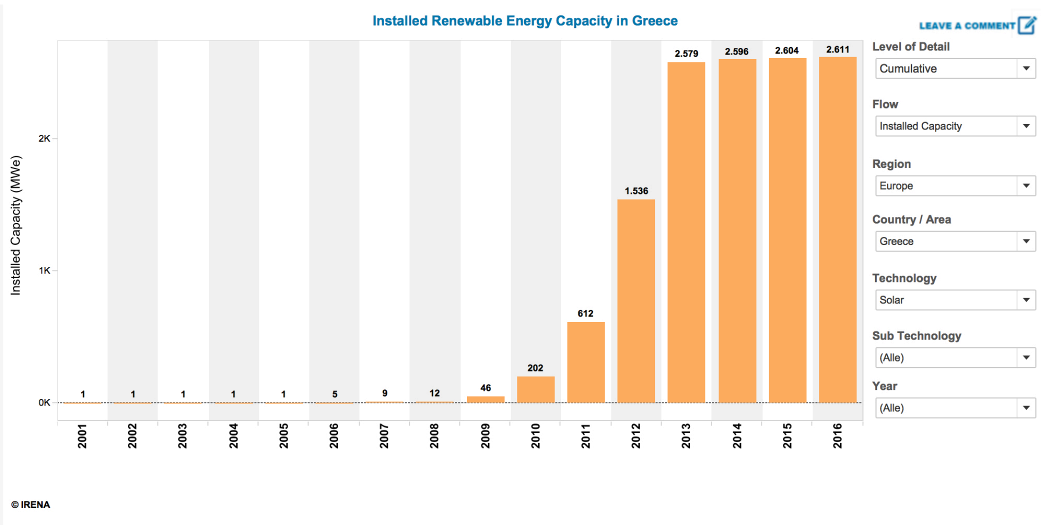


Table 22: Development of electricity production and capacities in Greece from 2000 to 2016 (data sources: IRENA 2017 and US EIA 2017)

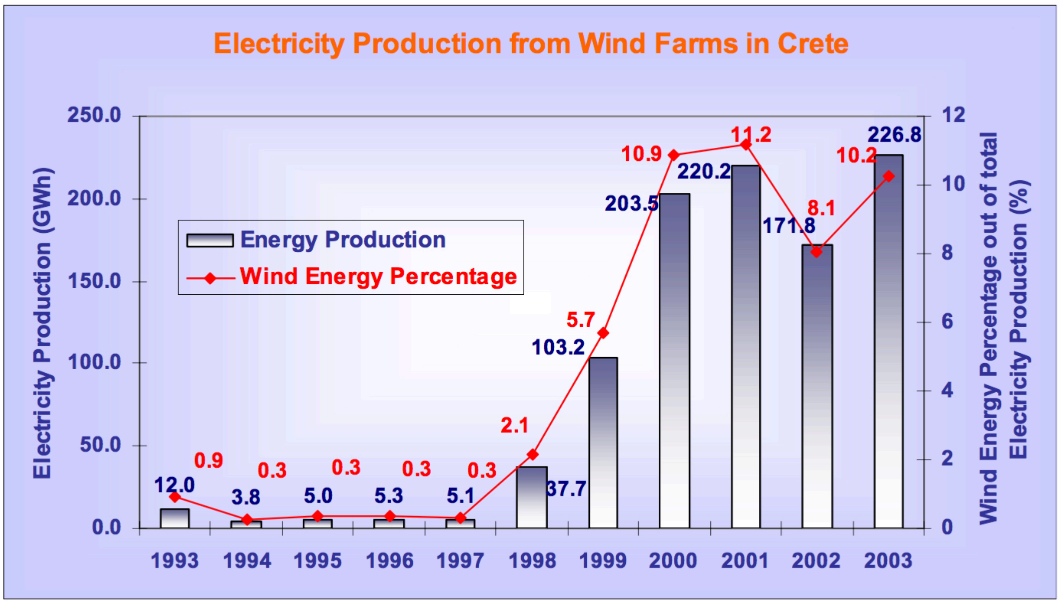
| Greece | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation capacity in MW | 11,000 | 11,000 | 12,000 | 12,000 | 12,000 | 13,306 | 13,570 | 13,686 | 14,253 | 14,499 | 15,184 | 16,524 | 17,751 | 18,855 | 18,895 | | |
| Total RE capacity in MW | 2601 | 2670 | 2689 | 2780 | 2894 | 2922 | 3211 | 3343 | 3549 | 3757 | 4055 | 4820 | 5869 | 6971 | 7311 | 7437 | 7728 |
| Wind | 226 | 270 | 287 | 371 | 470 | 491 | 749 | 846 | 1022 | 1171 | 1298 | 1640 | 1753 | 1809 | 1978 | 2091 | 2374 |
| PV | 1 | 1 | 1 | 1 | 1 | 1 | 5 | 9 | 12 | 46 | 202 | 612 | 1536 | 2579 | 2596 | 2604 | 2611 |
| Biogas | 1 | 22 | 22 | 22 | 24 | 24 | 24 | 39 | 40 | 40 | 41 | 45 | 45 | 46 | 47 | 49 | 50 |
| Hydropower, large | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2317 | 2470 | 2470 | 2470 |
| Hydropower, medium | 42 | 45 | 45 | 50 | 59 | 63 | 95 | 95 | 114 | 151 | 163 | 172 | 184 | 187 | 185 | 188 | 188 |
| Hydropower, small | 14 | 15 | 17 | 19 | 23 | 26 | 21 | 37 | 44 | 32 | 34 | 34 | 34 | 33 | 35 | 35 | 35 |
| | | | | | | | | | | | | | | | | | |
| Total electricity production in GWh/a | 50,000 | 50,000 | 51,000 | 55,000 | 55,000 | 55,966 | 56,673 | 58,835 | 59,049 | 57,708 | 54,478 | 55,961 | 57,612 | 54,475 | 47,957 | | |
| Share of RE | 8.3 % | 5.9 % | 7.0 % | 10.7 % | 10.8 % | 11.4 % | 13.5 % | 7.8 % | 9.7 % | 14.2 % | 19.3 % | 14.6 % | 17.6 % | 26.3 % | 25.4 % | | |
| Share of non hydro RE | 0.9 % | 1.7 % | 1.5 % | 2.0 % | 2.3 % | 2.5 % | 3.2 % | 3.4 % | 4.1 % | 4.9 % | 5.6 % | 7.4 % | 10.0 % | 14.7 % | 16.1 % | | |
| Total RE electricity production in GWh/a | 4,144 | 2,932 | 3,577 | 5,893 | 5,918 | 6,406 | 7,679 | 4,595 | 5,749 | 8,186 | 10,522 | 8,143 | 10,150 | 14,350 | 12,177 | | |
| Non hydro RE production in GWh/a | 451.0 | 835.0 | 777.0 | 1127.0 | 1246.0 | 1389.0 | 1814.0 | 2003.0 | 2438.0 | 2811.0 | 3062.0 | 4132.0 | 5748.0 | 8003.0 | 7701.0 | | |
| Wind | 451 | 756 | 651 | 1021 | 1121 | 1266 | 1699 | 1818 | 2242 | 2543 | 2714 | 3315 | 3850 | 4139 | 3689 | | |
| PV | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 5 | 50 | 158 | 610 | 1694 | 3648 | 3792 | | |
| Biogas | 0 | 79 | 126 | 105 | 124 | 122 | 114 | 184 | 191 | 218 | 190 | 207 | 204 | 216 | 220 | | |
| Hydropower, large | 3,527 | 1,962 | 2,650 | 4,521 | 4,369 | 4,693 | 5,477 | 2,297 | 2,987 | 4,808 | 6,703 | 3,430 | 3,733 | 5,575 | 3,775 | | |
| Hydropower, medium | 140 | 95 | 92 | 169 | 212 | 218 | 299 | 177 | 207 | 446 | 613 | 485 | 549 | 650 | 572 | | |
| Hydropower, small | 26 | 40 | 58 | 76 | 91 | 106 | 89 | 118 | 117 | 121 | 144 | 96 | 120 | 122 | 129 | | |

Figure 68: Development of installed solar PV capacity in Greece from 2000 to 2016 (data source: IRENA 2017)



In Crete wind energy had reached a capacity of 117 MW in 2003. At this time the total installed wind energy capacity in Greece was at 371 MW. Thus, Crete, although having just 5.5% of the overall power demand of Greece had 31.5% of the installed wind energy capacity. As no direct figures on the installed wind energy capacities on Crete are available figures on the electricity production from wind farms in Crete are used to give a rough impression of the installed capacities (see Figure 69). Taking into account the variable wind speeds in the different years, it can be assumed that much of the wind energy diffusion in Crete happened between 1998 and 2001, when almost the full 117 MW of capacity installed in 2003 must have been reached already.

Figure 69: Electricity production from wind energy in Crete 1993 to 2003 (source: Antonakis 2005, p. 20)




From the available data it is not clear, how the wind energy capacities developed in Crete between 2003 and 2012, the next year for which data could be found. According to the Greek distribution system operator HENDO (Hellenic Electricity Distribution Network Operator S.A) the wind energy capacity in Crete was173.94 MW in August 2012. This capacity increased to 186 MW by December 2013, 194.36 MW by December 2014, stayed constant in 2015 and increased to 200.31 MW by December 2016 (see HENDO homepage).

The development of PV seems to have followed a very similar path as in Greece at large. The Executive Agency for Competitiveness and Innovation states a PV capacity of 1.5 MW in Crete in 2008 (no year, p. 24). According to HENDO PV had reached an installed capacity of 70.37 MW by December 2012, which increased to 78.3 MW by December 2013 and remained constant ever since. Thus, PV in Create seems to have followed the same massive expansion pattern between 2009 and 2013 as in Greece.

In 2008 Greek feed-in tariffs for wind and PV (see Table 23) were well above the level in Germany, with 0.507 EUR/kWh (as compared to 0.4675 EUR/kWh in Germany) for PV and 0.09945 EUR/kWh for wind energy in non grid connected islands (German FIT at about 0.079 EUR/kWh).

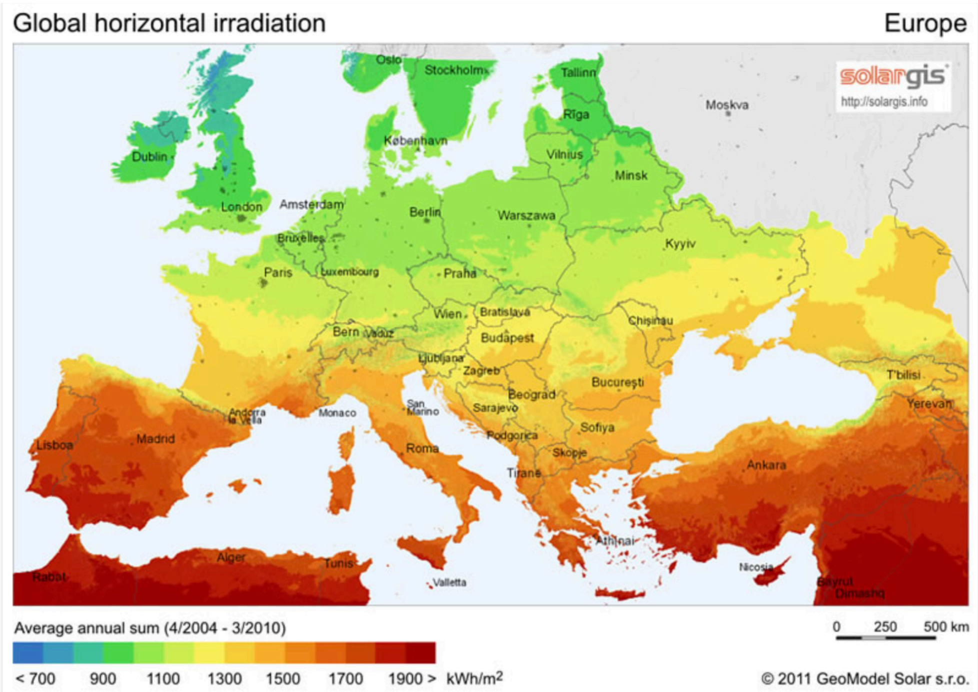
Table 15/2: Early feed in tariffs in Greece in 2008 (source: Executive Agency for Competitiveness and Innovation, no year, p.23)

| Electricity production from | Mainland | Non-interconnected islands |
|---|---|---|
| Wind | 87,85 | 99,45 |
| Off-shore wind | 104,85 | |
| Small hydro <15MW | 87,85 | 99,45 |
| Photovoltaics< 100kWp | 457,14 | 507,14 |
| Photovoltaics > 100kWp | 407,14 | 457,14 |
| Solar thermal < 5MW | 264,85 | 284,85 |
| Solar Thermal> 5MW | 244,85 | 264,85 |
| Other RES | 87,85 | 99,45 |
| Cogeneration | 87,85 | 99,45 |

Table 2. Feed-in tariffs for RES energy (€/MWh)

Considering the fact that the solar radiation in Crete is about 1.5 to 2 times as high as in Germany (see Figure 70) it becomes obvious that these feed-in tariffs induced the explosion of PV capacity in Greece and on the island of Crete, which we have seen in the market diffusion numbers.

Figure 60/5: Global horizontal solar radiation in Europe (source: solargis.info)




As of 2017 Greece has substantially modified its feed-in tariff system due to EU legislation forcing tendering procedures for any larger installations. Up to the end of 2015 the feed-in tariff for wind energy on non-interconnected systems (islands) was 0.11 EUR/kWh, while the FIT for PV was 0.095 EUR/kWh (EU Renewable energy policy database, accessed April 2017). These FITs still apply for wind energy plants up to 3 MW and PV plants up to 500 $kW_p$. Larger systems have to participate in the power market and are awarded a feed-in premium based on a tendering procedure. Renewable energy systems on non-interconnected islands are awarded fixed price contracts still, as they can not participate in the Greek power market.

The lessons to be learnt from the example of Crete are that FITs can induce a continuous (example wind) and explosive (PV) market diffusion of renewable energy sources depending on the ability of the regulator or policy makers setting the FIT rates to approximate the production costs of electricity for a given technology at a given time. As it was extremely difficult for a country with high scientific and administrative capacities like Germany to anticipate the full extend of the PV price reductions seen between 2009 and 2013 it was even more difficult for Greece to adjust its FIT rates fast enough. Nevertheless, it seems that the original FIT rates for PV set for 2008 were already comparatively high as compared to Germany, a country with far lower solar radiation and higher costs per kilowatt hour in the case of similar investment costs. This mistake in the setting of the Greek FIT rates could have been avoided by taking the FIT rates in other countries into account.
The other lesson to be learnt is that comparatively high FIT rates can induce an extremely fast market diffusion of renewable energy technologies, which may drive the absorption capacity of electricity systems in small island very fast to their technical limits, far faster than in large interconnected power systems like in Germany, where it was possible to absorb 40,000 MW of PV within a few years without any major system disruption (into a system with a peak load around 90,000 MW). In Greece this problem has been taken care of by the early legal provision that no more than 30% of the power production can be supplied by non controlled systems like wind and PV.
In small island states like in Barbados feed-in tariffs need to be accompanied by quantity restrictions based on the absorption capacity of the grid and subsections of the grid ensuring that the expansion of renewable electricity production from wind and solar energy only grows with the reinforcement of the grid and eventually with the construction of storage facilities.
A third lesson to be learnt from Crete is that it is necessary to combine the high level penetration of wind and solar energy in island systems with the building of storage. In Crete only hybrid plants (wind plus storage or large solar plus storage) are allowed into the grid in the case of major renewable energy capacity extensions due to the high penetration of wind and PV reached already. As the direct coupling of isolated renewable energy installations with storage will lead to suboptimal use of the storage, the development of centralised or dispatchable decentralised storage will be necessary to achieve higher penetration rates of wind and PV at the lowest possible cost. It is interesting to note that there are many considerations of the introduction of pump storage facilities in combination with additional wind parks in Crete ranging from sophisticated theoretical calculations (e.g. Karapidakis 2015) to actual projects in advanced planning stages (e.g. Terna Energy 2017).
An other lesson that can be learnt from Crete is that its electricity system is officially considered to be of a sufficient size (3,000 GWh/a of demand) to allow unbundling and competition at the generation level ((Executive Agency for Competitiveness and Innovation, no year, p.25).

### 9.5.4 The case of Cape Verde

The Republic of Cape Verde consists of 10 islands and 13 islets approximately 400 km off the coast of Senegal. The total land area is 4033 km$^2$. The population stands at 542,000 inhabitants (see ECREE Secretariat no year, p.3). The total electricity production was 325.5 GWh in 2014 (see Table 24 below) resulting in an annual per capita electricity consumption on about 600 kWh/cap, which is just about one fifth of the per capita electricity consumption in Barbados. By 2012 99% of the population had electricity access, but as in most other island nations the residential electricity tariff was very high at 38 US cents/ KWh (IRENA 2014, p. 6) even higher than the tariffs in Barbados at the time. The water and electricity supply of Cape Verde is in the hands of ELECTRA, which is owned to 85% by the Cape Verde government and 15% by different municipalities. The conventional energy generation is heavily depending on petroleum products like HFO and diesel. (see ECREEE Secretariat no year, p. 4) Out of 140.5 MW of total installed capacity 33.9 MW of wind (26.4 MW) and PV (7.5 MW) were installed by 2012 as Table 24 below shows. In 2012 this installed renewable energy capacity resulted in 21% of the total production.

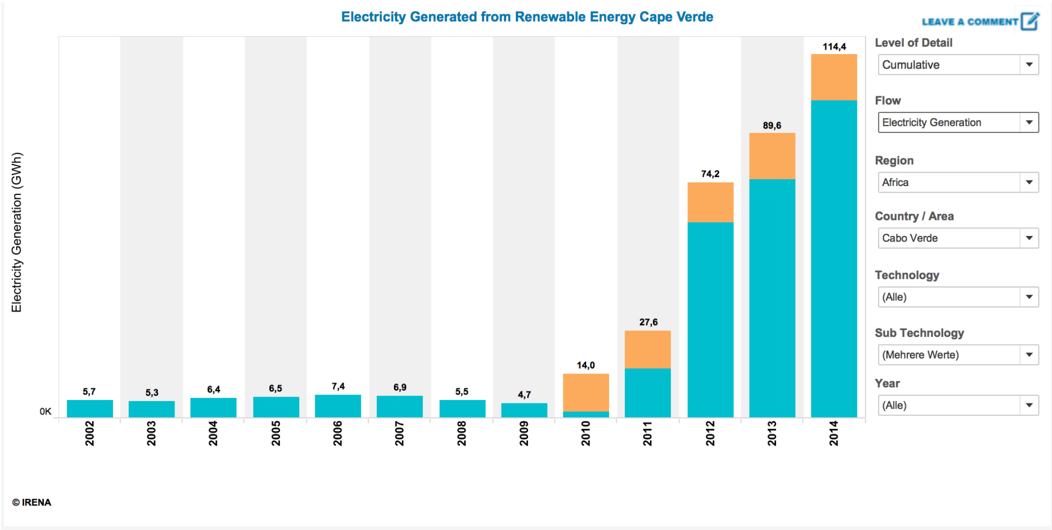
Table 24: Installed electricity generation capacities in MW, resulting production in GWh/a, electricity access and residential electricity rate in Cape Verde in 2012 (source: IRENA 2014, p. 6)

| | |
|---|---|
| Electricity Access in 2012 | 99 percent |
| Installed Capacity in 2012 | 140.5 megawatts |
| Renewable Capacity in 2012<br>• Wind<br>• Solar | 33.9 megawatts (24% of all capacity)<br>• 26.4 megawatts (19%)<br>• 7.5 megawatts (5%) |
| Electricity Generation in 2012 | 330 gigawatt-hours |
| Renewable Generation in 2012<br>• Wind<br>• Solar | 68.7 gigawatt-hours (21% of generation)<br>• 61.3 gigawatt-hours (19%)<br>• 7.4 gigawatt-hours (2%) |
| Electricity Tariff (residential) in 2012 | 38 US cents per kilowatt-hour |

As Table 25 below shows the share of electricity produced from renewable energy sources has increase in the Cape Verdes from 1.8% in 2009 to 35.1% in 2014. Different from Reunion and Fiji the Cape Verde islands did not have any major contribution from hydropower or large scale solid biomass combustion. Thus, the achieved high penetration of renewable electricity is exclusively driven by recent government policies. Figure 71 below shows the fast rising production from wind and PV since 2010.

A first national energy plan was published in 2003 for the time 2003 to 2010 to consolidate the energy sector and to guarantee national energy security. Unfortunately, the national utility went bankrupt, which increased the pressure to move to a commercially viable electricity supply based on rapid investment in renewable energy (see IRENA 2014, p 8). The government then developed a new Renewable Energy Plan for 2010 to 2020 to achieve a renewable energy share of 50% of the countries electricity supply by 2020. This included 94 MW wind energy, 24 MW solar and 7 MW biomass plus a new 20 MW pump storage power plant (see IRENA 2014, p.8).

Figure 71: Electricity generation from renewable energy sources in the Cape Verdes from 2000 to 2014 in GWh/a (data source: IRENA 2017)




The central policy mechanism to achieve these high penetration rates of renewables is a framework for IPPs (Independent Power Producers) and the law n1/2011 with guaranteed PPAs (Power Purchase Agreements) for 15 years. Within a very short time this framework lead to a 25.5 MW wind energy project developed by the IPP Cabeólica S.A. under a PPP (public private partnership) with IfraCo, a donor funded infrastructure company, Electra, the national utility company and the government of Cape Verde (see IRENA 2014, p. 8). The government of Cape Verde explicitly did not use any type of feed-in tariff (see IRENA 2014, p.8), but allowed negotiated guaranteed rates under single power purchase agreements. Nevertheless, the direct involvement of the government in the first large PPA shows some similarities to government administered feed-in tariffs.

Due to the strong involvement of the government the European Investment Bank and the African Development Bank agreed to finance the large IPP project with an investment cost of about USD 83 million (see IRENA 2014, p. 8). The PPP actually administers all aspects of the project consisting of 4 wind parks (IRENA 2014, p. 8). The project has signed a 20 year PPA with the national power company. As can be seen from Table 25 below, the project constitutes practically all of the new wind energy capacity that has been added under the new energy plan until 2016. At the same time it actually contributed 87% of the renewable electricity produced in 2014 or 30% of the total electricity supply of Cape Verde of that year.

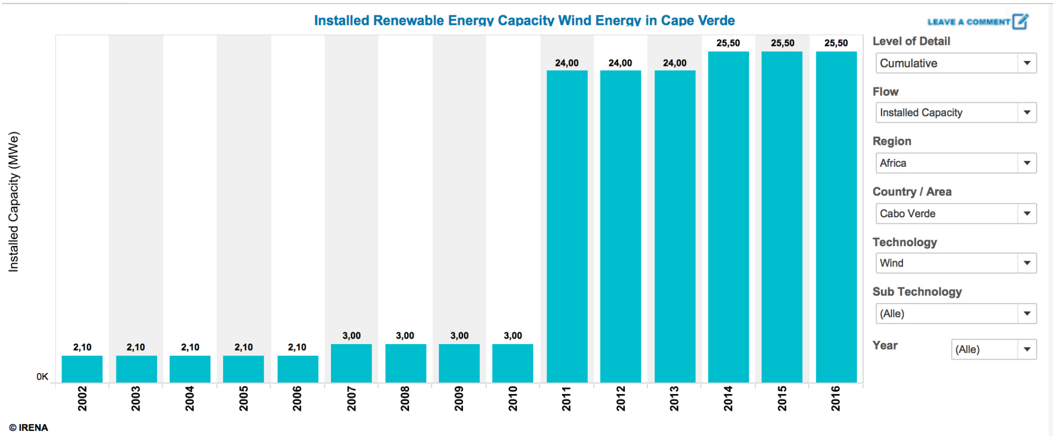
Besides the framework for independent power producers and power purchase agreements the law of 2011 provided a regime for micro generation, it sets out conditions for self producers and tax exemptions for imported equipment. The national utility Electra has provisions for bundling owners to install small scale roof PV under a net metering scheme. Only a minority of the households of Cape Verde can afford the investment, although the investments have very short pay-back times (see IRENA 2014, p. 9). Of the 11 MW of installed PV capacity at least 7.5 MW are due to single large projects (Santiago with 5 MW and Sal with 2.5 MW) (see ECREEE Secretariat no year, p. 4)

Table 25: Installed generation capacities and electricity production in the Cape Verdes from 2000 to 2014 (data sources: IRENA 2017 and US EIA 2017)

| Cape Verde | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation capacity in MW | 45 | 51 | 79 | 77 | 77 | 79.8 | 71.8 | 74.8 | 89.8 | 89.8 | 103.8 | 133.5 | 156.5 | 142.5 | 147 | | |
| Total RE capacity in MW | 0 | 0 | 0 | 2.1 | 2.1 | 2.1 | 2.1 | 3 | 3 | 3 | 10.5 | 31.5 | 32 | 33 | 35.5 | 36.2 | 36.5 |
| Wind capacity in MW | 0 | 0 | 0 | 2.1 | 2.1 | 2.1 | 2.1 | 3.0 | 3.0 | 3.0 | 3.0 | 24 | 24 | 24 | 25.5 | 25.5 | 25.5 |
| PV capacity in MW | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 7.5 | 7.5 | 8.0 | 9.0 | 10.0 | 10.7 | 11.0 |
| | | | | | | | | | | | | | | | | | |
| Total electricity production in GWh/a | 100.0 | 100.0 | 200.0 | 200.0 | 200.0 | 206.5 | 219.5 | 235.3 | 251.1 | 261.3 | 300.4 | 309.7 | 319.9 | 307.8 | 325.5 | | |
| Share of RE | 0.0 % | 0.0 % | 0.0 % | 2.7 % | 3.2 % | 3.1 % | 3.4 % | 2.9 % | 2.2 % | 1.8 % | 4.7 % | 8.9 % | 23.2 % | 29.1 % | 35.1 % | | |
| Total RE electricity production in GWh/a | 0 | 0 | 0 | 5.3 | 6.4 | 6.5 | 7.4 | 6.9 | 5.5 | 4.7 | 14 | 27.6 | 74.2 | 89.6 | 114.4 | | |
| Wind production in GWh/a | 0 | 0 | 0 | 5.3 | 6.4 | 6.5 | 7.4 | 6.9 | 5.5 | 4.7 | 2.0 | 15.6 | 61.4 | 75.2 | 100 | | |
| PV production in GWh/a | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 12 | 12 | 12.8 | 14.4 | 14.4 | | |

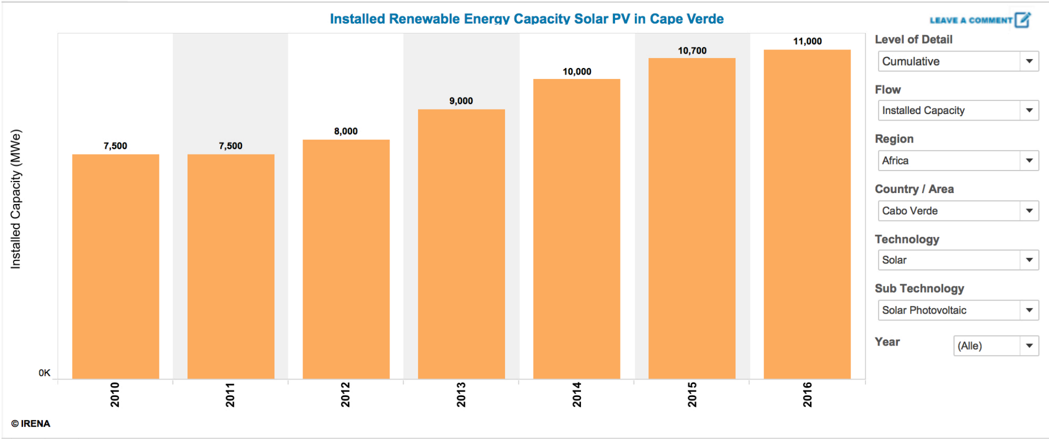
Figure 72 below shows the great impact of single wind energy projects on the installed wind energy capacity. It is interesting to see that the capacity expansion shown in Figure 72 is not immediately matched by an increase in wind energy production as shown in Figure 71 above. It seems that the capacity figures have been reported to the IRENA database before the wind parks were in full operation.

Figure 72: Installed wind energy capacity in Cape Verde from 2000 to 2016 in MW (data source: IRENA 2017)




In the case of PV development in Cape Verde about 500 kWp of PV capacity have been added per year after the two large developments (7.5 MW) had been completed in 2011 as can be seen in Figure 73 below.

Figure 73: Installed solar PV capacity in Cape Verde from 2000 to 2016 in MW (data source: IRENA 2017)




A lesson to be learnt from Cape Verde is that a very determined government of a small island state can achieve a very fast penetration of renewable energy sources with the help of appropriate market conditions and the help of international funding agencies and donors. As pointed out in a number of studies and plans such development has to be accompanied with a strengthening of the grid infrastructure and, as foreseen in the Cape Verde renewable energy plan, it has to be matched by adequate storage as soon as a share of 50% intermittent renewable electricity is reached. In the case of Cape Verde a pump storage hydro plant of 20 MW is foreseen as part of the first 50% renewable power supplied planned by 2020.

An other lesson, which can be learnt from Cape Verde, is that the participation of low income households in renewable energy investment is very difficult, even if the pay-back times are very short under favourable net metering programs.

### 9.5.5 The case of Hawaii

Hawaii is an archipelago consisting of eight main islands and a land area of 28,311 km². The population of about 1.4 million is mainly living on the island of Oahu (about 950,000) (Wikipedia 2017). As Table 26 shows only four islands have more than 10,000 inhabitants.

Table 26: Basic information on the main islands of the Hawaiian archipelago (source: Wikipedia 2017)

| Island | Nickname | Area | Population (as of 2010) | Density | Highest point | Elevation | Age (Ma)[24] | Location |
|---|---|---|---|---|---|---|---|---|
| Oʻahu[27] | The Gathering Place | 596.7 sq mi (1,545.4 km²) | 953,207 | 1,597.46/sq mi (616.78/km²) | Mount Kaʻala | 4,003 ft (1,220 m) | 3.7–2.6 | 21°28′N 157°59′W |
| Hawaiʻi[25] | The Big Island | 4,028.0 sq mi (10,432.5 km²) | 185,079 | 45.948/sq mi (17.7407/km²) | Mauna Kea | 13,796 ft (4,205 m) | 0.4 | 19°34′N 155°30′W |
| Maui[26] | The Valley Isle | 727.2 sq mi (1,883.4 km²) | 144,444 | 198.630/sq mi (76.692/km²) | Haleakalā | 10,023 ft (3,055 m) | 1.3–0.8 | 20°48′N 156°20′W |
| Kauaʻi[28] | The Garden Isle | 552.3 sq mi (1,430.5 km²) | 66,921 | 121.168/sq mi (46.783/km²) | Kawaikini | 5,243 ft (1,598 m) | 5.1 | 22°05′N 159°30′W |
| Molokaʻi[29] | The Friendly Isle | 260.0 sq mi (673.4 km²) | 7,345 | 28.250/sq mi (10.9074/km²) | Kamakou | 4,961 ft (1,512 m) | 1.9–1.8 | 21°08′N 157°02′W |
| Lānaʻi[30] | The Pineapple Isle | 140.5 sq mi (363.9 km²) | 3,135 | 22.313/sq mi (8.615/km²) | Lānaʻihale | 3,366 ft (1,026 m) | 1.3 | 20°50′N 156°56′W |
| Niʻihau[31] | The Forbidden Isle | 69.5 sq mi (180.0 km²) | 170 | 2.45/sq mi (0.944/km²) | Mount Pānīʻau | 1,250 ft (381 m) | 4.9 | 21°54′N 160°10′W |
| Kahoʻolawe[32] | The Target Isle | 44.6 sq mi (115.5 km²) | 0 | 0 | Puʻu Moaulanui | 1,483 ft (452 m) | 1.0 | 20°33′N 156°36′W |

In 2014 the total electricity production in Hawaii was about 10,200 GWh/a supplied by a total installed capacity of 2,670 MW (see Table 27). Thus, the electricity system has about ten times the size of Barbados, while the population is about five times as large.

Although Hawaii sees itself as a pioneer in renewable energy the market penetration of renewable electricity had reached only 12.7% in 2014 according to EIA statistics (see Table 27). At the same time three leading power companies Hawaiian Electric, Maui Electric and Hawai'i Electric Light give a joint penetration rate of 25.8% by 2016 (see Table 28). Historically geothermal energy, biomass and large hydropower have contributed substantially to Hawaii's electricity supply. In the year 2000 the three sources contributed about 920 GWh/a to Hawaii's electricity consumption of about 10,500 GWh. Due to a massive reduction in biomass combustion in 2001 the electricity production from renewable energy sources dropped to just under 600 GWh in 2001. Wind energy did not play a significant role until the year 2006, when the installed capacity increased from 11 to 43 MW and jumped to 64 MW in 2007. A second larger expansion happened in 2011 with an increase in capacity from 62 to 91 MW. In 2012 the capacity increased to about 200 MW (see Table 27). In contrast to Crete wind energy developed relatively late in Hawaii and compared to the 200 MW of wind energy reached in Crete, with a system of less one third of the size of Hawaii, Hawaii still has installed a rather limited wind energy capacity.

The same seems to apply for the market penetration of PV in Hawaii, which did not really start until 2012, when the installed capacities increased from 2 to 7 MW doubling in 2013 (15 MW) and 2014 (32 MW) (see Table 27). Compared to the European islands Crete (78 MW) and Reunion (183 MW) the installed capacity seems to be rather modest and the development has occurred rather late.

Table 27: Installed generation capacities and electricity production in the Hawaii from 2000 to 2014 (data source: US EIA 2017a and 2017b)

| Hawaii | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | | 3 major utilities 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation capacity in MW | 2,389 | 2,292 | 2,267 | 2,268 | 2,311 | 2,358 | 2,414 | 2,436 | 2,437 | 2,565 | 2,536 | 2,562 | 2,730 | 2,757 | 2,672 | | |
| Total RE capacity in MW | 217 | 213 | 173 | 175 | 173 | 175 | 207 | 228 | 229 | 342 | 341 | 371 | 503 | 539 | 553 | | |
| Wind | 12 | 11 | 11 | 11 | 11 | 11 | 43 | 64 | 64 | 64 | 62 | 92 | 206 | 206 | 206 | | 202 |
| PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 2 | 2 | 7 | 15 | 32 | | 665.7 |
| Biomass | 145 | 144 | 106 | 109 | 109 | 109 | 109 | 109 | 109 | 222 | 222 | 222 | 222 | 250 | 247 | | |
| Hydropower, large | 27 | 25 | 23 | 22 | 22 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 25 | 25 | 25 | | |
| Geothermal | 33 | 33 | 33 | 33 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 31 | 43 | 43 | 43 | | |
| | | | | | | | | | | | | | | | | | |
| Total electricity production in GWh/a | 10,593 | 10,633 | 11,663 | 10,976 | 11,410 | 11,523 | 11,559 | 11,533 | 11,376 | 11,011 | 10,836 | 10,723 | 10,469 | 10,267 | 10,204 | | |
| Share of RE | 8.7 % | 5.6 % | 4.0 % | 5.6 % | 5.6 % | 5.5 % | 6.4 % | 7.3 % | 7.6 % | 7.4 % | 7.5 % | 9.1 % | 9.9 % | 11.7 % | 12.7 % | | |
| Share of non hydro RE | 7.7 % | 4.7 % | 3.2 % | 4.8 % | 4.8 % | 4.7 % | 5.3 % | 6.5 % | 6.8 % | 6.4 % | 6.9 % | 8.2 % | 8.8 % | 11.0 % | 11.8 % | | |
| Share of non hydro and non geothermal RE | 5.2 % | 2.7 % | 2.6 % | 3.2 % | 2.9 % | 2.8 % | 3.5 % | 4.5 % | 4.8 % | 4.9 % | 5.0 % | 6.1 % | 6.3 % | 8.3 % | 9.3 % | | |
| Total RE electricity production in GWh/a | 920 | 598 | 467 | 618 | 643 | 635 | 738 | 845 | 860 | 817 | 817 | 975 | 1040 | 1204 | 1300 | | |
| Non hydro RE production in GWh/a | 817.0 | 497.0 | 372.0 | 527.0 | 549.0 | 539.0 | 618.0 | 753.0 | 776.0 | 704.0 | 747.0 | 882.0 | 925.0 | 1126.0 | 1206.0 | | |
| Non hydro and non geothermal RE | 555.0 | 290.0 | 299.0 | 349.0 | 336.0 | 317.0 | 406.0 | 523.0 | 542.0 | 536.0 | 546.0 | 658.0 | 664.0 | 851.0 | 952.0 | | |
| Wind | 17 | 2 | 2 | 2 | 7 | 7 | 80 | 238 | 240 | 251 | 261 | 341 | 378 | 503 | 579 | | |
| PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 4 | 5 | 19 | 39 | | |
| Biomass | 538 | 288 | 297 | 347 | 329 | 310 | 326 | 285 | 302 | 284 | 283 | 313 | 281 | 329 | 334 | | |
| Hydropower, large | 103 | 101 | 95 | 91 | 94 | 96 | 120 | 92 | 84 | 113 | 70 | 93 | 115 | 78 | 94 | | |
| Geothermal | 262 | 207 | 73 | 178 | 213 | 222 | 212 | 230 | 234 | 168 | 201 | 224 | 261 | 275 | 254 | | |

Considering the more recent information from the three major Hawaiian utilities, given for installed capacities in their territories, shows a strong increase in installed PV capacity to 666 MW by the end of 2016 (see Table 28), marking an explosive market diffusion of PV in 2015 and 2016. At the same time the wind energy capacity reported by the three utilities amounted to 202 MW by the end of 2016, a figure slightly below the value given for all of Hawaii by the US EIA statistics for the end of 2014. Thus, it seems that wind energy has only experienced a modest increase in 2015 and 2016 for all of Hawaii, although this can not firmly be concluded, as the three utility companies don't entirely cover Hawaii.

With respect to the use of different supportive instruments for the introduction of renewable energy sources Hawaii is a very interesting case, as a US federal state Hawaii has established renewable portfolio standards in 2004 for all companies selling electricity in Hawaii. These standards have successively been increased with a standard of 100% to be reached by 2045. As of July 1st, 2015 the following standards apply:

- 10% of its net electricity sales by December 31, 2010;
- 15% of its net electricity sales by December 31, 2015;
- 30% of its net electricity sales by December 31, 2020;
- 40% of its net electricity sales by December 31, 2030;
- 70% of its net electricity sales by December 31, 2040;
- 100% of its net electricity sales by December 31, 2045.

Existing renewables may be counted in the total. In addition, an electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the renewable portfolio standard. Hawaii actually became the only state with a legislative goal of 100% renewable energy by 2045 with enacting these standards (see NC Clean Energy Technology Center 2017a). All other instruments have to bee seen in the context of this RPS framework, which sets the binding quantity targets for the introduction of renewable electricity in Hawaii. Comparing the 2010 value reported in the US EIA statistics (see Table 27 above) to the RPS standard of 10%, Hawaii was short by 25%, reaching only a contribution of 7.5% in 2010. Looking at the figures for 2014, the last reported in the US EIA database, Hawaii seemed to fall short again reaching 12.7% one year before the 15% standard had to be met.

Table 28: Installed power generating capacities in the supply areas of Hawaii's three major utilities (source: Hawaiian Electric 2017)

# Power facts

The Hawaiian Electric Companies – Hawaiian Electric, Maui Electric and Hawai'i Electric Light - provide electricity for 95% of residents of the State of Hawai'i on the islands of O'ahu, Maui, Moloka'i, Lāna'i and Hawai'i Island.

Tri-company 2016 renewable energy percentage* is 25.8%
**Total customers: 460,000 (Residential: 403,000)**
**Total employees: 2,662**

**HAWAIIAN ELECTRIC**

Customers: .......... 304,261

**Firm generation:**

**Hawaiian Electric plants**
- Waiau (oil) .......... 500 MW
- Kahe (oil) .......... 650 MW
- Campbell Industrial Park (biofuel) .......... 120 MW

**Independent power producers**
- HPOWER (waste-to-energy) .......... 68.5 MW
- Kalaeloa Partners (oil) .......... 208 MW
- AES-Hawai'i (coal) .......... 180 MW

**Total firm capacity** .......... 1,726.5 MW

**Deactivated units:**
- Honolulu Power Plant (oil) (113 MW) .......... 0 MW

**Variable (as-available) generation:**

**Independent power producers**
- Kahuku Wind .......... 30 MW
- Kawailoa Wind .......... 69 MW
- Wai'anae Solar .......... 27.6 MW
- Par Hawaii .......... 18.5 MW
- Chevron .......... 9.6 MW
- Waihonu Solar .......... 6.5 MW
- Aloha Solar Fund 1 .......... 5 MW
- Kalaeloa Solar Two .......... 5 MW
- Kalaeloa Renewable Energy Park .......... 5 MW
- Kapolei Sustainable Energy Park .......... 1 MW
- Customer-sited solar .......... 411 MW

**Approximate non-firm capacity:** .......... 588.2 MW

**Renewable energy percentage*** .......... 19.4%

**MAUI ELECTRIC**

Serving Maui Island, Moloka'i & Lāna'i
Customers .......... 70,872

**Firm generation:**

**Maui Electric plants (oil)**
- Mā'alaea .......... 212.1 MW
- Kahului .......... 37.6 MW
- Lāna'i .......... 10.4 MW
- Moloka'i .......... 12.0 MW
- Hāna (dispersed generation): .......... 2.0 MW

**Total firm capacity** .......... 274.1 MW

**Variable (as-available) generation:**

**Independent power producers**
- Kaheawa Wind Farm I .......... 30 MW
- Kaheawa Wind Farm II .......... 21 MW
- Auwahi Wind Farm .......... 21 MW
- Mākila Hydro .......... 0.5 MW
- Lāna'i Sustainability Research (PV) .......... 1.2 MW
- Customer-sited solar .......... 93.7 MW

**Approximate non-firm capacity:** .......... 167.4 MW

**Renewable energy percentage*** .......... 36.9%

**HAWAI'I ELECTRIC LIGHT**

Customers .......... 85,029

**Firm generation:**

**Hawai'i Electric Light plants (oil)**
- Hill .......... 35.5 MW
- Puna .......... 38 MW
- Keāhole .......... 79.8 MW
- Kanoelehua .......... 21 MW
- Waimea: .......... 7.5 MW
- Dispersed generation: .......... 5 MW

**Independent power producers**
- Puna Geothermal Venture .......... 34.6 MW
- Hāmākua Energy Partners (oil) .......... 60 MW

**Total firm capacity:** .......... 281.4 MW

**Retired units:**
- Shipman (oil) (15.2 MW) .......... 0 MW

**Variable (as-available) generation:**

**Hawai'i Electric Light plants**
- Waiau Hydro .......... 1.1 MW
- Pu'u'eo Hydro .......... 3.25 MW

**Independent Power Producers**
- Wailuku River Hydro .......... 12.1MW
- Pakini Wind (Tawhiri) .......... 20.5 MW
- Hawi Renewable Development (wind) .......... 10.56 MW
- Customer-sited generation .......... 81.5 MW

**Approximate non-firm capacity** .......... 129.01 MW

**Renewable energy percentage*** .......... 54.2%

* Renewable energy percentages as of 12/31/16 as defined by Hawai'i Revised Statutes 269-91
Generation projects as of 3/15/2017. Generation capacity figures in gross megawatts.

Hawaiian Electric
Maui Electric
Hawai'i Electric Light

For more information visit: www.hawaiianelectric.com

3/2017

In September 2009, the Hawaii Public Utilities Commission (PUC) issued a decision that established a feed-in tariff in Hawaii. The rates for the feed-in tariff, schedule, and standard interconnection agreements were approved on October 13, 2010. This program was to be reviewed by the PUC two years after the start of the program and every three years thereafter. The FIT for Tiers 1 and 2 opened November, 2010 (see Table 29 below for the definition of the different Tiers). Rates for Tier 3 were approved November 22, 2011 and revised tariffs were filed by December 30, 2011. Tier 3 projects are capped at 33% of the aggregate feed-in tariff cap for each of the HECO companies (see NC Clean Energy Technology Center 2017b). The FIT system was discontinued as of April 1, 2017. The FIT program on all islands and all Tiers have been closed to new applications (Hawaiian Electric 2017).

To apply for the feed-in tariff, applicants had to register and apply online at an Independent Observer FIT web site. After January 3, 2012, systems had to file a building permit application on the same day, or before applying for the feed-in tariff, unless no building permit is required by the county.
Under this program, qualified projects received a fixed rate over a 20-year contract. There were three tiers for rates, with the tiers and rates differentiated by technology and system size. The maximum caps on system size varied by island and by technology. Tier 1 included all islands and technologies where the project is less than or equal to 20 kilowatts-AC (kW-AC) in capacity. Tier 2 included systems sized greater than 20 kW-AC and less than or equal to 100 kW-AC for on-shore wind and in-line hydropower on all islands; 100 kW-AC for PV and CSP on Lanai and Molokai; 250 kW-AC for PV on Maui and Hawaii; 500 kW-AC for CSP on Maui and Hawaii; and 500 kW-AC for PV and CSP on Oahu. Tier 3 covered all systems larger than the Tier 2 caps, up to 5 megawatts-AC (MW-AC) on Oahu and 2.72 MW-AC on Maui and Hawaii. Wind projects on Maui and Hawaii were subject to the Tier 2 caps. (see NC Clean Energy Technology Center 2017b)

Table 29: Rates under the Hawaiian FIT program (source: NC Clean Energy Technology Center 2017b):

**Feed-in Tariff Rates***

| Tier | Technology | Eligible System Size | Rate |
|---|---|---|---|
| Tier 1 | Photovoltaics | Less than or equal to 20 kW | $0.218/kWh |
| Tier 1 | Concentrating Solar Power | Less than or equal to 20 kW | $0.269/kWh |
| Tier 1 | On-Shore Wind | Less than or equal to 20 kW | $0.161/kWh |
| Tier 1 | In-line Hydro | Less than or equal to 20 kW | $0.213/kWh |
| Tier 2 | Photovoltaics | Greater than 20 kW, less than or equal to 500 kW | $0.189/kWh |
| Tier 2 | Concentrating Solar Power | Greater than 20 kW, less than or equal to 500 kW | $0.254/kWh |
| Tier 2 | On-Shore Wind | Greater than 20 kW, less than or equal to 100 kW | $0.138/kWh |
| Tier 2 | In-line Hydro | Greater than 20 kW, less than or equal to 100 kW | $0.189/kWh |
| Tier 3 | Photovoltaics | Greater than 500 kW, less than or equal to 5 MW | $0.197/kWh |
| Tier 3 | Concentrating Solar Power | Greater than 500 kW, less than or equal to 5 MW | $0.315/kWh |
| Tier 3 | On-Shore Wind | Greater than 100 kW, less than or equal to 5 MW | $0.120/kWh |
| Baseline FIT | Other RPS-Eligible Renewable Energy Technologies** | Maximum size limits for facilities | $0.120/kWh |

The tariffs given in Table 29 take into account that income generated from renewable energy sources enjoys a 35% tax credit. The rate for applicants without such tax credit are approximately 30% higher (see Table 30).

Table 30: FIT rates under Tier 1 and 2 for applicants without 35% tax credit (source: Hawaiian Electric 2010, sheet 78D)

| Renewable Generator Type and Size | FIT Energy Payment Rate (¢/kWh) |
|---|---|
| Tier 1 PV ≤ 20 kW | 27.4 |
| Tier 1 CSP ≤ 20 kW | 33.1 |
| Tier 2 PV > 20 kW and ≤ 500 kW | 23.8 |
| Tier 2 CSP > 20 kW and ≤ 500 kW | 27.5 |

Due to the substantial caps on the volume of projects allowed under the FIT system, projects were allowed into a project queue. As a result Hawaii experienced speculative queuing of projects not ready for implementation. This problem was dealt with by an independent review of the project applications. If projects were considered not ready for implementation they were taken out of the queues (see Hawaii Clean Energy Initiative 2014).

Overall the FIT programme induced many renewable energy projects and easily reached the given quantity targets. The actual problem was an oversubscription of the program and the resulting speculative queuing of developers.

If the program would have been continued a frequent adjustment of the FIT rates would have been more than necessary.

> Hawaii's original net-metering law was enacted in 2001 and expanded in 2004 by HB 2048, which increased the eligible capacity limit of net-metered systems from 10 kilowatts (kW) to 50 kW. In 2005, the law was further amended by SB 1003, which authorized the Hawaii Public Utilities Commission (PUC) to increase certain limits outlined in the law and provided for the carryover of net excess generation (NEG) to the customer's next bill. In March 2008, the PUC issued an order to implement SB 1003. This order generally raised both the individual system capacity limit and the aggregate capacity limit for net-metered systems. In October 2008, Hawaii's governor; the Hawaii Department of Business, Economic Development and Tourism; the Hawaii consumer advocate, and the HECO companies entered into an energy agreement, a product of the Hawaii Clean Energy Initiative. This agreement provides that there should be no system-wide caps on net metering, and that net metering should transition towards a feed-in-tariff. In December 2008, the PUC issued an order to raise the aggregate capacity limit for net-metered systems in the service territories of HELCO and MECO. In January 2011, the PUC issued an order approving changes to Kauai's program, which was full, and the aggregate capacity limits for HECO companies were lifted and are now based on per-circuit caps rather than a percentage of peak demand. (NC Clean Energy Technology Center 2017c)

The original net metering program was stopped in October 2015 by the Hawaiian public utility commission (PUC) (see Rocky Mountain Institute 2015) in favour of two new options, the ‚grid-supply‘ and the ‚self-supply‘ option. The ‚grid-supply‘ option is similar to the former net metering, but the excess electricity sold to the grid is bought at a reduced rate (between 0.15 and 0.28 USD/kWh), while the average residential rate, at which net metering worked before was about 0.38 USD/kWh. Under the ‚self-supply‘ option no exports into the grid are allowed except for very limited amounts for very short periods. Any exported solar electricity is not paid for by the utility (see Rocky Mountain Institute 2015). Especially the ‚grid-supply‘ option seems to be in line with the agreement of October 2008, stipulating that net metering should transition towards a feed-in tariff. It actually is one of the possible forms of net billing discussed above.

In the case of Hawaii there are a number of lessons, which can be learnt. The first is that net metering with banking and substantial volumes of solar power being bought back by the utility has reached a limit, which should drive a substitution of a generous net metering system by net billing or a fair feed-in tariff, as agreed by the different stakeholders in Hawaii in 2008. By now solar PV costs have declined so much that a substitution by net billing seems to be more than justified. In Hawaii the electricity production cost from small systems are in the range of half the average consumer price, while the cost in Germany has gone to less than a third of the Hawaiian consumer rate for electricity.

A second lesson seems to be that a proper feed-in tariff needs to have a clear tariff reduction perspective. With the very dynamic development of PV system costs, a fixed FIT tariff with a volume cap but without a dynamic tariff reduction for future investments will induce oversubscription of the envisaged volumes and will lead to speculative queuing as in the case of Hawaii.

The third lesson seems to be that a quantity oriented support mechanism like RPS (renewable portfolio standards) does not necessarily lead to the achievement of the set quantity targets, especially when these targets are quite ambitious like in the case of Hawaii.

It remains to be seen how the Hawaiian support mechanisms will evolve in the future and whether these will actually achieve the set targets. So far the performance has been lower than in the case of the European islands Reunion or Crete, which are more comparable to Hawaii than Fiji or Cape Verde.

### 9.5.6 The case of the Dominican Republic

The Dominican Republic is of special interest, because it is the only country in the Caribbean with a feed-in tariff for renewable energy sources. It is a comparatively large island county. With 48,442 km$^2$ it has more than one hundred times the size and with about 10 million inhabitants it has more than thirty times the population of Barbados (see Wikipedia 2017a).

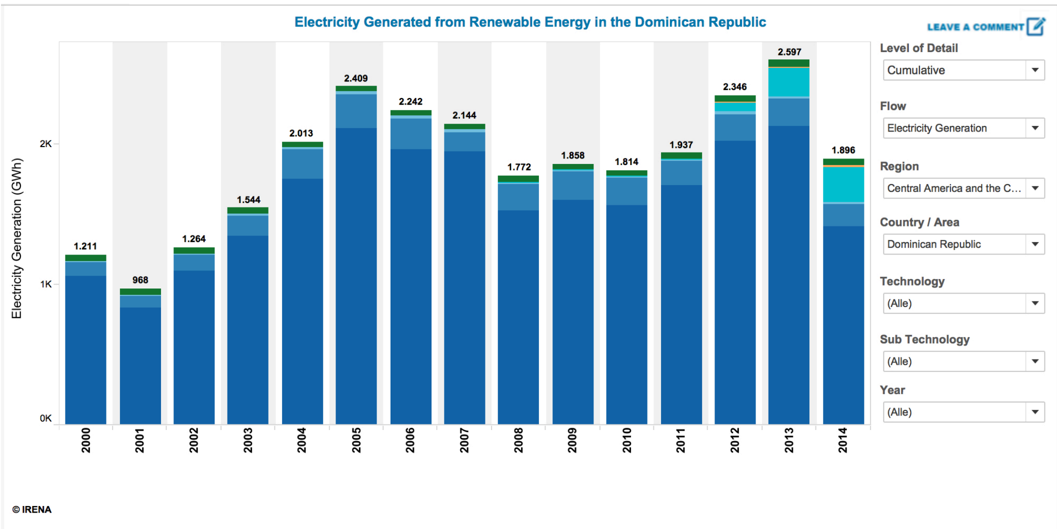
The electricity system of the Dominican Republic had an installed capacity of 3,778 MW in 2014, the last year reported in the US EIA statistics and produced about 14,350 GWh/a in the same year (US EIA 2017), which is almost fifteen times the power production of Barbados. The peak demand was about 1,800 MW in 2012 (Energy Transition Initiative 2015, p.2) The generation of electricity has been liberalised and up to 2012 13 private companies were generating power in the Dominican Republic (Energy Transition Initiative 2015, p.1). The largest generator in the country is AES Andre, which produced 15.64% of the total electricity generated in 2012 (Energy Transition Initiative 2015, p.1).

The Dominican Republic has a legislated feed-in tariff and uses net-metering (Energy Transition Initiative 2015, p.2). It has set a renewable electricity target of 25% for 2025 (Energy Transition Initiative 2015, p. 1), of which it had reached 14% in 2012 (Energy Transition Initiative 2015, p.2). The share of renewable electricity production is heavily dependent on hydropower and the rainfall of any given year, as Table 31 shows. In 2013 this has lead to a renewable share of 15.1%, which dropped to 11.3% in 2014 with little change in the overall electricity production level. The dominant influence of hydropower on the renewable electricity generation in the Dominican Republic can be seen clearly from Figure 74 (the dark blue representing large hydropower and the slightly lighter blue representing medium sized and small hydropower). The figure shows as well that only wind energy has started to supply a significant amount of renewable power other than hydropower since 2012.

Table 31: Installed generation capacities and electricity production in the Dominican Republic from 2000 to 2014 (data source: US EIA 2017a and 2017b)

| Dominican Republic | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation capacity in MW | 2,500 | 2,900 | 3,000 | 3,400 | 3,300 | 3,177 | 3,206 | 3,206 | 2,958 | 2,981 | 3,008 | 3,040 | 3,169 | 3,716 | 3,778 | | |
| Total RE capacity in MW | 400 | 400 | 500 | 500 | 500 | 480.61 | 479 | 479 | 482.2 | 504.2 | 533.2 | 566.6 | 588.6 | 685 | 695 | | |
| Wind | | | | | | | | | 0.2 | 0.2 | 0.2 | 0.2 | 33.3 | 81.1 | 85.0 | 85.5 | 135 |
| PV | | | | | | | | | | | | | 1.6 | 7.4 | 12.3 | 15.5 | 45.5 |
| Solid Biomass | 10.6 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 14 | 14 | 14 | 14 | 14 | 14.6 | 31.6 |
| Hydropower, large | 400 | 400 | 500 | 500 | 500 | 470.61 | 469 | 469 | 472 | 494 | 523 | 523 | 543 | 583 | 588 | | |
| | | | | | | | | | | | | | | | | | |
| Total electricity production in GWh/a | 8,100 | 9,700 | 12,000 | 13,000 | 11,000 | 11,980 | 13,060 | 13,650 | 11,676 | 11,558 | 12,304 | 13,093 | 13,963 | 14,082 | 14,367 | | |
| Share of RE | 10.3 % | 7.6 % | 7.8 % | 9.6 % | 15.2 % | 16.0 % | 13.6 % | 12.7 % | 12.1 % | 12.9 % | 11.9 % | 11.9 % | 13.5 % | 15.1 % | 11.3 % | | |
| Share of non hydro RE | 0.5 % | 0.4 % | 0.3 % | 0.3 % | 0.6 % | 0.0 % | 0.2 % | 0.3 % | 0.3 % | 0.2 % | 0.3 % | 0.2 % | 0.7 % | 1.7 % | 2.1 % | | |
| Total RE electricity production in GWh/a | 838 | 738 | 939 | 1,245 | 1,670 | 1,913 | 1,779 | 1,739 | 1,414 | 1,493 | 1,467 | 1,563 | 1,888 | 2,126 | 1,622 | | |
| Non hydro RE production in GWh/a | 38.0 | 38.0 | 39.0 | 45.0 | 70.0 | 5.0 | 29.0 | 38.0 | 29.5 | 28.5 | 31.5 | 31.5 | 103.5 | 242.9 | 298.9 | | |
| Wind | | | | | | | | | 0.5 | 0.5 | 0.5 | 0.5 | 67.9 | 197.0 | 246.9 | | |
| PV | | | | | | | | | | | | | 2.6 | 11.9 | 20 | | |
| Solid Biomass | 38 | 38 | 39 | 45 | 70 | 5 | 29 | 38 | 29 | 28 | 31 | 31 | 33 | 34 | 32 | | |
| Hydropower, large | 800 | 700 | 900 | 1,200 | 1,600 | 1,908 | 1,750 | 1,701 | 1,384 | 1,464 | 1,435 | 1,531 | 1,784 | 1,883 | 1,323 | | |

Figure 74: Annual power production from renewable energy sources in the Dominican Republic (dark blue: large hydro, slightly lighter blue: small and medium sized hydro, light blue: wind, dark green: biomass, orange: PV) (data source: IRENA 2017)



Before 2012 the renewable electricity capacity has been almost exclusively constituted by hydropower as Figure 75 shows. Wind energy has develop since 2012 in three major steps. In 2012 about 33 MW of wind capacity was taken into operation, in 2013 another 48 MW were added. In 2014 an additional capacity of just 4 MW were connected, while the capacity stayed virtually constant in 2015. Most of the capacity installed by 2014 consisted of the two wind parks Los Cosos I (25.2 MW) and Los Cosos II (52 MW). In 2016 an other 50 MW were added at the site El Guanillo (see Energy Transition Initiative 2015, p. 3) bringing the present capacity to 135 MW of wind energy (see Figure 76).

Figure 75: Development of the installed renewable electricity capacity in the Dominican Republic since 2000 (dark blue: large hydro, slightly lighter blue: small and medium sized hydro, light blue: wind, dark green: biomass, orange: PV) (data source: IRENA 2017)

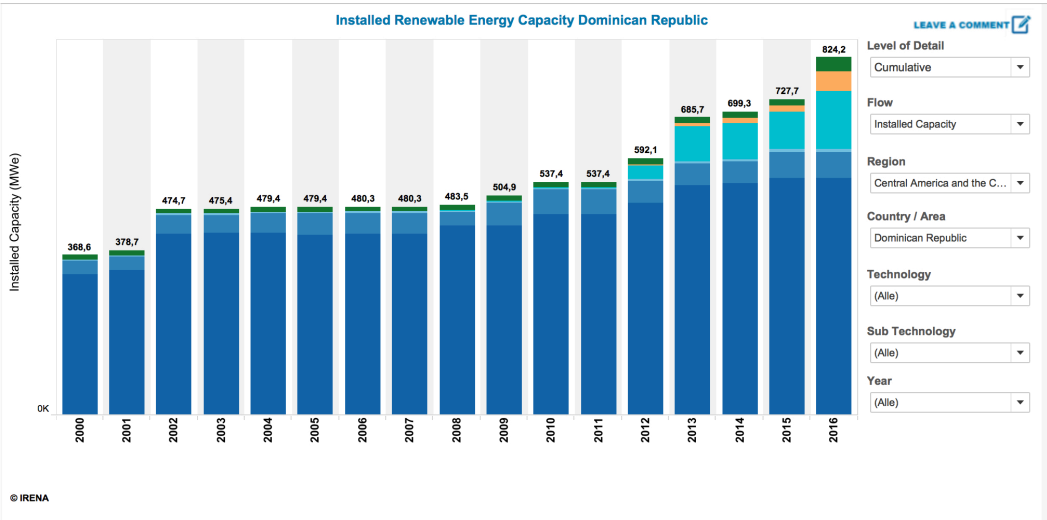
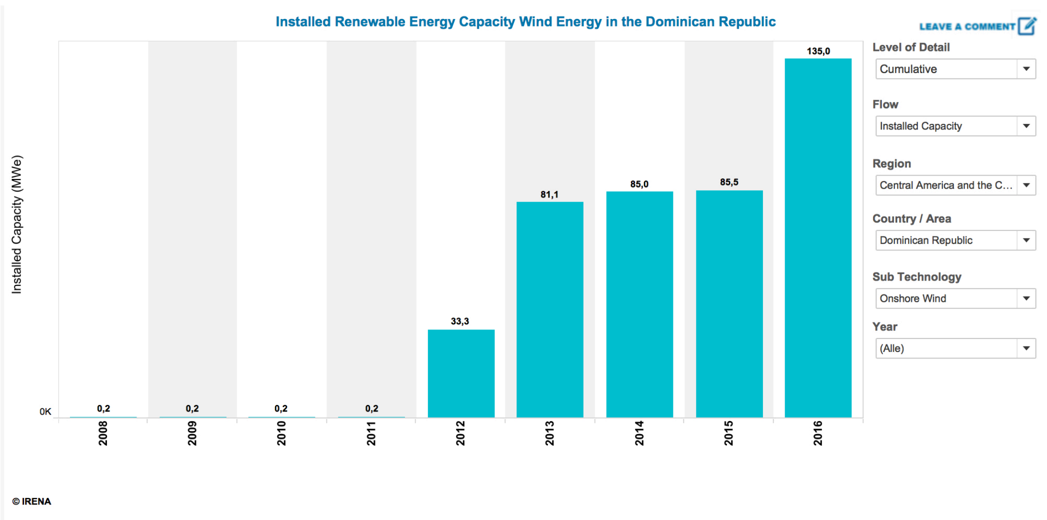


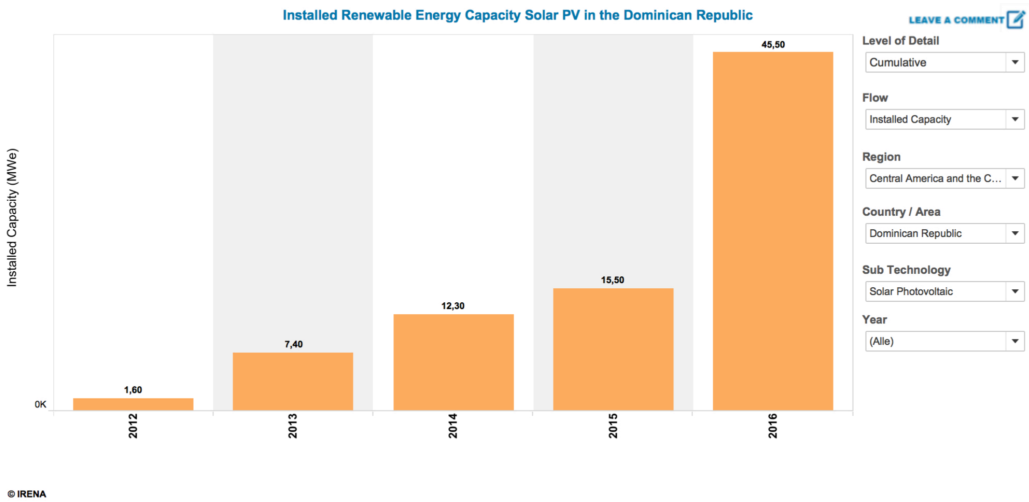

Figure 76: Development of the installed wind energy capacity in the Dominican Republic since 2000 (data source: IRENA 2017)




Like wind energy PV started to take off in the Dominican Republic in 2012, when the first 1.6 MW of PV were installed. In 2013 the new installations increased to 6.6 MW, while 4.9 MW were added in 2014. In

2015 further 3.2 MW were installed, while 2016 witnessed the addition of 30 MW of PV brining the total installed PV capacity to 45.5 MW by the end of 2016 (see Figure 77). This capacity is far below the expectations of 2015, when a 54 MW solar plant was under construction in Monte Plata, and additional contracts were awarded in 2012 for a 50 MW plant in the Santo Domingo province and a 58 MW plant in the the Monte Cristi province. An additional 130 MW of projects were to be developed by Grupo Empresas Dominicanas de Energy Renovable (see Energy Transition Initiative 2015, p.3).

Figure 77: Development of the installed solar PV capacity in the Dominican Republic since 2000 (data source: IRENA 2017)




The actual development of renewable energy sources other than large and medium sized hydropower seems to be in sharp contrast to the political ambitions of the Dominican Republic put forward in 2007 in Law 57-07 on *Renewable Sources of Energy Incentives and Its Special Regimes,* which set a target of a 25% share for renewable energy in the country's final energy consumption for 2025 (see Worldwatch 2015, p. 160). Besides setting up diverse tax incentives the law introduced the framework for feed-in tariffs for renewable energy sources. Beside setting out the framework the law actually contained feed-in tariffs in the form of a premium payment to the wholesale electricity price for both utilities and self-generators (see Worldwatch 2015, p. 163). The tariffs given in Table 32 below did not include an adjustment mechanism over time (like in the German FIT) and where extremely high as compared to international standards. The rate for PV was 0.54 USD/kWh at a time when the FIT in Hawaii was at 0.22, in Germany at 0.18 and in France at 0.14 USD/kWh as the comparison in Table 33 shows.

The very high feed-in tariffs were considered to be to high to sustain by CDEEE, the national utility company holding of all transmission and distribution companies, and the government followed this view (see Worldwatch 2015, p. 163). As a consequence the feed-in tariffs were never applied. Instead power

Table 32: Feed-in tariffs stipulated in law 57-07 (see Worldwatch 2015, p. 163)

**Table 8.4 Renewable Energy Feed-In Tariff Rates Under Law 57-07, Proposed But Not Enacted**

| Energy Source | Feed-in Tariff Rate |
|---|---|
| | U.S. cents per kWh |
| Wind (connected to SENI) | 12.5 |
| Wind (self-generation for sales to SENI) | 4.9 |
| Biomass (connected to SENI) | 11.6 |
| Biomass (self-generation for sales to SENI) | 4.8 |
| Municipal Solid Waste (for sales to SENI) | 8.5 |
| Solar PV (self-generation greater than 25 kW, for sale to SENI) | 10.0 |
| Solar PV (greater than 25 kW, connected to grid) | 53.5 |
| Solar PV (less than or equal to 25 kW, connected to grid) | 60.0 |
| Small hydro (connected to SENI) | 10.0 |
| Small hydro (self-generation for sales to SENI) | 4.8 |

*Source: See Endnote 55 for this section. ©Worldwatch Institute*

Table 32: Comparison of the feed-in tariff for PV of law 57-07 with international feed-in tariffs (see Worldwatch 2015, p. 163)

**Table 8.5 Select International Examples of Large-Scale Solar PV Feed-In Tariff Rates**

| Country | Feed-in Tariff Rate |
|---|---|
| | U.S. cents per kWh |
| **Dominican Republic** | **0.54** |
| Japan | 0.53 |
| Switzerland | 0.47 |
| Czech Republic | 0.40 |
| Israel | 0.39 |
| Malaysia | 0.38 |
| Slovenia | 0.38 |
| Uganda | 0.36 |
| Ontario, Canada | 0.33 |
| Malaysia | 0.26 |
| United Kingdom | 0.24 |
| Hawaii, USA | 0.22 |
| Germany | 0.18 |
| France | 0.14 |

*Source: See Endnote 56 for this section.*

purchase agreements (PPAs) were made with large solar installations like the 30 MW Monte Plata solar plant, which receives a price of 0.175 USD/kWh, which is equivalent to less than 1/3 of the official feed-in tariff for PV (see Worldwatch 2015, p. 163).

In 2011 the national energy commission (CNE) launched a net metering program. This net metering program allows consumers to balance their renewable energy overproduction with power consumption from the grid. Surplus energy can be sold to the grid operator at a given price (see Worldwatch 2015, p. 164). The program has been reasonably successful by the end of 2014 with 519 net metering customers (see Worldwatch 2015, p. 164). About two thirds of these customers had installations smaller than 10 $kW_p$ and 68% of the clients were residential (see Worldwatch 2015, p. 165). However, the size of the average installed system grew from 10.2 $kW_p$ in July 2012 to 23.7 $kW_p$ in 2014 (see Worldwatch 2015, p. 165). The total generation capacity under the net metering program was 13.3 MW by the end of 2014 with largely varying degrees of participation (42% with EDE Norte to 0.19% with CEB) (see Worldwatch 2015, p. 165). Although the program does not have a size cap only 76 out of 519 installations were larger than 25 kW (see Worldwatch 2015, p. 165).

One of the major problems for the program is a low level of public awareness and some customers showing distrust in the program (see Worldwatch 2015, p. 166). The Worldwatch report recommends: ‚To build public trust, it is also crucial that energy distributors dutifully remunerate net metering participants if they still have an accumulated credit in December of every year. So an emphasis must be placed on adequately and promptly paying clients, as this will build public trust and credibility‘ (Worldwatch 2015, p. 166).

A second concern is that the absence of a cap for potential capacity could prove problematic due to the limited technical and financial capacity of the countries power system (Worldwatch 2015, p. 166). The Worldwatch report (2015, p.166) recommends: ‚..that CNE and other government agencies develop a maximum net metering installed capacity that allows for significant growth but ensures stability for the grid‘.

Lessons to be learned from the renewable energy policy in the Dominican Republic are that the net metering program has been less successful than the RER in Barbados and that the feed-in tariffs established by the judiciary were just so unrealistic and ill informed that they met with strong resistance by the national transmission system operator and the government, which lead to the fact that they were never actually applied. At the same time the expansion of large scale wind and solar installations has progressed based on power purchase agreements (PPAs) with independent power producers (IPPs). Nevertheless, many projects seem to be far behind schedule and it is unclear whether this is due to cumbersome administrative procedures or difficulties in project financing. As the Worldwatch report (2015, p.167) mentions ‚Private local and international banks remain reluctant to offer loans to renewable energy projects due in large part to the perceived risks of these investments. The Dominican Republic's poor credit rating and the lack of established sustainable energy markets create a high-risk lending environment.‘

### 9.5.7 Conclusions for support mechanisms from the island examples

All islands looked at in this short review have different support mechanisms for renewable energy in place. Some of them are so successful that they have to be limited or substantially modified, others have not had such success.

Net metering is and has been applied in the Dominican Republic, Cape Verde, Crete and Hawaii. In the case of Hawaii the scheme has been so successful that it has been modified in 2015 to resemble a net billing system. After agreement between the different stakeholders reached in 2008 on the development of net metering in Hawaii towards a feed-in tariff system, this step takes into account that the costs of solar systems have fallen so far and the success of the net metering system has been so great that a continuation at the customer retail price rate would cause to high a burden on the average rate payer. In the case of Reunion and Crete the feed-in tariff for small systems actually establishes a similar system of net billing, but the rates for small PV installations seem to be substantially lower than in the proposed net billing case in Hawaii. Thus, for the future of net metering or net billing in Barbados it seems to be appropriate to move into the direction of net billing.

Feed-in tariffs, which are and have been used in Crete, Reunion, Hawaii and the Dominican Republic have been very successful in inducing a fast diffusion of wind and solar energy. In the case of Crete and Reunion short term explosive expansions of installed PV capacity could not be avoided between 2009 and 2014 due to the very fast decline in PV system costs and due to the fact that no cap was applied to the installed capacities. Eventually, the tariff rates were adjusted downwards fast enough to eventually stop the explosive diffusion of PV in these island systems. In Hawaii no similar development occurred as the installed quantities were heavily capped, but a removal of most caps seemed to have driven a very fast expansion of PV in 2015 and 2016.

In the case of wind energy feed-in tariffs performed quite well in Crete allowing an early fast but gradual development of the wind capacity up to the set limit of 30% of the system generation. In the Dominican Republic unrealistically high feed-in tariffs set by law lead to a strong resistance by the national grid operator and the government (who owns and controls the national grid operator) and a situation where the feed-in tariff system has not been applied since 2007.

For Barbados the international experiences with feed-in tariffs show that they can be a very strong support mechanism, but that they hinge on realistic tariffs set for the different technologies, a dynamic reduction over time following the decrease in technology costs and on caps for the capacities of renewables installed to avoid technical problems for the island grid.

The case of Fiji shows that political target setting without much systematic support will not lead to a substantial expansion of renewable energy production, a fact which is masked by the large share of hydropower in Fiji's power production. Although, Fiji is often mentioned as a forerunner for the development of renewable energy use, the share of renewable energy based power production has decreased from over 92% in 2002 to 56% in 2014. Although, some of this difference is due to different amounts of rainfall in the respective years, the trend of the share of renewable power in Fiji is clearly downward.

Although the the Cape Verde islands have been very successful in increasing their share of renewable power from 0% in 2002 to over 35% in 2014 the lack of a clear support mechanism leads to the need for high government involvement in settling the conditions for large wind and solar installations. This has lead to a concentration on large projects with significant international ownership. For every country looking for a broad citizen participation and a high share of local ownership such a model is certainly not advisable.

## 9.6 BARBADOS MARKET SIZE AND MARKET STRUCTURE AS BACKGROUND FOR THE INTEGRATION OF RENEWABLE ENERGY SOURCES AND THE APPLICABILITY OF DIFFERENT MECHANISMS FOR THE PROMOTION OR RE DIFFUSION

The size of Barbados' electricity market poses substantial restrictions on the applicability of the different support mechanisms for renewable energy sources. In the past Barbados' electricity market has been converted from a publicly owned vertically integrated monopoly supplier to a regulated privatised vertically integrated monopoly supplier.

As Bacon (1995) has shown, the deintegration of a vertically integrated monopoly supplier may cause substantially higher costs in small countries than the possible cost savings achievable by the deintegration. Bacon shows that in small countries the vertical deintegration will cause substantial coordination costs specifically in the dispatch of production capacity. According to Bacon it is doubtful that any cost savings can be achieved by splitting up power generation into three to five competing companies with comparable assets enabling effective competition (Bacon 1995, p.21f). If vertical deintegration is meeting a situation with little competition in generation, its benefits will be minimal while costs will be high (Bacon 1995, p.15). Effective competition in generation requires that non of the competing firms dominates the market and that the competing companies own generating capacities, which directly compete against each other, which is to say that a cost reduction of a specific plant of one competitor enables him to substitute capacities of his competitors in the merit order (see Bacon 1995, p. 23). If such competitive capacity does not exist, there will be no effective competition.

Bacon and Beasant-Jones (2001) emphasise that developing countries with less than 1,000 MW installed generation capacity will not attract sufficient numbers of participants in generation and distribution to induce substantial competition. Besides the problem of attracting a sufficient number of investors for an unbundled power sector in Barbados it would be impossible to split up the generating capacities of Barbados Light and Power in such a way as to produce three or more competing companies with such generating equipment, even if the investors could be found.

A look at Table 9 (above) shows that the Spring Garden plant combines most of the essential generation capacity, while the Seawell plant only runs on peak capacities with high marginal cost and the Garission Hill plant consists only of one diesel engine with just about 5% of the total generation capacity. As it is totally unreasonable to split up the Spring Garden plant among different owners it is impossible to split up the existing generation capacity in such way as to create sufficient competition in generation. In such situation the advantages of keeping a vertically integrated power company clearly outweigh the advantages of deintegration (see Bacon 2005, p. 14f). In this much Barbados shows the typical structure of small economies and has achieved the maximum feasible degree of market liberalisation. As Bacon (1995, p.2) has put it: ‚.. *in small or very poor economies, where the existing power system is small scale, it is becoming apparent that the balances of advantages and disadvantages of a particular pattern of reform and restructuring may be quite different from those in a larger system.‘*

At the same time Barbados has empowered the Fair Trade Commission to control the privatised vertically integrated monopoly to reduce the danger of an inefficient uncontrolled monopoly. As compared to many developing countries Barbados has gone beyond the stage of hybrid models for power sector reform, where state owned and privately owned utilities coexist, like Gratwick and Eberhard (2008, p.3958) point out. Considering the stage of market liberalisation reached it is very likely and highly recommendable that this overall market structure should and will remain largely unchanged except for a legal vertical unbundling as discussed in WP 17, 19 and 20 below.

There may certainly be chances for improvement by the introduction of performance based regulation (as suggested by Woo et al. 2003, p.1103) and by strengthening the capacities of the FTC to effectively regulate the privatised vertically integrated monopoly (BL&P). In the situation where renewable energy technologies can contribute substantially to the reduction of electricity costs and massive spending of hard currency for fossil fuel imports for most SIDS Weisser (2004, p.108) concludes that *'it is important that power sector reform allows these technologies to play an integral - and in the long-run perhaps dominant - part of providing electricity in SIDS.'*

Weisser (2004, p.120) suggests that independent power producers (IPPs) producing electricity from renewable sources can play an important role in the diffusion of renewables into the market and that this will require certain precondition to be successful, namely the creation of a regulatory framework that allows fair competition or tender for power production from IPPs as well as ensuring PPAs and a transparent and stable electricity tariff regime (see Weisser, 2004, p.120). He ascertains that the introduction of IPPs can lead to the proliferation of renewable energy technologies *'especially where feed-in tariffs exist'* (Weisser 2004, p.120), but he points out that under some circumstances *'the provision of long-term stable feed-in tariffs in economies with weak currencies can constitute a considerable risk to both foreign investors and the power utility in the presence of significant variations in both the utilities own fuel prices and the country's currency value.'* (Weisser 2004, p.124). Thus, appropriate precautions need to be taken against such risk in case long-term stable FITs should be established.

Due to the limited size of the electricity system capacities of renewable energy technologies, which can be installed in the short- and midterm, are in the range of a few ten mega-watts for wind and solar PV as well as for the possible use of solid biomass, biogas or waste to energy. Even when the power system will be supplied 100% by renewable energy sources the installed capacities are in the range of about 200 MW for wind and PV each and in the range of a few ten mega-watts or even smaller for all other technologies. This will limit the number of utility scale installations. In wind energy utility scale wind parks are normally larger than 10 MW and easily in the range of 30 and more MW each. In the case of solar PV a utility scale installation will be most likely in the range of 10 MW to realise full economies of scale, while in solid biomass combustion single plants will be most likely in the range of 10 to 30 MW each. In the case of biomass gasification a tendency towards farm size installations in the range between 0.5 and 5 MW will be considerably smaller than 10 MW each. In most cases the use of anaerobic digestion of manure and agricultural residues to produce electricity from the biogas produced will most likely see smaller systems well below 500 kW.

Considering the scope of the present system integration studies we are looking at a total of up to 60 MW of combined additional wind and solar capacity to be installed within the next years, out of which 35 MW are supposed to be distributed (smaller) PV, 10 MW central PV and 15 MW wind (see GE Energy Consulting 2015, p.9). The draft NAMA strategy foresees a 22.5 MW bagasse cogeneration plant (solid biomass combustion) and a 13.5 MW waste to energy (plasma gasification) plant (Barbados Government 2013, p.42). The bagasse plant would be substantially more expensive, if the plant would be scaled down and the waste to energy plant even banks on imported waste to be able to scale to an economical size plant. Thus, it is quite clear that there will only be a few possible utility scale investors for each type of renewable technology applicable in Barbados. This has serious implications for the choice of the most appropriate policy for the promotion of the use of renewable energy sources in Barbados.

Considering the introduction of differentiated FITs the number of possible utility scale investors does not matter, thus, this policy is fully applicable in Barbados.

For the establishment of renewable portfolio standards and a green certificate market, where only BL&P would be required to fulfil the RPS standards, a monopsony would exist with the power to push down the rents of the competing producers of renewable electricity. A market for green certificates could not successfully be established, as the number of buyers in such a market would not be sufficient. Thus, due to the size and structure of the electricity system in Barbados no RPS system can be established.

In the case of an auctioning system the limited number and volume of auctions would make it very difficult to attract a sufficient number of bidders. It is highly doubtful that there will be a sufficient number of truly competing bidders for auctions in the range of 10 to 20 MW of wind or solar capacity per year, even if international participation would be invited. In the later case it is highly likely that the international bidders would be able to undercut Barbadian bidders due to their ability to access the necessary capital to favourable conditions and to contract larger volumes of renewable capacity. A similar trend towards international domination has been documented in power sector liberalisation in many developing countries (see Wamukonya 2003, p. 1276). Wamukonya shows that ten international companies dominated the investment into private electricity projects in developing countries. In the period of 1990 to 1997 156 out of 534 projects were controlled by the ten largest international companies representing roughly half of the entire investment volume of about 130 billion USD (see Wamukonya 2003, p. 1276). Among them four US companies and the French quasi monopoly EDF. Thus, though not impossible, auctions will be an instrument that may need to invite international bidders and end up with a situation were most renewable energy capacity is controlled be large international investors reducing the possible benefits to Barbados' economy as the income derived from the operation of renewable energy technologies will most likely be transferred out of Barbados' economy leaving Barbados with a similar money drain as the diesel imports for conventional power production.

While FITs do not have any problems with a limited number of possible investors and while they don't require a minimum economic size of an investor, they pose two other challenges for small economies like Barbados, which are the general asymmetry of information between the regulator and the investor and the regulator's inexperience in determining RE tariffs under an FIT system as Atherley-Ikechi (2015, p.35) suggests. Both problems are solved well by the auctioning process as shown above.

Concerning the first problem, the asymmetry of information, the German case shows that this problem can be handled in a way as to result in lower installation costs than quantity based instruments (see Barbos and Wyser 2013, p.3474). The German case shows that the setting of sliding FIT rates and their calibration was usually done with the help of experienced independent consultants and research institutes, an approach which is open to any government in the world. What is more, as most renewable energy technologies have matured considerably during the last 25 years, it is much easier to determine appropriate FIT rates today than in the early years of FITs. Cost data are usually well documented internationally and have to be adapted to the specific local condition, but they will not be fundamentally different around the world, as all technologies are traded internationally.

Concerning the second challenge, the inexperience of a regulator in determining appropriate FIT rates can be approached in the same way, by acquiring international experience and know-how through the help of experienced independent international consultants and research institutes.

Thus, although FITs face their own challenges in small countries, they may be a better fit than RPS or auctions, as they do not experience the same problems with a lack of possible market participants.

Work package 13 will apply the general considerations of this chapter to Barbados to derive the best possible market and policy framework for the successful market diffusion of renewable energy sources.

# WORK PACKAGE 10: ANALYSIS OF THE PRESENT MARKET SITUATION OF RENEWABLES IN BARBADOS

## 10.1 THE PRESENT MARKET STRUCTURE (AND REGULATOR)

The electricity market of Barbados is characterised by the dominant position of the BL&P, which is a vertically integrated utility company responsible for the generation, supply, and distribution of electricity (see IDB 2016, p. 28). Since 2014 BL&P is owned by EMERA Caribbean, which in turn is owned by EMERA, a Canadian-based company (80%), the National Insurance Board and approximately 1700 other shareholders (see IDB 2016, p. 29). With the passing of the Electric Light and Power Act (ELPA) in 2013 the power sector was opened to independent power producers (IPPs). As of 2016 no IPP has entered the market for either generation, transmission or distribution (see IDB 2016, p. 28). Despite the market opening to IPPs BL&P still holds an official mandate for the generation, transmission and distribution of electricity under its current license, which runs until 2028 (see IDB 2016, p. 29). Thus, the present electricity market of Barbados is dominated by a vertically integrated privately owned utility producing about 96% of the traded electricity acting as a single buyer for all other power producers.

According to the nomenclature of the World Bank developed for the full liberalisation of power markets (see Gratwick and Eberhard 2008, p. 3952) Barbados has adopted seven of nine reform steps (corporisation, commercialisation, passage of requisite energy legislation, establishment of an independent regulator, introduction of IPPs, divestiture of generation assets, divestiture of distribution assets). Only the two steps of restructuring (unbundling the vertically integrated utility) and the introduction of competition through the introduction of wholesale and retail markets have not been taken (compare Gratwick and Eberhard 2008, p. 3952).

According to Gratwick and Eberhard (2008, p. 3954) the Barbados situation resembles the single buyer model, which can be seen as one of the standard hybrid forms of power market liberalisation, which have evolved during the last two decades in the power market liberalisation of developing countries. It can well be argued that the power market in Barbados is too small to allow retail or wholesale competition or unbundling (see e.g. Bacon 1995, p.4 or Weiser 2004, p. 108f).

Looked at it in a functional way the present theoretical structure of Barbados' energy system is including the possibility of IPPs operating conventional and renewable generation capacity and consumers producing solar energy and feeding it back into the grid. It can be pictured as in Figure 78. It mainly consists of the privatised former monopoly (BL&P), which is responsible for the transmission and distribution of the electricity as well as for the functional control of the system. BL&P presently holds all significant conventional generation units and it is operating a substantial PV capacity. At the same time consumers are producing solar energy, which is partially fed back into the grid and is payed for under the fixed RER rate regime. According to the given legal framework it is possible that independent power producers own and operate renewable energy plants as well as conventional generation units.

In real life no IPP has successfully started its own production of electricity. This present system structure is depicted in Figure 79. In the case of wind energy an IPP has been formed (RePower Barbados), but so far the negotiations, licensing and permitting procedures have not been completed (see the discussion above). Nevertheless, there is a realistic option to start a successful IPP operation in the field of wind energy or PV, once a long term contract can be signed guaranteeing a fixed price for the electricity produced.

In the case of conventional power generation it is very unlikely that an IPP can successfully operate an additional conventional power plant in Barbados. As shown in Figure 80 to 83 it will not be possible to

Figure 78: Present theoretical structure of Barbados power supply system (own graphical representation)

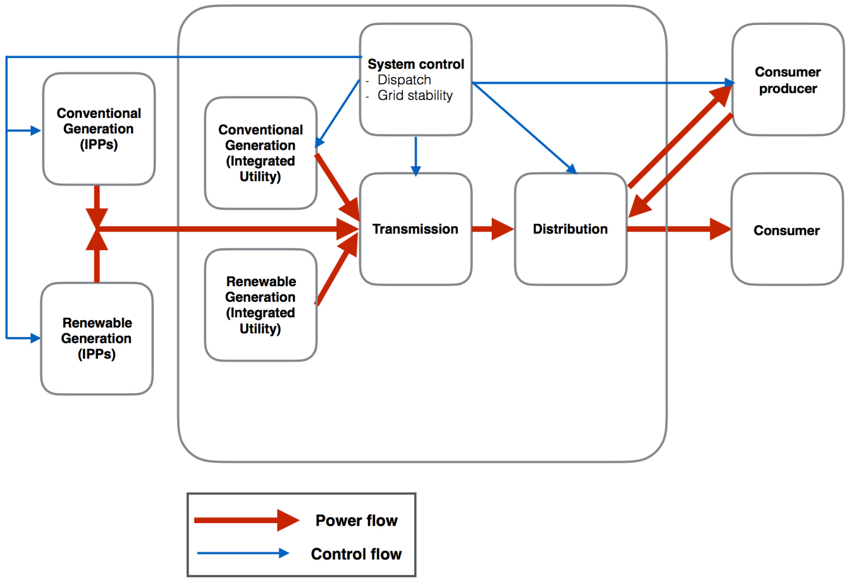
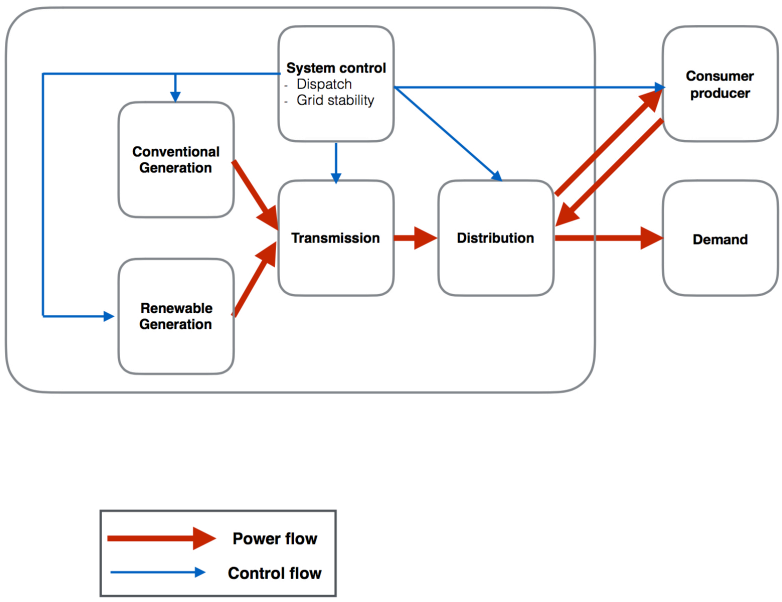



Figure 79: Present factual structure of Barbados power supply system (own graphical representation)




actually generate sufficient returns for such new conventional system due to the limited number of competitive generators in a power system of the relatively small size of Barbados.

Bohun, Terway and Chander (2001), have emphasised that developing countries with capacities below approximately 1,000 MW would not attract sufficient numbers of participants in generation and distribution to introduce sustained competition‘ (Wiser 2004, p. 109). By 2004 only five out of 54 SIDS had installed capacities over 1,000 MW (Cuba, Dominican Republic, Jamaica, Trinidad and Tobago and Singapore) (see Wiser 2004, p. 110). The minimum market size of 1,000 MW compares to just about 150 MW of peak load in Barbados.

Why is it impossible to have sufficient competition in conventional power generation in a system of 150 MW maximum load? This question can be answered by looking at the technically determined cost structure of the present conventional power supply for Barbados (see Figure 80). In a competitive market the use of power generation units is determined by their variable costs. Ordering the capacities of all units available to the market according to their variable costs results in the so called merit order. At any given point in time the electricity demand on the system determines the capacity necessary for the electricity generation. The units are operated in their order of merit (variable costs). The last unit necessary to cover the market demand, the marginal unit, determines the market price. All units which want to economically survive have to operate a substantial part of the year at market prices well above their marginal costs in order to recover their investment costs. For the overall system a reserve capacity is needed for all those periods when some of the low cost units are not in operation due to regular maintenance or downtime for unscheduled repair. Thus, all larger power suppliers need to run reserve units as well, which are mostly paid for from the earnings of the most cost effective units.

Figure 80: Merit order and system load of Barbados’ power supply in 2016 (based on heat rates of generators, used fuels and international fuel prices in April 2017)

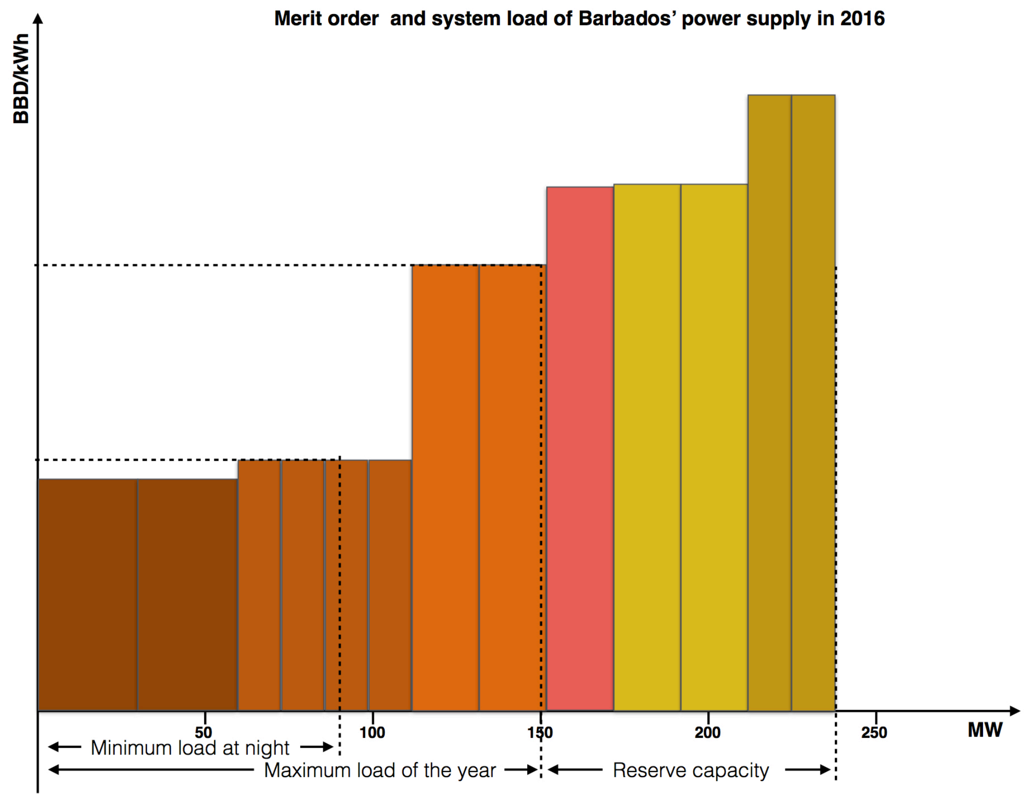
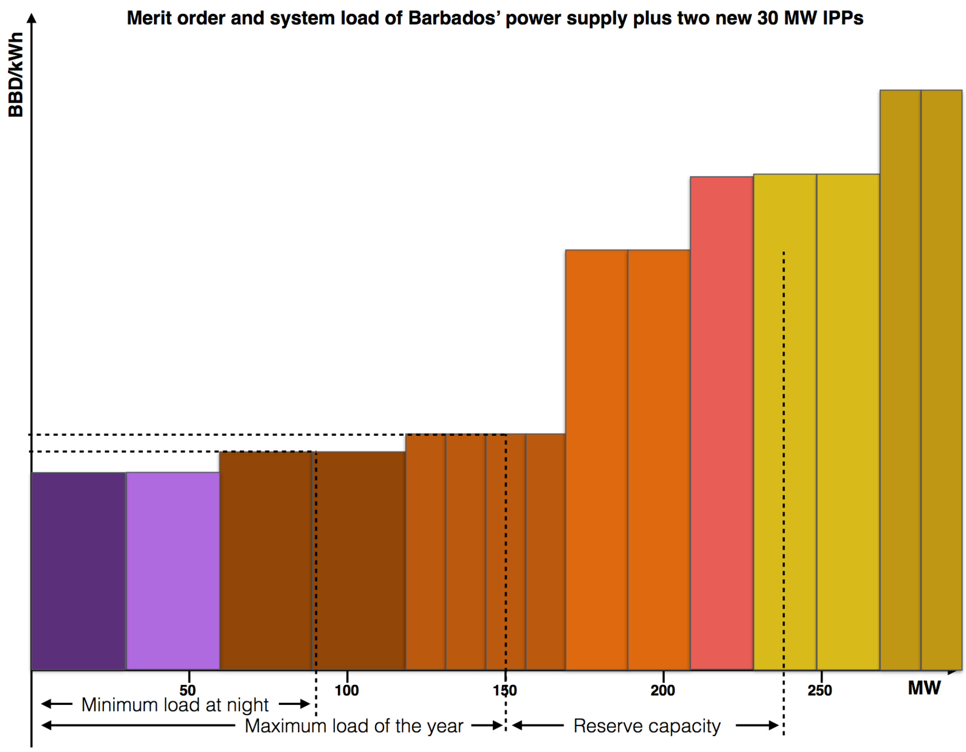


Figure 80 shows that only eight out of thirteen generators are necessary to supply the maximum load of 150 MW in the grid. The five other units are necessary as back-up, but it can not be expected that they will earn more than their variable costs in operation. At night time and minimum system load of around 80 MW only the five most efficient units with the lowest variable costs are necessary to service the load. For any further considerations on introducing competition at the generation level it has to be taken into account that the nine most efficient units are all located in the Spring Garden plant of Barbados Light and Power. Thus, it is not feasible to split the relevant existing production capacity into different companies each operating competitive units. Competition on the generation level can only be introduced by building independent new capacity. As will be shown below, this is not attractive to independent investors due to inherent restrictions of the relatively small power system of Barbados.

It can be seen from Figure 80 that the six lowest cost units can make substantial earnings during peak load hours, when the price is set by the next group of generators with substantially higher costs, while only the two most efficient units can make some small earnings during low load times (up to 110 MW). In case one or two of the most efficient units with 30 MW each are not in operation prices will increase substantially during higher load hours and may increase (if both units are not working) during the low load hours.

If we imagine that at least two additional competitors with competitive equipment are necessary to start liberalising the power market in Barbados (it actually takes more than that, but for the sake of a simple argument, we assume this), then two new 30 MW low speed diesel generators using HFO (heavy fuel oil is by far the cheapest fuel) will need to be added to the merit order. Lets assume they are slightly more efficient than the two best units of BL&P and they enter into the merit order all the way to the left hand side. This situation is pictured in Figure 81 below.

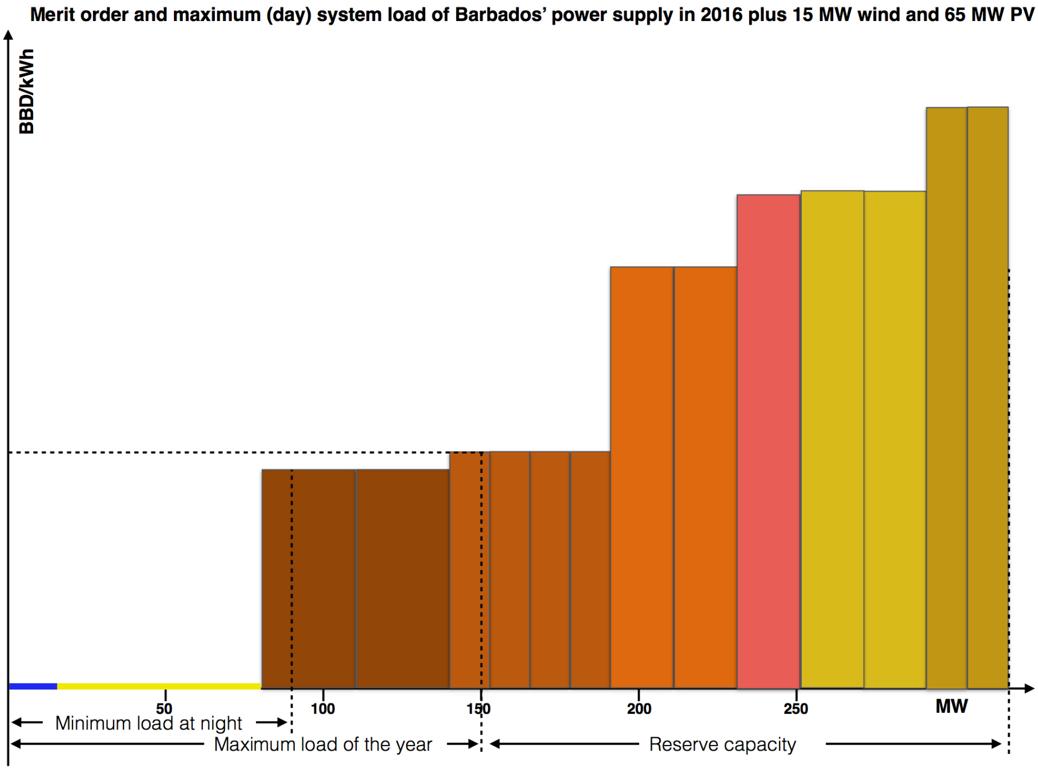
Figure 81: Barbados' merit order with two additional IPP generators of 30 MW each




In this case the new units would run all year, but the price during low load phases and even during high load phases will be reduced so far that these new generation units will never be able to recover their investment costs. What is more, Barbados Light and Power will not be able to generate sufficient returns to keep all the necessary reserve units in working order although the three least efficient units could be retired. Overall the new system will run into economic problems unless it will operate with substantial capacity payments to BL&P and even to the new IPPs.

What makes the situation even more hopeless for the conventional generators is the fact that the system is in transition to substantial shares of renewable energy production. As wind and solar energy have virtually no variable costs their production enters into the merit order to the left, as Figure 82 shows for 15 MW of wind and 65 MW of PV production (according to one of the scenarios of the BL&P grid integration study).

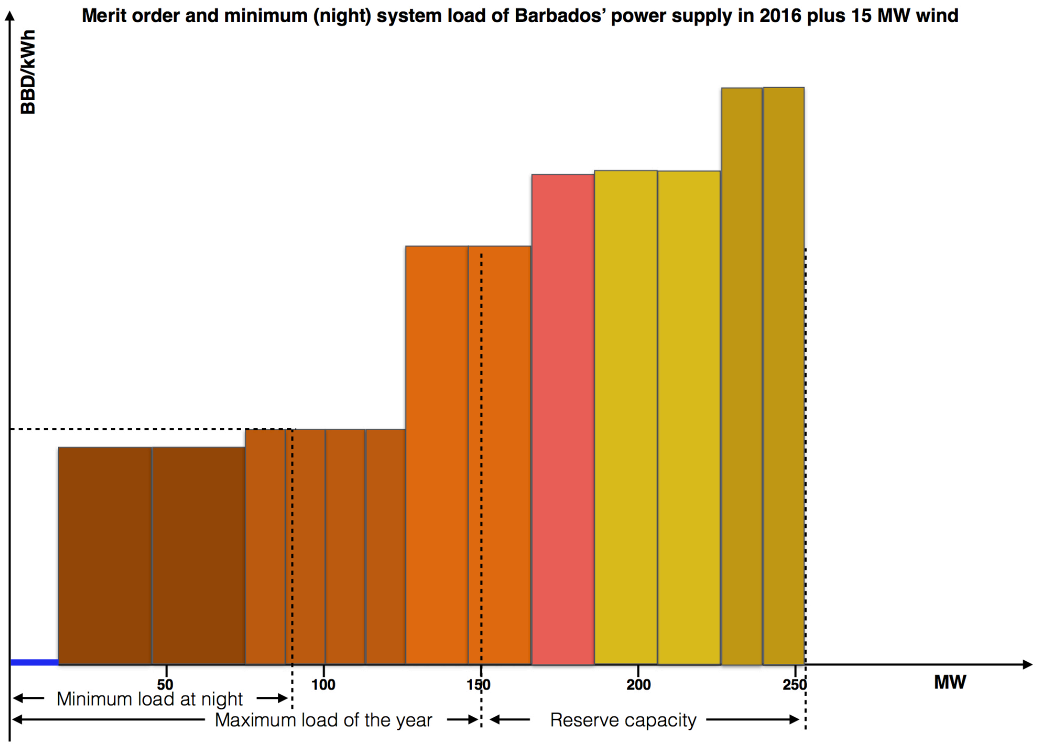
Figure 82: Barbados' merit order with the existing conventional capacity plus 15 MW of wind and 65 MW of PV production (situation at noon time, maximum load case)




Compared to the situation without wind and PV now the marginal power plant is not in the third most efficient category but in the second. Accordingly the market price for electricity is substantially lower. Again for a new market entrant this would leave even less room to earn enough money to recover his investment. During the night time, when load is low, but PV will not produce any electricity, the situation with production from 15 MW of wind is similar as Figure 83 shows. Again, only small margins can be earned by the most efficient generators.

These considerations show that the present power market and even more so Barbados' future power market with substantial shares of renewable energy sources don't make it attractive for independent power producers to start a business based on new conventional generation capacity.

Figure 83: Barbados' merit order with the existing conventional capacity plus 15 MW of wind production (situation at night time, minimum load case)




Even if the electricity demand will increase in the coming years as foreseen in the integrated resource plan of BL&P to about 210 MW in 2035 this will be accompanied by a strong growth in power generation from renewable energy sources. As the present conventional generators can back up a total system demand up to 235 MW it is questionable that the increased demand will create a business case for independent power producers. Even if Barbados switches to full e-mobility, which only makes sense if power is not generated from HFO or Diesel but from renewable energy sources, intelligent charging strategies (centrally dispatched charging between 10 a.m. and 3 p.m.) will not add any additional load to the system, which would need to be covered by conventional generation. Thus, even e-mobility will not create a business case for an IPP to invest into new conventional generation capacity.

Thus, taking into account the limited market size the liberalisation of the Barbados power sector has already reached a comparatively high level, where unbundling (splitting up the vertically integrated structure of conventional generation, transmission, distribution and system control) could be discussed but may well have high transaction costs and little positive effect, while it seems to be extremely unlikely that wholesale and retail competition could generate any positive returns (see the discussion above). As Bacon (1995, p.15) points out unbundling (vertical deintegration of generation, transmission and distribution) may come at a very substantial price in small economies and will not have substantial advantages if there is no effective competition at the generation level. Thus, unbundling would most likely come at high costs and low befits in Barbados.

In this situation, where the vertically integrated private conventional producer of fossil fuel based electricity is the main feature of the electricity market it is central that an independent regulator with the necessary regulating powers controls the pricing of the monopoly. Such control requires sufficient numbers of well trained staff. In Barbados this regulator is the Barbados Fair Trading Commission (FTC), which was established in 2001 under the Fair Trading Commission Act (see IDB 2016, p.31). Judging by the documented decisions of the FTC and by its legal powers, Barbados has a very competent regulator with the necessary powers. Nevertheless, it is doubtful that the FTC has a sufficient number of well trained staff to handle all the necessary tasks  to the control the vertically integrated monopoly on the one hand and to oversee the necessary expansion process of renewable power production in Barbados on the other. Fortunately, the necessary structures exist, but it will take a substantial increase in the FTC budget for additional highly qualified staff to meet the future challenges of the necessary power market transition.

## 10.2 RENEWABLE ENERGY POLICY TARGETS

Barbados is one of the signatories of the ‚Vision of the Climate Vulnerable Countries‘, which was published at COP 22 in Marrakech on November 18, 2016, which pledged that the signatory countries ‚strive to meet 100% domestic renewable energy production as rapidly as possible‘ (Climate Vulnerable Forum 2016).

In 2015 the goals for the renewable energy policy of Barbados have been (nominally) increased from the 2012 target of 29% for renewable power by 2029 (AOSIS 2012, p.6 and Revised National Sustainable Energy Policy, 3.3, first bullet) to 65% of the maximum electrical load in 2030 (Barbados Intended Nationally Determined Contribution 2015, p.5). Depending on the composition of the renewable energy sources used in 2030 to reach this share of 65%, this might just be the same target compared to the 29% for 2029, which referred to the total electricity produced by renewables per year. In the likely case that the renewable power production of 2030 will be mostly based upon wind and photovoltaic solar energy (PV) the share of 65% of the maximum electrical load of 192 MW in 2030 (derived from the IRP of Barbados Light and Power 2014, p.10) would equal 125 MW of installed wind and PV capacity. This would produce just about 350 GWh/a (assuming 50% PV and 50% wind), which would be equal to 28.2% of the annual system load of 2030 projected by BL&P (interpolated figure based on BL&P 2014, p.9). Thus, the nominal change of the target from 29% of annual electricity produced to 65% of the maximum capacity might hardly result in an increase of renewable electricity being produced.

Recently Barbados declared a 100% renewable power target to be reached by 2066 (declared by the Prime Minister of Barbados at the BREA Sustainable Energy Conference on November 10th, 2016). The proclaimed target of 100% renewable power by 2066 can hardly be seen to be in line with the claim to reach 100% renewable domestic energy supply ‚as rapidly as possible‘ as made by the CVF at COP 22. What is more, the new ‚ambitious' 100% target is nothing else than the 29% target for 2029. Assuming a linear distribution of the market diffusion of renewable energy over the 50 year period from 2017 to 2066 the new policy target implies a growth of 25.48% from 2017 to 2029. If this is added to a renewables share of roughly 4% by the end of 2016 the set policy target for 2029 remains virtually unchanged as compared to the target set in 2012. It seems that some policy makers try to leave the impression with the public in Barbados and the world that Barbados is speeding up its pace in the introduction of renewable electricity, while they are still just pursuing the old target of 2012. Thus, it has to be concluded that the renewable energy target measured in the share of power produced is still just about 30% of the total power production by 2030.

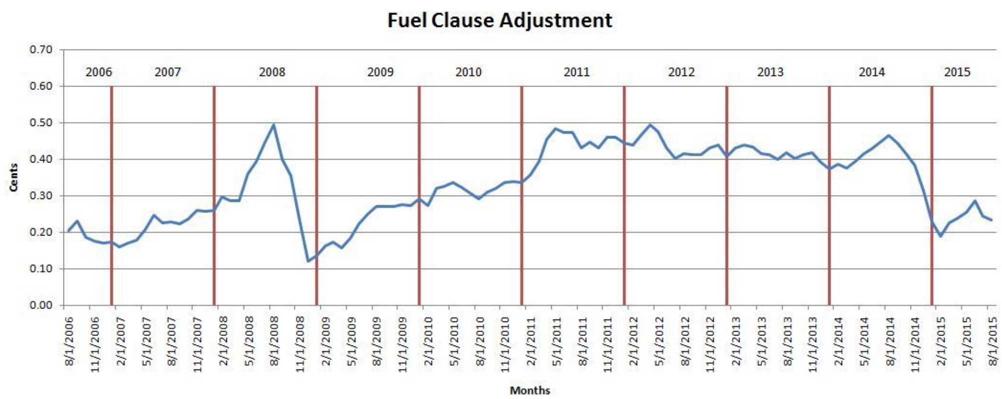
A recent study has shown that a 100% renewable electricity supply for Barbados is possible, if a sizeable pump storage hydro plant is integrated into the system (Hohmeyer 2015, p.24). From the evidence available so far it can be concluded that ‚to meet 100% domestic renewable energy production as rapidly as possible‘ for Barbados would mean about ten to twenty, but not 50 years from now. Such fast transition to a 100% renewable electricity supply will result in substantially lower electricity costs than the average conventional power generation cost of the last ten years and its expected future cost. Furthermore, it will result in vastly lower net outflows of hard currency for imports and substantial economic growth for Barbados.

## 10.3 RENEWABLE ENERGY POLICY INSTRUMENTS

The present regulatory framework for the use of renewable energy sources in electricity production is characterised by high uncertainties for the average investor and very high license fees for the permission to operate a renewable energy installation like a solar PV system.

The first instrument to promote the market diffusion of renewable power production was the instrument of the Renewable Energy Rider (RER), which linked the payments for the electricity produced by a solar or wind energy facility to the avoided fuel costs of the conventional electricity. The RER was suggested by Barbados Light and Power and accepted by the Fair Trade Commission (FTC) in 2010 for a two year pilot programme. The RER was combined with a floor of 0.315 BBD/kWh. During this time 1.6 MW of solar PV systems were installed. In 2013 the FTC granted the permission to make the RER permanent, but it removed the provision of a floor. By the middle of 2015 9 MW of solar PW were installed (see IDB 2016, p. 12). As the RER was developed from the perspective of the monopoly utility company operating all conventional generation assets it was straight forward to base the payment for renewable electricity on the avoided fuel cost of the conventional production. In this way the RER did not have any major impact on the cost structure of BL&P, but it left the investors in renewable power production in a gambling situation as their income was directly linked to the development of the international oil prices.

Figure 84: Development of the Barbados Fuel Clause Adjustment (source: Solar Barbados)




After years of high oil prices and high fuel costs for the conventional power generation by BL&P and high payments under the RER based on the so called Fuel Clause Adjustment investors realised in 2015 with slumping oil prices that they were confronted with extremely high uncertainty about the future cash flows of their renewable energy investments, which in wind and solar energy are characterised by high up front investment costs and low operating costs. Figure 84 shows the development of the Fuel Clause Adjustment, the basis for the RER calculation. Many investors, who had invested in times of high oil prices and high RER, were running into a substantial chance of bankruptcy.

Due to massive complaints the FTC decided on July 13th, 2016, to established two fixed rates for wind (0,315 BBD/kWh) and solar PV installations (0,416 BBD/kWh) of a capacity up to 500 kW (FTC 2016, p.

23), trying to avoid the most severe consequences of the fallen oil prices and the vast drop in the RER rates (FTC 2016, p. 4f).

Nevertheless, these new rates have been qualified by the FTC as temporary RER credits (FTC 2016, p. 5) and the decision does not fix these credits for a specified time for any new installation. Thus, although the decision of the FTC was intended to do so, it did not give the necessary certainty about the future cash flow produced from a given RE investment, as the rates can always be substituted by altered new rates for any existing installation. As a consequence investor confidence does not seem to be restored.

The present policy framework for the introduction and market diffusion of renewable energy sources seems to be insufficient to reach even the very modest targets of 29% by 2029 or 100% by 2066. The present situation of the renewable energy policy and the regulatory and planning framework seem to be major obstacles for a rapid market diffusion of renewable energy sources. Thus, Barbados is looking for a new policy framework and mechanisms to enable a faster transition to a renewable energy based power supply.

## 10.4 Renewable energy permitting and licensing

At the moment three different licenses, permits or approvals have to be granted for a renewable power production facility larger than 5 kW (private households) or 20 kW (commercial operators). This is an approval granted by the Chief Electrical Engineer, a planning permit from Town and Country Planning and a license under the Electric Light and Power Act. In addition the installation has to comply with the requirements laid out by BL&P for grid connection.

The Electric Light and Power Act (ELPA) enacted in 2013 and amended in 2015 was aiming at a further market liberalisation and at increasing the share or renewable energy sources in Barbados by introducing independent power producers (IPPs). But instead of speeding up the market diffusion of renewable energy sources the ELPA ended up introducing new financial and organisational obstacles. Due to the critical budget situation of the Barbados government (induced mainly by the sugar crisis and the high import spending on extremely expensive fuels for power generation) it introduced a new annual license fee system for power generators, which according to well informed critics have taken up to 40% of the earnings of the operators of renewable power plants and diminished the economics of the systems further in an investment situation already stressed by the high uncertainty about the income generated under the RER.

Besides the financial burden the execution of the ELPA resulted in a substantial delay of the permitting and licensing process for renewable energy installations. The ELPA set up the Electric Power Advisory Committee, which is made up of nine experts, to advise the minister responsible for energy on the award of electricity supplier licenses. Such licenses are required for any commercial operator with a capacity of more than 20 kW and any domestic operator with a capacity of more than 5 kW. Instead of using the expert advice to streamline the process and to discuss very difficult cases like the licensing of large IPPs and new issues to be resolved, the ELPA is used to practically review every single license application. Thus, after being formally cleared by the Energy Division, every application is put in front of the ELPA for approval. Thus, every application is delayed at least to the next ELPA meeting, which should normally be called in an one month cycle, but recently has met at longer intervals, a process which could be done for the bulk of the applications by a streamlined process executed by the Energy Division without every license application going to the ELPA committee..

For wind energy the overall licensing and permitting processes are extremely lengthy and unclear. The first independent power producer (IPP) to apply for the necessary permits and licenses for a wind energy project reports that so far this has been an almost never ending process of trying to find out, which licenses and permits are need and which information has to be supplied to be acquired to finally get permission to operate the wind turbine. So far the company in question has spend over ten years in the process of trying to get all necessary permits and the license to operate. It can be stated that there are neither clearly specified requirements nor does a streamlined permitting process exist, which would allow to estimate the necessary time and effort to get a project from the first planning stages to realisation.

Due to the fact that standard wind turbines have capacity of well over 1 MW (internationally 2-3 MW per turbine are the present standard for onshore installations) the FTC rulings on rates paid to wind energy producers, which have an upper limit of 500 kW, don't apply. Thus, virtually each wind energy investor has to go through a lengthy negotiation process with BL&P to get an idea on the payment he will receive for the electricity produced by his wind turbine. As discussed above, this is a totally asymmetric bargaining situation, as a small IPP has to negotiate the terms of his IPP contract with the vertically integrated monopoly. Although the outcome of the negotiations is subject to FTC approval, the FTC does not have any experience to judge the fairness of such an agreement. Thus, every wind energy investor (trying to install turbines of a capacity over 500 kW) will be confronted with an extremely lengthy licensing and permitting process and an unclear situation about the possible economic returns on his investment. This has led to the situation that only one IPP has tried to undergo this procedure and that there is no wind energy capacity installed in Barbados so far.

One other factor seriously limiting the possible development of wind energy in Barbados are the distance rules applied by Town and Country Planning to the permitting of wind turbines in Barbados. Different from international procedures Town and Country Planning applies distance rules for a wind turbine to the boundaries of the property on which the wind turbine is located. Internationally the distance rules always consider the distance from objects or areas which need to be protected from certain impacts of wind energy like noise or impacts on birds and bats. If for example a distance of 500m or three rotor diameters of the wind turbine from the next house is set as a limit, this can include a number of different properties between the turbine and the dwelling. In Barbados the rule applies to the distance of the turbine to the boundaries of the property on which the turbine is located. Thus, only very large pieces of property will qualify for the location of wind turbines with the effect that most of the possible good wind sites on the island are blocked due to the ownership structure of farmland around the country. Considering the need to move to 100% renewable energy supply in the long term and the fact that wind energy will most likely be the cheapest source of renewable electricity this very unfortunate distance rule applied by Town and Country Planning may induce high cost to Barbados ratepayers and the country.

At the same time there is a lack of earmarked land for wind energy development in the present physical development plan and in the planned amendment (see Cameron et al. 2016). Only very few single locations (like the Lamberts site, for which BL&P has been planning a wind park for many years) are identified in the physical development plan and the planned amendment so far. Considering the widespread sprawl of residential property around Barbados, this lack of planning for the future location of wind energy in the best sites with the least negative impacts on all other land uses will lead to an unplanned reduction of the possible wind capacity of about 450 MW to most likely only a few ten megawatt within the next few years. Again this lack of foresight will cost Barbados ratepayers and the country dearly as a large share of the possible capacity of the most cost effective form of renewable power production will be lost due to uncoordinated planning procedures. In this respect much will depend on the inclusion of the present knowledge on the best areas for wind energy production (see Rogers 2015) in the amendment of the physical development plan for Barbados.

At the same time that a serious development of wind energy is massively discouraged by the circumstances. There is a danger that uneconomical small wind turbines will block the best available sites due to the existing incentive structure. The latest ruling of the FTC on fixed rates under the RER guarantees a tariff of 0.315 BBD/kWh (FTC 2016, p.23), which has created an extremely strong signal for small wind energy turbines in the range between 100 and 500 kW to be installed. Compared to the international cost of wind energy of about 1,700 USD/kW or 3,400 BBD/kW the assumed 7,500 BBD/kW seems to be extremely high leading to a very high tariff per kilowatt-hour. The first application for smaller wind turbines is a project of three turbines with 275 kW each with investment costs in the range of 6,000 BBD/kW (concluded from information submitted for the ELPA license). If this is build under a 0.315 BBD/kWh tariff, it will result in unreasonably high profit margins on the one hand and in the blocking of sites most likely suitable for larger turbines, which could make a higher contribution to Barbados' renewable energy supply at substantially lower cost.

At the same time that wind energy will get a relatively high tariff as compared to international cost data (more than factor 2) solar energy is given a similarly strong incentive. At first sight the 5,500 BBD/kWp used by the FTC as a basis for its calculation of the fixed tariff (0.416 BBD/kWh) seem to measure well against the average investment cost of 6,250 BBD/kWp of the approximately 500 applications for an ELPA license, but a second look reveals that these average figures are heavily influenced by seriously overpriced systems. Considering the lowest cost systems in the different size categories reveals that it is possible to construct PV systems in the size range of 0.5-3 kWp in Barbados at investment costs as low as 3,100 BBD/kWp, while PV systems in the size range from 3-10 kWp have been realised at investment costs as low as 2,130 BBD/kWp. Interestingly enough larger systems in the range of 10-200 kWp have been realised at minimum cost of 2,500 BBD/kWh. These empirical figures from Barbados show that the tariff set by the FTC can be lowered substantially and still leave substantial profit margins for the investors.

## 10.5 Status of renewable energy market diffusion

Since 2009 the installed capacity of solar PV installations connected to the public grid has increased to about 10.4 MW by the end of 2015 and to about 23 MW by the end of 2016 as Table 34 below shows. Part of the capacity reached in 2016 is the 10 MW PV plant installed by BL&P in 2016 (see IDB 2016 p. 12f). BL&P reported payments for 18.7 GWh for the renewable energy capacity installed in 2015 (see IDB 2016, p. 17), which would be equal to about 2% of the annual gross power production by BL&P, which amounted to 969.4 GWh/a in 2015 (see IDB 2016, p. 14). Although the capacity doubled in 2016 the solar power produced will most likely not have doubled as the 10 MW PV plant of BL&P came online only in the second half of 2016. The project costs are quoted to be 43 million BBD for 10 MW (Greaves and Gill, no year, slide 12). Picture 1 gives an arial view of the solar farm.

Table 34: Development of PV capacity in Barbados since 2010 (sources: UNDP no year, p.19, IDB 2016, p.12 and application data for ELPA licenses)

| Year | No. of PV Systems | Cumulative Installed Capacity (kW) |
|---|---|---|
| 2010 | 4 | 7 |
| 2011 | 8 | 14 |
| 2012 | 63 | 910 |
| 2013 | 350 | 2900 |
| 2014 | 710 | 5500 |
| 2015 | ? | 10400 |
| 2016 | 850 | 22855 |

Picture 1: Ariel view of the 10 MW PV solar farm of BL&P (source: Greaves and Gill, no year, slide 10)

By the end of 2016 there was no operating wind turbine installed in Barbados feeding electricity into the public grid. As early as 1986 a 250 kW Howden wind turbine was built at Lamberts. Obviously, the system failed after few years of operation. Nevertheless, it is reported that the broken down turbine was up for many more years.

Besides the 825 kW wind project, which applied for an ELPA license in 2016, there is one larger IPP wind energy project that has been pursued by RePower Barbados since 2009. In 2011 RePower announced the plan to build a 5.6 MW wind park in Barbados (RePower Barbados 2011, p.1). At the moment the last hurdle for the project is the modernisation of the airport radar system of Grantley Adams International Airport, which was announced for 2017 (personal communication with Mr. Barry Reid Creamer on November 23rd, 2016). In addition there are plans by BL&P to built a wind farm at Lamberts. The size of the wind farm is planned to be 10 MW composed of 11 wind turbines with a capacity of 850 kW each. It is foreseen that the Lamberts wind farm will be operational by 2018.

A grid integration study commissioned by Barbados Light and Power, which was published in March 2015, suggests that 55 MW of solar and wind energy can be taken up by the existing system without any mitigation measure and 80 MW could be integrated with modest mitigation measures (GE 2015, p. 127). The report does not give information on higher renewables penetration, as no such scenarios were commissioned for the analysis. Presently a follow up study is underway, which is supposed to look at up to 150 MW of renewable generation capacity in a power system with a peak load of a little more than 150 MW.

In the field of power production from biomass there are mainly two projects in planning stages at the moment. One is the bagasse co-generation plant planned by the Barbados Cane Industry Corporation. It is a solid biomass combustion fired with bagasse during the sugar cane harvest season, fired with river tamarind during the rest of the year. The planed capacity is 22.5 MW electric, which will require large volumes of bagasse and large land areas for river tamarind production (29 $km^2$) according to the Barbados Draft NAMA document (p. 42). More details on the project are given in Work Package 2 (WP2) above.

The second project is far more recent. It assumes that the production of sugar may not be economically viable in Barbados in the long run. Therefore, the farmers initiating the project have been looking for a grass type which can be used in crop rotation like sugar cane in order to stabilise the top soil, which yields a relatively high biomass output per acre and which can be harvested continuously all around the year. After a first pre selection successful field trials have been conducted with King Grass. The biomass yield has been 19 t of biomass at 10% moisture per acre and year with an energy content of 18 GJ/t of biomass at 10% moisture. To allow a flexible production of electricity from this biomass source, a gasification process is chosen which produces 1897,4 $Nm^3$ of syngas per ton of biomass at 10% moisture with an assumed gasifier conversion efficiency of 70% (see Fichtner 2016, p.10). The produced syngas has an energy content of 5.5 MJ/$Nm^3$(see Fichtner 2016, p.10). A gasifier with a feed throughput of 575 kg biomass/hr will produce 1,091 $Nm^3$ of syngas per hour, which would be sufficient to operate a 600 $kW_{el}$ gas engine for power production (see Fichtner 2016, p.10). (For more details see WP2 above).

Thus, besides the substantial development of solar PV since 2012 all other renewable energy developments for electricity production are still on paper and lag far behind the political ambitions of Barbados.

## 10.6 Main deficits of the present situation of renewable electricity in Barbados

In summary the main deficits of the enabling policy and regulatory framework leading to a very slow uptake of renewable energy sources for power production are:

- an insufficient incentive structure, which still leaves investors at a substantial risk
- no incentives for renewable energy investments in installations larger than 500 kW
- an asymmetrical bargaining situation between IPPs trying to invest in larger renewable energy installations and the vertically integrated monopoly BL&P
- an unclear and drawn out permitting and licensing process for installations larger than 5 kW (domestic) and 20 kW (commercial)

- a totally insufficient physical development plan not setting aside the appropriate areas for wind energy development in Barbados
- a distance ruling for wind turbines, which requires extremely large pieces of property to be able to install any sizeable turbine

# WORK PACKAGE 11: COMPARISON OF PRESENT MARKET SITUATION AND INSTRUMENTS TO POSSIBLE ALTERNATIVE CHOICES

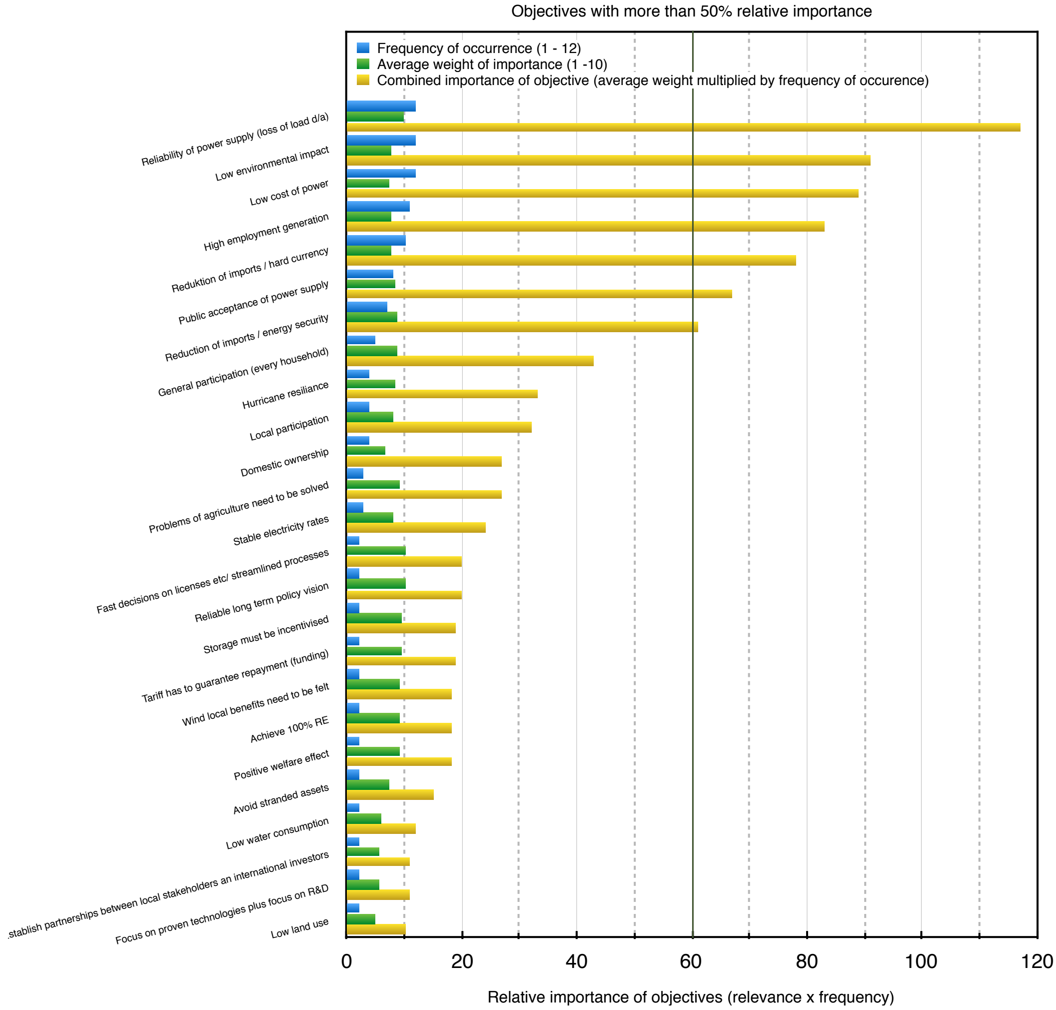
As WP10 has shown there are substantial deficits in the present market situation and the instruments used to promote an adequate market diffusion to meet the goals of the energy policy of Barbados. This Work Package will systematically compare the present instruments and the theoretically available instruments (WP9) for the promotion of renewable energy technologies with the most important objectives for an energy policy derived from the stakeholder interviews in WP1. The following six instruments will be discussed:

- Renewable Energy Rider (RER)
- Fixed rates for wind and PV under the RER
- Net metering
- Feed-in Tariffs (FITs)
- Renewable Portfolio Standards (RPS) with green certificate trading and
- Auctioning.

To recap the outcome of the stakeholder interviews Figure 1 from WP1 is reproduced below as Figure 85. The results of the interviews were condensed in a score in relative importance of a policy objective, which was defined as the product of the average weight attached to an objective multiplied by the frequency at which this was mentioned by the interviewed stakeholders (maximum possible score120). The text summing up the results on the relative importance of different goals is reproduced in the following to recap the main results from WP1:

*‚The graphing of the relative importance (RI) values shows that there is a group of four objectives, which follows the outstanding criterion of Reliability of power supply (RI=117) at a high level of importance with RI values between 78 and 91 (Low environmental impact (91), Low cost of power (89), High employment (83) and Reduction of imports (78)). Within the group the distance between every pair of neighbouring objectives is less than 7 points. Thus, this can be seen as a group of objectives of similar high importance. The next group of objectives is constituted by just two objectives, which have a distance of more than ten points to the lowest ranking objective of the top group and a distance of almost twenty points to the next objective. At the same time both objectives (Public acceptance of sources of power supply (67) and Reduction of imports for energy security (61)) are the only remaining objectives achieving at least 50% of the maximum RI score. Of the remaining objectives only three reach at least 25% of the maximum possible IR score (General participation (41), Hurricane resilience (33) and Local participation (32)) forming the next group of objectives by importance. Three further objectives reach at least 20% of the maximum possible score (Domestic ownership (27), Solving the problems of the agricultural sector (27)*

Figure 85: Frequency of occurrence, average weight of importance and relative importance of the twenty five objectives mentioned by at least to key stakeholders (Table with data in annex 1)




*and Stable electricity rates (24)), while the other ten objectives, which were mentioned by at least two stakeholders reached RI scores between 11 and 20.*

*While the results of the survey clearly point to the fact that energy policy has to address substantially more objectives than just the of short term low cost energy for the ratepayers, the number of important objectives seems to be quite manageable. Although a low cost of electricity is among the most important objectives low environmental impacts or high employment generation and the net reduction of energy imports for balance of payment and energy security reasons were seen to be of similar or even higher importance by the interviewees.*

*Besides these core objectives public participation in the new energy system in its different forms all the way to domestic and local ownership seems to be a strong concern of the key stakeholders interviewed. If a new energy policy will be able to make a substantial contribution to the solution of Barbados' agricultural problem connected to the decline of the sugar industry and if it can deliver a very high* *reliability of the future electricity supply including a substantial hurricane resilience, it will be able to address the prime concerns voiced by the interviewees*.'(text taken from WP1 above)

In the following the thirteen objectives with scores above 20 in relative importance will be used to assess the performance of six instruments to be discussed. In addition two further criteria are included in the discussion, which may have a substantial impact on the choice of the most appropriate instrument. One is the applicability of an instrument to a small island economy like Barbados, as an instrument may theoretically be able to meet all criteria, but it may still be possible that its application needs a far larger energy system and economy to be successfully applied. As we have seen in WP9 this may be the case for RPS with green certificate trading. The second additional criterion is the administrative effort, needed for the execution of an instrument. Again, this is not a policy objective in itself, but it may have strong implications for the successful implementation of an instrument. Different from the first criterion, which may be a killer criterion, if not met, the second criterion is more of a gradual nature, as it will not make it impossible to implement a certain instrument, but it may burden the administration heavily. Thus, it should be taken into account in the choice of instruments. In total a set of 13 objectives and two criteria will be used to check the six instruments under discussion. These are (in the sequence of their scores on relative importance:

- Reliability of supply
- Low environmental impact
- Low cost of power
- High employment generation
- Reduction of imports / hard currency
- Reduction of imports / energy security
- General participation (every household)
- Hurricane resilience
- Local participation
- Domestic ownership
- Solution for Barbados' agricultural problems
- Stable electricity rates
- Applicable to Barbados
- Administrative effort necessary.

Each instrument will be discussed to whether it has a positive or negative impact on each of the objectives and criteria. The results are represented in a simple matrix showing either a green field for a positive impact or a read field for a negative impact. This matrix will give an overview on the match between the objectives for Barbados' policy for the promotion of renewable energy and the available instruments.

## 11.1 Reliability of power supply

The highest scoring policy objective from the stakeholder interviews is the reliability of Barbados' power supply. It is quite obvious that any policy risking this would not be supported by any stakeholder. The instruments that might eventually risk some stability would be the original RER and net metering without controlling the capacity for which net metering or the RER are used. To the old RER this did not apply, as it was restricted to rather low volumes of PV. Net metering and an uncontrolled RER may give a very strong incentive to install roof top PV systems inducing a very fast transition to large shares of uncontrolled PV production capacity. Such fast growth can potentially destabilise certain grid regions. Thus, net metering  and (uncontrolled RER) get a negative rating on this objective (red) (see Table 35).

Table 35: Scores of the different instruments for *Reliability of Power Supply*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Reliability of power supply (loss of load d/a) | 117.0 | | | | | | | |

As Feed-in Tariffs and single Power Purchase Agreements (PPAs) are primarily price instruments they can have a tendency towards a high speed of renewable energy implementation, if they are not well linked to the prevailing cost of a technology in the market (as the German example of very fast PV expansion after a sudden price drop in 2009 has shown, see WP9). Nevertheless, a well tailored FIT will induce a reasonable growth rate, which can normally be accommodated without grid stability problems. In small electricity systems like in Barbados it should be coupled with quantity caps linked to the results of technical grid integration studies. It might even be advisable to cap quantities for a certain period of time for every feeder area, as to insure the stability of every section of the grid. Thus, FITs  are rated positive (green) as their impact on grid stability can be well controlled. For the existing fixed tariff under the RER (fixed by the FTC) a quantity cap applies already. Therefore, this fixed tariff is rated positive as well. PPAs are controlled by the utility and the FTC, thus it is extremely unlikely that the capacity installed under single PPAs will interfere with grid stability. Therefore individual PPAs get a positive rating. The quantity policies (RPS and Auctioning) control the quantity of installed renewable capacity directly either via the setting of quantity targets (standards) or via the auctioned volumes, thus, if the quantities are set in agreement with the grid capacities, these instruments should never cause any reliability problems of the power supply. Therefore, both get a positive rating.

## 11.2 Low environmental impact

As all support mechanisms will allow an increased market diffusion of renewable energy technologies, they all score positive on this account.

Table 36: Scores of the different instruments for *Low environmental impact*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Low environmental impact | 91.0 | | | | | | | |

## 11.3 Low cost of power

Although, the low cost of electricity does not have quite the score of low environmental impacts, it is virtually just as important to the stakeholders as the reduction of negative environmental impacts by increasing the use of renewable energy sources. This is to say that it would be best, if the introduction of renewable energy sources would not lead to an increase in power cost, but that it has such a high score that some increase in power cost can be traded against a high score on solving the environmental problem, but the massive market diffusion of renewable energy sources should certainly not lead to a massive increase in power cost.

The different support mechanisms include very different possibilities to curtail the cost of the market diffusion of renewable energy technologies. The renewable energy rider (RER) was designed to be cost neutral to BL&P, nevertheless, as it paid out factor 1.6 times the fuel adjustment clause, this would not hold if the RER would have been used on very substantial renewable energy capacities. The lower the cost of renewable energy sources will be compared to the fuel costs of conventional power generation it will turn more and more into an instrument unnecessarily increasing the cost of a renewable energy diffusion. Therefore, the RER gets a negative rating. Net metering and the presently fixed tariffs (fixed by the FTC) are by tendency granting to high payments for renewable energy sources and don't have any mechanism for adjustment to renewable energy cost reductions over time. Therefore, net metering and the presently fixed tariffs under the RER get a negative rating like the RER. As shown in WP9 renewable portfolio standards (RPS) allocate the full producer surplus to the producer, but they achieve cost reductions according to decreased equipment costs, while differentiated FITs can redistribute some of the producer surplus to the consumer and lower prices and auctioning can discover the marginal cost curve and minimise producer surplus and cost to the consumer. Therefore, RPS, FITs and auctions get a positive rating on low cost (see Table 37).

Table 37: Scores of the different instruments for *Low cost of power*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Low cost of power | 89.0 | | | | | | | |

## 11.4 High employment generation

Employment generation is strongly related to the ability of a support mechanism to foster national ownership of renewable energy technologies. All mechanisms requiring a substantial number of large investors, like auctioning and to a certain extent RPS will need to draw on international investors to stimulate the markets necessary for their functioning. Therefore, auctioning and RPS get a negative score on the objective of employment generation. The original RER, the present fixed tariffs under the RER, FITs in general and net metering don't need any international investors to facilitate the full scale diffusion of renewable energy sources in Barbados. Therefore, they all are rated positive on domestic employment generation. As individual PPAs will require somewhat stronger investors to negotiate with the integrated monopoly, there is some tendency to favour experienced international investors, although, this is not an absolutely necessary feature as in the case of auctioning. Therefore, PPAs are still rated positive on this objective as can be seen in Table 38.

Table 38: Scores of the different instruments for *High (domestic) employment generation*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| High employment generation | 83.0 | | | | | | | |

## 11.5 Reduction of imports / hard currency

The reduction of the necessary use of hard currency for imports or of the drain of hard currency is one of the key objectives for the country as a whole, as every dollar not leaving the country actually causes a growth of GDP. As in the employment question RPS and auctioning will lead to high involvement of international investors in renewable energy sources. International ownership will lead to the fact that the profits made will eventually be transferred out of the country to the account of the investor. This has a similar effect as the import of fossil fuels for hard currency. Therefore, while reducing the import bill for fossil fuels through the use of renewable energy sources the money will leave the country through a different route. As RPS will result in very high profits for these investors and as auctioning will most likely crowd out most domestic investors both are rated negative on import reductions. Although, individual PPAs will induce more international investment as the price oriented mechanisms, PPAs are rated positive on this objective, as the pressure for international investment is considerably lower as in the case of auctioning and RPS. The RER, net metering and the present fixed tariffs under the RER don't induce international investment avoiding the problems of RPS and auctioning. Therefore, they are rated positive. As dynamic and differentiated FITs can lead to low investment costs and can as well induce 100% domestic investment, they are rated positive on import reductions and the reduction of outflow of hard currency (see Table 39).

Table 39: Scores of the different instruments for *Reduction of imports / hard currency*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Reduktion of imports / hard currency | 78.0 | | | | | | | |

## 11.6 Public acceptance of power supply

For renewable energy a main problem in public acceptance is related to the local acceptance of wind energy. Most of the other technologies don't experience major acceptance problems, with the exception of biomass creating serious smell problems (biogas from manure) or very large energy crop monoculture, as in some cases of maize growing as an energy crop. Sometimes the use of potential food biomass for energy production can lead to strong public resentment (see a willingness to pay analysis conducted by Hohmeyer et al. in Schleswig-Holstein in 2014). For Barbados the most relevant acceptance problem to avoid will be related to the local acceptance of wind energy, if this is to be deployed with large capacities. It is well know that the local perception of wind energy is significantly different depending on the ownership structure. Citizens wind parks have lead to very high local acceptance of wind energy in coastal areas of northern Germany, while outside investment combined with a rush for the best locations has created a long lasting resistance against wind energy in Wales (see Mitchel 2004, p.1937). As discussed in WP9 auctioning and RPS have lead to very low local involvement leaving the investment to large outside investors. Therefore, auctions as the most extreme form are ranked negative, while RPS are ranked negative as well as they create a rush for the best sites. The RER and the present fixed tariffs under the RER don't induce such a strong race for the best sites and allow a high share of local investment, but they don't allow a differentiation of the rates for different wind sites to spread the installation of wind energy more evenly, as it can be done with differentiated FITs. Well tailored FITs can even include provisions for the ownership by proximity. So people living directly around a wind site could get their own small share in a wind park for their exposition (without having to pay money into the investment). Such feature, generating a regular income to these persons or families, could increase the local acceptance of wind developments very substantially. At the same time FITs could induce the investment of local credit unions, due to the fact that a guaranteed FIT will allow an extremely save investment. Through such vehicle the local acceptance of wind energy can be increased further. FITs, RER and the present fixed tariffs under the RER are ranked positive. As individual PPAs will require strong investors it is highly unlikely that citizens wind parks will be induced by PPAs. As local involvement is not very likely with PPAs they will not have a similar positive impact on local acceptance. But as PPAs don't create a rush for the best sites they are still rated positive on this objective (see Table 40).

Table 40: Scores of the different instruments for *Public acceptance of power supply*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Public acceptance of power supply | 67.0 | | | | | | | |

## 11.7 Reductions of imports / energy security

A second reason for reducing imports is to increase the energy security of Barbados. The mechanisms all induce an increased market diffusion of domestic renewable energy sources and by this virtue reduce the import of fossil fuels for power production and eventually for transportation, if the green power is used to convert Barbados' transport sector to green electricity from domestic renewable energy sources. Therefore, all support mechanisms score positive on this objective (see Table 41).

Table 41: Scores of the different instruments for *Reduction of imports / energy security*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Reduction of imports / energy security | 61.0 | | | | | | | |

## 11.8 GENERAL PARTICIPATION (EVERY HOUSEHOLD)

A wide participation in the development of renewable energy sources is a much discussed objective in Barbados and it is voiced in different forms (democratisation, local participation, general participation, local ownership). But in its most general form it can be interpreted as the request that every household should have a chance to become part of the development. Auctioning, RPS and PPAs all are addressing large investors leaving no room for a broad participation. Therefore, they are all ranked negative on this objective. The RER as well as net metering and the fixed tariffs under the RER address property owners, who own a property and have enough income to invest into their own renewable energy installation. By this virtue non owners are excluded from participating actively in the development of renewable energy sources. Nevertheless, RER, the present fixed tariffs and net metering perform substantially better than RPS or auctioning and are rated positive on this objective. As FITs have shown their potential for broad citizens involvement and offer even the possibility to involve non owners in the development of renewable energy technologies (e.g. through credit unions, pension funds or local shares based on exposition to wind parks), FITs are rated positive on this objective (see Table 42).

Table 42: Scores of the different instruments for *General participation (every household)*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| General participation (every household) | 43.0 | | | | | | | |

## 11.9 HURRICANE RESILIENCE

Hurricane resilience is another objective that has been stressed by some interviewed stakeholders. It relates very much to the objective of a stable power supply, but it addresses a very specific aspect of this. Hurricane resilience matters with wind turbines and solar PV installations just as much as with overhead grid lines. Nevertheless, if wind turbines are not built to stand a very strong hurricane, this may have a longer lasting impact on the power system as a certain share of power lines being brought down, as a failure of a large number of turbines can cause severe problems to the power supply needing to fall back on the old fossil fuel generators for a substantial period of time, as not all the spare parts necessary to repair a large scale failure of many turbines can be stocked on the island (different from the cables necessary to repair overhead lines. The same applies if large shares of PV panels would be blown away and seriously damaged. Nevertheless, all support mechanisms are neutral with respect to this objective and are rated to be neutral (yellow) (see Table 43). It can be discussed in how far an FIT system could be modified to include a provision to encourage hurricane resilience.

Table 24: Scores of the different instruments for *Hurricane resilience*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Hurricane resiliance | 33.0 | | | | | | | |

## 11.10 LOCAL PARTICIPATION

The objective of local participation relates strongly to the objective of democratisation of the energy system on the one hand and to the objective of public acceptance on the other. As it does not require every household to have a chance to be involved, it is not as strict a requirement as the general participation discussed above, but it is mixed with local acceptance. As FITs are rated positive on both objectives, they can address the issue of local participation in both respects and are rated positive on local participation as well. RER, the present fixed tariffs under the RER and net metering can involve many local home owners and score higher on public acceptance, while they are not doing quite as well as tailor made FITs, but they still are rated positive. As PPAs require large investors it is very unlikely that these will be local investors (with some exemptions). Therefore, they are rated negative on local participation. RPS and auctioning will drive the development towards a dominance of large international investors. Therefore, RPS and auctioning are rated negative (see Table 44).

Table 44: Scores of the different instruments for *Local participation*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Local participation | 32.0 | | | | | | | |

## 11.11 DOMESTIC OWNERSHIP

Domestic ownership is an other aspect of the objective of general participation, although this objective would be satisfied, if only a few large local investors would own all of the renewable energy investments. Thus, it is only a minor part of the objective, but it relates strongly back to the objective of import reductions for the reduction of the outflow of hard currency, as domestic ownership (by many or few) would keep the profits made in Barbados' economy. RER, the present fixed tariffs under the RER, net metering and FITs all encourage domestic ownership and don't need international investors. Therefore, they all are rated positive. As individual PPAs require strong investors there is a certain incentive for international ownership. As this is only a week incentive PPAs still are rated positive on this objective. As RPS and auctioning will require strong international market participation to function, they both are rated negative on this objective (see Table 45).

Table 45: Scores of the different instruments for *Domestic Ownership*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Domestic ownership | 27.0 | | | | | | | |

## 11.12 PROBLEMS OF AGRICULTURE NEED TO BE SOLVED

At least by a number of stakeholders the objective was put forward that the introduction of a large share of renewable energy in power production needs to help solve the problem of the sugar industry crisis. Even if it would not solve the problem of the sugar industry it still would need to help to establish an alternative grass crop for rotation agriculture, as the thin topsoil needs the rotation cropping with a form of grass to stabilise the soil for the cropping of other crops like vegetables, which can not stabilise the soil against water erosion in heavy tropical rain fall. Due to the fact that most stakeholders interviewed do not know this background it is a special objective. Accordingly, it was only voiced by the experts in the agricultural field, but for them this objective was extremely important.

As the RER and the present fixed tariffs under the RER don't address biomass for power production at all, they are rated negative on this objective. Due to the fact that renewable portfolio standards (RPS) address all kinds of renewables with the same green certificates and due to the fact that the use of biomass will most likely have higher cost for renewable power production as wind, biomass will be crowded out under RPS in Barbados. Therefore, RPS are rated negative on this objective. Individual PPAs can be done for power from biomass. Therefore, individual PPAs are rated positive. Net metering could be used on larger farms producing power from biomass in smaller installations (e.g. 500 kW). Therefore, net metering is rated positive. Feed-in tariffs and auctioning of quantities for single renewable technologies could induce the full biomass potential by either differentiated FITs or by technology specific auctions. Therefore, FITs and auctions are rated positive on the possible contribution to solving the central agricultural problem of Barbados (see Table 46).

Table 46: Scores of the different instruments for *Problems of Agriculture need to be solved*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Problems of agriculture need to be solved | 27.0 | | | | | | | |

## 11.13 Two additional criteria: applicability to Barbados and administrative effort

As pointed out above it is necessary to evaluate for the different support mechanisms whether they are applicable to such a small island economy like Barbados and whether the administrative effort involved in a certain support mechanism can be handled successfully by Barbados' authorities. This evaluation and the resulting scores are discussed in this subchapter.

The criterion that a support mechanism is applicable to Barbados is a necessary condition. That is to say, if this criterion is not fulfilled all other scores are irrelevant as the support mechanism can not be used in Barbados. For RER, the present fixed tariffs under the RER, PPAs and net metering the criterion is easily fulfilled, thus Table 47 shows a positive rating (green) for these support mechanisms. For differentiated dynamic FITs the answer is not as easy, as this support mechanism requires substantial knowledge about the cost of the different renewable energy options for Barbados and a good understanding of the local solar and wind resource. At the moment this knowledge is not directly available at the Energy Division and the FTC, the two agencies, which would have to administer such FITs. Nevertheless, even the German government is regularly using contractors and research institutes to acquire the necessary cost and resource information to base its FIT decisions. Specifically with the help of the EU and other international donors, putting great emphasis on the development and diffusion of renewable energy technologies, it will not be difficult to built up the necessary in house capacities at the Energy Division and at the FTC and to pay for the necessary independent consultant work to assess the actual cost of the different renewable energy options for Barbados on a regular basis. The EU Delegation seems to be quite positive on the financing of a full fledged wind measuring program to allow even community wind parks to acquire bankable wind data for the relevant sites in Barbados. Thus, even differentiated dynamic FITs can be applied in Barbados and FITs are rated positive. In the case of renewable portfolio standards (RPS) the discussion in WP9 has shown that Barbados can not implement a system of traded green certificates and a spot market for the trade of electricity. For the full implementation of RPS these markets would both need futures trading in addition to spot market trading. Therefore, RPS can not be applied to Barbados and Table 47 shows a negative rating (red). The case of auctions can not easily be answered. On the one hand, although it will be difficult for the FTC to administer frequent auctions for different renewable energy technologies, it might be possible, but on the other hand it is doubtful that the auctioned quantities will draw enough competitors to fully explore the marginal cost curves of different renewable energy technologies in each auction by a sufficient number of bids. Therefore, although it is possible to implement auctions for renewable energy they may not be very successful. As a result the criterion of applicability to Barbados is barely fulfilled, but auctions are still qualified as applicable. Therefore, Table 28 notes a positive rating for auctioning.

Concerning the second criterion the RER, the present fixed tariffs under the RER, individual PPAs and net metering require a minimum administrative effort by the FTC and the Energy Division. This is actually considering the ELPA license process as an administrative procedure which is not necessary to the present extent for these support mechanisms. Most of the present effort relates to the desire to collect additional government income but is not necessary for the administration of these mechanisms. Therefore these four mechanisms are all rated positive. As pointed out above the administrative effort for setting and frequently reevaluating differentiated dynamic Feed-in tariffs is substantial and will require frequent consultant support. Nevertheless, once the tariff structure is set, relatively little administrative effort is necessary for the application of the FITs. Therefore, FITs are rated positive on administrative effort. Renewable portfolio standards can be set by a legislative act, nevertheless, green certificates have to be granted for every kilowatt-hour of green electricity produced. Once the certificates are traded there has to be a register that follows each certificate sale and to check that all obliged entities hold the necessary green certificates at the end of a year. In case of a violation penalties have to be applied and the late compliance has to be checked. The certificate register requires a substantial effort on the side of the public administration in addition to the markets for certificates, which can be operated by private entities. Therefore, RPS are rated negative on administrative effort. Frequent auctions of quantities for different renewable energy technologies will require a very substantial effort by the public administration (in Barbados this would most likely be done by the FTC). At the moment the FTC is certainly not equipped to handle the necessary effort, nevertheless, with a substantial addition of highly qualified personnel this might be possible. Therefore, auctioning is rated positive.

Table 47: Scores of the additional criteria *Applicability to Barbados* and *Administrative effort*

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Applicable to Barbados | | | | | | | | |
| Administrative effort necessary | | | | | | | | |

## 11.14 SUMMARIZED ASSESSMENT OF THE DIFFERENT SUPPORT MECHANISMS

Table 48, summarising the assessment, shows that there is only one support mechanism that has the potential to successfully address all objectives and to fulfil the additional criteria for Barbados. This is a well tailored Feed-in tariff system. It does well on the low cost of power and very well on most other objectives. If it is not connected to clear limits of capacity to be installed, it can lead to problems in grid stability, which have to and can be avoided by capacity caps. The main disadvantages in the RER and the present fixed tariffs is that they lead to high costs for renewable electricity and that they can not address the problems of Barbados' agriculture. Nevertheless, combined with PPAs for biomass the present system can even be used to address this area, but at comparatively high electricity cost for the final consumer. The introduction of a differentiated dynamic FIT system can substantially reduce electricity cost as compared to the present support mechanisms, while it could address most other objectives better than the present system.

Renewable portfolio standards (RPS) are not applicable to Barbados, as the economy is far to small for the establishment of such system. Even if it would be applicable it would not be able to address most other objectives due to the need to bring in international investors to make the system work.

Auctioning can be implemented in Barbados with a very high administrative effort, but due to the limited market size and the number of bidders, which could be attracted to frequent auctions of rather limited capacities, it is very unlikely that it will result in low electricity cost. What is more, similar to RPS , it will not be able to address most other objectives due to the need to involve a sizeable number of international investors in the bidding to make the process work at all.

Thus, it is strongly recommended to establish a differentiated dynamic FIT system for Barbados in order to achieve its goals at low cost to the consumers and at a maximum benefit for the people of Barbados. It can be argued that for very small consumer producers a simple net metering may be used together with the dynamic FIT system for all larger producers. It seems to be reasonable to limit net metering to roof top PV installations of 1 kWp. This will allow to benefit lower income households with a rather high tariff, while it will not overburden the bill of the average utility customer.

Table 29: Summary of the scores of all support mechanisms on thirteen objectives for the renewable energy policy of Barbados and two additional criteria

| Priority objectives | Relative importance of objective (Score, max. 120) | Support mechanisms | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Barbados today | | | Options for the future | | | |
| | | RER | FTC fixed tariffs | Single PPAs | Net metering | FIT | RPS | Auctioning |
| Applicable to Barbados | | | | | | | | |
| Administrative effort necessary | | | | | | | | |
| Reliability of power supply (loss of load d/a) | 117.0 | | | | | | | |
| Low environmental impact | 91.0 | | | | | | | |
| Low cost of power | 89.0 | | | | | | | |
| High employment generation | 83.0 | | | | | | | |
| Reduktion of imports / hard currency | 78.0 | | | | | | | |
| Public acceptance of power supply | 67.0 | | | | | | | |
| Reduction of imports / energy security | 61.0 | | | | | | | |
| General participation (every household) | 43.0 | | | | | | | |
| Hurricane resiliance | 33.0 | | | | | | | |
| Local participation | 32.0 | | | | | | | |
| Domestic ownership | 27.0 | | | | | | | |
| Problems of agriculture need to be solved | 27.0 | | | | | | | |

# WORK PACKAGE 13: DEVELOPMENT OF THE MOST PROMISING MARKET DESIGN AND POLICIES FOR THE PROMOTION OF RE TECHNOLOGIES AND STORAGE UP TO A SHARE OF 100% RENEWABLE POWER

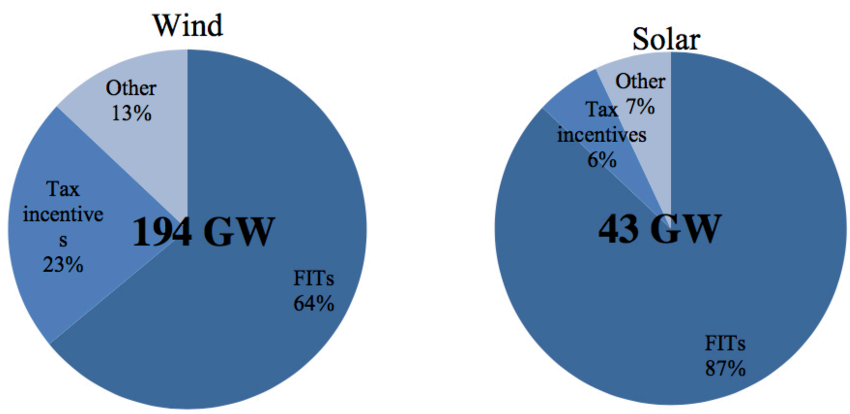
The assessment of WP11 has shown that the most promising policy for a low cost stable development of renewable power production guaranteeing stable prices for renewable energy sources is a well designed feed-in tariff system meeting the different criteria of the main stakeholders in Barbados.

As shown above a well designed FIT system can reduce costs to the ratepayers by lowering the risk for investors and banks and, by that virtue, lowering the financing costs of renewable energy investments. At the same time a well designed FIT system can reduce imports and the drainage of hard currency from Barbados as much as possible, if it puts emphasis on local ownership. Through the maximum reduction of imports and the promotion of local ownership such a FIT system can boost Barbados' GDP growth and employment more than any other support mechanism for the market diffusion of renewable energy. By the same mechanism a well designed FIT system will increase Barbados' tax income more than any other support mechanism.

## 13.1 BASIC REQUIREMENTS FOR A WELL FUNCTIONING FIT SYSTEM

Feed-in tariffs have bee used for the successful market introduction of renewable energy sources since 1990, when they were first introduced by the German parliament. Since then they catalyzed the installation of hundreds of gigawatts of renewable energy capacity in 75 different countries (see REN 21, p.109). By 2010 64% of the installed 194 GW of global wind energy capacity and 87% of the 43 GW of global solar capacity had been installed under FIT systems (see Rickerson et al. 2012, p.6). By 2015 the installed capacities increased to 443 GW of wind energy and 227 GW of PV (see REN 21 2016, p.141). Unfortunately, a similar breakdown by support mechanisms as given for 2010 is not available for 2015.

Figure 86: Global installed wind and solar capacities under different support mechanisms by 2010




Source: Tringas (2011)

This has lead to a wide array of different experiences and an intensive scientific debate about the most appropriate way to design proper FITs. Some of the most influential publications have been ‚The Feed-in Tariff Handbook' by Mendonca et al.(2010), the NREL ‚Policymaker's Guide to Feed-in Tariffs' by Couture et al. (2010), the NREL study on ‚Innovative Feed-in Tariff Designs that Limit Policy Costs' by Kreycik et al. (2011) and the 2012 UNEP report on ‚Feed-in Tariffs as a Policy Instrument for Promoting Renewable Energies and Green Economies in Developing Countries' by Rickerson et al. (2012).

The structure of the Feed-in Tariff system suggested for Barbados in this report builds on this literature and the more than twenty five years of personal involvement of the author in the development and scientific discussion of the German FIT system, which is the oldest and one of the most advanced FIT systems in the world.

FIT systems can be tailored to the specific circumstances and needs of a country. Although, there are some studies, which have focused on ‚best practice' FIT policies (like Kreycik et al. 2011, p.99-103) the UNEP report on Feed-in Tariffs (2012, p.6) points out that there may be other important policy considerations by law makers specifically in developing countries, which may lead to somewhat different FIT designs specifically tailored to a given country and its needs and objectives. Depending on how these different objectives are weighted and on the specific situation of a country a certain design of the country's FIT will result. The following policy considerations and the impact of specific FIT design options on these considerations are discussed at length in the UNEP report (see Rickerson et al. 2012):

- *Investor security*
- *Energy access*
- *Grid stability*
- *Policy cost*
- *Electricity price stabilization*
- *Electricity portfolio diversity*
- *Administrative complexity and*
- *Economic development and job creation.*

With the exception of *Energy access,* which has already been reached to a hundred percent, all of these considerations apply to Barbados. *Investor security* is a central precondition for sufficient private investment into renewable energy sources and its importance has been highlighted by several reports (e.g. Corfee et al. 2010 or DB Climate Change Advisors 2009). Based on a detailed discussion Kreycik et al. 2012, p.7) conclude that ‚FITs can minimize key investor risks when compared to other policy types, thereby lowering the cost of capital required to finance projects.' De Jager and Rathmann (2008) have estimated that this reduction can lower levelised costs of electricity by as much as 10 to 30% (see Rickerson et al. 2012, p.7).

As FITs can induce very fast renewable energy diffusion smaller countries and specifically small island countries need to protect grid stability and control the installed capacities according to the technical grid limitations. As Rickerson et al. (2012, p.7) put it ‚..countries may wish to complete detailed grid integration studies and to design their FITs to support market growth in bounded, manageable stages based on the studies‘ results.’ At the same time the cost to the ratepayers need to be taken into account in the introduction of large renewable energy capacities, as in less developed countries large shares of the population may be very vulnerable to high electricity prices. In the case that conventional power costs are vastly fluctuating and often very high, as in all countries relying on imported mineral oil products for power production, FITs for low cost renewable power production can help to stabilize electricity costs at a comparatively low level. ‚Renewable energy can decrease the magnitude of the impact of price fluctuations on ratepayers..‘(Rickerson 2012, p. 8).

Rickerson et al. (2012, p.8) point out that countries relying on a very narrow fuel mix are not only exposed to price volatility but to energy security challenges such as fuel supply disruption as well. In such cases like in the Caribbean relying exclusively on mineral oil products ‚Integrating a wider range of renewable resources into the national generation portfolios can create more flexible and resilient electricity systems‘. With respect to *Economic development and job creation* Rickerson et al. conclude that ‚FIT design can influence the degree to which economic benefits from renewable energy development are captured domestically.‘ Thus, the specific design of an FIT system needs to take these considerations, the objectives and specific circumstances of a country into account, in order to secure the maximum benefits for the country.

Rickerson et al. (2012, p.21) discuss eighteen FIT design issues from the i*ntegration with other policy targets* through the questions of *eligibility* and *tariff differentiation* to the *interaction with other incentives* with respect to the eight policy considerations. As Table 30 shows, not every policy consideration will have an impact on each FIT design issue, but there is no FIT design issue which is not influenced by at least two different policy considerations.

Table 30: FIT design issues and policy considerations (source: Rickerson et al. 2012, p.21)

| | Policy Considerations | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **FIT Design Issue** | **Investor security** | **Energy access** | **Grid stability** | **Policy costs** | **Price stabilization** | **Electricity portfolio diversity** | **Administrative complexity** | **Economic development** |
| **Integration with Policy Targets** | ✓ | | | | | | ✓ | |
| **Eligibility** | | ✓ | ✓ | ✓ | | ✓ | | ✓ |
| **Tariff Differentiation** | | ✓ | | ✓ | | ✓ | ✓ | ✓ |
| **Payment Based On** | ✓ | | | ✓ | ✓ | ✓ | ✓ | |
| **Payment Duration** | ✓ | | | ✓ | ✓ | | | |
| **Payment Structure** | ✓ | | | ✓ | ✓ | | ✓ | |
| **Inflation** | ✓ | | | | ✓ | | | |
| **Cost Recovery** | ✓ | | | ✓ | | | | |
| **Interconnection Guarantee** | ✓ | | ✓ | | | | | |
| **Interconnection Costs** | ✓ | | ✓ | ✓ | | | | |
| **Purchase and Dispatch Requirements** | ✓ | | | ✓ | | | | |
| **Amount Purchased** | ✓ | | | | | | ✓ | |
| **Purchasing Entity** | ✓ | | | | | | ✓ | |
| **Commodities Purchased** | ✓ | | | ✓ | | | ✓ | |
| **Triggers & Adjustments** | ✓ | | ✓ | ✓ | ✓ | | ✓ | |
| **Contract Issues** | ✓ | | | | | | | |
| **Payment Currency** | ✓ | | | ✓ | | | | |
| **Interaction with Other Incentives** | ✓ | | | ✓ | | | | |

For FITs a number of design and implementation options exist and should be chosen to best fit a country’s needs and objectives. Couture at al. (2010, p.XI) give a very systematic summary of these options, which is reproduced in Table 31. Two basic FIT models are differentiated: Fixed FIT rates and Premium Price FITs. Because *Premium-price* FITs are paid as a premium on top of the average spot market electricity price, they do require the existence of a power exchange with a large

Table 31: Summary of Feed-in tariff design and implementation options (source: Couture et al. 2010, p. XI)

| FIT Payment Levels | | | | |
|---|---|---|---|---|
| **Design Options** | | **Notes** | **Fixed*** | **Premium*** |
| **Price setting based on** (one of the following): | Cost of generation | Determined in relation to the actual cost of developing the technology, plus a targeted return. | X | X |
| | Value to the system | Based on either time of delivery, avoided costs, grid benefits, or other supplementary values. | X | X |
| | Fixed price incentive | Fixed payment level, established without regard to RE generation costs or to avoided costs. | X | ** |
| | Auction-based price discovery | Periodic auction or bidding process, which can help set technology- and/or size-specific FIT payment levels | X | ** |
| **Payment differentiated based on** (one or more of the following): | Technology and fuel type | Tailors the FIT policy to target desired technologies and/or fuel. Payment levels broken out to recognize differences in cost, by project | X | X |
| | Project Size (kW or MW) | Helps stimulate both large and small projects by offering different prices for each. Lower payments are awarded to large generators to account for economies of scale. | X | X |
| | Resource quality | Can be used to limit windfall profits and dispersing projects and benefits across jurisdictions. | X | ** |
| | Location (or application) | Can help target specific applications such as rooftop PV or offshore wind energy. | X | ** |
| **Ancillary Design Elements** (one or more of the following) | Pre-established Tariff Degression | Pre-determined downward adjustments (typically annual) for subsequent projects to track, and encourage, cost reduction | X | ** |
| | Responsive Tariff Degression | Enables the rate of market growth to determine the future rate of degression, and thus, the future FIT payment level | X | ** |
| | Inflation adjustment | Protects the real value of RE project revenues from changes in the broader economy (i.e. CPI) | X | X |
| | Front-end loading | Higher tariff for an initial period, replaced by lower levels afterwards; helps financing. | X | X |
| | Time of Delivery | Tiered payment levels according to times of high and low demand (by day/season); encourages market-orientation | X | X |
| **Further differentiated with bonus payments to encourage:** | **High efficiency** systems (e.g. cogeneration), use of specific **waste streams** (e.g. farm wastes, municipal wastes, construction and demolition waste, etc.), **physical location of systems** (e.g. building-integrated), **repowering** of old wind and hydro-electricity projects, certain **ownership structures** (e.g. community-ownership), use of innovative technologies, etc. | | X | X |

| Implementation Options | | | |
|---|---|---|---|
| **Implementation Options and Notes** | | **Fixed*** | **Premium*** |
| **Eligibility** | **Project Owner:** can be limited to certain investor or owner types | X | X |
| | **Technology**: can include all renewable technologies or a subset | X | X |
| | **Size**: can be designed for all project sizes or a subset | X | X |
| | **Location**: can be limited to certain areas on the grid | X | X |
| **Purchase Obligation** | Yes – requires the utility to purchase the power generated from the project | X | |
| | No – the RE developer sells the power into an active spot market | | X |
| **FIT Policy Adjustments** | **FIT Payment Adjustments:** Adjustments to FIT payment levels over time (e.g. annually) | Optional | |
| | **FIT Program Adjustments:** Adjustments to FIT policy structure and design (e.g. 2-4 years) | Optional | |
| **Caps** | Program-wide total capacity cap (MW, often by technology) | Optional | |
| | Individual project size (MW by project, usually technology-specific) | | |
| | Total program cost (either total dollars per year, or in sum) | | |
| Give renewables **grid interconnection and/or dispatch priority**, to the extent possible | | Optional | |
| **Obligate** the project owner to provide a forecast (day-ahead or hour-ahead) to help with balancing | | Optional | |
| **Transmission/ interconnection** | **Shallow:** Only the costs to connect to nearest transmission point, not including upgrades | Optional | |
| | **Deep:** All costs required for grid connection, including trans. & substation upgrades | | |
| | **Mixed:** Includes cost of connection and sharing of trans. & substation upgrade costs | | |
| **Funding options** | Ratepayer funded (e.g. rate base or through system benefit charge) | Must choose one or more ways to fund the FIT policy | |
| | Taxpayer funded (e.g. a specific allocation from the country's treasury) | | |
| | Supplementary options (carbon auction revenues, etc.) | | |
| **Inter-utility cost sharing** | Any marginal cost increases are shared across utilities in a jurisdiction | Optional | |

* Fixed FIT policies offer a guaranteed price for a fixed period of time for renewable energy; premium FIT policies offer either a sliding or a constant premium payment on top of the spot market price. They represent two different ways of designing a feed-in tariff policy.
** Incorporating such a design in a premium-price policy is theoretically possible, but has not yet been implemented.

number of producers trading electricity at such market. Therefore, *Premium-price* FITs don't apply to Barbados, which does not have such a market structure and a spot market for electricity due to the very limited total system size. Therefore, the last column of Table 31 on *Premium* FITs does not apply to Barbados.

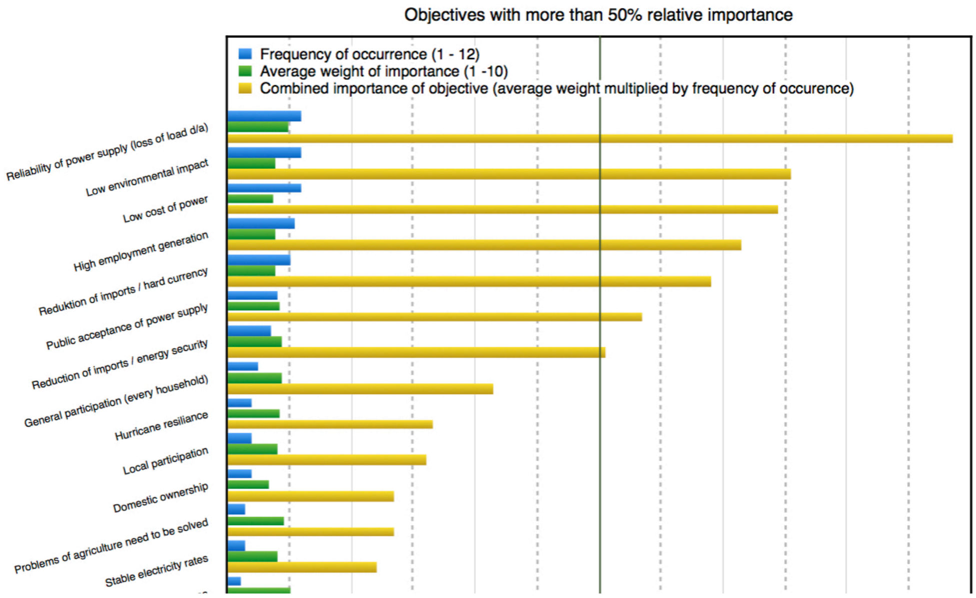
From the international experience Couture et al. (2010) derive a number of best practices for the design of FIT payment structures and for the implementation of FITs. For the payment structure **price and policy stability** are of great importance as ‚Rapid or unexpected changes in payment levels or policy structure can damage investor confidence and significantly impede the pace of renewable energy growth (Lüthi 2010 and Dinica 2006 cited in Couture et al. 2010, p.99). Successful FIT policies rely on **differentiated payments based on the generation costs of renewable energy**. By introducing a high degree of differentiation in setting payment levels (e.g. by technology, by project size, by location and by resource quality) a country can ensure that diverse renewable energy investments are fostered (see Couture et al. 2010, p.99). Such ‚high level of differentiation also ensures that jobs, manufacturing opportunities, and associated economic activities are created in several renewable energy technology sectors‘ (Couture et al. 2010, p.99). **Scheduled ‚tariff digression** helps to anticipate cost reductions in the future, while reducing the risk of overcompensation in the long term‘ (Couture et al. 2010, p.100). For dispatchable renewable energy sources (biomass not wind or PV) differentiated FIT prices by time of delivery (or size of residual load) can induce the production of electricity from such renewable resources at the times of the greatest need for them, which can create a number of benefits for electricity customers, grid operators and society (see Couture et al. 2010, p.100). Targeting certain policy objectives like local investment and community involvement by **bonus payments** as part of the FIT can help to meet certain policy objectives.

Concerning the implementation of FIT policies there are a number of best practice points, which can be readily identified. **Guaranteed grid access** for the renewable electricity produced has been one of the cornerstones of successful FIT policies. In the European Union every country has ‚to offer guaranteed, nondiscriminatory access to the grid for all renewable energy producers‘ (see Couture et al. 2010, p. 101). This ruling ‚played a significant role in increasing investor confidence in the market and helped reduce the administrative barriers to renewable energy development‘ (see Couture et al. 2010, p.101). The requirement of a **purchase obligation by utilities**, which guarantees that renewable electricity will be purchased wherever and whenever it is produced, is important for investor confidence, as it provides a higher degree of certainty and reduces the perceived risk of the policy to banks and other financiers (see Couture et al. 2010, p.101). **Clear transmission and interconnection rules** can help to streamline connection procedures and lower administrative costs for renewable energy projects (see Couture et al. 2010, p.101). **Fair sharing of all incremental costs of new renewable capacity** can ensure the success of the policy because it mitigates the problem of free-ridership. Combined with a high degree of transparency this can lead to a high level of public acceptance of the overall policy. ‚The most common practice for cost sharing is to integrate any added costs directly into the rate base for all electricity consumers‘ (Couture et al. 2010, p.101). This is normally done in the form of a uniform renewable energy levy applied to each kilowatt-hour of electricity sold. **Progress reports** outlining milestones, anticipated revisions, any difficulties and unresolved issues and any recommendations going forward are often required from either utilities or authorities responsible for overseeing energy issues (see Couture 2010, p.101). These reports provide a tool that can help citizens and politicians to better understand the development of renewable energy in their country (see Couture 2010, p.101).

## 13.2 MAIN DESIGN FEATURES OF THE FIT SYSTEM PROPOSED FOR BARBADOS

For all design and implementation options for fixed FIT systems it has to be discussed, which options should be chosen for Barbados to give the best fit to the specific circumstances of a rather small isolated island system (150 to 200 MW peak load) and to the most important policy objectives voiced by the different stakeholders reproduced in Figure 87 below. In the following the different design and implementation options are discussed in the sequence given in Table 31 above, which was taken from Couture et al. (2010).

Figure 87: Most important renewable energy policy goals mentioned by the interviewed stakeholders for Barbados




### 13.2.1 Price setting

For the setting of the price or tariff there are four different possibilities available. By far the most frequently used choice is a **tariff based on the production cost** of a specific renewable energy technology plus an fair return on the investment. This approach has been used successfully in many countries and it leads to high investor confidence, investment security and low financing cost. Different from the cost based approach is the **value to the system** approach, which is given by the avoided cost of conventional production. In some cases these avoided costs have been used as a basis for the tariff setting. As experienced with the RER (Renewable Energy Rider) such tariff is subject to extreme fluctuations, as it hinges on the price development for conventional fuels used in electricity production. Therefore, value based tariffs lead to low investment security and investor and bank confidence. This in turn leads to relatively high financing cost due to the necessary risk margins calculated by the investors and financing institutions. A third option to set the tariffs is a **fixed price incentive**, which is set independently of the actual cost or the value of the electricity produced. Such fixed incentive, if it is successful in inducing renewable energy investments, is most like set too high as compared to the actual production cost and will in turn lead to higher cost for the ratepayers and the economy at large. The last option are **auction based price discovery** processes. Such procedure has been used in China, where the feed-in tariffs were based on initial auctioning procedures. As with a system fully based on auctions and tendering the success of such price setting procedure will depend heavily upon a sufficient number of bidders in the auction process. For a relatively small market like Barbados this will most likely only be possible if a large number of projects or a very substantial total capacity is pooled in the auction. It should be discussed whether such procedure might be applicable for a pooled order of wind turbines or wind parks.

In the case of Barbados it seems to be most appropriate to base the FIT tariff setting on the cost of generation plus a fair return on the investment. This approach should lead to high investor confidence and low financing cost and by that virtue to the lowest possible renewable energy cost for Barbados. Table 32 gives an overview of the suggested choices for the design of the new FIT system for Barbados.

### 13.2.3 Payment Differentiation

International experience shows that a differentiation by technology, fuel (in the case of biomass), project size, resource quality and location (or application) can help to induce the development of all relevant renewable energy technologies, the participation of a large part of the population in the investment in renewable energy production and at the same time avoid overpaying installations with specifically low costs or favourable resources. Due to the advantages of differentiated FIT rates it is suggested that the FIT system for Barbados will be **differentiated by technology** and fuel type (PV, wind energy, solid biomass, biomass gasification, biogas from manure and agricultural residues, and possibly waste to energy). At a later point in time other technologies like OTEC (ocean thermal energy conversion) or wave energy may be added when they reach the stage of technical maturity.

In the case of solar PV and biomass differentiation by project size is international standard due to the cost digression over size. It is suggested that the FIT system for Barbados will be **differentiated by project size** within these technologies. In the case of PV four size categories for roof mounted systems are suggested (1 to  10 kW, 10 to 100 kW, 100 1,000 kW and larger than 1,000 kW). As ground mounted PV systems are normally very large (larger than 1,000 kW) no cost digression over size is suggested. In the case of electricity production from biogas based on manure the costs for smaller installations are substantially higher than for larger ones. Thus, five size ranges are suggested in line with international experiences, namely less than 75 kW, 75 to 150 kW, 150 to 500 kW, 500 to 5,000 kW and larger than 5,000 kW. Further size differentiations for other technologies are not suggested. In the case of wind energy a size differentiation should not be used in order to ensure that larger wind turbines are used in the development, as large turbines make far better use of a limited wind energy potential restricted by the available area. Small wind turbines would use up substantially more space for the same output and by this virtue increase difficulties with the acceptance of wind energy. Specifically in the case of solar PV a sufficient differentiation by project size can ensure that every household owning some roof space has a fair chance to participate in the investment in renewable energy technologies.

In the case of wind energy a payment **differentiation by resource quality** has become international standard. This is to make sure that the owner of a wind turbine at a very favorable location is not overpaid and that all relevant wind sites, which should contribute to the wind energy supply of a country are chosen for investment. There are a number of different ways, which have been used for the payment differentiation by resource quality. Most of the approaches chosen are used in combination with the so called front-end loading of payments, which grants a higher tariff for an initial period of operation and a lower payment for the rest of the operational life of an installation. For the FIT system for Barbados it is suggested that a front-end loading of the tariff is based on the output of a reference plant in a good location and is tailored to a 10 year loan based financing. Thus, the reference plant will get the high tariff

Table 32: Suggested FIT design for Barbados: 1. FIT payment choices

| | Design options | Possible choices | Choice for Barbados |
|---|---|---|---|
| | | FIT Payment choices | |
| 1 | **Prices setting based on** | - Cost of generation<br>- Value of generation / avoided cost<br>- Fixed price incentive<br>- Auction based price discovery | Cost of generation |
| 2 | **Payment differentiation by** | Technology | Yes (wind, biomass, waste to energy, storage) |
| 3 | | Fuel type (biomass) | Yes (biomass: bagasse, syngas from gasification) |
| 4 | | Project size | Yes (PV, biomass) |
| 5 | | Resource quality | Yes (wind, PV) |
| 6 | | Location (roof top, facade, ground mounted) | Yes (PV: roof top or ground mounted) |
| 7 | **Ancillary design elements** | Pre-established tariff degression | Yes (wind, PV, biomass) |
| 8 | | Indexed tariff degression (international cost development) | Yes (PV, wind, storage) |
| 9 | | Responsive tariff degression | Yes (PV, wind, biomass, storage) |
| 10 | | Inflation adjustment (O&M and fuel costs) | Yes (O&M for wind, PV, storage and waste to energy; fuel costs for biomass) |
| 11 | | Front-end loading | Yes (PV, wind, biomass, storage) |
| 12 | | Time of delivery (dispatchable production) | Yes, eventually (for biomass and waste to energy) |
| 13 | **Further differentiation (bonus)** | Bonus for community ownership | Yes (wind, PV) |
| 14 | | Ownership by impact (proximity to wind turbines) | Yes (wind energy, up to 10% of investment cost) |
| 15 | **Payment duration** | Short, medium and long term | Long term (20 years plus x) |
| 16 | **Payment currency** | BBD / USD | BBD |
| 17 | **Net metering** | Yes / No. Capacity limits are possible. Limitation to certain customer groups is possible. | Yes (PV with a capacity limit of 1 kWp and a limit to 25% of all households (lowest income quarter) |

for its output calculated for the first ten years. Every other plant will get the high tariff for the same number of kilowatt-hours per kilowatt installed capacity as the reference plant. Thus, an installation in a very good location may get the high payment only for nine years while an installation in a less favourable location may get it for twelve or fifteen years.

A **differentiation by application or location** may apply to PV, where it is desirable to use much of the available roof area in order not to use too much open space for PV installations. Thus, PV FIT rates are normally differentiated between rooftop and ground mounting. Sometimes facade integrated PV is paid an even higher special FIT rate as the solar radiation on a vertical surface is considerably lower than on a solar panel positioned at an optimal angle. For wind energy a differentiation between on- and offshore locations is international standard as offshore installations have far higher investment and installation cost. In the case of Barbados offshore wind can not be seen as a mature technology due to the extreme water depth around Barbados requiring floating wind turbines, which are just in the demonstration phase and which are still far too expensive for a serious inclusion in a FIT system. Setting such rates would induce extremely high electricity costs for the Barbados ratepayers. Nevertheless, such rates may be established once the technical and economic viability of floating offshore wind turbines has been proven and generation costs have been seriously reduced. Thus, it is suggested to differentiate the FIT rates in Barbados between rooftop and ground mounted PV systems and to consider special FIT rates for offshore wind energy once the technology has matured.

### 13.2.4 Ancillary Design Elements

International experience has shown that a **tariff degression over time** is necessary for new installations as renewable energy technologies experience considerable cost reductions with growing production volumes. Keeping tariffs for future installations at the initial level would result in overpaying the investor, excessive returns and unnecessarily high energy costs for ratepayers and the economy. As a result **pre-established tariff degressions** have been introduced in most FIT tariffs trying to anticipate future cost reductions. Such degression rates are usually based on so called technical learning curves, which show the rate of cost reduction for every doubling of production of a certain product. This rate is then combined with estimates of future global production volumes of the technology in question to arrive at pre set the annual cost degression rates. In recent years **responsive tariff degression** rates have been set to capture cost reductions resulting from non anticipated growth in production volumes (e.g. in Germany or Spain). This development was mostly induced by the unprecedented price drop for PV systems between 2009 and 2012, which lead to substantial overpayment of investors, as the pre-determined tariff degressions reduced the tariff far too slow, and to an unprecedented investment boom due to extremely strong investment incentives. In order to control this development responsive tariff degressions were introduced. If a target capacity corridor was exceeded by the installed capacities this lead to an additional reduction of the pre-set tariff. If the installed capacities were in the target corridor the pre-set tariff reduction was applied and if the target corridor was not reached the pre-set tariff reduction was reduced by a given percentage. Specifically in smaller electricity systems, like in the case of small island states, a combination of pre-established tariff degression combined with a responsive tariff element is likely to allow for a controlled capacity expansion and an adequate tariff reduction according to the actual cost decreases in the different technologies. Thus, it is suggested that the Barbados FIT system includes a combination of pre-establish and a responsive tariff degression.

Although the costs of most renewable energy technologies are mainly based on investment costs there are some cost elements, which are subject to inflation. In the case of constant feed-in tariffs (once granted at the time of commissioning) this leads to a tariff reduction in real terms reducing the calculated return for the investor. In some countries an estimated long term inflation rate is included in the initial calculation of the feed-in tariff, as in the case of Germany. In countries with substantially fluctuating inflation rates such approach may not be feasible due to the fact that the long term inflation rate can not be estimated with any degree of certainty. In such cases like in Uganda a given share of the total cost of a technology assumed for operation, maintenance and fuel cost is subject to an **annual inflation**

**adjustment,** while the rest of the tariff is kept constant (see Rickerson 2012, p.49), as the investment costs are not subject to inflation once the investment has been made. As the share of operation and maintenance (O&M) costs varies substantially between different technologies and as only a few renewable energy technologies rely on fuels (e.g. biomass) the percentages subject to inflation adjustment should be differentiated by technology. As it seems to be relatively difficult to estimate a long term (20 year) inflation rate for Barbados it is suggested that inflation adjustments are introduced for Barbados' FIT system.

Investments in renewable energy installations are normally credit financed to a large extend. As most renewable energy technologies are investment cost dominated this leads to high financing costs during the repayment phase of the loan and a sharp drop in annual costs after the loan has been repaid. If a feed-in tariff is paid as a constant rate per kilowatt-hour for the full time of operation this leads to a constant income stream. As a result the cash flow from the project will be negative during the repayment phase and highly positive during the last years of operation once the loan is paid back. Specifically for smaller investors such negative cash flow over ten and more years is impossible to bear and leads to a crowding out of investors with low capitalisation. This consideration has lead to the so called **front-end-loading** of feed-in tariffs granting a high FIT tariff during the first years of operation, while the loan is paid back, and a substantially lower FIT tariff during the rest of the operation. Such front-end loading can be designed to result in a positive discounted cash flow of the investment in every year of the operation. In the case of Germany front-end-loading has lead to extremely high bankability of wind energy projects, which have been financed with up to 100% loans in some cases, allowing small investors and community wind parks to take a major share of the initial wind energy investments in Germany. It is suggested that the Barbados FIT system should use front-end-loading to allow for positive cash flows over the whole operation period of renewable energy investments and to meet the objective of wide local participation to the highest possible extend.

As future RE based electricity systems will rely mainly on intermittent renewable energy sources like wind and solar energy all dispatchable power production units will need to fill in the gap between the hourly system load (demand) and the production from the intermittent sources. This gap is called residual load. The requirement to meet the residual load applies to renewable energy sources like biomass or hydropower just as to conventional generators. At the same time constant feed-in tariffs for such sources as biomass would lead to a constant electricity production at full capacity for as many hours during the year as the technology allows. Thus, a constant feed-in tariff for dispatchable renewable energy sources leads to an undesirable mismatch between the induced and the necessary electricity production. In order to avoid such mismatch the feed-in tariff for dispatchable renewable energy sources needs to be **responsive to residual load**. Such a tariff grants high rates in case of a high residual load and goes to zero in the case of a zero or negative residual load. Zero or negative residual load signals that the intermittent renewable energy sources are already satisfying all demand or are even producing more electricity than needed. In such cases it would be a waste of energy and money to produce electricity from dispatchable sources or even pay for fuel cost. In order to minimise the electricity production cost to the Barbados ratepayer and to the economy it is suggested that residual load responsive feed-in tariffs are selected for all dispatchable renewable energy technologies.

### 13.2.5 Further Bonus payments

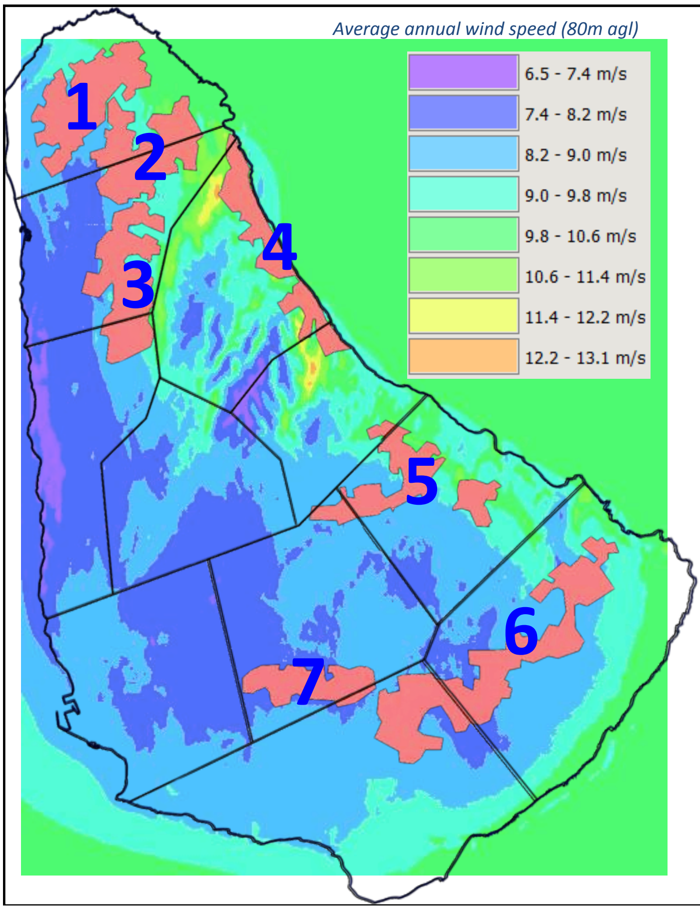
**Additional bonus payments** can be used to foster specific policy targets. In some cases there are bonuses paid for local ownership to foster community development and local and regional economic benefits. For example Ontario has incorporated a bonus for community-led projects into its feed-in tariff policy (see Couture et al. 2010, p.48). At the same time a higher FIT rate can be paid for locally manufactured systems like in the case of mini-hydro systems in Sri Lanka (see Rickerson 2012, p.36). As local content, domestic ownership and broad citizen participation feature high on the list of policy objectives for Barbados it is suggested that a feed-in tariff differentiation according to community ownership is introduced for wind energy, which is very susceptible to local acceptance, and possibly for larger ground mounted solar installations. It needs to be discussed in how far a certain threshold for local content can be used for FIT differentiation. Such differentiation would only make sense if there are sufficient preconditions (local production capacities) for such differentiation to have a positive impact on local content.

**Ownership by proximity to wind turbines (ownership by impact)** is a new measure suggested for Barbados, which builds upon the experiences made in Germany and in many other countries that acceptance of wind energy is critical for a high level deployment of wind energy and the fact that acceptance of wind turbines very close to homes depends on participation in the project. In northern Germany citizen wind parks with very broad local ownership have lead to situations where the population of some villages, which were already heavily exposed to near by wind parks (they own), asked for the permission to erect additional wind parks on the village territory beyond the actual country planing of the federal state of Schleswig-Holstein. At the same time investor based projects in the vicinity of other villages met with very strong resistance, although the total exposition to wind energy was far lower in the second case. As Barbados has a very good wind resource, but as it is very densely populated, wind turbines will often need to be placed relatively close to at least some dwellings to make adequate use of the cheapest energy source available to Barbados. Due to the distribution of wind speeds and open space around Barbados most wind parks will be located in the north and the east of the island (see Figure 88) in relatively low income areas. Thus, many of the people, who will be exposed to wind parks will not have the necessary funds to invest into the wind parks to become part of the owners.

The proposition is that citizens living very close to a wind park, who are directly effected by audible sounds from the park, are automatically granted a small share in the ownership of the park. For all citizens affected by a wind park this share should not exceed 10% of the total ownership and the shares should decrease with the square of the distance to the closest wind turbine (just as the noise level decreases) and should take into account the actual noise impact at the dwelling based on the annual distribution of wind speeds and wind directions in an average reference wind year.

As this additional ownership has a right to a proportionate share of the annual profit made by a wind park, the feed-in tariff needs to be increased by such factor that the original investors get the same return on their investment as if the additional ownership would not exist. In order not to interfere with the normal business of successfully running the wind park the additional shares are silent and don’t have voting rights. Such ownership shall not be sold and will not move with a person moving out of the dwelling, but it will remain with the persons actually living in the location. As the actual return on the invested capital, not on the loan financing, is a minor part of the total FIT payment, an increase of the value of the ownership (equity) by 10% leads to a significantly lower percentage increase in the FIT payment. Thus, a high degree of local acceptance can be achieved by a comparatively low increase in the specific generation cost of wind energy. At the same time the average electricity cost for Barbados can be kept low by a better utilisation of Barbados’ cheapest renewable energy source.

Figure 88: Average annual wind speeds at 80m and possible zones for locating wind turbines on Barbados (Rogers 2015)




| Zone | Area ($km^2$) |
|---|---|
| 1 | 9.4 |
| 2 | 9.2 |
| 3 | 9.4 |
| 4 | 7.0 |
| 5 | 7.9 |
| 6 | 16.2 |
| 7 | 5.2 |
| | **64.2** |

### 13.2.6 Payment Duration

FIT payments can be guaranteed for a short (3 to 7 years), medium (8 to 14 years) or long term (15 to 20+ years) (see Rickerson 2012, p.41). As Couture et al. (2010, p.72) put it ‚Typically, a FIT is a long-term policy commitment, involving contracts that span 15-25 years.‘ In their evaluation they come to the result that ‚Longer term contracts provide stability, security and risk reduction to the RE developers and investors. The contract length is generally considered essential in minimising financial risks, with longer contract terms generally leading to a lower cost of capital and a higher degree of investment security‘.

The longer the payment is guaranteed the better is the foresight of the discounted cash flow from a project and the lower is the financial risk for the investor and the financing bank. This in turn leads to lower interested rates on borrowed capital and lower risk premiums to be calculated by the investor. What is more, longer term contracts for fixed-price FIT policies can help to hedge against the risk of volatile future energy prices and lower the up front cost of RE development as compared to FIT rates only fixed over the short or medium term (see Couture et al. 2010, p.73).

Therefore, it is suggested to guarantee the FIT rates in Barbados for at least 20 years. Notwithstanding that the rates will be split into two different rates due to the suggested front-end loading for the first 10 years of the reference plant operation. Although, the FIT is split into two different tariffs for the first and second phase of the guarantee period, the FIT rates are guaranteed from the beginning for the entire 20 year period. Thus, an investor or bank knowing the technical specifications of the installed devices and knowing the quality of the specific site can calculate the discounted cash flow of an investment under this tariff structure for the next 20 years. Together with the suggested automatic annual inflation adjustment the long term FIT guarantee leads to a very low risk investment situation.

Even without the annual inflation adjustment for operation and maintenance cost, which is not used in Germany, the state owned investment bank of the federal German state of Schleswig-Holstein has financed hundreds of wind energy projects with a total volume of more than 2 billion Euros since 1990 under the German FIT law. According to the head of the bank not a single loan from this portfolio has faulted making this the only business area of the bank with no defaulting loan (personal communication with the author).

### 13.2.7 Payment Currency

The payment under an FIT can be made in local currency or in an international currency like USD or EURO, with the later becoming more important, if foreign currency financing is involved over the entire lifetime of a project. This may be especially the case, if international investors own a project and expect their returns in USD or EUROs. If the FIT is paid in local currency such investors may be subject to a substantial devaluation risk of the local currency (see Rickerson et al. 2012, p.72). Even if a project is financed by local investors a major share of the equipment will need to be paid for in hard currency. If this only happens at the beginning of the project and the FIT rate is guaranteed on the basis of the actual exchange rate at the start of the operation of the project, the exchange rate risk can be eliminated for local investors even if the FIT payments are made in local currency. The only remaining devaluation risk for local investors would result form a FIT rate guaranteed in local currency at the time of the project application and serious delays in the realisation of a project for example in the case of a larger wind park, which may take more than a year from the original application to full operation.

As Barbados aims for local investment in order to maximise the benefits for the local economy, it is recommended that the FIT payments are made in Barbados Dollars and that eventual devaluation risks between the original application and the first day of commercial operation of the installation are taken care of by an adjustment of the FIT according to a change of the exchange rate between the application and the first day of operation. If the exchange rate of the Barbados Dollar will remain fixed to the US Dollar no such adjustment will be necessary.

### 13.2.8 Net metering

As pointed out before, large scale net metering is seen critical in the international discussion as it can lead to the shifting of the overall system costs for the grid, for back-up capacity and for the maintenance of frequency and voltage stability to all other customers not under the net metering system. With a high penetration of private roof top PV systems this can lead to an unfair burden sharing of the system costs of electricity production shifting the costs from high income households to the poorest customers not able to afford a PV system or not owning a house. For this reason Hawaii has discontinued its very successful net metering scheme in October 2015 (see Dyson and Morris 2015).

Nevertheless, net metering can provide a very strong incentive to low income households in Barbados to install small PV systems on the roofs of their houses (if they own some small property). Although, this shifts some of the costs to the other electricity consumers, this can be justified for social reasons if net metering is restricted to low income households. In addition such provision would lead to the broadest possible participation in the necessary transition of the energy system and to the broadest possible support for the transition. Therefore, it is suggested to introduce net metering only for PV systems up to 1 $kW_p$ and only for the lowest income quarter of the households of Barbados.

In the suggested net metering system the electricity produced beyond demand can be banked for the following month. At the end of each year overproduced electricity not used by the owner of the PV installation will be paid for by the grid operator. The rate will equal the consumer tariff applicable to the owner of the installation. Every household can own only one 1 $kW_p$ PV system under net metering. Net metering is limited to the quarter of Barbados' households with the lowest income at the time of connection of the PV system. This status has to be proven by official papers like an income tax declaration or a social security payment receipt. The maximum installed PV capacity under net metering is limited to 27.5 $MW_p$ (a quarter of 110.000 household customers of BL&P times 1 $kW_p$). As soon as other PV capacity is owned by the same household the net metering facility will become part of a regular PV installation under the appropriate FIT rate and net metering for the 1 $kW_p$ installation will be terminated.

### 13.2.9 Eligibility

In the international discussion four different eligibility criteria are discussed: the operators included in the FIT system, the technologies eligible to participate, the allowed project size and the location of the interconnection with the grid (see Couture et al. 2010, p.67). These criteria are sometimes used to target the FIT policy to certain operators, technologies, project sizes and locations. In many countries FIT rates are differentiated by technology and project size, but they are eligibility is hardly limited at all, like in the case of Germany, where every renewable energy technology has its own FIT tariff and every operator is eligible to participate in the system. Project size is only limited in the case of solid biomass combustion (max. 20 $MW_{el}$) and landfill gas combustion (5 $MW_{el}$).

In the case of Barbados a very broad participation of different local operators will allow a fast diffusion of renewable energy by engaging as many local investors as possible and it will help to mobilise very broad support for the energy transition in all parts of society. Considering the objectives voiced by the different shareholders preferring domestic and local **ownership** it seems to be advisable to put restrictions on international investments in renewable energy installations in Barbados. Such restrictions can be implemented by restricting the eligibility of international investors to participate in the FIT system. Other limitations of eligible ownership don't seem to be advisable.

At the moment only a few mature **renewable energy technologies** apply in Barbados due to its geographical and physical preconditions. These are solar PV, onshore wind energy and the use of different forms of biomass. Hydropower can only contribute a very small annual power production and seems to be difficult to realise for geological reasons with water disappearing in the porous underground. Concentrating solar power (CSP) is not applicable in Barbados due to the frequent clouds over the island. CSP requires a virtually cloudless sky for its operation as it collects only direct parallel sunlight. Other technologies like offshore wind energy, OTEC (ocean thermal energy conversion) or wave power, have not reached the level of technical and economic maturity necessary to contribute to the production of renewable electricity at a reasonable cost level. Therefore, these technologies should not be promoted by FIT payments before they have reached technical maturity and reasonable cost levels, as they would impose an unreasonable burden on Barbados' ratepayers. Thus, it is suggested to include solar PV, on shore wind energy and biomass in Barbados' FIT system for the time being. Table 33 gives an overview of the suggested choices for the different implementation options suggested for Barbados.

Concerning the **size of systems** eligible for FIT payments it can be discussed whether a maximum system size should be introduced. Internationally this is handled very differently with some constituencies introducing overall size limits of 10 MW to all technologies (like Ontario in 2006), while others introduced size limits only for some technologies (like Spain for ground mounted PV or Germany for biomass and landfill gas). As installed overall capacities will need to be restricted in Barbados by grid area for reasons of technical grid stability on the one hand, while the utilisation of the best wind resources may require larger wind farms on the other, it does not seem to be advisable to introduce additional size restrictions of renewable energy installations at the moment.

Concerning the **location** of systems eligible for FIT payments it is good international practice to restrict the use of wind energy to preselected areas, which qualify for the use of wind energy according to different criteria. Such criteria are the quality of the wind resource, the distance from dwellings, the distance from natural protection areas and the obstruction of very scenic views. Normally, such priority areas for wind energy are preselected in a robust planning process with adequate public participation. Once the priority areas are selected investors have a higher planning security than in constituencies without such planning framework, as it can be seen in the different federal states of Germany with different planning procedures. It is suggested that Barbados Town and Country Planning initiates such a dedicated planning process for priority wind areas for Barbados in close cooperation with the Energy Division. Similar restrictions on the location of installations don't seem to be necessary for solar PV as the solar resource is more evenly distributed around the island and as the impacts of PV are extremely limited. In the case of biomass combustion general restrictions may apply to the location of larger combustion facilities and need to be considered as applicable.

### 13.2.10 Purchase obligation

Purchase obligations have been a critical part of the successful FIT systems implemented in different European countries and have been an important part of increasing investment security and reducing risk (see Couture et al. 2010, p.70). A purchase obligation requires the grid operator to purchase all renewable electricity offered to the grid and to sell it to the ratepayers. It guarantees a project developer that he can sell all the renewable electricity produced by his project allowing him to calculate his future cash flow from his investment as soon as he knows the amount of the tariff, the guaranteed duration of the payment and the output from his installation.

It is suggested that Barbados follows the successful European examples and installs a purchase obligation for all renewable electricity produced under the new FIT system.

### 13.2.11 Fit Policy adjustments

An important implementation design option relates to the question of how often and in which way the overall FIT policy is adjusted over time (see Couture et al. 2010, p.74). It relates to two types of adjustments, the incremental adjustment of payments and the more comprehensive program revision.

**Adjustments of FIT payments** do not change the functional properties of the FIT system, but they may be necessary to adjust the payments of future investments to decreases in technology costs. Such adjustment are often pre-determined as annual reduction rates or as automatic responses to capacity expansions or as automated inflation adjustments. All such adjustments are suggested for the new FIT system for Barbados (see above). Pre-set annual FIT digression rates need to be technology specific as the different RE technologies have very different cost digression potentials.

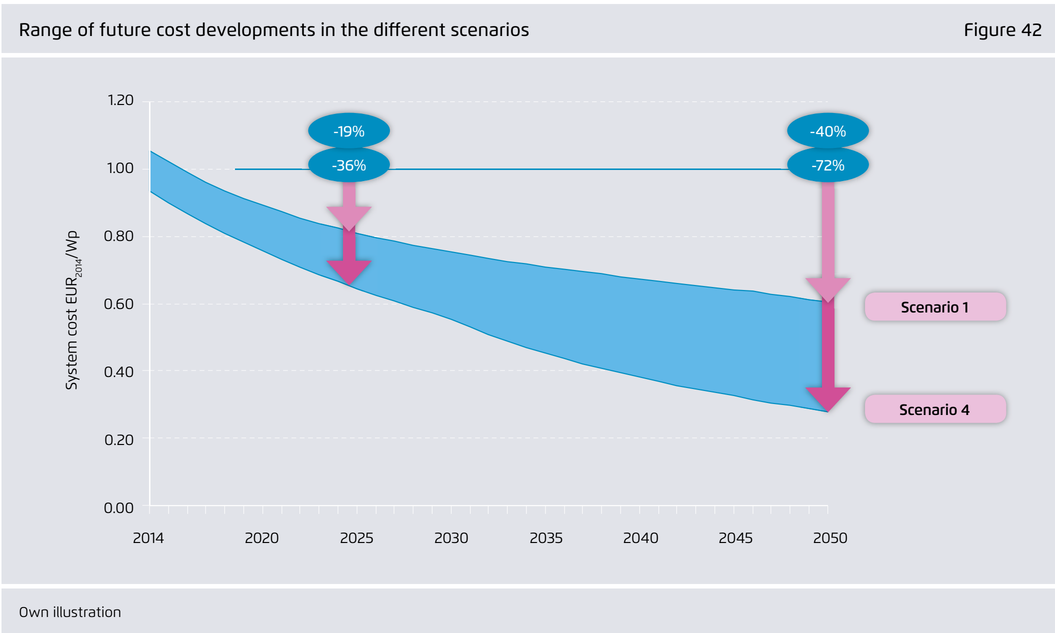
Table 33: Suggested FIT design for Barbados: 2. Implementation options 1

| | Design options | Possible choices | Choice for Barbados |
|---|---|---|---|
| | | **Implementation options** | |
| **18** | **Eligibility** | All technologies, possible operators, sizes and locations can be eligible or eligibility can be restricted. | All RE technologies, all owners, all sizes, all locations (based on location specific caps) |
| **19** | **Purchase obligation / Interconnection guarantee** | Yes/No | Yes, within the technical limits BL&P has to buy |
| **20** | **Purchasing entity** | Utility company, grid operator, government | Grid operator (BL&P) |
| **21** | **FIT policy adjustment** | Yes / No. Adjustment of FIT payment levels or of FIT program | Adjustment of payment levels (every two or three years) in addition to automatic degression After five years a revision of the overall policy should be considered in the light of the lessons learned (without endangering investor trust in the policy). |
| **22** | **Caps** | Capacity cap, project size cap, cap to program cost | Technical caps for every grid section. Grid operator has to remove technical limits as planned and agreed with the Energy Division. In the planning of the transition pathway the cost to the ratepayer should be analyzed in advance in order to limit rate increases above the average rate development under conventional electricity production. |
| **23** | **Interconnection priority for RE** | Yes / No | Yes (within the limits set by the caps, otherwise queuing until technical limit has been removed) |
| **24** | **Dispatch priority for RE** | Yes / No | Yes, to the extent possible |
| **25** | **Obligation for production forecast** | Yes / No (for larger installations) | No, much cheaper to do for entire system |
| **26** | **Transmission and interconnection cost allocation** | - Super shallow (no connection cost)<br>- Shallow (connection cost to the nearest transmission point)<br>- Deep (All cost for grid connection including transmission and substation upgrades)<br>- Mixed (connection cost plus some share of transmission and substation upgrade) | Super shallow for systems up to 100kW. (No connection cost paid by RE operator.)<br>and<br>shallow for system larger than 100kW. (Connection cost to the nearest transmission point paid by RE operator.) |

In the case of Barbados it is suggested to use a **pre-set cost digression** rate of **2.4%/a for PV** systems. This rate results from the cost reductions rates calculated by AGORA (2015, p.) for PV until 2025 (see Figure 89). Over the long run a system cost digression of about 1%/a is foreseen by the same study. It will have to be seen in how much the suggested pre-set cost digression rate based on the international cost development trend does apply to the specific situation of Barbados, as local cost elements may decrease faster or slower than international trends. This could specifically be true for the local installation costs as installers may still be on an early part of the learning curve allowing for more substantial cost digressions for this part of the costs as international cost trends would signal. The second proposed adjustment mechanism according to a target capacity reached, may help to correct for the present lack of better Barbados specific cost information.

In the case of wind energy international cost developments show only very slight digressions after a cost increase between 2007 and 2010 due to increased steel prices. As there is no clear international wind energy system price trend at the moment it is suggested to start with a digression rate of **0%/a for on shore wind** energy and to adjust this rate after some local experiences have been gained in the installation of wind turbines in Barbados. Most likely the wind farm project at Lambert's farm will give some first robust results on the specific wind energy system costs in Barbados.

Figure 89: Range of future cost developments for PV system costs until 2050 (source: AGORA 2015, p. 52)




In the case of biomass a pre-set cost digression does not seem to be warranted at the moment, as the technology used for the bagasse combustion is based on well established steam cycle power plant technology. A substantial cost digression for this technology seems to be highly unlikely due to the state of techno-economic maturity reached. Therefore, it is suggested to start with a digression rate of **0%/a for bagasse combustion.**

In the case of King-Grass gasification and the use of the produced syngas the first plant will be at the demonstration stage once it is completed. Although gasifiers are a proven technology for other fuels it remains to be seen how much cost digression potential will remain for the investment in the gasifier system. The engine part of such power plant is proven technology (large gas combustion engines are state-of-the art technologies). The growing and harvesting of King-Grass is another state-of-the art technology with low cost digression potentials. For the beginning it is suggested to start with a digression rate of **0%/a for King-Grass** gasification and power production.

In the case of the use of manure for the production of biogas for power production it is likely that there will be substantial local learning effects, while the initial local installation and operation costs will be substantially higher than international costs, as farmers in countries like Denmark or Germany have used this technology for more than 30 years by now. This specific local situation leads to a rather high initial FIT rate for electricity generated from manure, while it warrants possible substantial cost degressions over time. As the envisaged local cost digressions are connected to the number of successfully installed and operated plants the FIT digression should mainly be driven by the number and total capacity of the biogas plants installed. This should be done through the correction factor based on the envisaged capacity corridor. For the general pre-set digression rate it is suggested to start with a **rate of 0%/a for power production from biogas** based on manure.

In the case of solid waste combustion robust state of the art technology should be used. The costs for such waste combustion plants are quite stable and don't show substantial cost digressions any more. As it can be assumed that the waste to be combusted will be delivered at zero fuel cost it does not provide for substantial cost digression potential either. Therefore, it is suggested to start with a digression rate of **0%/a for solid waste combustion** for power generation.

As the FIT rates for storage will be set later, no pre-set FIT rate digression is suggested for storage.

Besides pre-determined tariff digressions there can be **triggered FIT rate adjustments**, which are dependent on the quantities of renewable energy capacities installed. In Spain solar PV FIT rates have

Table 34: Responsive FIT degression in Germany for 2009 to 2011 enacted in 2008 (source: Kreycik et al. 2011, p.15)

| Year | Annual Installed Capacity | Result on the Rate of Annual Degression |
|---|---|---|
| 2009 | < 1,000 MW | Declines 1% (e.g., 9% to 8%) |
| | 1,000–1,500 MW | No change |
| | > 1,500 MW | Increases 1% (e.g., 9% to 10%) |
| 2010 | < 1,100 MW | Declines 1% (e.g., 9% to 8%) |
| | 1,100–1,700 MW | No change |
| | > 1,700 MW | Increases 1% (e.g., 9% to10%) |
| 2011 | < 1,200 MW | Declines 1% (e.g., 9% to 8%) |
| | 1,200–1,900 MW | No change |
| | > 1,900 MW | Increases 1% (e.g., 9% to 10%) |

been adjusted according to set capacity targets in the FIT law of 2008. In case that less than 50% of a given capacity target was reached the FIT payment level was revised upwards by 2.6%, in case the capacity was between 50 and 75% of the target, the FIT payment level was unchanged and in case more than 75% were reached, the payment level was decreased by 2.6% (see Couture et al. 2010, p. 75). In Germany a new reactive FIT tariff scheme was first introduced in 2008 for 2009, 2010 and 2011 (see Table 34) . This scheme was was adjusted in 2010 for the PV capacities installed in 2011 and 2012 due to the fast capacity increase in 2009 (see Table 35) as the changes put in place in 2008 proved to be to small.

The new responsive mechanism installed for 2011 and 2012 assumed a normal FIT payment reduction by 9%/a, if the annual installed capacities stayed within a corridor of 2,500 to 3,500 MW/a. As it can be seen from Table 35 the downward adjustment could have reached up to 12% in 2011 and up to 21% in 2012.

Table 35: German responsive FIT degression scheme for PV enacted in 2010 (source: Kreycik et al. 2011, p. 16)

| Year | Annual Installed Capacity | Resulting Rate of Annual Degression |
|---|---|---|
| 2011 | 1,000–1,500 MW | Declines 6% |
| | 1,500–2,000 MW | Declines 7% |
| | 2,000–2,500 MW | Declines 8% |
| | 2,500–3,500 MW | Declines 9% |
| | 3,500–4,500 MW | Declines 10% |
| | 4,500–5,500 MW | Declines 11% |
| | 5,500–6,500 MW | Declines 12% |
| 2012 | 1,000–1,500 MW | Declines 1.5% |
| | 1,500–2,000 MW | Declines 4% |
| | 2,000–2,500 MW | Declines 6.5% |
| | 2,500–3,500 MW | Declines 9% |
| | 3,500–4,500 MW | Declines 12% |
| | 4,500–5,500 MW | Declines 15% |
| | 5,500–6,500 MW | Declines 18% |
| | > 6,500 MW | Declines 21% |

The response rates given in the German example can be interpreted as extreme. They were only necessary due to the fast drop in PV prices between 2009 and 2012. Since then the price reductions of PV systems have slowed down considerably and seem to stabilise around a minus of 2 to 3% per annum.

For Barbados it is suggested to define an annual capacity expansion target for PV, which might be in the range of 10 MW and a similar expansion target for wind energy. In all other cases expansion targets and capacity responsive target setting does not seem to be warranted at the moment, as in the case of bagasse combustion only one single plant can be supported by Barbados' agriculture and in the case of King-Grass gasification and manure use for biogas it is unclear what the political targets will be. Even in the case of wind energy a responsive rate setting may not be helpful due to the necessary size of some developments, which make it unlikely that wind energy will be installed in a smooth continuous way in Barbados. It is more likely that the expansion of wind capacity will proceed in a few rather large steps leading to arbitrary FIT increases in the case of no or low wind energy capacity installations in a given year or to strong reductions in FIT rates due to single large projects being realised in the previous year. Thus, a responsive FIT payment adjustment is only suggested for solar PV for Barbados at the moment.

Table 36 shows the structure of the FIT system suggested for Barbados including the differentiation by technology and by system size, the suggested duration of the guaranteed FIT rates, the duration of the increased payments for the reference plant, the suggested pre-set annual FIT payment degression for PV and the suggested responsive rate adjustments. The table does not show the initial FIT rates as of yet, because these will be discussed in the next chapter of the report. A later version of the table will include the suggested initial price points as well.

Besides automatic and pre-set tariff adjustments a **comprehensive program revision** may be necessary after a few years of experiences have been gained and a targeted adjustment of the overall framework may prove to be necessary. This can include policy targets (like the target year for reaching a 100% renewable power supply, the targets for the different technologies making up the mix of renewable energy technologies to be used, the inclusion of new technologies, which may have reached techno-economic maturity at lower costs than at the outset. A more comprehensive program revision can allow to correct features of the system, which have not proven to be successful. Nevertheless, such more comprehensive program revision needs to keep investor confidence in the overall policy high. Thus, program revisions need to signal continued support of the overall approach in order not to loose investors confidence in the reliability of the system. Only if the confidence of investors and banks in the system is kept at a high level the low risk financing conditions for which the FIT rates are tailored will apply (see Couture et al. 2010, p.77).

Periodic program revisions establish a fixed schedule for FIT revisions every few years. For example the German FIT system has program revisions planned every four years. This predictable revision period creates a stable investment environment during the set four-year period (see Couture et al. 2010, p.77), while it ensures that policy can track market developments in between and adjust FIT payment rates as markets and costs develop.

According to Mendonca et al. (2010, p. 64) it is highly desirable to establish the basic elements of FIT systems by law in order to maximise investor confidence and security. For Barbados it is suggested to achieve this legal status by amending PART III of the ‚Electric Light and Power Act‘. PART III of the act could be renamed in ‚INTERCONNECTION, PRICING AND TARGETS FOR ELECTRICITY SUPPLY FROM SOURCES OF RENEWABLE ENERGY‘ and a new section ‚Pricing of renewable energy sources‘ could be inserted into PART III of the act.

Considering the substantial lead times for major policy decisions in Barbados it is suggested to have a periodic revision of the FIT system every four years and to keep all conditions binding as long as no new policy has been enacted, which changes some of the specific rules and regulations applied. No guaranteed conditions or tariffs shall ever be revoked once they have been granted, otherwise investor confidence will immediately be destroyed and the financing costs will drastically increase for ever future RE investment, dramatically increasing the costs of electricity in Barbados in the longer term.

### 13.2.12 Caps

Caps for the capacities of renewable energy technologies have been used with a varying degree of success. Hawaii, for example, introduced caps at 5% of the peak demand of each of the Hawaiian electricity companies (see Kreycik et al. 2011, p.8) due to the concern that the FIT system would require utilities to accept large or unlimited quantities of renewable energy projects without a project-by-project approval or review (see Kreycik et al. 2011, p.7). As projects had to be queued for their implementation due to limited grid capacities Hawaii experienced speculative applications in order to reserve favourable positions in the queue even for projects which were very far from realisation. To solve this problem Hawaii resorted to an independent review off all queued projects resulting in a substantial number speculative applications to be excluded from the queues. (see: Public Utilities Commission of the State of Hawaii 2014, p.1).

Due to the small market size of Barbados and the limited technical ability of the existing electricity system the newly installed RE capacities need to be capped by grid area based on the limited technical ability of the grid to absorb intermittent RE electricity production. If such limit is not applied, too large RE capacities installed too early can massively destabilise grid voltage and frequency and by that virtue damage the existing infrastructure and jeopardise the security of Barbados' electricity supply, which is actually the highest ranked objective of all stakeholders interviewed.

At the same time the technical limits for each grid area (substation) need to be given and the reasons for these limits will need to be explained on the internet in order to allow for the highest possible level of transparency and investor confidence. In addition the planned final capacity of each grid area and the planned schedule for grid capacity expansion will need to be given on the internet as well. This information will need to be made available to every customer of Barbados Light and Power and every serious investor.

In case that there is an oversubscription of renewable energy capacity for a given grid area, the qualified applications exceeding the given grid limit will be queued for future grid connection. Applications should only be considered as qualified if they can actually produce the required building permits and all necessary permits for their operation.

Capacity caps should only be applied under high **transparency** of information to all possible investors to keep investor confidence as high as possible. The application queues for all grid areas will need to be reported on the internet daily with all relevant information (technology, capacity, date of application, planned date of commissioning) to allow maximum transparency for all potential investors. At the same time the presently installed RE capacities and the technical limits of each grid area will need to be given on the internet daily along with the planned capacity expansions.

It is suggested that the actual level of installed RE capacities and grid area limits will be signalled by a simple traffic light scheme. As long as there is still plenty of capacity available for new installations without getting close to the technical limit of a grid area, the grid area will be shown as green on the Barbados grid map. As soon as the installed capacities are approaching the limit (e.g. starting at 80% of the limit) the map will be coloured in yellow and as soon as the grid limit has been reached by the installed capacity the grid area is shown in red on the grid map.

### 13.2.13 Interconnection and dispatch priority

Purchase obligations, which are an important part of a successful FIT system require that the interconnection of RE installations is given priority. In many countries like in Germany the FIT law constitutes the right of interconnection for every RE system, which is seen as a positive model case by Mendonca et al. (2010, p.31). In the case of Barbados this interconnection right will only be limited by the capacity caps of each grid area and by the overall renewable target of Barbados' energy policy. The purchase obligation requires a priority use or dispatch of renewable energy capacities once they are connected to the grid. Thus, conventional capacity will always need to be taken off the grid to allow the use of all renewable energy supplied to the grid. This dispatch priority shall only be limited by technical grid limitations and in case that such procedure would seriously endanger frequency and voltage stability of the grid. In return the grid code for the interconnection of renewable energy sources needs to include provisions for grid services to be supplied by renewable energy technologies as far as possible. Such grid codes have been implemented for example in the later FIT rules in Germany (German RES Act of 2014, Section 9 (6).

Table 36: Structure of the proposed Barbados FIT system not including initial price points for FIT payments

| Technology | Size range in kW | Initial FIT rates: Phase I | Initial FIT rates: Phase II | Guarantee period | Annual reduction | Capacity target corridor | Increase by under-achievement | Decrease by over-achievement |
|---|---|---|---|---|---|---|---|---|
| | | Duration in years for reference site | Duration in years for reference site | in years | in % | in MW/a | in % per 10% | in % per 10% |
| **PV roof** | 1-10 | 10 | 10 | 20 | 2.4 % | 5 - 10 | 1 % | 1 % |
| | 10-100 | 10 | 10 | 20 | 2.4 % | | 1 % | 1 % |
| | 100-1,000 | 10 | 10 | 20 | 2.4 % | | 1 % | 1 % |
| | > 1,000 | 10 | 10 | 20 | 2.4 % | | 1 % | 1 % |
| **PV ground mounted** | | 10 | 10 | 20 | 2.4 % | 5 - 10 | 1 % | 1 % |
| **Wind** | Investor owned | 10 | 10 | 20 | 0 % | 0 - 20 | ? | ? |
| | Community owned | 10 | 10 | 20 | 0 % | | ? | ? |
| **Biogas from manure** | 0-75 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| | 75-150 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| | 150-500 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| | 500-5,000 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| | > 5000 | 20 | 0 | 20 | 0 % | ? | ? | ? |
| **Biomass gasification** | | 10 | 10 | 20 | 0 % | ? | ? | ? |
| **Solid biomass combustion** | | 10 | 10 | 20 | 0 % | none | none | none |
| **Solid waste combustion** | | 10 | 10 | 20 | 0 % | ? | ? | ? |

## 13.2.14 Forecast obligation

In some constituencies RE operators are required to forecast their production for the next 30 hours. In Spain every RE project larger than 10 MW has to deliver such a forecast to the regional grid operator. In Slovenia and Estonia RE generation owners operating facilities larger than 1 MW are required to supply a production forecast (see Couture et al. 2010, p. 85). In contrast the German FIT law requires the grid operator to do the forecasting of production from renewable energy sources (see: Mendonca et al. 2010, p.45) In small countries like Barbados a production forecast for wind and solar power production is likely to be better, if it is made by the system operator for the entire country. If not every RE operator is required to supply a production forecast the system operator will need to make his own production forecast for the different parts of the island anyhow. In such case the forecast obligation for single RE operators will only increase costs as forecast will be done twice for the same installation. What is more, the obligation to forecast will put higher financial burdens per unit of output on smaller installations, as the absolute costs of a forecast will be very similar for example for a 1 MW or a 40 MW wind park. A similar consideration applies to PV installations.

In Germany the law stipulates that all renewable electricity of installations connected to the grid has to be bought by the grid operator. In cases of serious grid congestion or stability problems the grid operator has the right to down regulate the installed renewable energy capacities to the maximum output which can be absorbed by the grid (see: Mendonca et al. 2010, p.45). Nevertheless, the down regulated production has to be paid for even though it was not produced. This regulation allows investors in RE capacities to calculate their future cash flow independent of possible temporary future down regulation of their production (see: Mendonca et al. 2010, p.46). In turn every RE installation with a capacity of more than 100 kW has to be able to reduce output by remote control (see: Mendonca 2010, p.45), which is exercised by the grid operator under the special conditions of the law.

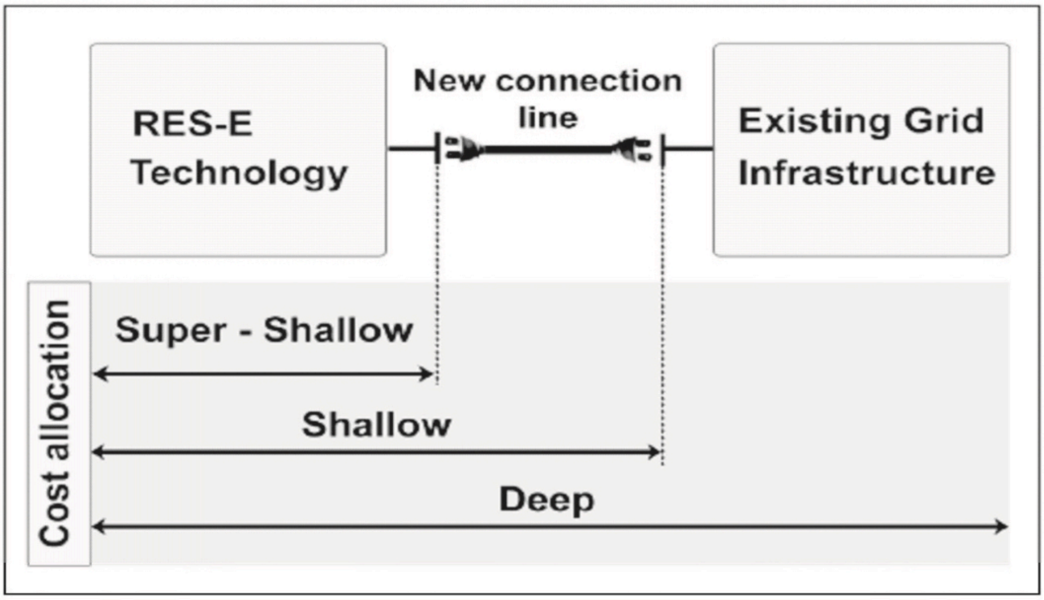
For Barbados it is **not recommended to introduce forecast obligations** for RE operators, **but** it will be essential for the central production forecast that **all foreseen downtimes of equipment for example for maintenance or repair need to be announced to the system operator as soon as possible** and no later than 24 hours in advance for scheduled downtimes. It is further suggested to require every RE installation with more than 100 kW to be equipped with remote control technology and that the system operator will have the right to down regulate production if necessary. This has to be combined with the right of compensation for down regulated RE production and needs to be limited to exceptional cases as stipulated in Section 11 the German FIT law of 2009.

### 13.2.15 Interconnection and transmission cost allocation

Interconnection and transmission costs have been allocated in three different ways internationally. They consist of two major parts, first the cost to physically connect the RE installation to the grid and second, the cost of any transmission upgrades necessary to allow this connection (see: Couture et al. 2010, p. 87). The costs are often allocated in a ‚shallow‘ way, which only requires the RE generator to pay for the physical connection to the nearest point of the transmission grid. A different approach is deep connection charging, where generators have to cover all the costs related to their facility being connected to the grid (see: Couture et al. 2010, p.87). A third approach is a hybrid of the two, which is often called mixed connection charging (see: Couture et al. 2010, p.87). In the last years even a ‚super shallow‘ cost distribution has been applied, in which the RE operator does not pay any of the grid connection costs (see: Mendonca et al. 2010, p.33). Figure 90 shows the different cost-sharing methodologies for grid connections.

Super shallow connection charging seems to be most preferable, if small producers are targeted, as this approach puts a lower burden on them and makes overall project costs more transparent and predictable to the investors. As the costs of grid connection would have to be calculated into the FIT rates deep, shallow or hybrid connection charging would require substantially higher rates resulting in overpayment for installations with low overall connection costs. If the upgrade costs for the transmission system are allowed to be put into the rate calculation of the system operator, only the incurred costs will need to be paid for by the ratepayers, who would overpay these costs, if they had to be calculated into the general FIT rates. Thus, it is suggested that Barbados adopts a **super shallow cost allocation model** for RE grid connections, where RE operators only have to pay for the costs of the physical grid connection to the nearest point of the grid. It should be discussed, whether the super shallow cost allocation principle shall be applied to RE installations with a capacity over 100 kW as well, or whether these should pay according to the shallow cost allocation principle.

Figure 90: Cost-sharing methodology for grid connections (source: Mendonca 2010, p.32 cited from Auer et al. 2007)




### 13.2.16 Funding options

Feed-in tariffs can be funded in three different ways: by the ratepayers, by the taxpayers or by some other form of funding like the revenues from emission certificate sales. The international standard is the funding of the FIT costs trough a levy put on all ratepayers. Couture et al. (2011, p.102) point out that ‚This approach provides an equitable strategy for accounting for the benefits of renewable energy, while providing an intrinsic and uniform incentive for energy efficiency and conservation.' Some countries have tried to finance FITs through taxes, but this approach soon runs into financing problems and it shifts energy costs away from ratepayers. Thus, it cannot be recommended for any substantial expansion of renewable energy capacity. In other instances financing through additional income sources like the income from emission certificate sales have been discussed, but again these funds are limited and the funding shifts the cost away from the electricity consumers.

For Barbados it is r**ecommended to use a FIT levy put onto every kilowatt-hour consumed,** which includes all costs incurred for the production of renewable electricity under the FIT system made up of the direct FIT payments and the costs of the necessary system upgrades required as well as all information costs to achieve the necessary high level of transparency for all investors and ratepayers.

### 13.2.17 Inter Utility cost sharing

In many countries a fair cost sharing between different utility companies is necessary, as the renewable resources are not evenly distributed throughout larger countries. In the case of Barbados inter utility cost sharing **does not apply**, as Barbados Light and Power services the entire country.

Table 34: Suggested FIT design for Barbados: 2. Implementation options 2

| Design options | | Possible choices | Choice for Barbados |
|---|---|---|---|
| | | Implementation options | |
| 28 | Inter-utility cost sharing | Yes / No (In the case of more than one utility cost increases are shared between them) | Does not apply to Barbados |
| 29 | Transparency | Different levels of transparency in FIT calculations, cap setting, actual installed capacities, capacities in application. | All relevant information on FIT calculations, cap setting, actual installed capacities, actual RE output, capacities in application procedures, planned grid upgrades, available capacities under local caps and other relevant information needs to be made available on a daily basis on the internet accessible for every potential investor |
| 30 | Agriculture friendly | Yes / No (FIT tariff setting takes into account the special challenges for the agricultural sector and incorporates such considerations into the making of the FIT structure and rates) | Yes. Special FITs are payed for biomass to contribute to the solution of the agricultural challenges faced by Barbados |

### 13.2.18 Transparency

The general acceptance of FIT policies depends critically upon transparent processes. Ratepayers will only accept a substantial FIT levy if they are informed about the overall impacts of the expansion of renewable energy use on their electricity rates and if they have the feeling that the payments under the FIT system are fair and well justified. At the same time investors need a very high degree of transparency in the rate setting and the setting and administration of the local capacity caps to secure the highest possible degree of investor confidence. Internationally different degrees of transparency are used in the setting of FIT rates, while high transparency in the publication of installed capacities and grid bottlenecks are international standard.

As already discussed in the case of capacity caps for Barbados it is suggested that the highest possible level of transparency should be applied in the Barbados FIT system. This includes transparent rate setting as well as maximum information on planned RE targets and a clear RE expansion timeline, grid bottlenecks, local caps, installed capacities, queues, and plans for grid capacity expansion. All information needs to be made available on line on a daily basis.

### 13.2.19 Agriculture Friendly

As discussed before, Barbados faces a serious agricultural challenge due to the persistent problems of the sugar cane industry in the world market. As most of Barbados' other agriculture has to be performed in crop rotation with sugar cane or similar grasses Barbados' agriculture will only be able to survive if the sugar cane industry can be revived or an other type of grass can be economically cropped to supply the basis for rotation agriculture. As mentioned before, there seem to be two distinct possibilities to support Barbados' agriculture through the energetic use of bagasse from sugar cane or the energetic use of King-Grass as an alternative grass crop. First calculations show that both forms of bioenergy use can be integrated into the future renewable energy supply system of Barbados at very moderate additional costs per kilowatt-hour. Therefore, it is suggested that the combustion of bagasse as well as the energetic use of King-Grass are integrated into the Barbados FIT system. By this means an important objective of the stakeholders interviewed can be served and Barbados' economy can benefit from a healthy operation of Barbados' agriculture.

# WORK PACKAGE 14: DEVELOPMENT OF FIRST PRICE POINTS FOR PRICING MECHANISMS/POLICIES

After the structure and main elements of the suggested FIT system for Barbados have been developed in Work Package 13 some first price points for solar PV, onshore wind energy will be developed in this work package. A first discussion of possible preliminary price points for the different forms of biomass use and solid waste combustion will be included as well, but it has to be stressed that these price points need to be subject to an intensive local discussion with the different stakeholders and that in the case of biomass or waste to energy conversion these price points are only very rough first approximations.

## 14.1 GENERAL ASSUMPTIONS

The calculation of the FIT rates for the different technologies depends on the design features of the FIT system, like preferential rates for community owned wind turbines or the special design of a front-loading mechanism, as well as on financial and cost assumptions, like the assumed interest rate for and the percentage of debt financing or the assumed fair rate of return on equity. In the following the assumptions applicable to all technologies are specified. Afterwards the specific assumptions for each technology are discussed in separate subchapters. The general assumptions made for the price point calculations are given in Table 35. In case that more than one value is shown, the value is set in bold typeface is the central assumption and the other parameter values have been used for sensitivity analysis.

The general assumptions relate to the duration and cost of financing, the fair return on equity assumed, the income tax rate applied and the duration of the guaranteed FIT payments as well as the duration of the higher up front FIT payments due to front-end loading. The calculations are based on a **10 year loan duration** to allow for relatively low costs during the pay-back period of the loan. The **share of loan financing** is assumed to be **80%**, a share which should be available for very low risk projects with a clear future cash flow. Additional sensitivity calculations with 60 and 70% shares were performed as well and the impact on the project cost are be shown. The **interest rate assumed for loan** financing is taken to be **5%**, which seems to be a conservative assumption, as we have seen PV funding conditions even below 4%/a in Barbados in recent months. A general **lenders fee** of **3%** is assumed on the basis of U.S. practices. This value will need to be updated for Barbados specific values.

The **fair return on equity** for a low risk investment is set to at **8%/a before taxes**, which can be considered high compared to other low risk investments like e.g. German federal bonds, which pay 0.3%/a at the time of writing (early June 2017), while US government bonds pay 2.2%/a at the moment and high risk Greek government bonds pay 6.08%/a with a very substantial default risk. These returns are all before tax. Thus, a rate of 8%/a return on a low risk RE investment under a guaranteed Feed-in Tariff is certainly to be seen as a fair if not high return. For sensitivity reasons the assumed return rate on equity is varied to 6 and 10%/a as well. It is assumed that all return on equity is taxed with the standard **income tax rate** of **25%** in Barbados, therefore, the assumed 8%/a before taxes are equivalent to **6%/a after taxes**.

The assumed **total duration** of the guaranteed **FIT payments** is **20 years** for all technologies and the assumed initial **period for the higher FIT payment** due to front-end loading of the FIT rates is assumed to be **10 years** for the reference plant specified for each technology.

It is assumed that there will be **no substantial license fees under the ELPA** for the renewable energy installations under the FIT system.

Table 35: General assumptions made for key parameters of the first price point calculations

| Parameter | Unit | Assumed value | Reason for the assumed value |
|---|---|---|---|
| **Duration of loan** | years | 10 | Low risk loans are available for at least 10 years duration in Barbados |
| **Share of loan financing** | % | 60 / 70 / **80** | Highest possible share of low interest loan allows lowest financing costs |
| **Interest rate on loan** | %/a | 4 / **5** / 6 | Low risk loans have been seen in this range in Barbados for RE investments |
| **Lenders fee** | % | 3 | Taken from international literature (NREL). Needs Barbados specific adjustment. |
| **Rate of return on equity (before income tax)** | %/a | 6 / **8** / 10 | Seems to be a reasonable to high range for low risk investments in Barbados |
| **Income tax rate** | % | 25 | General income tax rate for Barbados |
| **Rate of return on equity after tax** | %/a | 4.5 / **6** / 7.5 | Is derived from rate before income tax minus 25% income tax |
| **Total duration of guaranteed FIT payment** | years | 20 | Based on most successful international FIT practices (e.g. Germany). |
| **Duration of first payment period for reference plant (front loaded FITs)** | years | 10 | Based on available loan duration for project financing. |

The specific assumptions on the different technologies discussed in the following subchapters mainly concern the different cost components and the assumed output of a reference plant per kilowatt installed capacity per year.

## 14.2 SOLAR PV

The **solar radiation** in Barbados is assumed to be **2196 kWh/$m^2$** per year, which is the average value of solar radiation on a horizontal surface. As Table 36 shows the radiation on horizontal surfaces is the same for different cities in Barbados.

Table 36: Solar radiation on horizontal surfaces in different locations in Barbados according to the solar radiation calculator of the Solar Electricity Handbook 2017

| | | Radiation on a horizontal surface (90° against the vertical) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Bridgetown | | Basheba | | Holetown | | Oistins | | Speightstown | |
| **Month** | **Days** | kWh/ $m^2$*d | kWh/ $m^2$*m | kWh/ $m^2$*d | kWh/ $m^2$*m | kWh/ $m^2$*d | kWh/ $m^2$*m | kWh/ $m^2$*d | kWh/ $m^2$*m | kWh/ $m^2$*d | kWh/ $m^2$*m |
| **January** | 31 | 5.4 | 168.6 | 5.4 | 168.6 | 5.4 | 168.6 | 5.4 | 168.6 | 5.4 | 168.6 |
| **February** | 28 | 6.1 | 170.2 | 6.1 | 170.2 | 6.1 | 170.2 | 6.1 | 170.2 | 6.1 | 170.2 |
| **March** | 31 | 6.6 | 204.3 | 6.6 | 204.3 | 6.6 | 204.3 | 6.6 | 204.3 | 6.6 | 204.3 |
| **April** | 30 | 6.8 | 204.0 | 6.8 | 204.0 | 6.8 | 204.0 | 6.8 | 204.0 | 6.8 | 204.0 |
| **May** | 31 | 6.6 | 204.0 | 6.6 | 204.0 | 6.6 | 204.0 | 6.6 | 204.0 | 6.6 | 204.0 |
| **June** | 30 | 6.1 | 182.1 | 6.1 | 182.1 | 6.1 | 182.1 | 6.1 | 182.1 | 6.1 | 182.1 |
| **July** | 31 | 6.4 | 197.8 | 6.4 | 197.8 | 6.4 | 197.8 | 6.4 | 197.8 | 6.4 | 197.8 |
| **August** | 31 | 6.4 | 199.6 | 6.4 | 199.6 | 6.4 | 199.6 | 6.4 | 199.6 | 6.4 | 199.6 |
| **September** | 30 | 6.0 | 180.0 | 6.0 | 180.0 | 6.0 | 180.0 | 6.0 | 180.0 | 6.0 | 180.0 |
| **October** | 31 | 5.6 | 173.0 | 5.6 | 173.0 | 5.6 | 173.0 | 5.6 | 173.0 | 5.6 | 173.0 |
| **November** | 30 | 5.1 | 153.0 | 5.1 | 153.0 | 5.1 | 153.0 | 5.1 | 153.0 | 5.1 | 153.0 |
| **December** | 31 | 5.2 | 159.7 | 5.2 | 159.7 | 5.2 | 159.7 | 5.2 | 159.7 | 5.2 | 159.7 |
| **Annual average** | 365 | 6.0 | | 6.0 | | 6.0 | | 6.0 | | 6.0 | |
| **Annual total** | | | 2196.3 | | 2196.3 | | 2196.3 | | 2196.3 | | 2196.3 |
| **Barbados average in kWh/$m^2$*a** | | | 2196.3 | | | | | | | | |
| **Source** | | Solar Electricity Handbook 2017, Homepage:http://solarelectricityhandbook.com/solar-irradiance.html (access 3.6.2017) | | | | | | | | | |

An optimal angle towards the sun can increase the received radiation of a southward panel to about 2288 kWh/$m^2$ per year, as Table 37 shows. In this case the calculations show minor deviations between the different locations in Barbados between 2287.1 for Bridgetown and Oistins and 2288.6 for all other locations calculated. The deviation of 1.5 kWh/$m^2$ per year is less than one per mill. Thus, it can be assumed that there is no significant difference in solar radiation in different locations in Barbados. The radiation on a horizontal surface (2196 kWh/m$^2$*a) will be used for the calculations of the PV reference site.

Table 37: Solar radiation on south facing surfaces with an angle of 77° against the vertical in different locations in Barbados according to the solar radiation calculator of the Solar Electricity Handbook 2017

| | | Installation facing south at optimal angle (77° against the vertical) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Bridgetown | | Basheba | | Holetown | | Oistins | | Speightstown | |
| Month | Days | kWh/ m²*d | kWh/ m²*m | kWh/ m²*d | kWh/ m²*m | kWh/ m²*d | kWh/ m²*m | kWh/ m²*d | kWh/ m²*m | kWh/ m²*d | kWh/ m²*m |
| January | 31 | 6.60 | 204.6 | 6.61 | 204.9 | 6.61 | 204.9 | 6.60 | 204.6 | 6.61 | 204.9 |
| February | 28 | 6.81 | 190.7 | 6.82 | 191.0 | 6.82 | 191.0 | 6.81 | 190.7 | 6.82 | 191.0 |
| March | 31 | 6.67 | 206.8 | 6.68 | 207.1 | 6.68 | 207.1 | 6.67 | 206.8 | 6.68 | 207.1 |
| April | 30 | 6.20 | 186.0 | 6.21 | 186.3 | 6.21 | 186.3 | 6.20 | 186.0 | 6.21 | 186.3 |
| May | 31 | 6.39 | 198.1 | 6.39 | 198.1 | 6.39 | 198.1 | 6.39 | 198.1 | 6.39 | 198.1 |
| June | 30 | 6.04 | 181.2 | 6.04 | 181.2 | 6.04 | 181.2 | 6.04 | 181.2 | 6.04 | 181.2 |
| July | 31 | 6.29 | 195.0 | 6.29 | 195.0 | 6.29 | 195.0 | 6.29 | 195.0 | 6.29 | 195.0 |
| August | 31 | 6.06 | 187.9 | 6.06 | 187.9 | 6.06 | 187.9 | 6.06 | 187.9 | 6.06 | 187.9 |
| September | 30 | 5.82 | 174.6 | 5.82 | 174.6 | 5.82 | 174.6 | 5.82 | 174.6 | 5.82 | 174.6 |
| October | 31 | 5.98 | 185.4 | 5.98 | 185.4 | 5.98 | 185.4 | 5.98 | 185.4 | 5.98 | 185.4 |
| November | 30 | 5.96 | 178.8 | 5.97 | 179.1 | 5.97 | 179.1 | 5.96 | 178.8 | 5.97 | 179.1 |
| December | 31 | 6.39 | 198.1 | 6.39 | 198.1 | 6.39 | 198.1 | 6.39 | 198.1 | 6.39 | 198.1 |
| Annual average | 365 | 6.266 | | 6.270 | | 6.270 | | 6.266 | | 6.270 | |
| Annual total | | | 2287.1 | | 2288.6 | | 2288.6 | | 2287.1 | | 2288.6 |
| Average in kWh/m²*a | | | 2288.0 | | | | | | | | |
| Source | Solar Electricity Handbook 2017, Homepage:http://solarelectricityhandbook.com/solar-irradiance.html (access 3.6.2017) | | | | | | | | | | |

Based on modern inverter technology with an efficiency of 98% and an assumed average solar cell operating temperature of 62.5°C, which reduces the output by 18% as compared to the module design temperature of 25°C, the AC output of the system is reduced by about 20% from 2196 kWh/kW$_p$ DC to 1757 kWh/kW$_p$ AC. Based on this output a capacity factor of 20.1% (1757/8760) is used for the AC output of the reference system. All assumed parameter values specific to solar PV installations are summarized in Table 38 below.

The investment costs assumed for different PV systems are based on cost figures for systems with 0.5 to 10 kWp for which ELPA licenses were granted in Barbados in 2015 and 2016, as the installations in this size range have by far been the most frequent installations in Barbados. The average investment cost for this size range was 7.3 BBD/W$_p$ (see Table 4 above). The investment costs for all larger systems are base on data used by the National Renewable Energy Lab (NREL) and the investment cost ratios between different system sizes (NREL 2016a). NREL is using four size ranges for PV roof top systems (1 up to 10

$kW_p$, 10 to 100 $kW_p$, 100 to 1,000 $kW_p$ and larger as 1,000 $kW_p$). Recalculating the NREL cost data to percentages of the investment costs of the smallest size range (up to 10 $kW_p$) results in 89% investment cost for the systems up to 100 $kW_p$, 64% for systems between 100 and 1,000 $kW_p$ and 52% for systems larger than 1,000 $kW_p$. For large ground mounted systems NREL uses the same 52% as for rooftop PV systems over 1 $MW_p$. These cost ratios (percentages) are used to calculate the investment costs for larger PV systems in Barbados based on the average investment cost of 7.3 BBD/$W_p$ for the small systems realised in Barbados in 2015 and 2016. The resulting investment costs are 6,497 BBD/$kW_p$ for PV systems between 10 and 100 $kW_p$, 4,672 BBD/$kW_p$ for PV systems between 100 and 1,000 $kW_p$ and 3,796 BBD/$kW_p$ for rooftop PV systems over 1 $MW_p$ and for ground mounted PV systems.

The operation and maintenance costs for rooftop PV installations are assumed to be 34 BBD/$kW_p$ per year based on the operation and maintenance costs NREL (2016a) is assuming for the United States (17 USD/$kW_p$*a).

Based on the central assumptions of 80% debt funding at 5% and a pre-tax return on equity of 8%/a, a first set of price points for FIT rates result for a front-end loaded FIT tariff for PV. To allow for positive cash flows from the first year of operation, a tariff structure with a ratio of 100% in the first ten years and 55% in the later years is assumed. This structure and all the assumptions given result in the FIT rates for different PV systems given in Table 39 below. Depending on the system size the 20 year average FIT rates are between 0.281and 0.491 BBD/kWh. Due to the front-end loading the average rate of 0.4428 BBD/kWh for a  PV installation between 10 an 100 $kW_p$ translates into 0.5713 (first period) and 0.3142 BBD/kWh (second period).

A reduction of the interest rate paid for the debt financing part from 5 to 4%/a increases the pre-tax return on equity from 8 to 8.26%/a, while an increase in the debt financing interest rate to 6%/a reduces the annual pre-tax return on equity to 7.71%/a. These impacts are shown for the example of the 10 to 100 $kW_p$ PV system in Table 39 below.

A reduction of the share of debt financing from the assumed 80% to 70 or 60% will reduce the average return on equity before taxes from 8%/a to 5.95 and 4.55%/a respectively.

Table 38: Assumptions made for the FIT calculations for the PV reference plants for Barbados

| Parameter | Unit | Assumed value | Reason for the assumed value |
|---|---|---|---|
| **Solar radiation per year** | $kWh/m^2*a$ | 2,196 | Average radiation on a horizontal surface in Barbados |
| **PV DC to AC system efficiency** | % | 80 % | Average operating temperature assumed at 62.5°C with output reduction of 0.4%/1°C temperature increase over 25°C design temperature. 98% inverter efficiency assumed |
| **Output (AC to grid) per year** | $kWh/kW_p$ | 1,757 | Resulting from solar radiation and AC system efficiency |
| **Capacity factor (AC)** | % | 20.1 % | Resulting from AC output |
| **Investment cost per $kW_p$** | | | |
| **- roof up to 10 $kW_p$** | BBD/kWp | 7,300 | Based on Barbados cost figures for 2015 and 2016 |
| **- roof 10.1 to 100 $kW_p$** | BBD/kWp | 6,497 | Based on Barbados cost figures for small systems times NREL (2016a) ratio for larger size (89%) |
| **- roof 100.1 to 1,000 $kW_p$** | BBD/kWp | 4,672 | Based on Barbados cost figures for small systems times NREL (2016a) ratio for larger size (64%) |
| **- roof larger 1,000 $kW_p$** | BBD/kWp | 3,796 | Based on Barbados cost figures for small systems times NREL (2016a) ratio for larger size (52%) |
| **- ground mounted PV** | BBD/kWp | 3,796 | Based on Barbados cost figures for small systems times NREL (2016a) ratio for larger size (52%) |
| **Operation and maintenance cost** | $BBD/kW_p*a$ | 34 | Based on NREL 2013 (17 $USD/kW_p*a$) |
| **Duration till first partial equipment replacement** | years | 10 | Assumed replacement of inverter after 10 years |
| **Cost of first partial equipment replacement** | $BBD/kW_p$ | 470 BBD | Assumed cost for inverter replacement based on NREL 2016a (235 $USD/kW_p$) |
| **Duration till second partial equipment replacement** | years | 20 | Assumed second inverter replacement after 20 years |
| **Cost of second partial equipment replacement** | $BBD/kW_p$ | 470 BBD | Assumed cost for inverter replacement based on NREL 2013 (235 $USD/kW_p$) |
| **Useful life of project** | years | 25 - 40 | International experience with lifetime of PV plants operating (NREL 2017) |

Table 39: Suggested first price points for PV in Barbados

| System | Average FIT rate over the entire period | FIT rate period 1 (year 1-10) in BBD/ kWh | FIT rate period 2 (55% of period 1 for year 11-20) | Assumed investment cost in BBD/kW$_p$ | Share of equity assumed | Assumed interest on debt financing | Interest earned on equity before taxes in %/a |
|---|---|---|---|---|---|---|---|
| PV rooftop | | | | | | | |
| 1-10 kW$_p$ | **0.4910** | **0.6335** | **0.3484** | 7.300 BBD | 20 % | 5.0 % | 8.0 % |
| 10.1-100 kW$_p$ | **0.4428** | **0.5713** | **0.3142** | 6.497 BBD | 20 % | 5.0 % | 8.0 % |
| 100.1-1,000 kW$_p$ | **0.3337** | **0.4306** | **0.2368** | 4.672 BBD | 20 % | 5.0 % | 8.0 % |
| over 1,000 kW$_p$ | **0.2813** | **0.3630** | **0.1997** | 3.796 BBD | 20 % | 5.0 % | 8.0 % |
| PV ground mounted | **0.2813** | **0.3630** | **0.1997** | 3.796 BBD | 20 % | 5.0 % | 8.0 % |
| | | | | | | | |
| Impact of varied assumptions | Rooftop PV system 10.1 - 100 kWp | | | | | | |
| Basic system used for FIT calculations | **0.4428** | **0.5713** | **0.3142** | 6.497 BBD | 20 % | 5.0 % | 8.0 % |
| 4% interest rate on debt financing | **0.4428** | **0.5713** | **0.3142** | 6.497 BBD | 20 % | 4 % | 8.26 % |
| 6% interest rate on debt financing | **0.4428** | **0.5713** | **0.3142** | 6.497 BBD | 20 % | 6 % | 7.71 % |
| 70% share of debt financing | **0.4428** | **0.5713** | **0.3142** | 6.497 BBD | 30 % | 5 % | 5.95 % |
| 60% share of debt financing | **0.4428** | **0.5713** | **0.3142** | 6.497 BBD | 40 % | 5 % | 4.55 % |

The solar reference plant is defined by the output of 1,757 kWh/kW per year. Thus, every PV plant will receive the high front-end loaded tariff for 10 x 1,757 kWh = 17,570 kWh. In case an installation does only reach an output of 1,500 kWh/kW per year, it would receive the high front-end loaded tariff for 17,570 / 1,500 = 11.67 years or 11 years and 8 months.

## 14.3 Wind Energy

The output calculated for the wind energy reference plant is based on the wind resource analysis performed for Barbados by Rogers (2015). Rogers identifies seven different areas on Barbados with preferential conditions for the use of wind energy. Based on a typical 3 MW wind turbine he calculates the possible capacities, which could be installed in each of the areas, the annual output of the turbines in each area in kWh/kW*a and the resulting capacity factors. For the selected size of turbines the output per kW varies between 2,759 and 4,091 kWh/kW*a resulting in capacity factors between 31.5 and 46.7%. On average the output is 3,496 kWh/kW*a with a respective average capacity factor of 39.9%. The calculations of the capacity factors are shown in Table 40 below. The calculated weighted average capacity factor of 39.9% is used for the FIT calculations for wind energy.

Table 40: Production and capacity factors from a typical 3 MW wind turbine in different preferential wind locations in Barbados

| Area | Installed capacity at 3 MW | Fraction of total potential | Capacity factor | Output in kWh/a per kW installed | Weighted capacity factor |
|---|---|---|---|---|---|
| 1 | 57 | 0.125 | 45.3 % | 3,968 | 5.66 % |
| 2 | 72 | 0.158 | 42.9 % | 3,758 | 6.77 % |
| 3 | 72 | 0.158 | 41.6 % | 3,644 | 6.57 % |
| 4 | 48 | 0.105 | 46.7 % | 4,091 | 4.92 % |
| 5 | 48 | 0.105 | 40.5 % | 3,548 | 4.26 % |
| 6 | 120 | 0.263 | 34.3 % | 3,005 | 9.03 % |
| 7 | 39 | 0.086 | 31.5 % | 2,759 | 2.69 % |
| Total | 456 | 1.000 | | 3,496 | 39.90 % |

The calculated average production of 3,496 kWh/kW*a is very similar to the output of the wind turbines in the NREL ‚Technology Resource Group' (TRG) 6, with an assumed net capacity factor of 40% or 3,531kWh/kW*a (see NREL 2016a). For 2016 NREL assumes investment costs of 1,867 $USD_{2014}$/kW for the wind turbines in this group. Using an inflation of about 1.38% between 2014 and 2016 in the United States and a 2:1 exchange rate between BBD and USD translates into typical investment costs of 3,786 $BBD_{2016}$/kW for wind turbines used in the United States today. A value in line with the international wind energy cost assessment given in WP 2. Due to a lack of better local information an adder of 25% on the US investment costs is used to approximate the present investment costs in Barbados, which will be higher especially due to additional transport costs, smaller lot sizes and higher costs for very large cranes necessary for the erection of the turbines, which are not readily available on the island. Thus, for the first FIT price point an investment cost estimate of 4,732 BBD/kW is used. It will need to be seen, how much these extra costs can be decreased in the future due to larger lot sizes and cost reductions in Barbados. Together with all other wind energy specific assumptions this investment cost figure is shown in Table 41 below. In the table the overall investment is split up into the major components of the investment according to NREL 2015 (p.12), which gives a detailed cost break-up of wind turbine investment, operation and maintenance costs.

Table 41: Assumptions made for the FIT calculations for the wind energy reference plant for Barbados

| Parameter | Unit | Assumed value | Reason for the assumed value |
|---|---|---|---|
| **Capacity factor of reference site** | % | 39.9 | Average capacity factor for Barbados seven wind zones according to Rogers 2015 |
| **Output (AC to grid) per year** | $kWh/kW_p$ | 3,496 | Output of reference plant with average capacity factor (see above) |
| **Investment cost per $kW_p$** | BBD/kW | 4732 | Cost according to NREL 2014 and 2016a plus 25% adder for higher cost in Barbados |
| **- Rotor module** | BBD/kW | 825 | Cost according to NREL 2014 and 2016a plus 25% adder for higher cost in Barbados |
| **- Nacelle module** | BBD/kW | 1942 | Cost according to NREL 2014 and 2016a plus 25% adder for higher cost in Barbados |
| **- Tower module** | BBD/kW | 591 | Cost according to NREL 2014 and 2016a plus 25% adder for higher cost in Barbados |
| **- Balance of system** | BBD/kW | 949 | Cost according to NREL 2014 and 2016a plus 25% adder for higher cost in Barbados |
| **- Financial cost** | BBD/kW | 424 | Cost according to NREL 2014 and 2016a plus 25% adder for higher cost in Barbados |
| **Operation and maintenance cost** | BBD/ kW*a | 129 | Cost according to NREL 2014 and 2016a plus 25% adder for higher cost in Barbados |
| **Duration of construction period** | Months | 6 | First guess for duration of construction period in Barbados. |
| **Interest rate during construction period** | %/a | 5 | Based on the interest rate assumed for the debt financing of the overall investment. |
| **Duration till first partial equipment replacement** | years | 10 | Based on international experiences |
| **Cost of first partial equipment replacement** | $BBD/kW_p$ | 826 BBD | New rotor module after 10 years |
| **Duration till second partial equipment replacement** | years | 15 | Based on international experiences |
| **Cost of second partial equipment replacement** | BBD/kWp | 608 BBD | New drivetrain after 15 years |
| **Useful life of project** | years | 20 | International experience with lifetime of wind turbine operation (NREL 2017) |

Based on the operation and maintenance cost figure used by NREL for its most recent calculations (NREL 2016) of 51 $USD_{2014}$/kW*a the operation and maintenance costs for Barbados are derived by adding 25% for possibly higher operation and maintenance costs in Barbados. Thus, operation and maintenance costs of 129 $BBD_{2016}$/kW*a are assumed for the first price point calculations for the FIT rates for Barbados.

It is assumed that the construction of a wind park will take six month requiring external financing of a substantial share of the investment during this time. The interest rate assumed for this financing of the construction time is assumed at 5% like the debt financing of the investment during the first ten years of operation.

In addition some component replacements are assumed during the lifetime of the wind turbines. After ten years a replacement of the rotor module is assumed, which is calculated at Barbados specific costs (25% higher than US costs) of 826 $BBD_{2016}$/kW. After fifteen years a replacement of the drive train is assumed, which is calculated at Barbados specific costs of 608 $BBD_{2016}$/kW. The useful project life is assumed to be 20 year, which is in line with the useful life of wind turbines assumed by NREL (2017). Nevertheless, it has to be pointed out that well maintained wind turbines have been running for over 30 years in Denmark and Germany by now, showing that the useful life of a well kept wind turbine may well be far longer than the assumed 20 years.

The resulting first price point estimate for the initial FIT rate for a reference wind turbine with a capacity factor of 39.9% is 0.1975 $BBD_{2016}$/kWh for the average FIT rate over 20 years. Due to the front-end loading the FIT rate for the first ten years is 0.2549 $BBD_{2016}$/kWh and the reduced FIT rate for the second ten year period is 0.1402 $BBD_{2016}$/kWh (see Table 42 for details). The reference plant will receive the high FIT rate for a total of 34,960 kWh per kW installed capacity, which is equivalent to an output of 10 years or 120 month of operation of the reference plant. Due to the different capacity factors in the different preferential wind energy areas in Barbados the length of the high FIT payment varies between 102.5 and 152 months. Thus, in the area with the best wind speeds (area 4) the high payment will last for eight years and 6.5 months, while the high payment will last for twelve years and eight month in the area with the lowest wind speeds (area 7) (see Table 43 below). Although the average FIT rates are higher at the less favourable sites the total payments received at these sites over the guarantee period of 20 years is lower due to the lower total production in the guarantee period.

If we assume that a community owned wind park has about 10% higher investment costs due to less bargaining power and less experience in building larger projects, the FIT rate would need to be approximately 7.2% higher than the FIT rate for investor owned wind turbines. Thus, the resulting average FIT rate is 0.2118 BBD/kWh. In the case that an investor owned wind park has a substantial number of impacted dwellings requiring an additional 10% ownership for the people living close by, an increase in interest owned on equity by 10% (to 8.8%) would be required to satisfy the additional owners. This would lead to a maximum increase of 5.1% for additional ownership and to an increase of the average FIT rate to 0.2075 BBD/kWh.

Table 42: Suggested first price points for wind energy in Barbados

| System | Average FIT rate over the entire period | FIT rate period 1 (year 1-10) in BBD/kWh | FIT rate period 2 (55% of period 1 for year 11-20) | Assumed investment cost in BBD/kW$_p$ | Share of equity assumed | Assumed interest on debt financing | Interest earned on equity before taxes in %/a |
|---|---|---|---|---|---|---|---|
| **Basic wind turbine (investor owned)** | **0.1975** | **0.2549** | **0.1402** | 4732 | 20 % | 5 % | 8.00 % |
| **Basic turbine (community owned)** | **0.2118** | **0.2733** | **0.1503** | 5205 | 20 % | 5 % | 8.00 % |
| **Basic wind turbine investor owned plus 10% ownership for proximity** | **0.2075** | **0.2678** | **0.1473** | 4732 | 20 % | 5 % | 8.80 % |
| **4% interest rate on debt financing** | **0.1975** | **0.2549** | **0.1402** | 4372 | 20 % | 4 % | 8.26 % |
| **6% interest rate on debt financing** | **0.1975** | **0.2549** | **0.1402** | 4372 | 20 % | 6 % | 7.71 % |
| **70% share of debt financing** | **0.1975** | **0.2549** | **0.1402** | 4372 | 30 % | 5 % | 5.95 % |
| **60% share of debt financing** | **0.1975** | **0.2549** | **0.1402** | 4372 | 40 % | 5 % | 4.56 % |

Table 43: Duration of high FIT rate and resulting FIT rates in the different preferential wind areas of Barbados

| Area | Installed capacity at 3 MW | Fraction of total potential | Capacity factor | Output in kWh/a per kW installed | Weighted capacity factor | Duration of high FIT rate in months | Average FIT rate in BBD/kWh | Total FIT payments over 20 years in BBD/kW |
|---|---|---|---|---|---|---|---|---|
| **1** | 57 | 0.125 | 45.3 % | 3,968 | 5.66 % | 105.7 | 0.1918 | 15,226 |
| **2** | 72 | 0.158 | 42.9 % | 3,758 | 6.77 % | 111.6 | 0.1939 | 14,575 |
| **3** | 72 | 0.158 | 41.6 % | 3,644 | 6.57 % | 115.1 | 0.1953 | 14,237 |
| **4** | 48 | 0.105 | 46.7 % | 4,091 | 4.92 % | 102.5 | 0.1909 | 15,623 |
| **5** | 48 | 0.105 | 40.5 % | 3,548 | 4.26 % | 118.2 | 0.1967 | 13,959 |
| **6** | 120 | 0.263 | 34.3 % | 3,005 | 9.03 % | 139.6 | 0.2085 | 12,531 |
| **7** | 39 | 0.086 | 31.5 % | 2,759 | 2.69 % | 152.0 | 0.2168 | 11,964 |
| **Total** | 456 | 1.000 | | 3,496 | 39.90 % | 120 | 0.1975 | 13,808 |

## 14.4 Bagasse Combustion

In the case of the bagasse combustion plant planned by the Barbados Cane Industry Association it is suggested to assume the values calculated by the project (see Table 44) and to pay a **FIT rate of 0.28 BBD/kWh**, which is the cost calculated by the Cane Industry association (personal communication with Mr. Charles Simpson, head of the project). As these costs are average costs over the lifetime of the power plant it is suggested to pay this FIT rate without front-end loading or a differentiation into a first and second phase of the tariff. As the basis for the calculations has been an operational lifetime of 25 for the plant, it is suggested to pay the FIT rate for the entire period of 25 years. Most values in Table 44 are based on figures given by the head of the project.

In the case of bagasse combustion a considerably higher share of the total electricity cost is made up by operation, maintenance and fuel costs. Therefore, a far higher share of the FIT rate will need to be adjusted for inflation in future years.

Table 44: Key assumptions made for combined bagasse and river tamarind combustion

| Parameter | Unit | Assumed value | Reason for the assumed value |
|---|---|---|---|
| **Expected operational life** | Years | 25 | Personal communication Mr. Charles Simpson Barbados Cane Industry Association |
| **Installed capacity** | MW | 22.3 | Personal communication Mr. Charles Simpson Barbados Cane Industry Association |
| **Capacity available during cane season** | MW | 18.5 | Personal communication Mr. Charles Simpson |
| **Capacity factor during cane season** | % | 83 % | Personal communication Mr. Charles Simpson |
| **Capacity factor during rest of season** | % | 90 % | Barbados Draft NAMA Strategy 2013 |
| **Total investment cost** | Million BBD | 460 | Personal communication Mr. Charles Simpson |
| **Output per year** | GWh/a | 169 | Personal communication Mr. Charles Simpson |
| **Fuel costs bagasse** | BBD/GJ | 5.0-5.6 | Personal communication Mr. Charles Simpson |
| **Fuel costs for river tamarind** | BBD/GJ | 7.49 | Personal communication Mr. Charles Simpson |
| **Share of energy from bagasse** | % | 29 % | Personal communication Mr. Charles Simpson |
| **Share of energy from river tamarind** | % | 71 % | Personal communication Mr. Charles Simpson |
| **Estimated cost per kWh** | BBD/kWh | 0.28 | Personal communication Mr. Charles Simpson |
| **Acreage required for river tamarind production** | $km^2$ | 29 | Barbados Draft NAMA Strategy 2013 |

## 14.4 King-Grass gasification

After a first crop pre selection successful field trials have been conducted with growing King Grass in Barbados at ARMAG farms. The biomass yield has been 19 t of biomass at 10% moisture per acre and year with an energy content of 18 GJ/t of biomass at 10% moisture. Assuming a load factor of 80% and a biomass yield of 60 green t/acre (equivalent to 19 t/acre at 10% moisture) about 216 acres (4104 t at 10% moisture) of King Grass are needed to operate a 600 kW gas engine 7,008 hours per year producing 4.204 GWh of electricity per year. Gasifiers in the required size range come at about 3-9 Million USD/MW (see Fichtner 2016, p.17). Gas engines combined with generators will most likely cost between 2 and 3 Million USD/MW. Operation and maintenance costs are most likely in the range of 10% of the initial investment costs per annum. So far the exact costs of growing and harvesting King Grass as well as the operation and maintenance costs of the gasifier and the power production unit have not been analysed in detail, as a first pilot plant will be built in 2017. At the moment the farmers involved in the project calculate that 3 t of wet King Grass needed to produce 1 t of dry King Grass (at 10% moisture) will cost about 120 BBD or 6.67 BBD/GJ (personal communication with Mr. Richard Armstrong ARMAG Farms).

As the information on the possible costs of the King-Grass gasification based power production is extremely preliminary the calculations shown in Table 45 below need to be seen only as very rough first guesses of the actual costs and possible FIT rates. At the moment the lowest cost system (applying the minimum cost estimates for the gasifier and the motor-generator set will have an average cost of just about 0.53 BBD/kWh over the entire 20 year lifetime of the system. Using the medium range of the cost estimates results in about 0.82 BBD/kWh and the high cost estimates result in about 1.11 BBD/kWh. If a front loaded FIT tariff would be used, this would translate into FIT rates of 0.67, 1.06 and 1.45 BBD/kWh during the first ten years, while the debt is paid back, and into FIT rates of 0.39, 0.59 and 0.78 BBD/kWh for the last ten years, when the debt has been paid back. All figures should be taken with extreme caution and should not be understood as first price points ready for application. It needs to be seen what the actual costs of the first gasification plant will be and how much these cost can be reduced when more plants are built for regular operation. Nevertheless, King-Grass gasification seems to be an important option for stabilising the economic future of Barbados’ agricultural sector. Thus, it is strongly recommended to secure sufficient funding for the first demonstration plants to allow the necessary learning processes and the resulting cost reductions.

Table 45: Key assumptions made for the demonstration King-Grass gasification plant

| Parameter | Unit | Assumed values | | | Source of assumed value |
|---|---|---|---|---|---|
| | | Low | Medium | High | |
| Expected operational life | Years | | 20 | | Own assumption |
| Investment cost | Million BBD | 10 | 17 | 24 | Fichtner 2016 |
| Capacity | $kW_{el}$ | | 600 | | Fichtner 2016 |
| Investment cost | BBD/kW | 16,667 | 28,333 | 40,000 | Fichtner 2016 |
| Total el production | kWh/a | | 4,204,000 | | Fichtner 2016 |
| Power production per kW | kWh/kW*a | | 7,007 | | Fichtner 2016 |
| Debt pay-back period | Years | | 10 | | Own assumption (see Table 35) |
| Interest on Debt in % | % | | 5.0 % | | Own assumption (see Table 35) |
| Share of debt financing | Fraction of 1 | | 0.8 | | Own assumption (see Table 35) |
| Interest on equity | % | | 8.0 % | | Own assumption (see Table 35) |
| Compound interest in % | % | | 5.6 % | | Own assumption (see Table 35) |
| Annuity per kW | BBD/kW | 2,222 | 3,777 | 5,332 | Resulting calculations |
| Capital cost per kWh | BBD/kWh | 0.3171 | 0.5391 | 0.7610 | Resulting calculations |
| Fuel cost per t | BBD/t dry biomass | | 120 | | ARMAG Farms 2017 |
| Fuel cost per GJ | BBD/GJ | | 6.67 | | Resulting calculations |
| Total biomass required per year | Dry t/a | | 4,104 | | Fichtner 2016 |
| GJ/t dry biomass | GJ/t dry biomass | | 18 | | Fichtner 2016 |
| Total biomass required per year in GJ | GJ | | 73,872 | | Fichtner 2016 |
| Total cost of biomass per a | BBD/a | | 492,726 | | Resulting calculations |
| Cost of biomass per kW and year | BBD/kW*a | | 821.2 | | Resulting calculations |

| Parameter | Unit | Assumed values | | | Source of assumed value |
|---|---|---|---|---|---|
| | | Low | Medium | High | |
| Cost of biomass per kWh | BBD/kWh | 0.1172 | | | Resulting calculations |
| Operation and maintenance cost per kW and year | BBD/kW*a | 1,667 | 2,833 | 4,000 | Resulting calculations |
| O&M costs per kWh | BBD/kWh | 0.23787 | 0.40438 | 0.57088 | Resulting calculations |
| | Possible resulting FIT rates of first rough calculations | | | | |
| FIT rate year 1 to 10 | BBD/kWh | 0.6722 | 1.0606 | 1.4491 | Resulting calculations |
| FIT rate year 11 to 20 | BBD/kWh | 0.3931 | 0.5863 | 0.7794 | Resulting calculations |
| Average FIT rate | BBD/kWh | 0.5326 | 0.8235 | 1.1143 | Resulting calculations |

## 14.4 Biogas from manure and farm residues

As there are no cost figures available on the production of electricity based on the anaerobic digestion of manure and agricultural residues for Barbados some first orientation can be gained from the FIT rates in Germany and the UK. Due to the fact that the technology application in Barbados is in its infancy, the early FIT rates from other countries are far more applicable than the latest rates based on massive deployment of such technologies.

In the UK biomass installations for electricity production are differentiated into three size categories (up to 250 kW, 250 to 500 kW and 500 to 5,000 kW. There is no differentiation of the FIT rates as to which substrates or which processes are used. The FIT rates in 2011 were actually increased from the first FIT rates granted in 2010. For small installations the FIT rate was raised from 0.429 BBD/kWh to 0.513 BBD/kWh for installations up to 250 kW. In 2010 no differentiation between installations below 500 kW was made. In 2011 the FIT rate for the larger installations (250-500kW) was increased to 0.474 BBD/kWh, considerably less than for the smaller installations (see Table 46).

In Germany the market diffusion of biomass installations for the anaerobic digestion of manure and agricultural residues started in 2004 with a Feed-in Tariff of 0.542 BBD/kWh granted for installations up to 150 kW. The tariff decreased substantially over system size with 0.498 BBD/kWh for installations up to 500 kW, 0.415 BBD for installations up to 5,000 kW and 0.298 BBD/kWh for larger installations. Although the German FIT rates are in the same range as the older UK rates, they differentiate more strongly between small and large installations. In 2012 an new version of the Feed-in Tariff law (EEG 2012) introduced a special FIT rate for small systems (up to 75 kW) for the anaerobic digestion of manure and agricultural residues at 0.661 BBD/kWh.

If Barbados is going to introduce a first FIT value for electricity production from manure and agricultural residues it is suggested to adapt the FIT values used in Germany and to apply an adder for higher specific costs in Barbados of 25%, as suggested in the case of wind energy. The resulting FIT rates are shown in the lower part of Table 46. Although this procedure might give a decent starting point for FIT rates for Barbados, it will be necessary to closely monitor the cost of such systems and their operation in Barbados. This would allow to switch to Barbados specific FIT rates based on actual costs and fair rates of return as soon as possible.

Table 46: Early FIT rates for biomass in the UK (2001-2012) and in Germany (2004-2009 and 2012-2014)

| Size of installation | FIT in BBD/kWh | Source |
|---|---|---|
| | Early FIT rates for Biomass in the UK (2011-2012) | |
| 0-250 kW | 0.513 | Ofgem 2017 |
| 250-500 kW | 0.474 | Ofgem 2017 |
| 500-5,000 kW | 0.346 | Ofgem 2017 |
| | Early FIT rates for Biomass in Germany (2004-2009) | |
| 0-150 kW | 0.542 | EEG 2004 |
| 150-500 kW | 0.498 | EEG 2004 |
| 500-5,000 kW | 0.415 | EEG 2004 |
| Larger than 5,000 kW | 0.298 | EEG 2004 |
| | Special tariff for anaerobic digestion of manure in Germany 2012-2014 | |
| 0-75 kW | 0.661 | EEG 2012 |
| | First suggested FIT rates for Barbados | |
| 0-75 kW | 0.826 | German FIT rates times 1.25 |
| 75-150 kW | 0.678 | German FIT rates times 1.25 |
| 150-500 kW | 0.623 | German FIT rates times 1.25 |
| 500-5,000 kW | 0.519 | German FIT rates times 1.25 |
| Larger than 5,000 kW | 0.373 | German FIT rates times 1.25 |

## 14.5 Waste to Energy

Feed-in Tariffs for the combustion of municipal solid waste are in use in a number of developing countries, while they don't exist in the major industrialized countries like Germany, the UK or the US, where waste combustion plants participate in the regular power market. Nevertheless, the FIT rates in different developing countries have been quite similar. Indonesia had introduced an FIT rate for electricity from waste combustion of 0.105 USD/kWh, which was increased to 0.1655 USD/kWh in 2014 (see Yuliani 2016, p.5). In 2014 Vietnam announced a FIT rate for electricity from waste at 0.1005 USD/kWh (Otto and Cooper 2014) and Uganda used a FIT rate for 0.103 USD/kWh for municipal solid waste combustion (see Electricity Regulatory Authority, 2012, p.12).

As there are no prior experiences with waste to energy combustion in Barbados it is suggested that the international FIT rate of about 0.1 USD/kWh plus an adder for Barbados specific cost of 25% could be used as a starting point for a FIT for Barbados, which would be 0.25 BBD/kWh for electricity from waste combustion. Although this procedure might give a first starting point for FIT rates for waste to energy for Barbados, it will be necessary to closely monitor the cost of such systems and their operation in Barbados. This would allow to switch to Barbados specific FIT rates based on actual costs and fair rates of return as soon as possible.

## 14.6 Overview of all first price points for FIT rates suggested

Table 47 summarises all suggested first price points for the FIT rates for all different technologies discussed above. As most Barbados specific information was available for solar PV systems, the price points for this technology can be interpreted as relatively robust already. In the case of wind energy the 25% cost adder for higher costs in Barbados than in the US or Germany is only a vague guess. Thus, the wind energy price points are only solid in their international cost components. It has to be seen how much the specific wind energy investment costs will be higher in Barbados than in the international lead markets for wind energy. Front-loaded FIT rates with higher FIT payments for the first 10 years are only suggested for PV, wind energy and King-Grass, as the available data for the other technologies don't allow such detailed calculation.

In the case of bagasse, there is one calculated project for the solid biomass combustion of bagasse and river tamarind giving cost data, which seem to be rather solid. Thus, these costs are the basis for the suggested price point for solid biomass combustion. In the case of King-Grass gasification only very preliminary feasibility calculations have been performed so far and the first gasifier will be constructed in 2017 or 2018. Thus, the cost data on King-Grass gasification are extremely preliminary and can only be seen as a first educated guess. In the case of the anaerobic digestion of manure and agricultural residues no cost data for Barbados are available, but early international FIT rates from the UK and Germany can give a first idea of the appropriate range of FIT rates. As in the case of wind energy it is suggested to use a 25% adder to the international FIT rates for biomass (taken from Germany) to adjust for the higher costs of such systems and their operation in Barbados.

A similar approach as to the anaerobic digestion is taken for solid waste combustion. As in this case no FIT rates are available for industrial countries like the UK, Germany or the US, FIT rates from other developing countries have been taken as a basis. Like in the case of wind energy or anaerobic digestion a 25% adder for higher costs in Barbados has been included to derive the first price points for solid waste combustion.

Preset annual reductions of FIT rates for future investments have only been suggested for solar PV. For all other technologies it seems to be more appropriate to modify future FIT rates based on set expansion corridors and the over or underachievement of the set corridors.

Table 47: Summary of suggested first price points for all technologies considered for possible FIT rates for Barbados

| Techno logy | Size range in kW | FIT rates | | | | | Guarantee period | Annual reduction |
|---|---|---|---|---|---|---|---|---|
| | | Average FIT rate in BBD/ kWh | Phase I | | Phase II | | | |
| | | | Rate in BBD/ kWh | Duration in years | Rate in BBD/ kWh | Duration in years | in years | in % |
| PV roof | 1-10 | 0.491 | 0.634 | 10 | 0.348 | 10 | 20 | 2.4 % |
| | 10-100 | 0.443 | 0.571 | 10 | 0.314 | 10 | 20 | 2.4 % |
| | 100-1,000 | 0.334 | 0.431 | 10 | 0.237 | 10 | 20 | 2.4 % |
| | > 1,000 | 0.281 | 0.363 | 10 | 0.200 | 10 | 20 | 2.4 % |
| PV ground mounted | | 0.281 | 0.363 | 10 | 0.200 | 10 | 20 | 2.4 % |
| Wind | Investor owned | 0.198 | 0.255 | 10 | 0.140 | 10 | 20 | 0 % |
| | Community owned | 0.212 | 0.273 | 10 | 0.150 | 10 | 20 | 0 % |
| | Investor owned plus 10% ownership for proximity | 0.208 | 0.268 | 10 | 0.147 | 10 | 20 | 0 % |
| Biogas from manure | 0-75 | 0.826 | 0.826 | 20 | 0.826 | 0 | 20 | 0 % |
| | 75-150 | 0.678 | 0.678 | 20 | 0.678 | 0 | 20 | 0 % |
| | 150-500 | 0.623 | 0.623 | 20 | 0.623 | 0 | 20 | 0 % |
| | 500-5,000 | 0.519 | 0.519 | 20 | 0.519 | 0 | 20 | 0 % |
| | > 5,000 | 0.373 | 0.373 | 20 | 0.373 | 0 | 20 | 0 % |
| Biomass gasification | | 0.824 | 1.061 | 20 | 0.587 | 0 | 20 | 0 % |
| Solid biomass combustion (bagasse) | | 0.280 | 0.280 | 25 | 0.280 | 0 | 20 | 0 % |
| Solid waste combustion | | 0.250 | 0.250 | 20 | 0.250 | 0 | 20 | 0 % |

## WORK PACKAGE 15: DISCUSSION OF FUTURE PRICING OF SYSTEM SERVICES AND GRID OPERATION

The costs of power generation production, transmission and distribution can be split up into three major components, the cost of direct electricity production, the cost of transmission and distribution and the cost system services. Each of these components contains fixed and variable cost elements. In the case of the basic power generation these are the fixed capital costs for the generation equipment, the fixed costs for operation and maintenance, the variable non fuel costs for the operation and maintenance of the generation equipment and the fuel costs. In the case of the transmission and distribution of electricity the cost elements are the fixed capital costs of the grid including the transmission and distribution lines, transformers and other necessary equipment, the fixed operation and maintenance costs as well as the variable operation and maintenance costs for operating the grid. In the case of the system services these are the capital costs for frequency and voltage stabilisation, for restarting the system after a system break down and for the coordination of the grid operation, the fixed and variable operation and maintenance costs for these services and the fuel costs for the operation of the reserve capacities called upon in the case of a need for system stabilisation or restart.

Table 48: The different cost elements of supplying electric power

| | Fixed capital cost | Fixed O&M cost | Variable O&M cost | Fuel cost |
|---|---|---|---|---|
| **Basic power generation** | x | x | x | x |
| **Transmission and distribution** | x | x | x | - |
| **System services** | x | x | x | x |

In large electricity systems separate markets exist for normal electricity production and different types of reserve capacities. The costs of grid operation are normally paid for in the form of approved grid levies, as the grid infrastructure constitutes a natural monopoly, thus, no market for grid services can exist. As a result the electricity prices charged to customers are made up of different elements: the wholesale price of electricity, a grid charge for transmission, a grid charge for distribution and a charge for system services. In the case of FITs an additional FIT levy is charged as well. Under such differentiated price system future costs of grid expansions or additional costs for system services due to an increasing share of intermittent renewable energy sources can easily be allocated to the different price components.

In Barbados the total costs of power production are only allocate by type of cost as the following consideration shows. The present tariff structure of Barbados Light and Power (BL&P) as approved by the FTC (see FTC 2010a, p.4 and 21) is based on four main elements to allow BL&P to recover its cost and to earn a fair return (10%) on its equity. These elements are:

- the *customer charge* for all smaller consumers with less than 5 kVA billing demand
- the *demand charge* for customers with a billing demand of at least 5 kVA
- the *base energy charge* and
- the *fuel clause adjustment*.

The purpose of the *customer charge* and the *demand charge* are to cover the fixed costs of providing the electricity service, while the *base energy charge* is supposed to cover the non fuel cost induced variable costs of providing the electricity service and the *fuel clause adjustment* is supposed to cover the fuel costs of the electricity produced. Therefore, the costs are only differentiated with respect to the type of cost, namely fixed, variable or fuel cost, but not with respect to the part of the power system, from which they generate (generation, grid or system services).

Due to the present allocation of costs it is not transparent, which part of the fixed costs of BL&P originate from the basic power generation, the transmission and distribution of electricity or the necessary system services. The same applies to the distribution of the variable costs of BL&P and even to the allocation of the fuel costs between basic power generation and the necessary operation for system services.

For the future electricity supply system of Barbados, with increasing shares of different renewable energy sources, the need for grid expansion and reinforcement, the increasing need for storage and an even more important role of system coordination and system control, the present cost allocation mechanism as well as the present cost information supplied by Barbados Light and Power will be insufficient for a fair and transparent allocation of the future system costs. Thus, it will be necessary to allocate costs according to both dimensions given in Table 48 above.

As system services like frequency control, voltage control, black start capacity and system coordination will mostly be supplied by Barbados Light and Power it needs to be discussed how these services will be priced in the future and how these prices will be regulated by the FTC.

Frequency and voltage control are achieved through the use of primary and secondary reserve capacities. These capacities need to be available within seconds in the case of primary reserve and within minutes in the case of secondary reserve. To enable such fast availability a certain capacity of generators (or storage units in the future) need to be in a state of operation where they can easily be ramped up (positive reserve) to increase their output or ramped down (negative reserve) to decrease output. In general such operation requires the guaranteed availability of capacity (normally at 99.9% security), no matter whether it is actually called upon or not. With conventional combustion based generators even the fast availability of primary positive reserve may require partial load or even idle operation of reserve capacity to enable such instantaneous availability. Thus, even making primary reserve capacity available may require substantial variable costs. In the future there will need to be separate capacity payments for guaranteed reserve capacities (positive and negative) as well as payments for actual reserve generation in Barbados.

In the future pump storage hydropower systems can supply a major share of the necessary reserve and black start capacity for Barbados, as such systems can be ramped up far faster than any fossil fired generators. In the case of pump storage the full capacity of the system can be made available in 60 to 90 seconds as positive or negative reserve capacity. As a future pump storage system does not have to be owned by Barbados Light and Power it will need to be discussed, how the prices for primary and secondary reserve capacity will be determined and how these prices will be split between the guaranteed capacities and the actual operation. The same consideration applies to the price for black start capacity, which is needed to restart and synchronise the entire electricity system in case of a total system break down. This black start capacity is presently supplied by Barbados Light and Power, but in the future it may well be that a pump storage plant not operated by BL&P can supply such system service. In the future Barbados will need to introduce differentiated tariff components for the eleven standard cost components of supplying electricity (compare Table 48 above) plus an FIT levy to enable transparent electricity pricing. Most tariff components will need to be regulated by the FTC based on detailed cost information supplied by Barbados Light and Power.

Although it is clear that a transparent and fair pricing procedure for all system services needs to be introduced in the future and that this will require a far more transparent and detailed cost reporting by Barbados Light and Power, it is beyond the scope of this analysis to derive the details of such solution.

# WORK PACKAGE 16: DISCUSSION OF MOST APPROPRIATE SUPPLY MODE FOR RENEWABLE POWER

In the discussion of the future FIT system for Barbados it has been stressed that net metering should only be applied to PV systems up to 1 $kW_p$. For all other renewable energy technologies and all size ranges the Feed-in Tariff system will be applied. In order to balance the distribution of the costs and benefits of the increased use of renewable energy systems between the investors and the average Barbados rate payer it is suggested that the entire FIT system will be based on the so called ‚buy-all, sell all' rule. This means that every kilowatt hour produced from a renewable energy system under the FIT regime will be bought by the system operator at the FIT rate specified for this technology and system size (sell all). Even electricity that has to be down regulated by the electricity system operator will be paid for according to the FIT rate. Thus, every investor knows from the start of operation of his system how much money he will earn for every kilowatt hour of electricity produced. As discussed before, this will allow the calculation of the discounted cash flow of a renewable energy investment as soon as the investor has measured the resource quality of his site and as he has invested in solid technology producing the anticipated electricity output. On average the payments he will receive will generate an annual return before taxes of about 8% on his equity, if he has financed his investment with a 20% equity share (see the detailed discussion of the suggested price points in WP 14 above). At the same time each electricity customer in Barbados has to buy all the electricity he uses from the grid (buy all) in order not to introduce partial net metering through the back door. In this way it is guaranteed that all system costs for maintaining a well functioning and robust electricity grid are shared equally between all customers and every kilowatt hour consumed. The only exemption from this rule are the volumes of electricity produced under the net metering scheme for very small PV systems.

There has been some discussion of the introduction of so called wheeling and banking of renewable energy to promote the use of more renewable energy. As discussed in Heeter et al. (2016) wheeling and banking has been used for this purpose in some states of the United States, in Mexico and in India for more than ten years. According to Heeter at al. (2016, p.2) wheeling is ‚a transmission service that enables the delivery of electricity between a buyer and a seller, often under a long-term PPA' (PPA: power purchase agreement). In the same context Heeter et al. (2016, p.2) define banking as ‚a financial and accounting mechanism under which a service provider earns credit for excess RE supplied to the grid'. As it can be seen from Table 49 below banking of renewable energy is not used in the US context but is used in Mexico and in India. While wheeling is available to RE producers in the US at the normal wheeling rates used for conventional electricity Mexico and India grant discounted wheeling rates for renewables.

Wheeling actually allows the sale of renewable electricity directly to a customer independent of any wholesale or retail market or the need to sell to a grid or system operator acting as a single buyer. Such an arrangement may be of interest, if renewable electricity has to be sold at the normal power exchange or when the combination or renewable electricity certificates (under a renewable portfolio standard policy) and the power price at the power exchange are either very uncertain or expected to be low. In such case a renewable energy producer may enter into a long term power purchase agreement with a specific customer, who wants to buy renewable electricity (like in the case of Apple trying to change its power supply to 100% RE electricity).

In the case of established FIT tariffs and guaranteed grid access there is no need for the RE producer to sell his electricity to a specific customer. This could just be attractive if the RE producer can produce at very low cost, which would allow him to sell outside the FIT system to a customer at a price below the normal electricity price, which this customer would have to pay otherwise. In this case the two parties could share their advantage and both could be better off as in the case of the ‚buy all, sell all' FIT regime. Nevertheless, this calculation comes at the expense of all other electricity customers, who would have to

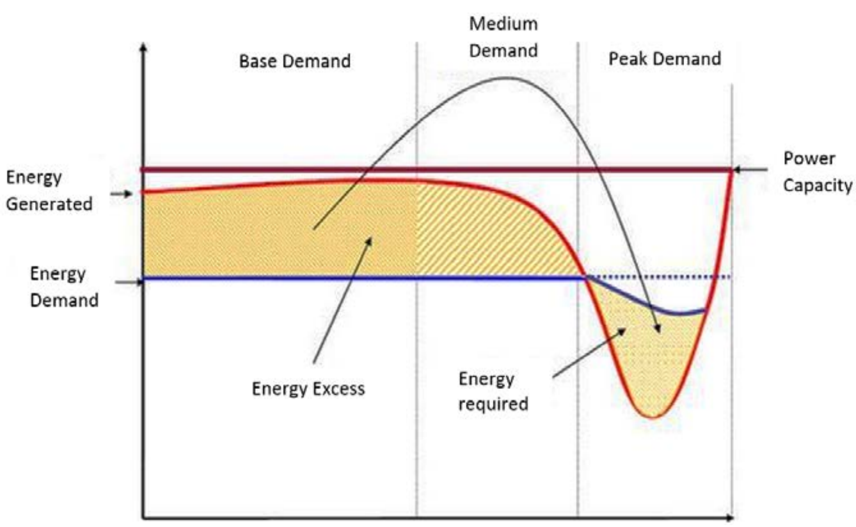
Table 49: Definitions of wheeling and banking of renewable energy and their use in the United States, Mexico and India (source: Heeter et al. 2016)

| | **Wheeling** | **RE Banking** |
|---|---|---|
| General definition | Wheeling is a transmission service that enables the delivery of electricity between a buyer and seller, often under a long-term PPA | Banking is a financial and accounting mechanism under which a service provider earns credit for excess RE supplied to the grid |
| United States context | Transmission services to deliver power from a generator's dispatch point to where the buyer takes title to the power purchased on the grid; no discounted wheeling rates for RE generators | Banking is not used on the wholesale level |
| Mexico context | Discounted wheeling rates allowed wind generators to serve large commercial and industrial customers with electricity; providing known, flat-rates allowed for reliable planning by wind generators | All variable RE technologies can use banking, as mandated by the Energy Regulatory Commission for no charge. |
| India context | Discounted wheeling rates in some states allow wind and solar generators to supply electricity to customers at competitive rates | Discounted banking provisions for wind and solar generators exist in some states and typically are provided by state utilities |

pay higher prices as in the case of the ‚buy all, sell all' regime, which allocates the advantages of the low cost renewable energy source to all electricity customers through a lower overall electricity rate.

In the case of banking of renewable energy the producer of RE electricity is allowed to feed all his renewable electricity into the grid whenever he is producing it, although he has a contract to deliver the electricity to his customer at times different from his production. The electricity system absorbs his excess production and supplies the electricity whenever he is in deficit. There are no additional charges as long as the sum of the renewable electricity generation is the same as the volume sold to the customer (see Figure 91 below). It is quite obvious that in the case of banking all other electricity customers subsidise the contract between the producer of renewable electricity and his customer by absorbing the additional costs for balancing the system.

Figure 91: Diagram illustrating the energy compensation in the energy banking model for renewables (source: Heeter et al. 2016, p.17)



The report by Heeter et al. (2016), although very positive on wheeling and banking for renewable electricity, is quite clear about the motives behind both mechanisms. In the case of Mexico, which uses discounted wheeling as well as banking of renewable electricity the report states: ‚These instruments were designed under the assumption that no financial subsidies, such as feed-in tariffs, would be available, thus making it necessary to look for alternative measures to promote renewable energy.‘ This actually makes it quite clear that such mechanisms are only second best solutions for the promotion of renewable energy sources, specifically in the case of guaranteed priority grid access and long-term guaranteed fair FIT rates as suggested for Barbados.

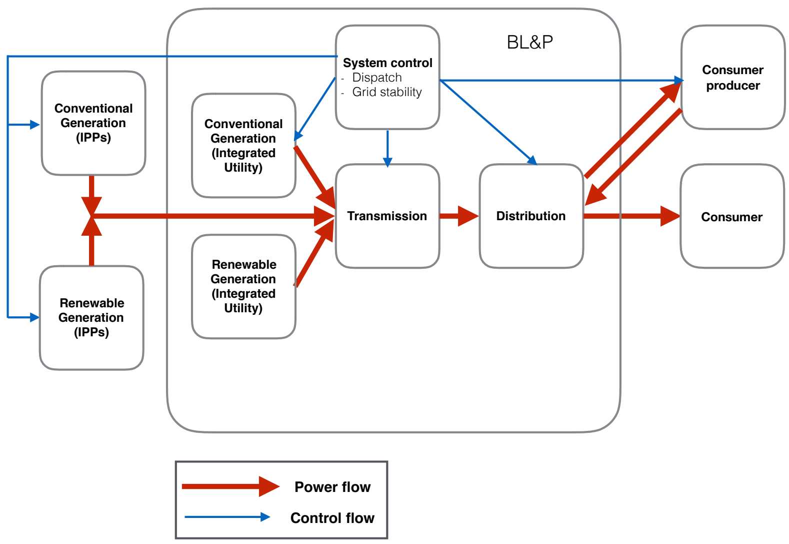
It can be concluded that the suggested FIT system based on guaranteed grid access, stable long-term FIT rates, fair rates of return on equity, the principle of ‚buy all, sell all‘ and the inclusion of all mature renewable energy technologies relevant to Barbados does not need other supply modes like wheeling or banking.

# WORK PACKAGE 17: SUGGESTION OF POWER MARKET STRUCTURE

Looked at it in a functional way the present structure of Barbados' energy system, as defined by the Electric Light and Power Act, is centred around Barbados Light and Power operating the conventional generating capacity and the grid. At the same time it is including the possibility of independent power producers (IPPs) operating conventional and renewable generation capacity as well as consumers producing renewable energy for their own consumption and for selling excess electricity to the grid. The functions and possible players in the electricity market can be pictured as shown in Figure 92. The structure mainly consists of the privatised former monopoly (BL&P), which is responsible for conventional and renewable electricity generation, the transmission and distribution of all electricity as well as for the functional control of the system.

BL&P presently holds all significant conventional generation units, is operating a substantial PV capacity and plans to build the first wind park of Barbados at Lambert's Farm. At the same time private and commercial consumers are producing solar energy, which is partially fed back into the grid and is payed for under the fixed renewable energy rider (RER) rate regime. According to the given legal framework it is possible that independent power producers own and operate renewable energy plants as well as conventional generation units.

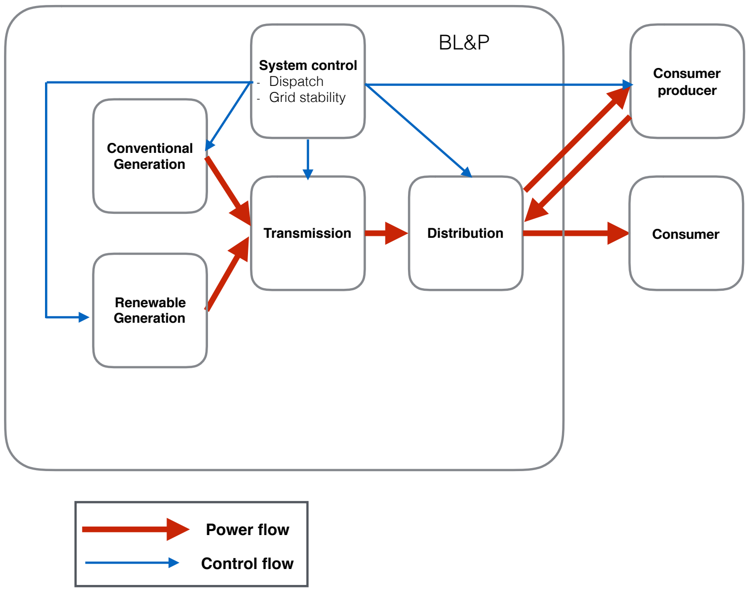
Figure 92: Present theoretical structure of Barbados power supply system (own graphical representation)




Nevertheless, no competition has developed for conventional generation due to the size of the electricity system and the resulting lack of economic production opportunities for IPPs as discussed in WP 10 above. Thus, the introduction of competition in conventional generation has not been achieved and is extremely unlikely for the objective reason of total system size.

Another important question connected to the problem of small market size is the question of vertical unbundling of generation, transmission and distribution of electricity. Some arguments why the vertical deintegration or unbundling of an integrated monopoly may not be feasible in small electricity systems have been raised by Bacon (1995). Bacon has shown that the deintegration of a vertically integrated monopoly supplier may cause substantially higher costs in small countries than the possible cost savings achievable by the unbundling. Bacon shows that in small countries the vertical deintegration will cause substantial coordination costs specifically in the dispatch of production capacity while it is doubtful that any cost savings can be achieved by splitting up power generation into at least three to five competing companies with comparable assets enabling effective competition in generation (Bacon 1995, p.21f). Whenever vertical unbundling meets a situation with little competition in generation, its benefits will be small while the costs will be high (Bacon 1995, p.15). Due to the circumstances given in Barbados characterised by a small system size and the very early development stage of renewable electricity production there are no IPPs in conventional or renewable power generation. Thus, the present factual system structure pictured in Figure 93, witnesses a situation in which Barbados Light and Power (BL&P) is controlling a larger share of all system activities and IPPs play a far less important role of than the legal framework would allow.

Figure 93: Actual present structure of Barbados' electricity system




If the suggested FIT system will be established and an ambitious transformation process towards a 100% renewable power supply will be started by setting ambitious policy goals (e.g. 100% renewable electricity by 2035) the situation on the generation side can be changed fundamentally. Under such framework the major share of Barbados' electricity can be produced from renewable energy systems owned by private and commercial consumers as well as independent power producers. At the same time the role of Barbados Light and Power will change towards more emphasis on system control, system services, transmission and distribution of electricity, storage and system back-up by the present conventional generators eventually running on bio fuels. The resulting system structure of Barbados' electricity system with a substantial development of consumer producers and IPPs producing renewable electricity from thousands of systems will look like Figure 94 below.

It can be argued that a certain form of legal vertical unbundling of Barbados Light and Power into different functions may be reasonable as long as coordination costs can be kept low. There could be a legal unbundling into two units: generation (conventional and renewable) and grid operation as shown in Figure 95 below. Where generation would include conventional generation for normal power supply, conventional generation for grid services, renewable energy generation and storage. Grid operation would include the transmission and distribution of power and the system control, which would be in charge of dispatching all power producers and all aspects of system stability like frequency and voltage control. Although, the two units of BL&P would be legally unbundled, they would still need to be operating as functionally connected entities to avoid high additional coordination costs as pointed out by Bacon (1995). Such legal unbundling has successfully been applied in the electricity market liberalisation e.g. in Germany.

Figure 94: Future structure of Barbados power supply system with RE IPPs entering into the market (own graphical representation)

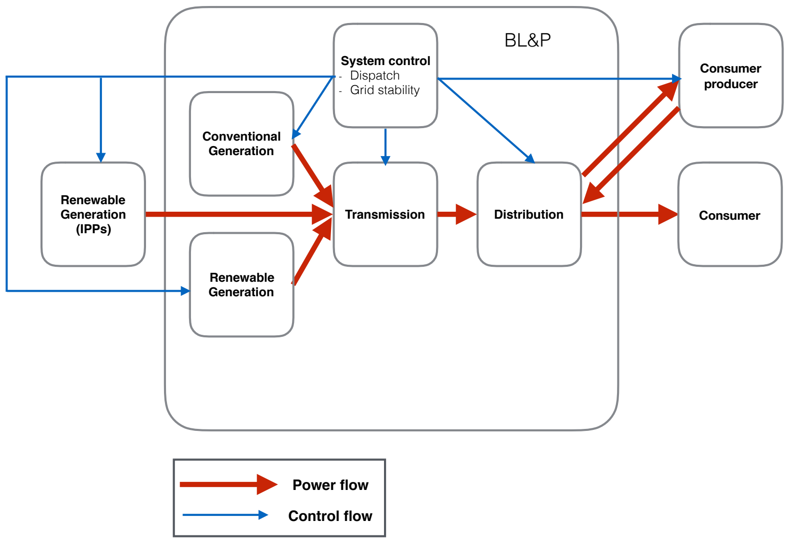
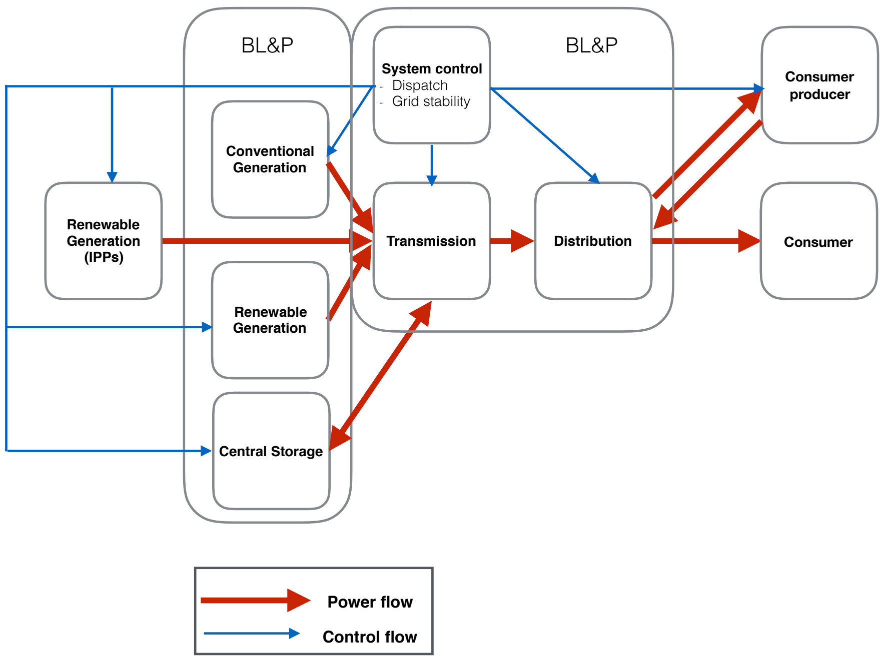


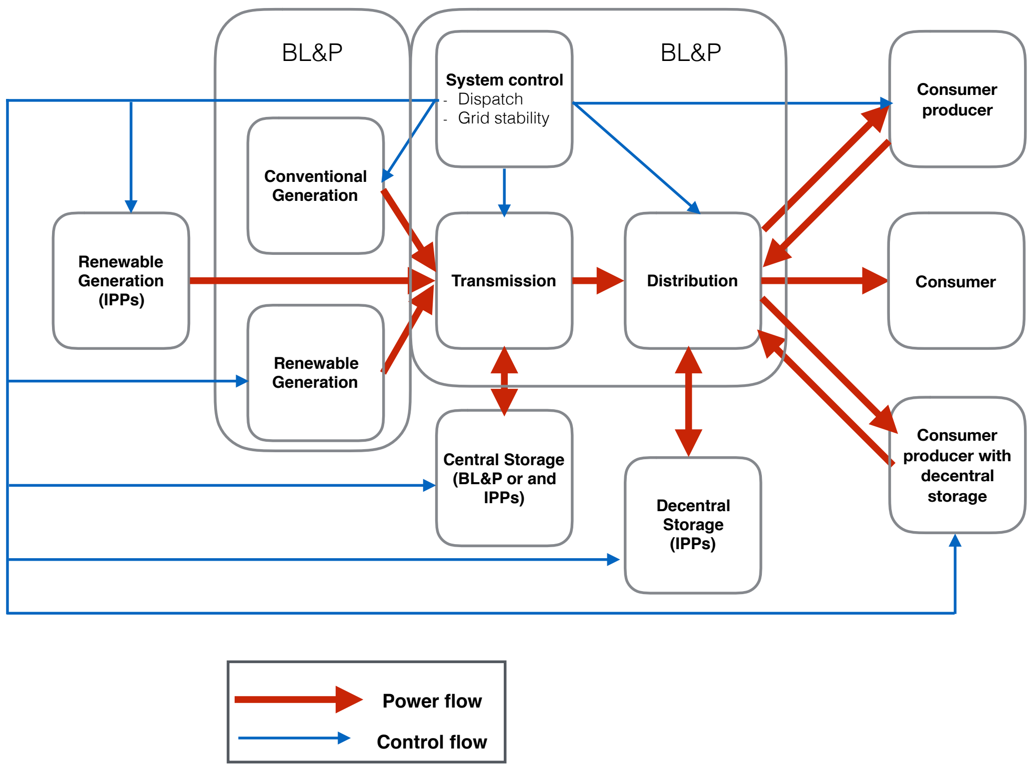

Figure 95: Possible additional legal unbundling of Barbados Light and Power into generation and system operation including grid operation (own graphical representation)




As soon as storage will start to play a major role in Barbados' future electricity system it will be possible to allow decentralised storage on the basis of batteries by consumers or IPPs as long as these storage device can be centrally controlled. Central control of storage will be necessary in order to maximise the benefits of decentralised storage for the overall power system. If storage is not coordinated it is highly likely that it will eliminate automatic stochastic balancing processes between many consumers and many renewable power systems, as the storage operation will be optimised with respect to the single renewable power system and the single consumer connected to it. Under such operation substantially larger storage volumes will be necessary for the same positive effect on the system as in the case of centrally coordinated storage utilising the stochastic effects of the total system (see e.g. Teske 2015, p. 189).

For central storage, like the planned pump storage system, it is possible that these can be build by IPPs or by Barbados Light and Power or joint ventures of BL&P and independent investors. Such system is pictured in Figure 96 below. Nevertheless, it will be absolutely mandatory that the central storage facilities are controlled by the system operator as they have an extremely high value for the overall system control and as they can not be operated independently. A major storage system run without the necessary real time information on the present system operation will most likely become a major burden to the system.

Figure 96: Possible advanced legal unbundling of Barbados Light and Power into generation, system operation including grid operation and the establishment of central and decentralised storage




If legal vertical unbundling of Barbados Light and Power should be possible without incurring high coordination costs between generation, transmission, distribution and system control, it is suggested that Barbados Light and Power should be split up into two legal units, one owning and operating conventional and renewable generation capacities and the other unit owning and operating the entire electricity grid and operating the entire system control. The second unit would then be in charge of connecting all consumer producers and IPPs operating renewable power systems to the grid and the organisation of all processes necessary for metering and paying for the renewable electricity sold to the grid. At the same time this unit would be metering and selling all electricity to consumers in Barbados. The question of ownership of future central storage can be left open at the moment as long as the system operator will have full control over the operation of the central storage units. How the suggestsed structure shown in Figure 96 relates to the power market structure will be discussed in WP 19 and WP 20 below.

## WORK PACKAGE 18: RECOMMENDATIONS FOR THE IMPLEMENTATION OF POLICIES, REGULATION AND LEGISLATION

The analysis has has looked at two main issues, the design of a policy framework to ensure stable prices for electricity from renewable energy source and the possibilities for a further liberalisation of Barbados' power market. The recommendations given in the following text mainly focus on the suggested framework for renewable energy sources. Some suggestions on policy measures for a further liberalisation of Barbados' power market will be given in WP 21, after the issues have been discussed in more detail in WP 19 and WP 20.

For the implementation of the suggested Feed-in tariff system a number of recommendations on the implementation of relevant policies, regulations and legislation can be made. In the following these recommendations will progress from the most general policy measures at the level of national energy policy targets through the level of FIT policy implementation measures all the way to the necessary changes in some rules in Town and Country Planning concerning the measurement of distance from wind turbines.

The following recommendations can be made on the basis of the work done in the different work packages of this consultancy assignment:

- The national energy policy needs to set the framework for the future expansion of the electricity production from renewable energy sources by deciding on the approximate **structure of the target energy system** reaching the envisaged goal of a 100% renewable power supply. This will be necessary to develop the quantitative targets for the different renewable energy technologies to be deployed. In the decision on the structure of the target system the approximate shares of wind energy, solar PV and biomass should be indicated to give orientation to potential investors.

- The national energy policy should indicate as well the **share of green e-mobility** envisaged in the target energy system, as this will require adequate additional renewable power generation capacities. On the basis of the analyses conducted so far it seems to be advisable to convert as much of the transportation sector to green e-mobility in order to reduce the fuel imports draining hard currency from Barbados' economy.

- The national energy policy needs to set a **target year**, when the envisaged 100% renewable energy system should be reached and by which year the additional switch to green e-mobility should be achieved. In the analysis of the consultant the target year 2035 has been used, as it seems quite achievable and as it would allow to effectively cap the electricity costs for Barbados' ratepayers relatively soon making Barbados independent of international developments in crude oil prices and allowing to keep a growing share of gross domestic product (GDP) presently used for fuel imports in Barbados' economy. Thus, an ambitious target year will allow to increase employment and the general income situation of Barbados' citizens as soon as possible.

- Once the target system and the target year are chosen the **transition pathway** to the target system can be designed. This transition pathway should have clear indications of the capacity corridors for the different renewable energy technologies for every year of the transition period, which will be needed to set the response corridors for the FIT rate adjustment by responsive FIT rates. Taking into account the necessary lead time of five to eight years for the building of a central pump storage facility, which will most likely be the cheapest and most versatile form of electricity storage for Barbados' future renewable energy based power supply, the transition pathway will indicate to possible investors the time, at which they need to start the preparation for the construction of such storage facilities.

- The national energy policy will need to **adopt the suggested Feed-in Tariff** (FIT) system in order to set the framework for a continuous and solid development of the use of renewable energy sources for power generation in Barbados. A clear decision to adopt the Feed-in Tariff framework combined with the decisions on the target energy system, the target year and the transition pathway will create a high level of investor security and can induce the intended development of renewable power generation in Barbados as soon as the FIT system has been established. The FIT system will establish stable and reliable prices (tariffs) for the different renewable energy technologies and will help to stabilise Barbados' electricity costs at a comparatively low level.
- Barbados' national energy policy will need to **decide whether** it wants **to adopt net metering for very small PV systems** (up to 1 $kW_p$) **in low income households** as suggested by the consultant. Net metering for low income households can be seen as a social component of the future renewable energy policy enabling as many low income households to participate in the future production of renewable energy. A limitation of net metering to small installations is necessary, because the electricity produced under net metering is not contributing to the financing of the overall system costs, paid for by all other ratepayers.
- The national energy policy will need to **decide** together with Barbados' agricultural policy **whether** it wants **to pursue** the plans for the combined **bagasse and river tamarind combustion** for electricity production or whether it considers the future prospects of Barbados' cane industry as to uncertain as to base a 460 million BBD investment on it. The economic success of the planned bagasse combustion plant will hinge upon the secure supply of large volumes of bagasse from Barbados' sugar cane industry. Thus, a further decline of Barbados' sugar industry may lead to an economic failure of the bagasse based power plant.
- Barbados national energy policy should **set** the necessary **framework conditions for the demonstration** and further development **of King-Grass gasification** for electricity production in Barbados, as this technical option can be a back-up solution for Barbados' agricultural problems connected to the decline of the sugar industry. King-Grass could provide the necessary grass plant for rotational cropping with other cash crops, which can only be grown in rotation with a grass crop due to the high sensitivity of Barbados' top soil to rain and wind erosion.
- To allow the full development of Barbados' very low cost wind resource the identified seven regions with very good preconditions for the development of wind energy in Barbados need to be **earmark**ed as **preferential wind areas as soon as possible** in the revised physical development plan for Barbados, which is in development at the time of writing of these recommendations. If these areas are not earmarked and other developments are allowed irrespective of the wind energy potential of these areas the development of wind energy can be seriously endangered due to the necessary distances between wind turbines and dwellings or settlements.
- To allow for a broad participation in wind energy citizen wind turbines and wind parks should be supported. One necessary precondition for the economically successful implementation of wind energy are bankable wind time series data, which need to be available at the time of application for the necessary debt funding part of the financing. At the moment such data is not available for the relevant wind energy sites in Barbados and has to be measured for a period of at least one year for a specific site. Such measuring campaign will cost about 500.000 BBD per site, which is unaffordable for citizen groups trying to establish a citizen wind park. Thus, it is suggested that the government of Barbados finances a **wind measuring campaign** at all seven preferential wind energy areas and that the results of this measuring campaign will be made publicly available to all interested investors free of charge.

There are indications that the EU delegation to the Caribbean is willing to fund such measuring campaign.

- In preparation of the broad citizen participation in the investment in the new renewable energy system of Barbados it will be necessary to start a **broad information campaign for Barbados' citizens** on the new FIT system, its conditions and the opportunities for citizen investment. It is highly recommended that such an information campaign will be conducted parallel to setting up the FIT system.
- It is highly recommended on the basis of decades of international experiences to **involve the local population** in the seven preferential areas for wind energy **in the development of the wind energy planning and the actual investment** in wind energy in each location. These efforts need to be based on a very thorough information campaign for the local population on all issues concerning wind energy. For the acceptance of local wind energy developments early involvement of the local population and the possibility of becoming one of the owners of the local wind park will be absolutely crucial.
- For the implementation of the FIT system it will be essential to **follow the basic rules for a good FIT design**. These rules require to implement a highly reliable system with long-term guaranteed FIT rates, to anchor the system in the energy law by amending the ELPA, not to make any changes to the system, which could jeopardise investments already made in renewable energy systems at the time of the policy change, to guarantee preferential access of renewable electricity to the grid, and to establish rules for the highest possible degree of transparency to every potential investor and to the general public. It is necessary to achieve the highest possible degree of investor security and public trust in the system to minimise the costs to the ratepayers by allowing very low risk financing conditions and the acceptance of very moderate low risk returns on the invested equity.
- With respect to **legislation** it is recommended to **amend PART III of the Electric Light and Power Act** (ELPA) by inserting a **new section on ‚Pricing of renewable energy sources'**. In this section all necessary regulation for the new FIT system can be laid down. Anchoring the new FIT system in the ELPA would give clear guidance to all stakeholders and would help to maximise investor confidence in the new support mechanism.
- With respect to **regulations** it will be absolutely necessary to **change from the present distance rule for wind energy** used in Town and Country Planning and wind energy licensing, which refers to minimum distances from the perimeter of property on which the turbine is located, **to the international standard of distance rulings**, which refer to the effective distance from dwellings, settlements, streets, nature preservation areas and other objects to be protected from excessive impacts of wind turbines. Without this change wind energy development will unnecessarily be restricted to a small fraction of the actual useful potential and it will be restricted to very large pieces of property and thereby to very wealthy property owners.
- It is highly recommended to establish the necessary rules and procedures to **achieve the highest level of information transparency for the general public and all possible investors**. As the installation of renewable energy capacities will most likely need to be capped for single grid areas until the necessary grid improvement has been achieved, it will be absolutely mandatory to make the reasons for the caps, the plans for the grid improvement (including timelines) and the exhaustion of each cap absolutely transparent in order to avoid unnecessary frustrations of potential investors due to investment plans for renewable energy installations being confronted with unexpected restrictions of grid access due to lack of transparency.

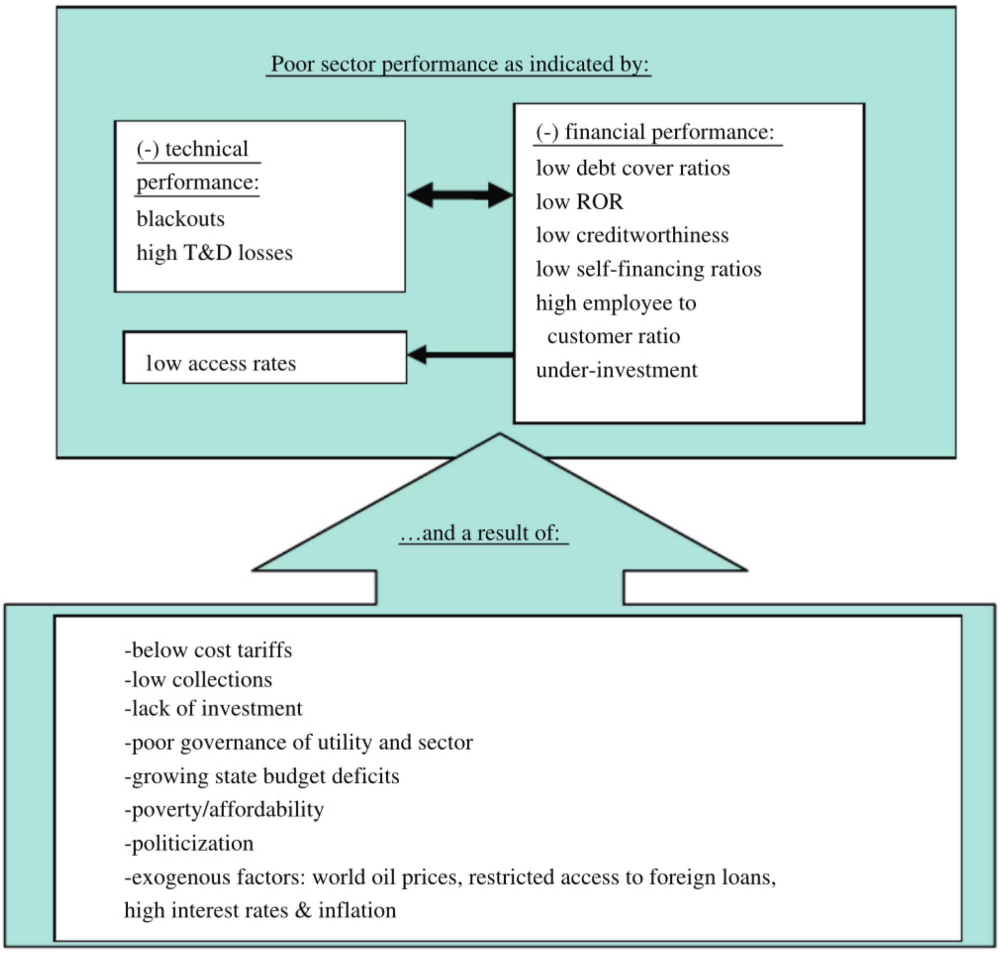
More detailed policy recommendations on the FIT system to be established can be found in WP 21 below.

# WORK PACKAGE 19: DISCUSSION OF A POSSIBLE LIBERALISATION OF THE BARBADOS POWER MARKET

Many components of possible market structures and aspects of liberalisation of Barbados' power market have been discussed in other work packages before. Some central arguments concerning the liberalisation of small power markets are repeated here to allow an easier understanding of the discussion.

Liberalisation of power markets has been discussed extensively in the literature. In the developing world liberalisation has often been seen as an instrument to improve the performance of the energy sector, which has been very poor in many developing countries. As a basis for the discussion of the liberalisation of power markets Gratwick and Eberhard (2008) have analysed the indicators of poor power sector performance and their most common reasons. The results of this analysis are pictured in Figure 97 below.

Figure 97: Poor power sector performance: indicators and causes (source: Gratwick and Eberhard 2008, p.3951)




In the case of Barbados the present technical and financial system performance is very good compared to all indicators listed by Gratwick and Eberhard (see Figure 97) and there seems to be only one aspect left for improvement, which is the political intervention into the electricity system, as it can be seen in some past political plans for questionable large scale investments in the power sector like the plan for a plasma gasification plant for waste. As far as the consultant knows, this plan was drawn up with the idea of very high guaranteed rates for the electricity to be paid by BL&P to the future operator of the plant in a situation, where neither the future costs of the plant nor the technical performance are known. Interventions of this kind can fundamentally endanger the performance of the electricity sector.

An other example for a questionable political intervention into the electricity sector is the plan to introduce imported liquified natural gas as a mandatory fuel for Barbados Light and Power in a situation where the direct transition towards renewable energy sources is the logical next step of the power system development due to economic and environmental reasons. Electricity prices would have to be increased substantially, if large quantities of gas would be forced into the power supply by the government. This is due to the fact that the imported quantities of LNG will most likely be more expensive per GJ of energy than HFO (heavy fuel oil) or diesel used at the moment and that the efficiency of the operation of the existing generators will be reduced, if they would have to be adapted to the combustion of LNG. Both impacts will increase the specific cost of electricity to the consumer in Barbados. What is more, the import of substantial volumes of LNG will require substantial new investments, which will turn into stranded investment as soon as the necessary transition towards a 100% renewable power supply gains momentum, making the investments obsolete before their costs have been recovered. It is highly likely that the costs of these stranded investments will need to be born by the average taxpayer in Barbados. Once the investment in such LNG infrastructure will be done this will create a substantial political pressure to delay the possible introduction of a substantial share of renewable energy in order to avoid the stranding of the investment and the burden on the taxpayer. Thus, the political pressure to switch from diesel and HFO to LNG will either reduce the possible performance of the electricity system and increase the cost to ratepayers or produce stranded investment and increase the costs to the taxpayer as well.

Based on the very good performance of Barbados' present electricity system, which is driven by the present legal framework and the performance of BL&P, it can be asked whether a further liberalisation can lead to any additional improvement of the system performance. The starting point for such discussion needs to be an assessment of the present situation of the electricity market liberalisation in Barbados as it was sketched in WP 10 above. As pointed out in WP 10 the World Bank has developed a nomenclature for assessing nine possible stages of power market liberalisation (see Gratwick and Eberhard 2008, p. 3952) as shown in Table 50 below.

According to the World Bank nomenclature Barbados has already adopted seven of nine reform steps. Only the two steps of restructuring (unbundling the vertically integrated utility) and the introduction of competition through the introduction of wholesale and retail markets have not been adopted so far (compare Gratwick and Eberhard 2008, p. 3952 and Table 50 below).

According to Gratwick and Eberhard (2008, p. 3954) the Barbados legal situation resembles the single buyer model depicted in the middle of Figure 98, which can be seen as one of the standard hybrid forms of power market liberalisation, which have evolved during the last two decades in the power market liberalisation of developing countries. As no IPPs for conventional power generation have developed during the years since the ELPA has been enacted, the actual situation concerning the conventional generation is still the factual monopoly pictured in the left hand part of Figure 98. As Barbados is too small for the establishment of IPPs based on conventional power generation (see the discussion in WP 10 above as well as Bacon 1995, p.4 or Weiser 2004, p. 108f).) and far too small for the establishment of a retail power market like a spot market as pictured in Figure 99 below, the only reasonable form of horizontal (generation) unbundling works through the establishment of IPPs and consumer producers operating renewable energy systems under a regulated tariff system (FIT). To avoid cherry picking by large renewable energy based IPPs and large commercial customers wheeling of renewable power was rejected in WP 16 above. Thus, the single buyer model combined with renewable energy based IPPs and consumers operating their own renewable energy system for electricity sales to the grid under guaranteed FIT rates seems to be the only reasonable fair market design with limited market power (limited by the FIT law) of the single buyer and regulated tariffs.

Table 50: The nine stages of electricity market liberalisation and the market situation in Barbados

| | State of liberalisation | Short characterisation | Status in Barbados |
|---|---|---|---|
| 1 | **Corporatisation** | Transformation of the utility into a separate legal entity | Achieved |
| 2 | **Commercialisation** | Cost recovering prices etc. | Achieved |
| 3 | **Passage of requisite legislation** | Provides legal framework for restructuring and private ownership | Achieved |
| 4 | **Establishment of independent regulator** | Aims to introduce transparency, efficiency and fairness in the management of the sector | Achieved |
| 5 | **Independent power producers (IPPs)** | Introduce new private investment in generation with long-term power purchase agreements (PPAs) | Legally achieved |
| 6 | **Restructuring** | Involves horizontal and/or vertical unbundling of the incumbent (state-owned) utility as preparation for privatisation | Not achieved |
| 7 | **Divesture of generation assets** | Divests state ownership of generation assets to the private sector | Achieved |
| 8 | **Divesture of distribution assets** | Divests state ownership of distribution assets to the private sector | Achieved |
| 9 | **Competition** | Introduces wholesale and retail markets for electricity | Not achieved |

Figure 98: Three different models of electricity markets according to Gratwick and Eberhard (2008, p. 3954)

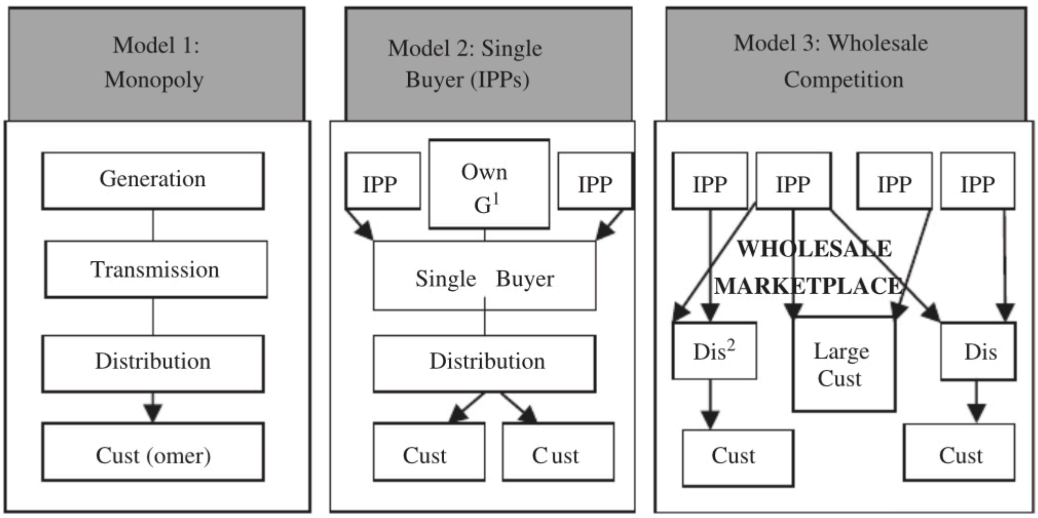
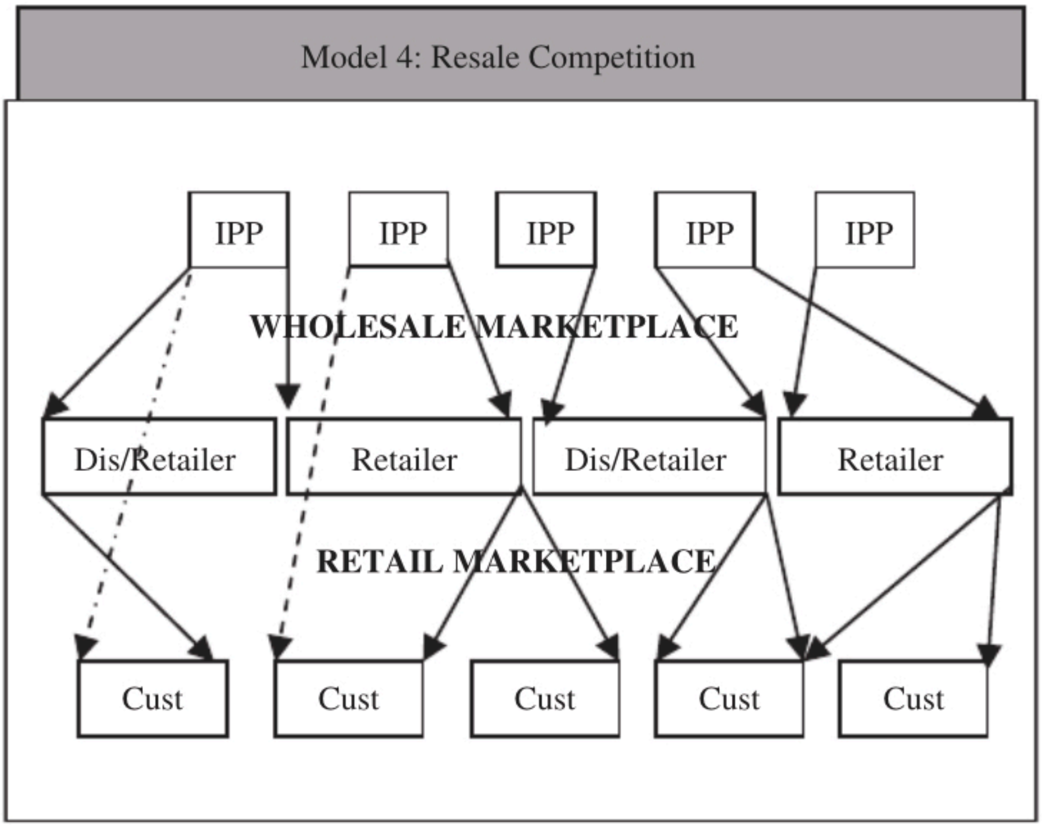


Figure 99: The model of resale competition in electricity markets according to Gratwick and Eberhard (2008, p.3954)




The question remains, whether a vertical unbundling of the single buyer might be advantageous for a further improvement of the system performance through additional liberalisation? Some arguments why the vertical unbundling of the integrated monopoly may not be feasible in small electricity systems have been raised by Bacon (1995). Bacon has shown that the deintegration of a vertically integrated monopoly supplier may cause substantially higher costs in small countries than the possible cost savings achievable by the deintegration. Bacon shows that in small countries a full vertical unbundling will cause substantial coordination costs specifically in the dispatch of production capacity, if the new entities are totally independent from each other and plan their capacity expansions independently. At the same time the benefits of vertical unbundling in a situation with little competition in generation may be small while additional coordination costs may be high (Bacon 1995, p.15).

Nevertheless, there may be a chance for some legal vertical unbundling of the single buyer by legally separating the generation part of BL&P from the grid and system operation part, as pointed out in WP 17 above. In this case the single buyer would be the grid and system operation part of BL&P. In the longer run the public trust in the system operator (single buyer) will increase, if this entity is separated from any generation assets, able to play a more neutral role in dealing with the thousands of future independent renewable energy producers in Barbados.

There may be some additional chances for improvement by the introduction of performance based regulation (as suggested by Woo et al. 2003, p.1103) and by strengthening the capacities of the FTC as a key player in a successful development of Barbados' electricity market.

# WORK PACKAGE 20: SUGGESTION OF A SUITABLE LIBERALISATION STRATEGY FOR BARBADOS' POWER MARKET

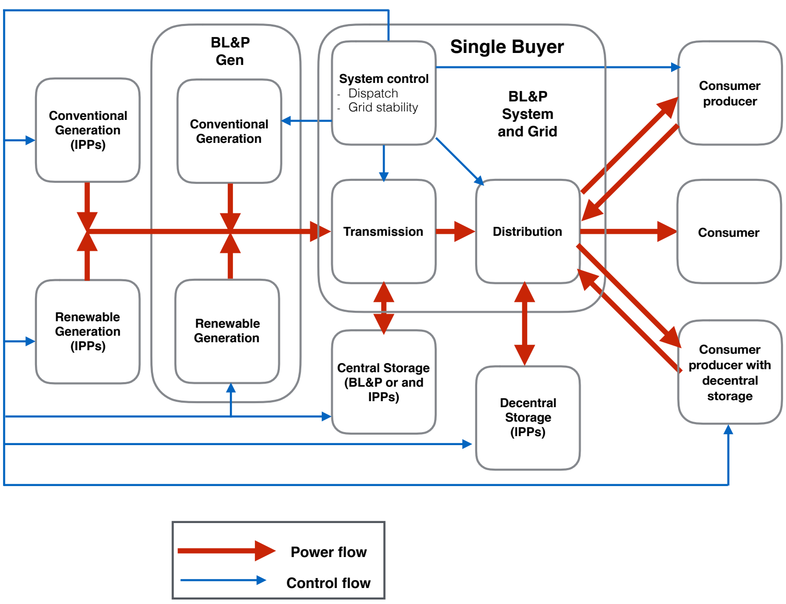
As Barbados has already reached a high level of electricity market liberalisation measured by international standards for small countries there are only two further steps to be taken to the maximum reasonable liberalisation of Barbados's power market (see WP 19). The first step, the diversification of electricity producers, will automatically be achieved by the suggested Feed-in Tariff system, as this will guarantee priority grid access for all electricity produced by IPPs and consumers from renewable energy sources. This will actually reallocate a far higher share of generation than any unbundling of the conventional generation could achieve. The second step can be the legal vertical unbundling of BL&P into two separate companies: ‚*Barbados Light and Power System and Grid*' and ‚*Barbados Light and Power Generation*'. Which still can be owned by the same holding company. Such unbundling would allow a neutral position of the ‚*System and Grid*' company as the single buyer in Barbados' future electricity market.

In the future the ownership of central storage plants can either be with Barbados Light and Power Generation, independent storage operators or with a joint venture between *Light and Power Generation* and independent investors. As pointed out before, it will be essential that the system operator will have full control over the operation of central storage facilities to make optimal use of them. Storage will most likely be paid for in two different ways. A basic payment for firm storage capacity available, based on the capital cost of the storage and a fair return on equity, and a payment per kilowatt hour for the production from storage, based on the variable costs of storage taking into account that excess renewable electricity production from wind and solar installations will be provided to storage operators by the single buyer free of charge, as this electricity would have to be down regulated otherwise.

Decentralised storage can be operated by every consumer or IPP as long as the system operator has full control of the devices. Again the payment for such storage will need to consist of the same two components as for central storage and should not be higher in order not to set incentives for expensive storage investment at the expense of the Barbados ratepayers. The exact rate setting for storage will need to be discussed in the future as too little cost information is available at the moment.

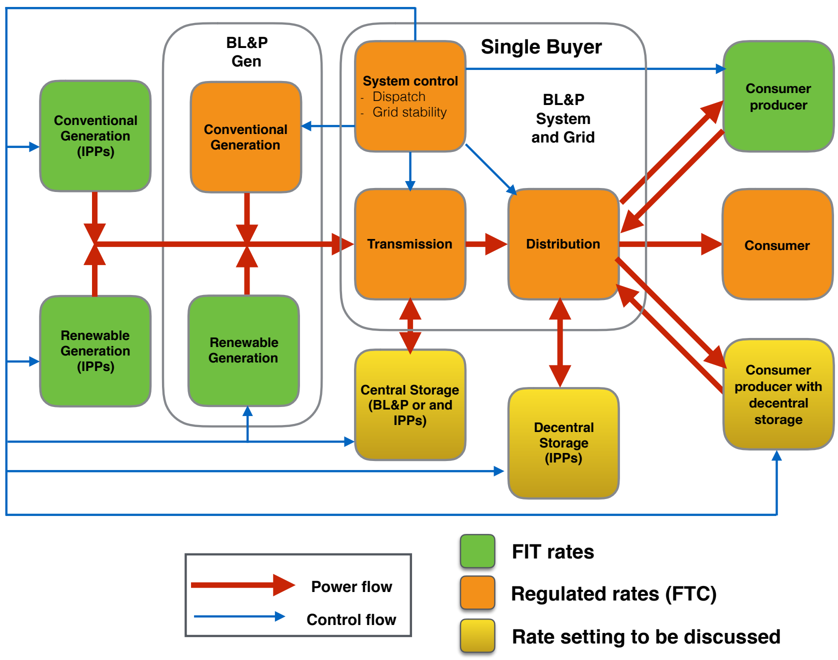
The market structure resulting from the suggested future strategic development of Barbados' electricity market results in the single buyer based electricity system with a maximum feasible liberalisation level pictured in Figure 100 below.

Figure 100: Resulting future electricity market structure of Barbados



The market balance between Barbados Light and Power and independent power producers as well as consumers operating renewable energy systems for electricity production will be guaranteed by the control of rates paid either directly by the FTC as for conventional generation, transmission, distribution and system control or by the rates set through the Feed-in Tariff system. In all cases the market power of Barbados Light and Power is controlled by the legal system set up (guaranteed grid access), by the FTC or by the FIT rates fixed independent of the market power of Barbados Light and Power as the single conventional power producer. In the case of storage a similar rate setting approach can be used. Nevertheless, the approach finally chosen for storage pricing needs further discussion amongst the different stakeholders, the FTC, the Energy Division and Barbados' policy makers. Figure 101 gives an overview of the suggested rate setting regimes for the different parts of Barbados' future electricity system characterised by the single buyer.

Figure 101: Suggested application of the different rate setting regimes for Barbados' future electricity system



## WORK PACKAGE 21: DETAILED POLICY RECOMMENDATIONS

In addition to the recommendations given in WP 18 additional policy recommendations are given here on two areas, first there are recommendations of the possible liberalisation of Barbados' power market based upon WP 19 and WP 20, and second some more detailed policy recommendations on the FIT system to be adopted, which go beyond WP 18.

Recommendations on the possible **further liberalisation of Barbados' power market:**

- **Stabilise the high technical reliability of Barbados' present power supply** achieved by the present level of liberalisation and by the very good performance of Barbados Light and Power.
- **Strengthen the FTC as effective independent regulator** by increasing the number of highly qualified staff employed for the regulation of the power sector. Although, the FTC has been very effective and efficient in the oversight over Barbados' power sector, the tasks of the FTC in its role as regulator for the power sector will substantially increase with the implementation of the new Feed-in Tariff system, the oversight over the guaranteed priority access for renewable electricity to the grid and the vastly increasing number of renewable electricity producers in Barbados.
- **Prepare for the legal unbundling of Barbados Light and Power into ‚Light and Power Generation' and ‚Light and Power Grid and System Operation'**. The system operator will gain a far more important role in Barbados' future power supply based mainly on renewable energy sources and as this role needs to be independent from any specific power generation interest. A legal unbundling of the system operator function from the power generation of Barbados Light and Power seems to be an appropriate step towards an independent system operator. As the operation of the grid will always be highly interwoven with the overall system operation, the system operator is normally identical with the transmission system operator. Thus, these two functions should remain closely connected and should remain in one legal unit.
- **Reduce political interventions into the power system** to a minimum, but **concentrate on setting a clear policy framework** for its future development. Direct policy interventions into the electricity system lead to low investor confidence and high risk premiums for financing investments in the electricity sector, whereas a clear and reliable energy policy framework allows investors and banks to foresee future developments and to realistically evaluate investment perspectives. The clearer and more reliable the political framework conditions are set the lower will be the cost of the electricity supply and the higher will be the technical reliability of the system

Recommendations for the Feed-in Tariff system to be adopted (details can be found in WP 13 and 14):

- For the implantation of the FIT system **follow the basic rules for a good FIT design**. Implement a highly reliable system with long-term guaranteed FIT rates, anchor the system in the energy law by amending the ELPA, don't make any changes to the system, which could jeopardise investments already made in renewable energy systems at the time of the policy change, guarantee preferential access of renewable electricity to the grid, and establish rules for the highest possible degree of transparency to every potential investor and to the general public. Try to achieve the highest possible degree of investor security and public trust in the system to minimise the costs to the ratepayers by allowing very low risk financing conditions and the acceptance of very moderate low risk returns on the invested equity.

- **The FIT system** implemented should have the following qualities. It **should be**:

  - **Differentiated**

    In order to support all relevant renewable energy sources relevant for Barbados, the FIT rates need to be differentiated by energy source, quality of site and system size. In order to incentivise local ownership the FITs should be differentiated by ownership as well. The FIT system suggested in WP 13 and 14 supports a high degree of differentiation.

  - **Reliable**

    To allow high investment security the FIT rates need to be guaranteed for a long time period (20 years) from the start of the operation of a renewable energy generation facility. Gird access needs to be guaranteed within the technical limits of grid stability. Should grid access be temporarily impossible due to technical reasons, a clear perspective needs to be given as to when an existing technical bottleneck will be removed by grid improvements. The FIT system suggested in WP 13 and 14 supports a high degree of reliability.

  - **Investment friendly**

    The FIT system should allow a positive cash flow from the first year of operation to enable easy financing and debt payments. To secure positive cash flows during the period of debt payment the FIT rates should have so called front-end loading with a high FIT rate during the debt payment period. The FIT system suggested in WP 13 and 14 supports front-end loading.

  - **Dynamic**

    The FIT system should implement dynamic FIT rates to follow the international trends in cost reductions for renewable energy technologies. Thus, the development of future FIT rates needs to be coupled to international RE cost developments and the FIT rates for future developments need to be decreased based on the developments of RE costs. The FIT system suggested in WP 13 and 14 supports dynamic tariff setting.

  - **Responsive**

    The FIT rates should allow to steer the installed RE capacities to follow the transition pathway set by the national energy policy. This can be reached by adjusting the FIT rates in response to the over- or underachievement of a set target corridor. The FIT system suggested in WP 13 and 14 supports responsive FIT rate corrections based on RE technology specific target corridors.

  - **Capped**

    The FIT system needs to allow for capping installed RE capacity in subsections of the grid to secure grid stability. Such RE caps should be temporary and clear plans for grid improvement to eliminate technical bottlenecks for the installation of RE capacity need to be part of the system. The degree of cap exhaustion has to be communicated clearly to potential investors. The FIT system suggested in WP 13 and 14 supports such temporary capacity caps.

  - **Transparent**

    A high degree of transparency of the FIT system and specifically of any cap and queue system has to be guaranteed to secure maximum public and investor confidence in the system. Besides the applicable capacity caps for subsections of the grid all informations on the exhaustion of each cap, the capacities queued, the technical reasons for the caps and the plans and timelines for the removal of the technical bottlenecks behind the caps need to be made public on a daily basis through the internet. It is recommended to use a simple traffic light system to show the status of each grid subsection with regard to the exhaustion of a given cap. As long as substantial capacity is still available for new investment the grid subsection is shown in green, when it approaches the limit (e.g. starting at 80%) the map turns yellow and as soon as the limit is reached, the map turns red. In this way every potential investor can immediately see the status of the grid subsection he is interested in. The FIT system suggested in WP 13 and 14 supports such transparency measures.

- **Low cost**

  By a well designed FIT system guaranteeing FIT rates of twenty years and priority grid access and operation for renewable energy sources the system can achieve very low electricity costs due to low cost of financing for low risk investments and due to low risk investment expectations of investors resulting in low necessary rates of return on equity. Dynamic and responsive FIT rates can lead to a steady decline in power generation costs. Therefore, the implementation of these features as part of the new FIT system for Barbados is highly recommended. The FIT system suggested in WP 13 and 14 supports these features leading to low electricity costs.

- **Tax neutral**

  The FIT system should be designed tax neutral. All expenses through the guaranteed FIT payments should to be recovered by a FIT levy on every kilowatt hour of electricity consumed in Barbados. This allows the full allocation of the power generation costs to the ratepayers, who will benefit from the long-term stable electricity rates. The FIT system suggested in WP 13 and 14 is based on the tax neutral financing through a FIT levy.

- **No license fees**

  In order to promote a low cost transition to a renewable electricity future for Barbados it is highly recommended to remove all license fees under the Electric Light and Power Act for renewable energy generation. These license fees distort the economic situation of renewable energy investments and put an undue burden on the investors. If the country is in need of additional income from electricity sales it needs to put a tax on every kilowatt hour of electricity consumed. Such tax would not distort the situation between the different forms of power production and would not undermine the confidence of investors.

- **Citizen centred**

  The design of the new FIT system needs to be citizen centred in order to generate the highest possible level of acceptance for the new energy system. Therefore, a broad public participation in all planning and broad local ownership of renewable energy systems should be aimed for. Public information campaigns should be a starting point for broad participation. In the next step local participation in the planning of new renewable energy capacities should be secured. Local participation in renewable energy investment needs to be encouraged in a further step. Bonus FIT rates for citizen wind turbines or wind parks are an additional step to increase local investment. Finally, impact based ownership, giving a certain share of the ownership of wind turbines to people living very near to the turbines should be implemented. In the case of very small solar PV systems (up to 1 $kW_p$) low income households should be offered net metering as an other social component of the new renewable energy policy to achieve the broadest citizen participation possible. The FIT system suggested in WP 13 and 14 directly supports the FIT related elements of this recommendation.

- **Domestic ownership based**

  The FIT payments should be made in Barbados Dollars. Payments in the local currency increase the risk of international investors to receive the targeted returns in their domestic currency, while it does not pose a risk for local investors as long as their debt is in Barbados Dollars as well. Thus, the payment in local currency will induce mainly local investment, which is one of the important objectives raised by the stakeholders interviewed. It may also be considered to add a provision to the general FIT rules requiring a minimum local share in every renewable energy investment. The FIT system suggested in WP 13 and 14 is based on FIT payments in Barbados Dollars.

- **Acceptance oriented**

  The new FIT system and the renewable energy policy need to put high emphasis on public acceptance, as the available space is very limited and the high population density will make it necessary to locate renewable energy facilities close to the average citizen. Without a high level of acceptance the large scale development of renewable energy generation will not be possible in Barbados. The highest possible level of public acceptance can be reached by putting priority on small investors (e.g. net metering program), by paying higher FIT rates for citizen wind energy, by provisions for ownership through impact of wind energy, by high levels of public participation and transparency, by very broad ownership of renewable energy systems and by long-term stable low electricity rates for the average ratepayer. The FIT system suggested in WP 13 and 14 supports such acceptance orientation.

- **Agriculture friendly**

  The transition to renewable power production offers a great chance to help to solve one of Barbados key problems in agriculture, which is the need for rotational cropping with a frequent use of grass crops for soil stabilisation. Due to the decline of the sugar industry all rotational cropping is endangered in Barbados. A well designed renewable energy policy offers the chance to either improve the economic viability of sugar cane cropping in Barbados through the energetic use of bagasse or to use a King-Grass crop for the production of energy, which can be used in rotational cropping just like sugar cane. It is recommended to support these energetic biomass uses in order to help to solve the agricultural problem Barbados is facing. Besides further analyses of the costs and resource potentials political decisions will be needed on the future energetic use of bagasse combustion and King-Grass gasification. The FIT system suggested in WP 13 and 14 supports the integration of the agricultural concerns into the future renewable energy policy of Barbados.

Before the suggested FIT system can be fully implemented a number of **decisions on the basic settings for the Feed-in Tariff** have to be made:

- Decide on the **rate of return on equity**, which can be considered a fair rate of return on low risk investments
- Decide on the basic assumptions on debt financing
  - Which **share of debt**/equity shall be assumed for low risk debt financing of renewable energy systems under the guaranteed FIT rates

- Which **interest rate for debt** financing shall be assumed for low risk debt finance of renewable energy systems under the guaranteed FIT rates.

- **Set** the **target corridors for each renewable energy technology** under the FIT system in accordance with the transition pathway and the target energy system and the target year for a 100% renewable energy system for Barbados.
- **Set the response rates for under- or overachieving the target** quantity for a given year as basis for the automatic FIT rate correction.
- **Decide on the adder for citizens wind parks** to the FIT rate paid for wind energy.
- Decide on the distance rules for wind energy and the distribution of **ownership by impact of wind turbines** and develop rules and procedures for ownership by impact.
- **Decide on the initial FIT rates** for the different renewable energy technologies based on the suggestions made in WP14.
- **Develop rules and procedures for grid area specific RE caps** and possible queuing of applications.

*Barbados has all the necessary preconditions for the transition to a low cost 100% renewable energy supply for all sectors. The success of the possible transition will depend mainly on setting the appropriate policy framework.*

*The policy framework developed in this report is based on a modern Feed-in Tariff system, taking into account the main objectives of the major stakeholders, it meets the challenge of guaranteeing a stable price for electricity from renewable energy sources allowing low risk investments at low (risk free) interest rates, it guarantees fair returns for investors and low prices for the average rate payer. At the same time the suggested policy framework will foster a vast reduction of fuel imports and the leakage of hard currency from the country, thereby increasing domestic economic growth and employment, which in turn will boost the countries tax income and help to substantially reduce its public deficit.*

*This report has tried to supply some of the necessary information to the Energy Division, policy makers and stakeholders to set an appropriate policy framework for a development, which can benefit the people of Barbados in many ways. While it has painted the broad picture of an appropriate policy framework a number implementation details still need to be discussed, as pointed out in the report.*

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# ANNEX 1: STAKEHOLDER INTERVIEW DATA

Table A1: Numerical values for Figure 1

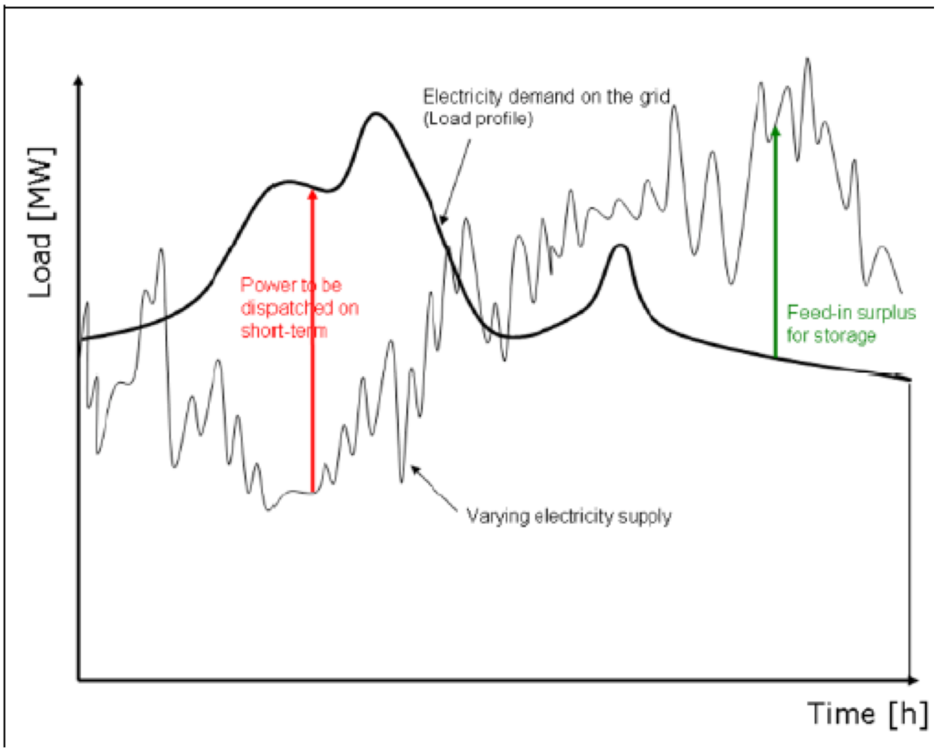
| | Objectives | Frequency at which the objective was mentioned | Average weight attached to objective | Relative importance of objective (Frequency x average weight) |
|---|---|---|---|---|
| 1 | Reliability of power supply (loss of load d/a) | 12 | 9.8 | 117.0 |
| 2 | Low environmental impact | 12 | 7.6 | 91.0 |
| 3 | Low cost of power | 12 | 7.4 | 89.0 |
| 4 | High employment generation | 11 | 7.5 | 83.0 |
| 5 | Reduktion of imports / hard currency | 10 | 7.8 | 78.0 |
| 6 | Public acceptance of power supply | 8 | 8.4 | 67.0 |
| 7 | Reduction of imports / energy security | 7 | 8.7 | 61.0 |
| 8 | General participation (every household) | 5 | 8.6 | 43.0 |
| 9 | Hurricane resiliance | 4 | 8.3 | 33.0 |
| 10 | Local participation | 4 | 8.0 | 32.0 |
| 11 | Domestic ownership | 4 | 6.8 | 27.0 |
| 12 | Problems of agriculture need to be solved | 3 | 9.0 | 27.0 |
| 13 | Stable electricity rates | 3 | 8.0 | 24.0 |
| 14 | Fast decisions on licenses etc/ streamlined processes | 2 | 10.0 | 20.0 |
| 15 | Reliable long term policy vision | 2 | 10.0 | 20.0 |
| 16 | Storage must be incentivised | 2 | 9.5 | 19.0 |
| 17 | Tariff has to guarantee repayment (funding) | 2 | 9.5 | 19.0 |
| 18 | Wind local benefits need to be felt | 2 | 9.0 | 18.0 |
| 19 | Achieve 100% RE | 2 | 9.0 | 18.0 |
| 20 | Positive welfare effect | 2 | 9.0 | 18.0 |
| 21 | Avoid stranded assets | 2 | 7.5 | 15.0 |
| 22 | Low water consumption | 2 | 6.0 | 12.0 |
| 23 | Establish partnership between local stakeholders and international investors | 2 | 5.5 | 11.0 |
| 24 | Focus on proven technologies plus focus on R&D | 2 | 5.5 | 11.0 |
| 25 | Low land use | 2 | 5.0 | 10.0 |

# ANNEX 2: A DETAILED DISCUSSION OF STORAGE

## A2.1 The concept of residual load

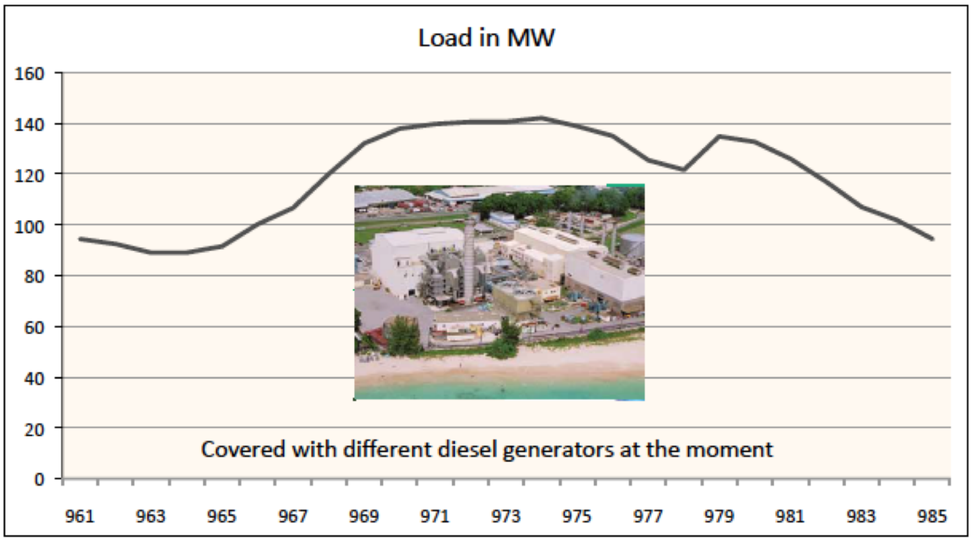
To understand how the energy demand can be met by using very large shares of wind and solar energy a new concept needs to be introduced, the concept of **residual load**. While in conventional electricity systems the hourly demand, which we call electrical load, had to be met by different controllable production units like base load or peak load power plants, in the new electricity systems the controllable units don't have to follow the load but they have to match the difference between the load (demand) and the uncontrolled production of wind and solar energy, which produce as much electricity as possible as soon as they are installed, because they don't have variable costs which could be saved by stopping their operation at times of low demand. No money can be saved by turning these power plants down or running them at partial load. The difference between the hourly load and the hourly production from wind and solar energy, which can be positive or negative, is called residual load. Thus, it is the task of all controllable units to meet the residual load of the system. As Figure A1 shows the residual load changes far faster than the load. This requires that all controllable production units can change their production much faster than in a conventional electricity system. As pointed out before, this can lead to substantial problems for the operation of solid biomass combustion based on bagasse and river tamarind in Barbados.

Figure A1: Hourly load, hourly production from wind and solar energy and the resulting residual load of a system with high shares of wind and solar energy (Source: Hohmeyer 2014, slide 9)



As an example, Figure A2 shows the load and the residual load for Barbados employing wind and solar PV in a system with 200 MW installed wind and 195 MW PV capacity on a day February (see Hohmeyer 2014, slide 10). The system was set up to cover almost 100% of Barbados' power demand by wind and PV across the year. We can see that the *residual load* can change by more than 100 MW (50% of the maximum system load) within an hour up or down. This is more than the change in the *load* during the entire day. Furthermore, the structure of the solar energy output leads to a negative residual load from the morning to the afternoon. Although, the sum of wind and solar energy production of the day seems to be sufficient to meet the total electricity demand of the day, it is quite clear that we will need substantial storage capacity to meet the residual load every hour of the day.

Figure A2: Load curve and residual load for Barbados on February 9th with 200 MW wind and 195 MW of PV installed (Source: Hohmeyer 2014, slides 5 and 10)



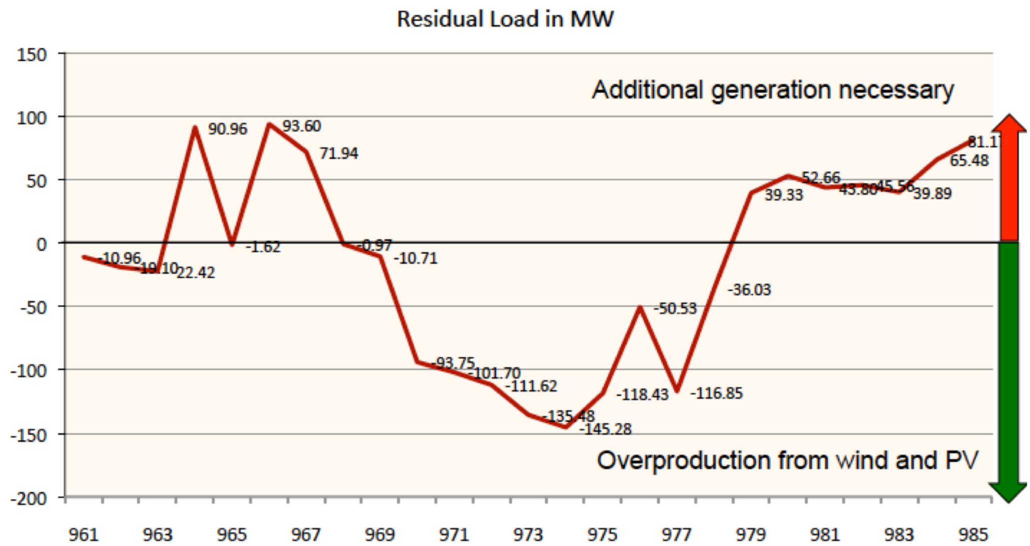
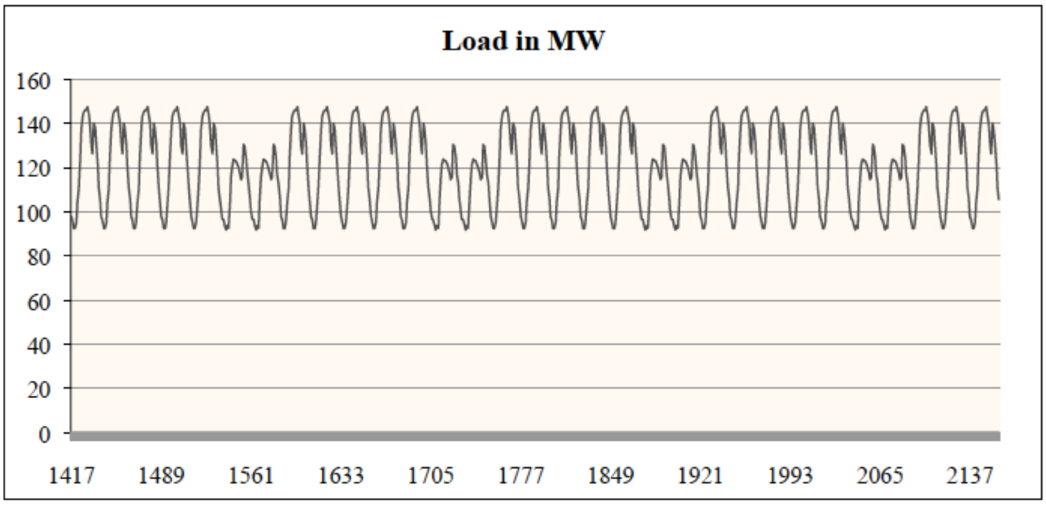




Figure A3a shows the daily and weekly pattern of the electrical load for the month of March, which needs to be met every hour of the month. Subtracting the wind and solar energy production of an installed capacity of 200 MW wind and 195 MW of solar energy leads to the fast fluctuating residual load shown in

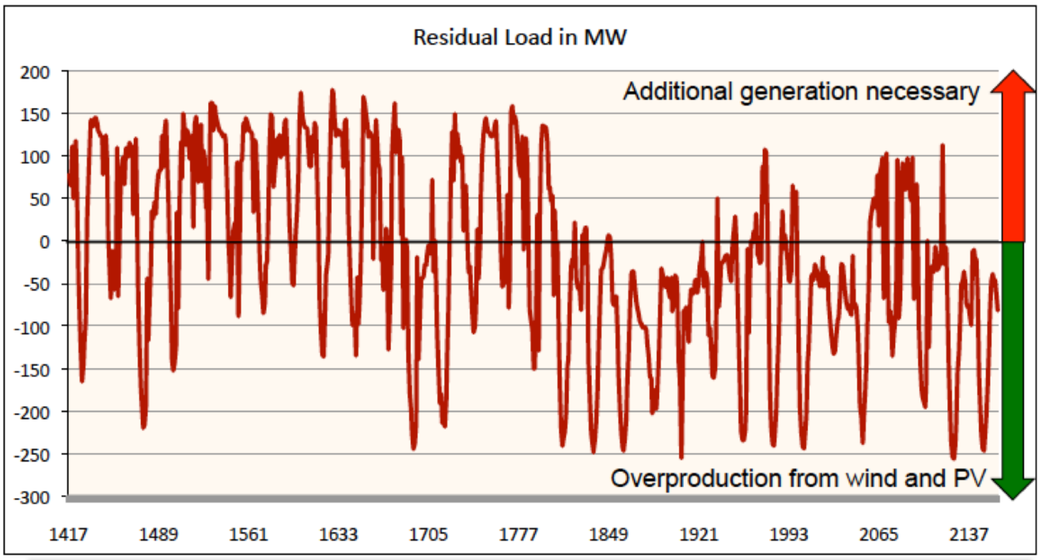
Figure 34b, which has to be covered by the controllable units of the system. In the first half of the month we have too little production from wind and solar energy to meet the full demand, while in the second half we produce more electricity than needed. The structure of the residual load suggests that Barbados will need substantial storage to balance the residual load in the case of a 100% renewable energy supply, if the availability of biomass is limited.

Figure A3: Load curve for the month of March (6.a) and resulting residual load with 200 MW wind energy and 195 MW PV installed (6.b) covering an increased electricity demand and load

A3.a Simulated hourly load curve (Source: Hohmeyer 2014, slide 15)




A3.b Hourly residual load curve (Source: Hohmeyer 2014, slide 18)



## A2.2 Storage in power systems with high wind and PV penetration

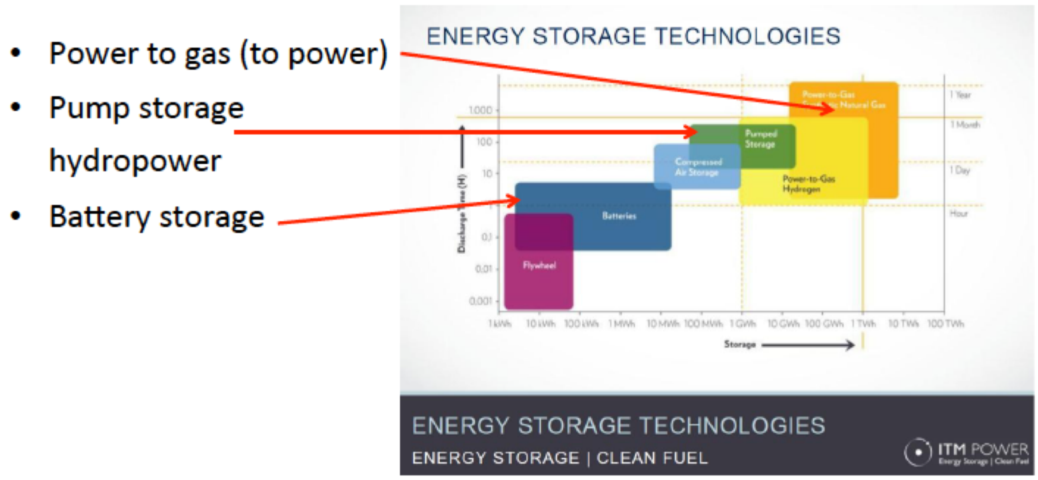
As a high share of solar and wind energy will lead to an electricity production which will at some hours be higher and at other hours considerably lower than the electricity demand, a power supply based predominantly on renewable energy sources will require substantial volumes of storage. The electricity produced by the storage should be available within a few minutes due to the fast changes in the residual load (see above). The capacity of the power production from the storage needs to be equivalent to the maximum load of the electricity system and the storage volume should be in the order of at least twelve hours of demand. If affordable it might be in the order of the power demand of a number of days or weeks, depending on the load characteristics of the country being served and the specific cost of storage. Considering a 100% renewable power supply for Barbados, based predominantly on wind and solar energy, the storage needs to have a generation capacity of 150 to 200 MW and a storage volume of 100 MWh to 10 GWh. These properties need to be taken into account in the selection of the most appropriate storage options.

If very flexible power production from biomass is available in large capacities this can substitute some storage for electricity, as the biofuels or biogases can be stored prior to combustion.  Nevertheless, such use of biomass can only cover some remaining load, but it can not absorb any overproduction from wind and biomass, as real storage can. Unfortunately, solid biomass combustion is not flexible enough to similarly substitute fast reacting storage like power generation from biofuels, biogas or syngas.

As electricity demand from many households combined is far smoother than the demand of every single household and as the production from many solar installations and many wind turbines combined is far more regular than the production from each single operation, the storage demand for a connected electricity system is considerably less than the storage necessary to level the renewable energy production from a single solar installation and the demand from a single household. Thus, even if decentralised storage is used, it has to be operated on the basis of the storage needs of the entire system not on the basis of the demand of single households. For this reason every storage installation needs to be centrally controlled ('dispatched' in the terms of power systems).

As Figure A4 shows, there are at least six different storage technologies that might be considered for use in Barbados' power system. Two of these options don't apply for technical reasons. First, flywheels, large rotating masses, which store kinetic energy have a capacity of 1 - 100 kWh. Therefore, they are not able to supply storage volumes in the necessary range of 100 MWh to 10 GWh.

Figure A4: Different storage technologies for electricity with range of storage volumes and discharge times (double logarithmic scale) (Source: Hohmeyer 2014, slide 14)



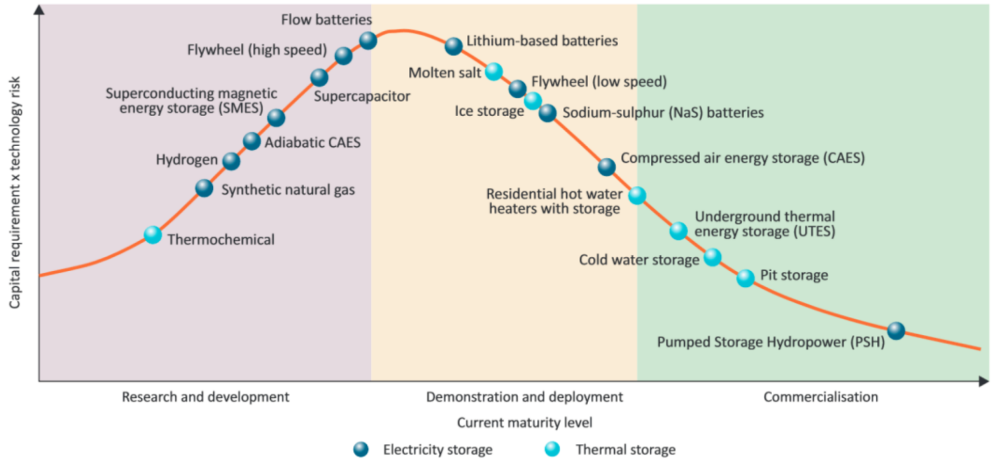

The second technology that does not apply in Barbados is compressed air storage (CAES). Compressed air storage needs very large underground salt formations to form caverns of a volume between 100,000 and 500,000 $m^3$. These are used to press air under high pressure into the caverns at times of overproduction of power. The maximum pressure in the cavern is brought up to about 150 bar. Whenever additional power is needed from the storage the compressed air is released through an air turbine to produce electricity. For this purpose the pressure is dropped to about 100 bar. Thus, the active storage is made up by the pressure difference between 100 and 150 bar in the salt cavern. As the air is heated up in compression to temperatures in the range of 500 to 600°C and the salt in the cavern would melt at such temperatures, the air has to be cooled down to ambient temperature. On the return the air has to be heated up to temperatures between 400 and 500°C before it can drive an air turbine. Thus, it is strongly desirable to store the heat energy as well. Such combined air pressure and heat storage systems are called adiabatic air storage (adiabatic CAES). There are no large salt formations under Barbados. Therefore, CAES is not an applicable storage option for Barbados, although, if applicable, it could supply storage in volumes of up to 1 GWh.

Thus, four storage technologies remain for a possible application in the case of Barbados, which can not be disqualified right from the beginning. These technologies are:

- Battery storage
- Pump storage hydropower
- Power-to-gas storage in the form of hydrogen
- Power-to-gas storage in the form of methane.

Nevertheless, it has to be taken into account that the different storage technologies are at very different levels of technical and economic maturity as Figure A5 shows.

Figure A5: Technical and economic maturity levels reached by different storage technologies




Source: Decourt, B. and R. Debarre (2013), "Electricity storage", *Factbook*, Schlumberger Business Consulting Energy Institute, Paris, France and Paksoy, H. (2013), "Thermal Energy Storage Today" presented at the IEA Energy Storage Technology Roadmap Stakeholder Engagement Workshop, Paris, France, 14 February.

Battery storage is a rather mature technology and available in very different sizes ranging from batteries for single devices like calculators to large containerised battery storage applications for the stabilisation of weak electrical grids. The storage capacity goes up to volumes in the range of 50 MWh (50,000 kWh). As Barbados will need storage volumes between 100 and 10,000 MWh (10,000,000 kWh), battery storage appears to be falling short in the necessary storage volume. Nevertheless, it is far closer to the target range than the flywheel technology discussed above. What is more, battery storage could be used in smaller units for certain grid services independent of the overall storage volume used to balance a power system mainly relying on wind and solar energy.

Figure A6: Pros and cons of battery storage (Source: Hohmeyer 2014, slide 13)

Battery storage:

- Easy to install
- High efficiency
- Electricity loss over time
- Relatively expensive (500-600 US$/kWh storage)
- Too small for Barbados (MWh range)

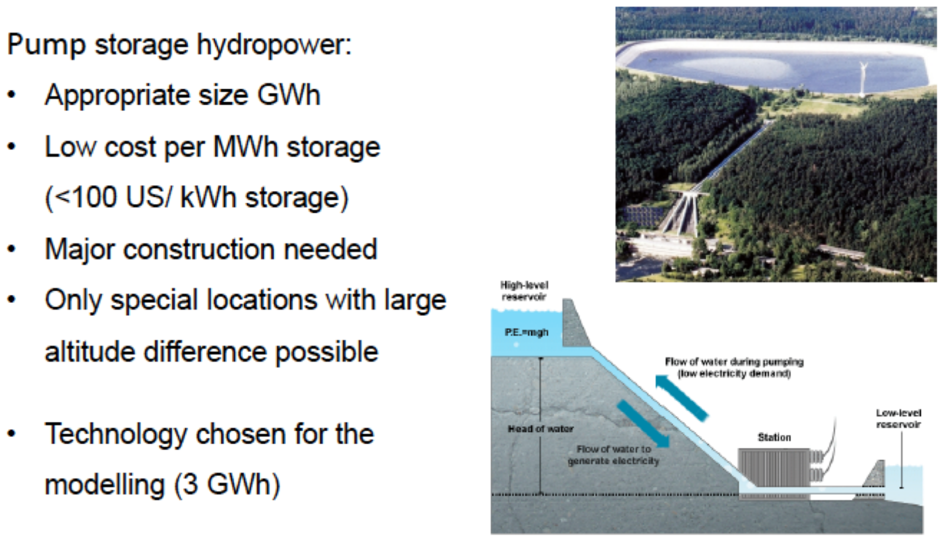
As battery storage can be bought 'off the shelf' in containers ready to be connected to a grid, it is very easy to install. It just takes the cabling and some foundations for the containers to set up this storage option. Figure A6 shows a picture of containerised battery storage and sums up the main pros and cons for battery storage.

Battery storage has a relatively high efficiency for the storage of electricity. In short term storage more than 90% of the energy stored may be retrieved from a battery, if it is used shortly after the energy has been stored. If a battery is used for energy storage over weeks it may loose a substantial share of the stored energy even without being used.

One of the major disadvantages of battery storage is its relatively high costs, which are in the range of 500 to 600 US$/kWh of storage volume. Thus, a storage volume of 1 GWh would cost about 500 to 600 million US$. The IRENA road map for Barbados assumes 700 USD/kWh (2016, p.30). During recent years there have been announcements of battery storage systems with costs as low as 250 USD/kWh, but so far these systems have not been made available in the market. At the same time batteries have a relatively short lifetime of 5 to 10 years compared to e.g. pump hydro storage (50 to 100 years) even if they are very well maintained.

Another relevant option is pump storage hydropower. This technology has been used for more than a hundred years all over the world to back up and stabilise larger electricity systems. It uses the gravitational potential energy held by water at high elevations. A normal pump storage system consists of an upper and a lower storage lake, which exchange freshwater. If energy needs to be stored, water is pumped with the help of an electric motor (driving a pump) from the lower lake into the higher lake. Once the energy is needed for the electricity supply the water runs from the upper lake to the lower lake driving a turbine, which is connected to an electric generator producing the electricity needed. Figure A8 shows a picture of the upper lake and the power plant of a pump storage hydro system and a cross section of such an installation showing the basic principle. The altitude difference between the two lakes should be greater than 100 m, as the stored energy is directly related to the height difference (head) and the volume of the water stored.

Figure A8: Pump storage hydro systems and their main advantages and disadvantages (Source: Hohmeyer 2014, slide 14)



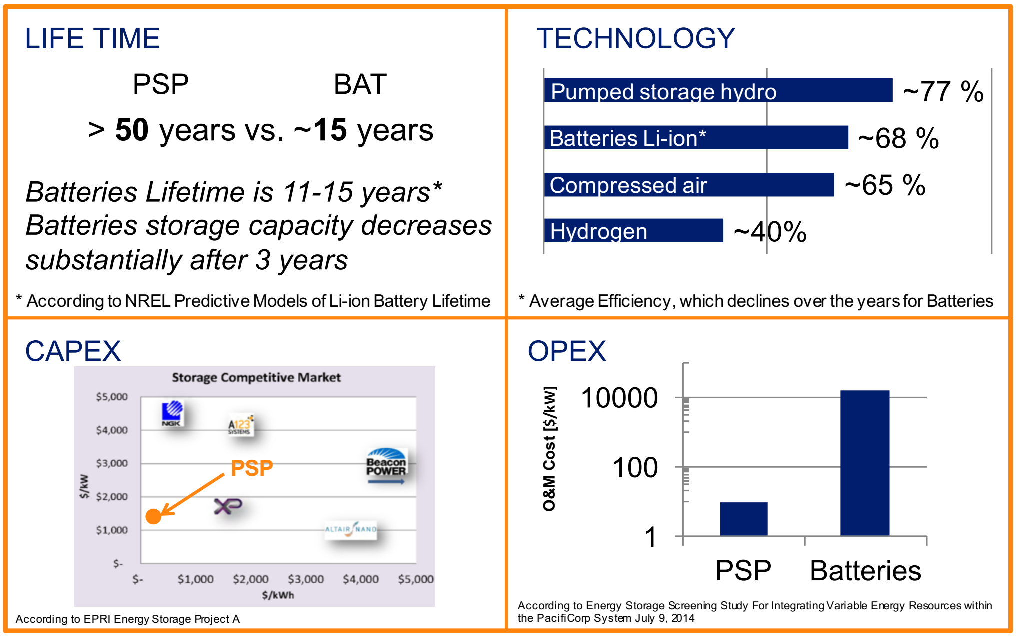

As the energy stored in the upper reservoir is directly proportionate to the hight above the lower reservoir, the volume of the reservoirs increase with a shrinking altitude difference. Assuming an altitude difference of 300 m the necessary storage volume of each lake to store 1 GWh (1,000,000 kWh) is about 1,250,000 m$^3$. As Barbados has substantial areas with an elevation around 300 m above sea level, the necessary storage volume can easily be estimated by multiplying each kWh of necessary energy storage by 1.25 m$^3$. If it should turn out that the location of the reservoirs will result in an altitude difference of 250 m this can be easily recalculated by 300 m / 250 m * 1.25 million m$^3$ = 1.5 million m$^3$.

In the overall storage operation about 20 to 30% of the original electricity is lost. Thus, the efficiency of the storage is not as high as in battery storage, but it is far better than in the power-to-gas storage discussed below. As Figure 35 above shows, pump storage hydro is applied in a range of 50 MWh to 50 GWh (50,000  to 50,000,000 kWh), which covers the most likely size range of the necessary storage for a power system predominantly based on wind in solar energy in Barbados. Although the cost of a pump storage hydro system will vary considerably with the construction costs of the storage lakes and the pipeline or tunnel connections (the so called penstock) between them, the costs for such systems are most likely below 100 USD/kWh of storage volume. Which is about one fifth of the cost of battery storage in the market or 40% of the costs quoted for the lowest cost battery storage devices announced so far.

One of the historic reasons for including pump storage hydro systems in almost all major electricity supply systems is the ability to ramp such a system from no operation to full load operation in about 90 seconds. Thus, a pump storage system can change from full load operation for storage to full load operation for electricity production within three minutes, with the most recent systems claiming just about 120 seconds for a complete turn around. This capacity has rendered pump storage hydro systems ideal for dealing with all short term fluctuations in power supply systems. Under normal circumstances the relation between the storage volume, measured in MWh, and the electricity production capacity, measured in MW, allows for a full load operation of 4 to 6 hours. In conventional power systems pump storage hydro systems are used for short term peak power production. The storage is normally filled by cheap electricity produced during low load hours during the night and electricity is produced during peak load hours of the day or to smoothen the production to exactly meet demand at every minute of the day.

A comparison of pump storage and battery storage shows the substantial advantages of pump storage for all systems with sufficient altitude drop and of a sufficient minimum size (see Figure A9 below).

Figure A9: Comparison of pump storage and battery storage systems (source: Stoebich 2016)



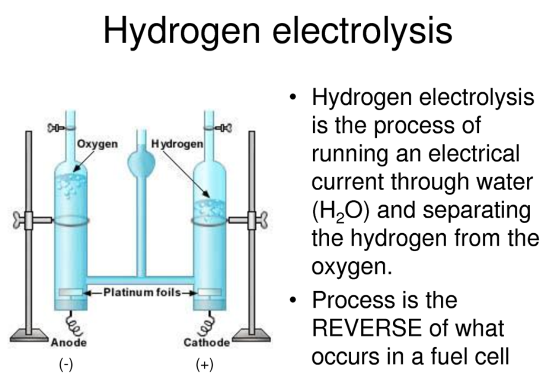

Although it will be necessary to do a very detailed site assessment for the location of a pump storage hydro plant on Barbados including detailed geological assessments of the underground between the two storage lakes, this technology seems to offer the right size and technical properties for the storage needed for an electricity supply for Barbados relying predominantly on wind and solar energy. Pump storage comes at substantially lower life-cycle cost as compared to battery storage.

Before a final decision on the storage system to be used in Barbados is made, the other options have to be looked at. These are the two so called power-to-gas technologies. In the first case the electricity to be stored is used to split water ($H_2O$) with electricity into its two components hydrogen (H) and oxygen (O) in a process called electrolysis. Figure A10 shows the basic principle of the electrolysis process.

In the electrolysis process the two produced gases (oxygen and hydrogen) have to be separated, because a mixture of the two gases is highly explosive (detonating gas). The energy is stored in the hydrogen produced. As soon this is recombined with oxygen from the surrounding air, the stored energy is set free. This recombination can be done in a combustion engine or in a fuel cell, which is just a controlled electrolysis process in reverse. In this recombination process of hydrogen and oxygen the stored energy is set free in the form of electricity (and waste heat). Although there are a number of different fuel cell technologies, most of the technologies are still in demonstration stage and are hardly available as robust commercial technologies.

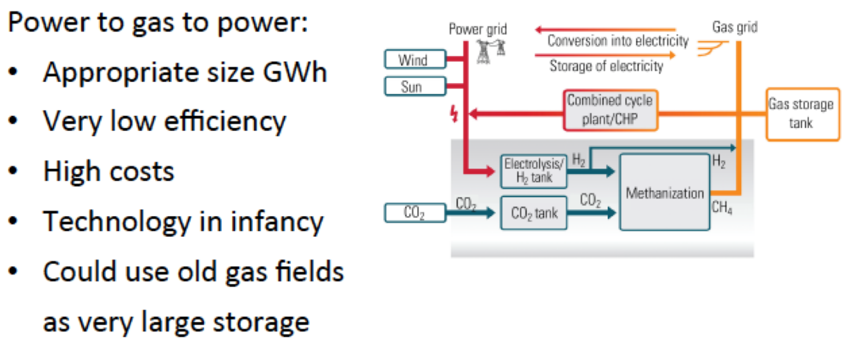
As hydrogen is relatively difficult and expensive to store the suggestion has been made to take this technology one step further to make storage much easier. This is achieved by using the hydrogen generated to produce methane ($CH_4$), which is a major part of natural gas. The idea is that methane can be stored and distributed using the natural gas infrastructure, pipelines and storage, existing in many countries.

Figure A10: Electrolysis: splitting water with electricity (Source: imagekid.com 2015)




This would reduce storage costs drastically. For the production of methane from hydrogen we need carbon dioxide ($CO_2$) to supply the carbon (C) necessary. This so called methanisation process is a standard synthesis process in the chemical industry. Once the electricity is needed the methane can be used in combustion engines or turbines to drive generators to produce electricity. Figure A11 shows the principle of power-to-gas storage of electricity.

Figure A11: The principle of power-to-gas storage and its major advantages and disadvantages (Source: Hohmeyer 2014, slide 12)




Due to the different conversion steps, 60% of the originally produced electricity will be lost in hydrogen storage. In the case of methane storage 70 to 80% is lost. Thus, from these types of storage 2.5 to 5 kWh of electricity need to be produced and fed into such storage system for every 1 kWh to be finally used after storage. The numerous conversion steps and the high losses lead to relatively high storage costs. As the technology is still in its early stages of development, actual cost figures for mature systems are not available.

Although power-to-gas storage covers the right size range of storage for Barbados and old gas fields could be used for methane storage, it will not be looked into further in this report, as it is not clear how expensive such a system would be as the technology is still in its infancy.

As a result of this preliminary analysis of the different possible storage options, pump storage hydro systems seem to have the greatest potential and the lowest costs for the necessary storage needed in the future power system of Barbados relying predominantly of wind and solar energy eventually achieving a 100% renewable power supply. During the last year first pre feasibility considerations for possible pump storage hydro systems have been carried out. The next sub chapter reports on the findings of these considerations.

## A2.3 First analysis of possible pump storage locations for Barbados

After a first discussion of the possibility to use pump storage hydro systems to supply the necessary storage for a 100% renewable energy system for Barbados (Hohmeyer 2015), the idea was picked up by interested investors, who commissioned a first prefeasibility report on the assessment of the potential for the development of a pump storage system in Barbados, which was carried out by Stantec Consulting Caribbean Ltd (Stantec 2016). The study was targeted to find possible locations with sufficient altitude differences for the upper and lower reservoir and to identify possible sources of water to supply the water necessary to fill the system and to replace evaporation losses during the operation of the system.

In principle Stantec identified different locations on the plateau above the Scotland district as possible locations for an upper reservoir and some locations at the lower end of the Scotland district. The achievable altitude drop between the upper and lower reservoirs are 270 and 240 meters (see Stantec 2016, p.3.1f). The available land areas for the upper reservoirs are in the range of 0.15 to 0.2 km$^2$ (see Stantec 2016, p.3.1ff). Depending on the depth to the reservoirs such lakes could hold between 1.5 to 4.0 Million m$^3$ of storage water if 10 or 20 meters deep. As the possible locations at the lower elevation are of a similar size, a pump storage system with an energy storage capacity of up to 2 900 MWh can be constructed if just one of the identified sites were to be used. This storage volume compares well with a first analysis of the necessary storage volume for a 100% renewable electricity system for Barbados based on 200 MW of wind and 195 MW of solar PV (see Hohmeyer 2015, p.19).

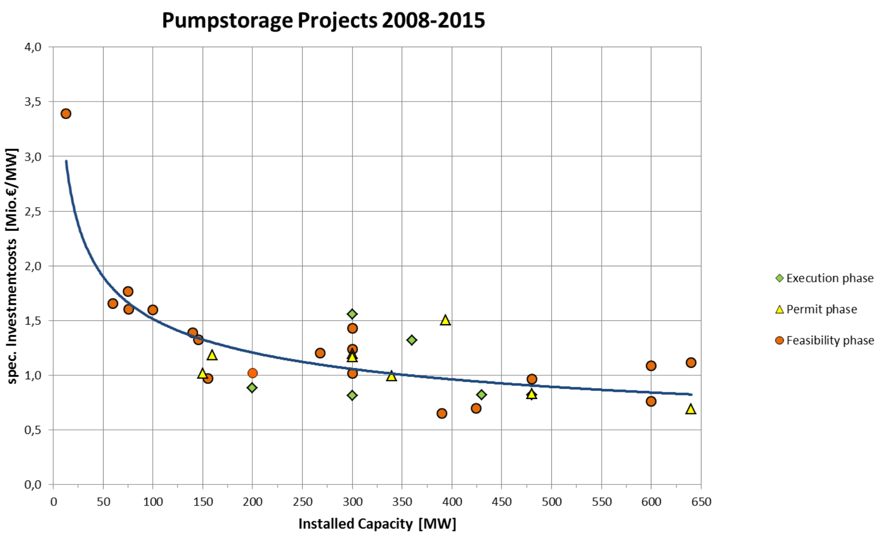
The Stantec study looked at the availability of runoff water from the watersheds from which the lower reservoir could collect water to fill the system. Even with a very conservative estimate for the annual precipitation in the area of 1,143 mm/a and a 50% runoff factor the two most relevant watersheds (Bruce Vale and St. Simons) will produce a runoff of more than 8 million m$^3$/a (see Stantec 2016, p.3.2), which is more than double of the required maximum volume to fill the system. At present this runoff is not used and dewaters directly into the Atlantic Ocean. What is more the two adjacent watersheds directly to the north of Bruce Vale and St. Simons, Bawdens North and Bawdens South add another 4.6 million m$^3$ of runoff per year (see Stantec 2016, p.3.5) dewatering into the Atlantic at almost the same location. Thus, the overall water availability in the area of the lower reservoir is about three times the maximum volume required to fill the system. After the system has been filled the annual evaporation losses are estimated at 30,000 m$^3$ for 20 hectares (0.2km$^2$) (see Stantec 2016, p.3.2) or the maximum reservoir size or 60,000 m$^3$/a for both reservoirs (upper and lower) together. Thus, for compensating the evaporation losses from the system less than 1% of the collectible runoff will be needed.

As the collection and purification facility for the runoff will have to be separate from the lower reservoir and as it will be scaled for the original filling needs of the pump storage system (1.5 - 4 million m$^3$) there will be a high excess water collection capacity once the pump storage system will be filled, although the collection and purification facility will need to continue operation for the substitution of evaporation losses. It has been discussed that an additional reservoir for irrigation and drinking water collection could easily be supplied with large volumes of runoff from the collection and purification facility once the pump storage system is filled initially. In a situation where Barbados considers itself to be a water scarce country and some areas of Barbados experience frequent shut off periods for the freshwater supply, this additional sweet water supply may add substantial value to the pump storage development. The collected water, once purified and stored in a separate fresh water reservoir could be pumped up to a large water pressure vessel of the Barbados Water Authority located on the upper rim of the Scotland District, from which it could be easily distributed to all parts of the Barbados freshwater supply system.

As land of the appropriate size and altitude as well as freshwater availability don't seem to be major obstacles for a pump storage development on Barbados the remaining challenge is the geology of the proposed sites. It is quite clear that the underground beneath the upper reservoir locations is coral rock, which is comparatively soft, but a stable limestone formation. The main lower reservoir location is located in an area of river alluvium and terrace deposits overlaying the Mount All Member (MA) formation consisting of grained sandstone (see Stantec 2016, p.3.3). At the moment it is not clear whether the underground between the upper and lower lake consist of stable formations or whether there are some moving formations in between, which could cause problems for the construction of the penstocks connecting the reservoirs.

In addition to the Stantec prefeasibility study a site visit was conducted by Christian Stoebich (in November 2016) an international expert for pump storage plants from Andriz Hydro, one of the leading pump storage producers in the world. According to the assessment of this expert a pump storage installation seems to be quite possible at the locations identified in the Stantec study. In order to avoid unstable underground formations for the penstocks a detailed geological analysis of the area under consideration is necessary. The most likely design will use vertical shafts underneath the upper reservoir down to the level of the lower reservoir to utilise as much of the coral rock environment as possible and then use horizontal tunnels to reach the lower reservoir. If the formations towards the lower reservoir prove to be less stable than the limestone, the power house could be located at the bottom of the vertical shafts. According to the expert opinion of Mr. Stoebich a pump storage installation for Barbados should cost in the range of 1,500 USD/kW installed, which is in the mid range of present worldwide pump storage investment costs for systems in the range between 50 and 200 MW installed capacity as Figure A12 shows.

Figure A12: Pump storage investment costs over installed capacity (source: Zeller(Poeyry) 2016, slide 12)



## A2.4 The calculation of pump storage investment and operation cost

Drawing upon the empirical evidence of German and Austrian pump storage hydro projects Conrad et al. (2014) have developed a model to calculate the investment and operation cost of pump storage installations. The investment is mainly dependent on the capacity installed (measured in MW) and on the storage volume connected to the system (measured in MWh). As the analysis was done in Europe the Euro is used as the monetary unit. Conrad et al. show that the investment cost can be calculated by multiplying the installed capacity by roughly 1 Euro/kW and adding to this the installed storage volume multiplied by 1.3 EURO/kWh. This calculation and the empirical data, which the function is based upon are shown in Figure A13.

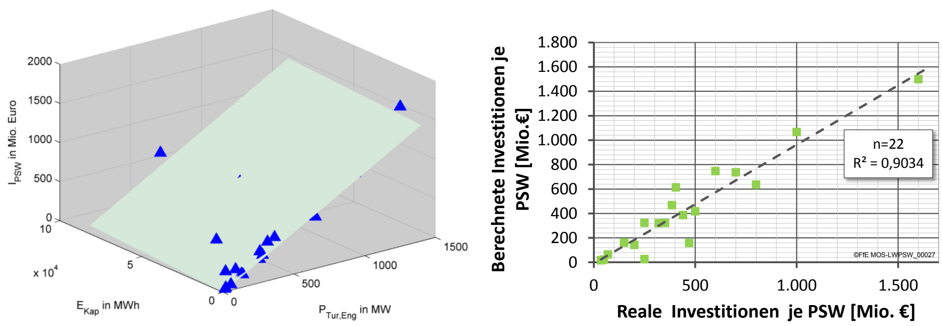
Figure A13: Estimated function for the investment cost of pump storage plants (source: Conrad et al. 2014, p. 12)

$$I_{PSW} = 1.059{,}24\,\frac{€}{kW}\cdot P_{Tur,Eng} + 1{,}3\,\frac{€}{kWh}\cdot E_{Kap} \qquad (4\text{-}2)$$

$I_{PSW}$: Investition für PSW

$P_{Tur,Eng}\ [kW]$: Engpassleistung der Turbine

$E_{Kap}\ [kWh]$: Nutzbarer Energieinhalt des PSW (Speicherkapazität)




The operation of pump storage plants induces fixed and a small share of variable costs. The fixed share can be calculated based on the installed capacity in MW. Conrad et al. estimate this term at 2.86 Euro/kW. Assuming a technical availability of 90% they estimate three types of variable operating costs. The first kind is directly proportionate to the number of system starts. This term is estimated to be 3.34 Euro/MW for each start of the turbine. The second kind is directly proportionate to the number of starts of the pump. This term is estimated to be 8.95 Euro/MW for each start of the pumps. The last term is proportionate to the electricity produced. This term is estimated to be 0.56 Euro/MWh of electricity produced. The different terms for the estimation of pump storage operating costs are given in Table A3 below.

Table A3: Fixed and variable operating costs of pump storage systems (source: Conrad et al. 2014, p.13) (German notation: comma used as decimal point)

| | | | | |
|---|---|---|---|---|
| Fixe Betriebs-kosten | Anteil bezogen auf die installierten Leistung | | $\left[\frac{\text{€}}{kW\cdot a}\right]$ | 2,86 |
| Variable Betriebskosten | Anteil bezogen auf die Startvorgänge pro Jahr | Anteil Turbine | $\left[\frac{\text{€}}{MW\cdot Start_{Tur}}\right]$ | 3,34 |
| | Anteil bezogen auf die Startvorgänge pro Jahr | Anteil Pumpe | $\left[\frac{\text{€}}{MW\cdot Start_{Pump}}\right]$ | 8,95 |
| | Anteil bezogen auf die erzeugte Strommenge | | $\left[\frac{\text{€}}{MWh}\right]$ | 0,56 |
| | Technische Verfügbarkeit | | | 0,90 |

It seems to be appropriate to use the cost calculations for pump storage installations developed by Conrad et al. in the case of a preliminary analysis for Barbados, but due to the fact that Conrad et al. base their estimates on average costs of 1000 Euro/kW installed capacity, it seems to be more appropriate to multiply their coefficients with the factor 1.5 to translate the estimates to the cost range of about 1,500 Euro/kW in the case of Barbados.

# ANNEX 3: EXTENSION AND UPDATE OF HOURLY POWER SYSTEM SIMULATION MODEL FOR BARBADOS (WORK PACKAGE 4)

## A3.1 THE MODEL USED BY HOHMEYER IN PAST ANALYSES ON 100% RE BARBADOS

In 2014 a first model for the hourly simulation of the Barbados power system with high shares of variable renewable energy sources was developed by Hohmeyer (Hohmeyer 2015) and used for a first analysis of possible 100% RE energy supply options for Barbados. The model included the existing generators and assumed the future use of the diesel generators as backup units for a future power supply largely based on wind and solar energy. The model included wind and photovoltaic solar energy production based upon hourly time series of wind speeds and solar radiation available from international data sources. The hourly electricity demand was reconstructed from a typical 24 hour load profile available for Barbados and from monthly power sales of Barbados Light and Power. Storage was modelled as a pump storage hydro system storing excess power production in times of high solar radiation and high wind speeds producing electricity from the storage in times of a lack of renewable energy production.

Ultimately, when there was a continuous underproduction of power from wind and solar and the pump storage was used up (all water in the lower reservoir) the existing diesel generators and gas turbines were used to cover the remaining power demand. Depending upon the installed wind and solar capacities and the volume of the storage the demand to be covered by the diesel generators could be kept as low as 2.5% of the annual power production. It was assumed that the diesel would be substituted by bio-diesel. Thus, it could be shown that a 100% renewable energy production for Barbados was feasible. In the publication of 2015 Hohmeyer showed that such a 100% renewable energy based system could save up to 30% of Barbados power cost as compared to 2013 assuming international cost figures for renewable energy technologies (see Hohmeyer 2015, p. 27). The model did not include any technology for the use of solid biomass or biogas, neither did it include any technology for the conversion of waste to energy.

In fall 2015 an new version of the model was extended through the inclusion of technologies for the combustion of solid biomass (based on the plans of the Barbados Cane Industry Corporation) and the plasma gasification of waste (as mentioned in the draft final report on a Barbados NAMA). Furthermore, the model was extended to include run-of-river hydropower and long term gas storage for the syngas produced from the plasma gasification.

This extended model was used in the stakeholder workshop ‚Renewable Energy and Energy Efficiency - Towards A Clean Energy Sector In Barbados‘ conducted by the Barbados Renewable Energy Association (BREA) and the Barbados Central Bank on November 2nd, 2015. Based on the discussion with about 25 stakeholders from all parts of society roughly 15 new scenarios on possible 100% renewable energy scenarios were run. During the discussion of the scenario results it became quite clear that a solid biomass combustion of the size planned by the Barbados Cane Industry Association would run into serious economic problems or that it would increase the overall cost of a 100% renewable power supply. While scaling down the size of the plant from 23.5 MW to 10 MW would increase the need for back-up diesel by about 50% and reduce the cost increase, it would still not be economically attractive. The production of syngas from the plasma gasification of waste would increase the total system cost even further especially if the syngas would need to be stored in larger volumes from a continuous plasma gasification process.

## A3.2 NECESSARY EXTENSIONS OF THE MODEL FOR THE PRESENT CONSULTING WORK

The extended model used in the workshop does not include the production of electricity from biogas produced from King Grass or sugar cane as presently planned at ARMAG Farms in cooperation with BL&P. As this is a serious proposition for a very flexible energy production from biomass, which could fit into the future electricity system with large shares of wind and solar energy substantially better than the solid biomass production from bagasse and river tamarind, it needs to be included in the model to give a realistic representation of the renewable energy options available to Barbados.

In addition some modifications in the operating schedule of the solid biomass production need to be tested on the possibility of cost reductions.

For the waste-to-energy plasma gasification plant a switch to short term storage needs to be analysed, as the very large volumes necessary for long term storage of syngas made this option extremely expensive. In the following the basic model logic and the new extensions of the model are described.

## A3.4 THE BASIC MODEL LOGIC

The starting point for the hourly modelling is the hourly load curve (demand) for electricity in Barbados for an entire year. Based on hourly wind and solar radiation data for Barbados and on typical wind turbines and solar PV installations the remaining load to be covered by other sources is calculated for a given hour (residual load 1). This residual load can be positive, which indicates a need for additional supply from other sources or it can be negative, indicating that wind and solar production actually exceed the demand in this hour. A negative residual load indicates how much energy could be stored, if enough storage is available.

In the next step all the production from other facilities, which have to run in this hour independent of the residual demand (must run) are subtracted from residual load 1 resulting in residual load 2, which again can be positive or negative like residual load 1. In the next step it is checked whether the remaining residual load 2 can be matched by the storage available. In the case of a positive residual load 2 the remaining demand will be covered by the power production from storage, as long as there is some storage production potential available (e.g. water in the upper reservoir of a pump storage system). If residual load is negative the energy will be stored as long as there is any partially empty storage available. Whenever total storage is entirely full, the excess energy has to be spilled or possible production has to be turned down. The remaining demand or the excess energy production after storage has been used is residual load 3, which is zero whenever residual load 2 is positive but there is enough stored energy to satisfy residual load 2 entirely.

In case residual load 3 is still positive, which is to say that wind, solar, all other must run technologies and storage did not suffice to meet the demand of a given hour, this demand is satisfied by operating the existing generators of BL&P, which are assumed to have enough fast starting capacity (gas turbines and diesel engines) to cover any remaining demand. This calculation is executed consecutively for every hour of the year.

Based on the available investment, operation, maintenance and fuel (as far as applicable) cost the total cost of the annual electricity production are calculated. This total cost is divided by the number of kilowatt-hours sold to arrive at the levelized cost per average kilowatt-hour sold.

In the model many technical and economic parameters can be varied to allow for the exploration of different scenarios as well as the analysis of sensitivities of the calculated results towards the variation of central parameters.

## A3.5 THE MODEL EXTENSION FOR THE INCLUSION OF KING GRASS GASIFICATION

The gasification of King Grass offers a number of systematic advantages over the combustion of bagasse and river tamarind combustion and one advantage over sugar cane gasification. King Grass can be harvested continuously all throughout the year. Thus, if there is a clear seasonality in wind and solar energy production, King Grass can be harvested almost with the opposite seasonality as the combined wind and solar production. This is not possible for sugar cane, which has to be planted at very specific times of the year and to be harvested in a fairly fixed cane season (personal communication with sugar cane farmers from Barbados). Thus, the production of sugar cane for an all year round operation of a gasification process is not possible and would need to be complemented by a second crop.

As compared to solid biomass combustion like bagasse and river tamarind, the gasification of King Grass is far more flexible, as it can be harvested according to seasonal demand (residual load 3) and the gas produced in a gasifier operating at a constant rate once fired up, can be stored in short term storage to adjust the hourly production during a day according to the prognosis of the hourly residual load 3. As the syngas can be used in combustion engines for electricity production the King Grass power production process can react to short term variations of the actual residual load very well. Typical combustion would be in gas engines with a capacity between 500 kW and 5 MW, which can be ramped from zero production to full load in less than 10 minutes. With this high degree of flexibility electricity production based on King Grass gasification can complement wind and solar energy quite well based on short term forecasts of wind speeds and solar radiation and the filling level of the pump storage.

In the model the power production from King Grass is integrated after storage is used. Based on the given seasonality of wind and solar energy production of a base year a complementary harvesting of King Grass (or a dry biomass storage fulfilling the same task) is assumed on a monthly basis. This determines the total gas volume to be converted to electricity in a given month. During each month a gasifier capacity is operated that converts the given volume of King Grass by constant operation entirely to syngas. The storage volume for syngas is calibrated to the constant gas production of 24 hours to allow a time shift of the power production during an entire day. According to the short term prognosis of residual load 3 (the residual load after storage operation) the power production is shifted to the hours with the highest positive residual load during a day (as a proxy for a future prognosis the data from a given past year are used as input to this calculation). After the power production from King Grass a new residual load results, which is then matched with back-up capacity (bio diesel or ordinary diesel). Thus, the introduction of power production from King Grass adds a new step to the model logic.

## A3.6 THE CHANGED OPERATION OF THE SOLID BIOMASS COMBUSTION

In the case of Barbados solid biomass combustion will most likely be done by the long planned bagasse combustion plant described in chapter 2. This plant will have a capacity of roughly 25 MW and operate a steam turbine driven by the solid biomass (bagasse and river tamarind) combustion in a steam boiler.

As the process has to be heated up to relatively high steam temperatures (about 400°C) for the turbine operation, it does take hours until the operation can start at all, as first the water boiler has to heat up the water and steam to about 400°C to begin the cold start of the turbine. The start up of a cold boiler can take anywhere between 2 and 6.5 hours (see Taler et al. 2015, p.159). Then the cold start of the turbine will take about 90 minutes to start with part load operation of 15-20% and it will take seven to eight hours to reach full load in order not to damage the turbine (see Figure 44). Thus, the full process from firing up the cold boiler to full load power production will take in the range of ten to 12 hours.

Figure 44: Typical cold start up operation of a steam turbine rotor (source: research gate / https://www.researchgate.net/figure/284930570_fig9_Fig-9-The-typical-cold-start-up-operation-curve-of-the-steam-turbine-rotor)

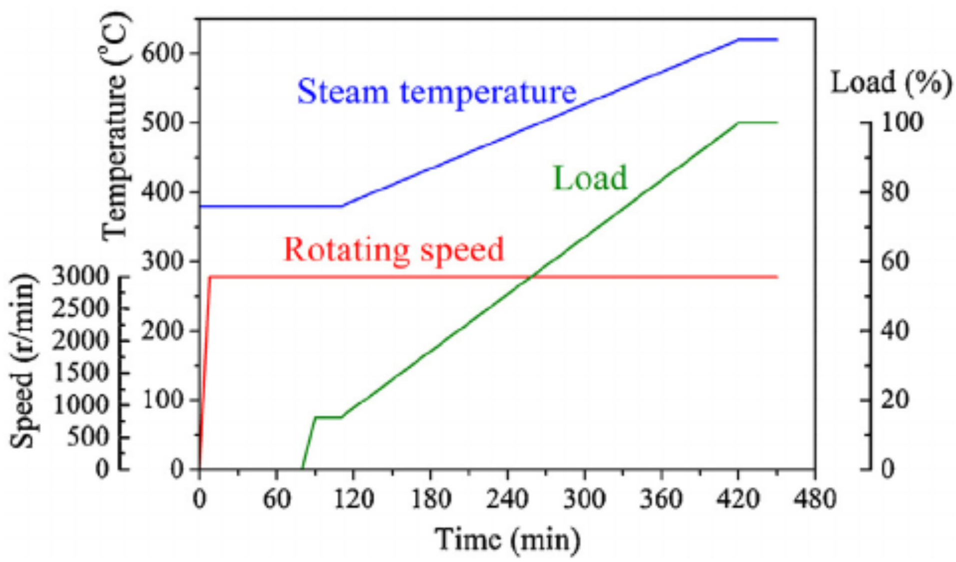
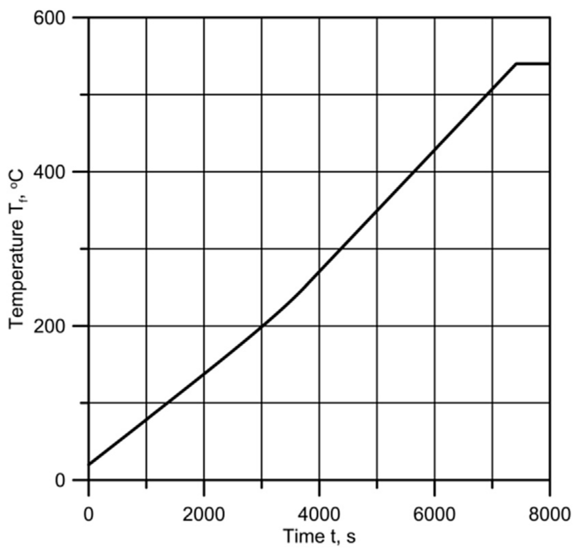



Figure 45: Steam temperature at the outlet of a power plant boiler after a cold start (source: Taler et al. 2015, p.157)




A power plant which takes more than 10 hours for a cold start will not be able to react to short term variations in residual load. Once it is fully operational (warm) it can be put into partial load operation. This will normally not be less than 25% and is often considerably higher. Thus, the solid biomass combustion could be entirely shut down for certain parts of the season, when residual load is expected to be low or negative. During the rest of the season it could be tried to vary the the operation between low partial load during times of high sunshine (around noon) and full load operation during the night hours. The exact operating cycle will depend on the technical specifications of the boiler and the turbine used.

The model has been modified to allow different operating schedules to accommodate as much of the foreseeable impact of wind and solar energy on residual load 1.

## A3.7 The introduction of short term syngas storage for the WTE plant

As the trials with large scale storage for the waste to energy plasma gasification plant, assuming a constant operation of the gasifier and the storage of all excess gas not used directly in combustion during the hour of gasification have shown that this would require extreme storage volumes inducing very high electricity cost, a new alternative has been included in the model, which uses all syngas produced within a day, but with a storage and generation capacity that allows to store up to 24 hours of syngas production and to use it in just a few hours, when wind and solar are low. As the actual power production during a day can be based on wind and solar energy forecasts the operation will be similar to the operation of the power generation from King Grass. It will be based on the 24 hour forecast of residual load 3.

## A3.8 The calculation of discounted cash flows for the different investments based on hourly model calculations

In order to allow an assessment of modified rate payments to the different investments necessary for the future energy system a new discounted cash flow module has been integrated into the model. It actually calculates the payments to each technology on the basis of the hourly operation calculated by the model. These payments will be made at the end of each month based on the sum of the monthly production. Assuming similar operation years over the lifetime of a technology the discounted cash flow can be calculated for the life time of an investment and it can be checked which payment per kilowatt-hour is necessary to result in a desired internal rate of return. The results of these calculations will be used for the estimation of first price points in WP14. They can be used in the discussion with stakeholders on appropriate tariffs for renewable energy sources. In addition these calculations can be used to show the impact of reduced operational hours on the economic feasibility of biomass or waste to energy plants.