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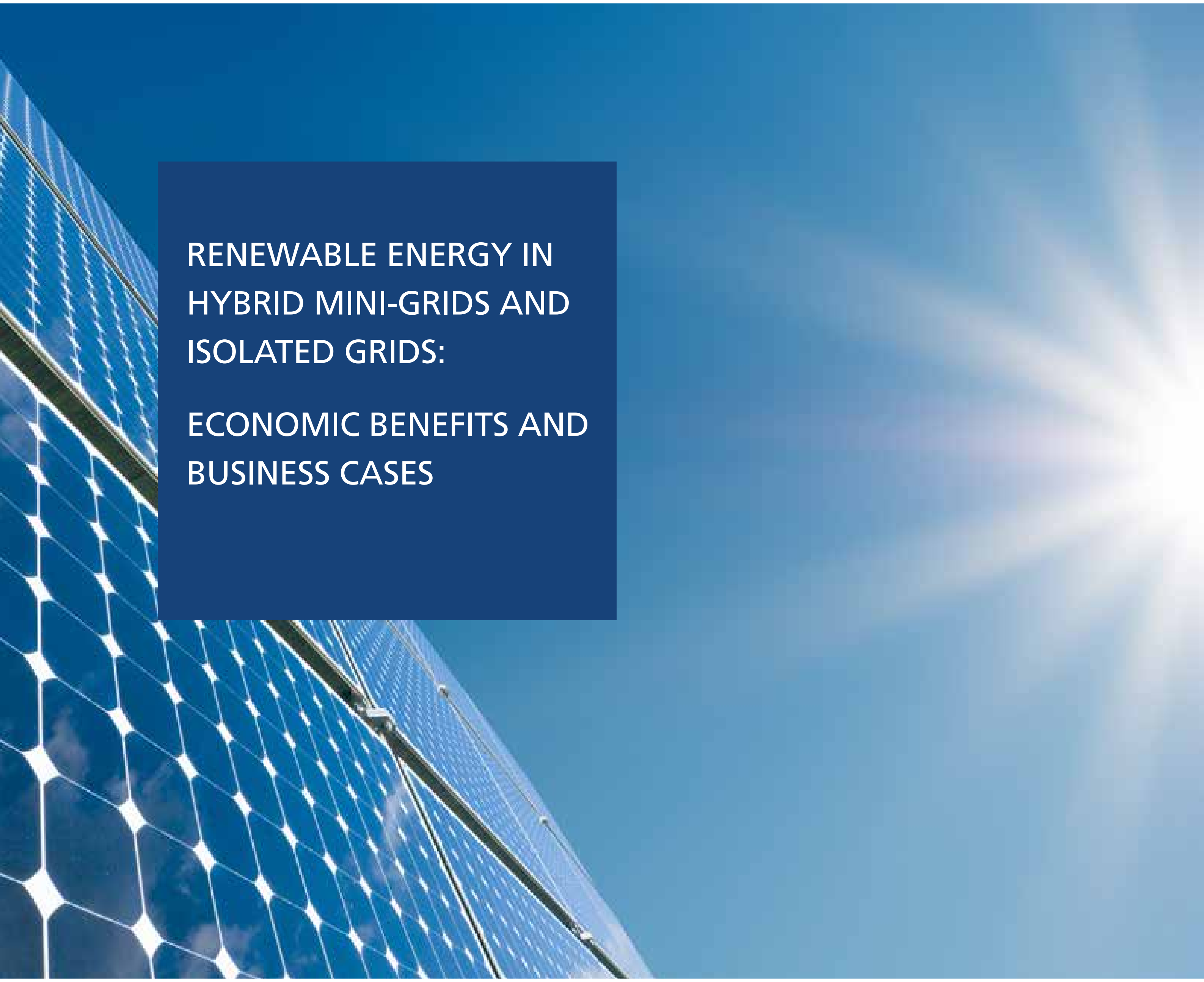

RENEWABLE ENERGY IN HYBRID MINI-GRIDS AND ISOLATED GRIDS:

ECONOMIC BENEFITS AND BUSINESS CASES

Sponsored and supported by:

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Frankfurt School – UNEP Collaborating Centre for Climate and Sustainable Energy Finance, 2015. Renewable energy in hybrid mini grids and isolated grids: Economic benefits and business cases.

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ABBREVIATIONS

AFD	Agence Francaise de Developpement
BISELCO	Busuanga Island Electric Cooperative
CAPEX	Capital Expenditures
CERs	Certified Emission Reductions
CDM	Clean Development Mechanism
CEDENAR	Electricity Company of Narino
CEET	Compagnie d'Energie Electrique du Togo
CIPC	Calamian Islands Power Corporation
DFI	Development Finance Institution
DSCR	Debt Service Cover Ratio
DSRA	Debt Service Reserve Account
EIA	U.S. Energy Information Administration
EIRR	Equity Internal Rate of Return
EMPULEG	Public Utility Company of Leguizamo
FI	Financial Institution
FiT	Feed-in-Tariff
HFO	Heavy Fuel Oil
HOMER	Hybrid Optimisation of Multiple Energy Resources
IEA	International Energy Agency
IFI	International Financial Institution
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
IPP	Independent Power Producer
KPLC	Kenya Power and Lighting Company
kW	Kilo Watt
LCOE	Levelised Cost Of Electricity
MW	Mega Watt
NAWEC	National Water and Electricity Company of The Gambia
NPC	National Power Corporation, the Philippines
NPV	Net Present Value
NREL	National Renewable Energy Laboratory of the US Department of Energy
O&M	Operation & Maintenance
OPEX	Operational Expenditures
PLN	Perusahaan Listrik Negara (State Electricity Company of Indonesia)
PV	Photovoltaic
RE	Renewable Energy
SENI	National Electric Interconnected Grid System in the Dominican Republic
SIN	National Electricity Grid of Colombia
SPV	Special Purpose Vehicle
SVG	St. Vincent and the Grenadines
UNEP	United Nations Environment Programme
VINLEC	St. Vincent Electricity Services
WACC	Weighted Average Costs of Capital
ZNI	Non-grid Connected Areas in Colombia

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ACKNOWLEDGEMENTS

This study was commissioned by the United Nations Environment Programme's Division of Technology, Industry and Economics (UNEP DTIE), in cooperation with Siemens and the International Renewable Energy Agency (IRENA). We would like to thank in particular Nicoletta Heilsberger, Matteo della Volta and Torsten Wetzel from Siemens; Stefanie Held, Jeffrey Skeer, Emanuele Taibi, Michael Taylor, and Mohamed Youba Sokona from IRENA; and Roberto Borjabad, Dean Cooper, Kornelia Guse, Mark Radka and Merlyn Van Voore from UNEP for their unwavering support and vital inputs.

A special thanks to Siemens, whose technical expertise enhanced the financial analysis provided by the Frankfurt School – UNEP Collaborating Centre.

This study would not have been possible had it not been for the utilities and other stakeholders at the selected sites, providing all required information and input data (particularly BISELCO, CEDENAR, CIPC, EMPULEG, IPSE, KPLC, NAWEC, NPC, PLN, and VINLEC) and the experts collecting this data, and supporting the Frankfurt School – UNEP Centre with the actual analysis (Unai Arrieta, Philipp Blechinger, Alan Dale Gonzales, Rebecca Gunning, Tobias Panofen, Komang Pribadiana, Mauricio Solano and Bernardo Tadeo).

Thanks also to Professor Dr. Michael Klein and Professor Dr. Ulf Moslener for their invaluable inputs during the compilation of the study; Jiwan Acharya, Jim Cohen and Achim Neumann for their peer review and critical comments; Pierre Knoche who supported this work as part of his studies at Frankfurt School of Finance & Management; and – last but not least – our advisory board that helped putting this work in a broader context: Philipp Gaggl, Steve Lindenberg, Peter Storey, Patrick Theuret, and Marcus Wiemann.

This was indeed a worthy exercise, and we at the Frankfurt School – UNEP Centre hope that this research can be used as a reference point for mini-grid work in the future. We also hope that these results generate interest that can cascade into a great success in the provision of clean and reliable energy for those living in rural areas.

FOREWORD

"Clean Energy Mini-Grids have the potential to increase energy access, renewable energy use and energy efficiency in developing countries. As such, they are a priority for the UN's decade-long Sustainable Energy for All initiative. This report uses public and private sector experience to show that clean fuel for such isolated grids can be cost-effective for suppliers, though remaining affordable to the targeted communities. It marks the start of a shift to decentralised electrification worldwide using local clean energy supplies to protect the local environment and improve local people's lives".

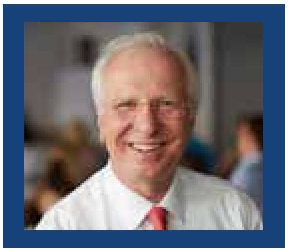
Achim Steiner, United Nations Under-Secretary-General and Executive Director,
United Nations Environment Programme

"The distribution of renewable power on hybrid mini-grids represents an excellent opportunity for islands and isolated communities to displace costly diesel fuel, boost energy security, contribute to emissions reduction and lower electricity costs. This report illustrates the potential cost savings achievable from hybrid mini-grids in seven different countries spanning Africa, Asia and Latin America. It provides further evidence of the increasing economic viability of renewable energy globally."

Adnan Z. Amin, Director General,
International Renewable Energy Agency

"To ensure that global energy systems satisfy the need for reliability, affordability and climate compatibility in the future, it will be critically important to combine and integrate the right technologies. As a globally active company, it's our responsibility to use our know-how and competence in developing and implementing new products and solutions, and to serve as a consultant in nearly all energy markets, for just this purpose. By exploring various approaches and analyzing their cost-effectiveness in developing sustainable solutions, this study is a valuable contribution to discussions on how to create tomorrow's energy systems."

Lisa Davis, Member of the Managing Board,
Siemens AG



"Public infrastructure investments can come along with significant capital cost requirements – especially if private financiers are involved. This also applies to the hybridization of decentralized electricity grids in the developing world. While the environmental benefit of renewable energies is non-controversial, they are still relatively capital intensive compared to diesel generation capacity. Besides fuel consumption, return on equity and interest on debt can possibly account for a bigger part of electricity generation costs. This study contributes to the very topical discussions on the affordability of climate change mitigation, the challenges in crowding-in the private sector, as well as the needs for continuous donor activities and technical assistance on-site. It is part of Frankfurt School's endeavor to advocate green energy without neglecting market realities and real economic costs."

Udo Steffens, President & CEO,
Frankfurt School of Finance & Management

OVERVIEW

Renewable power has significant potential to reduce the cost of electricity in rural and island settings across the developing world. In areas distant from main power grids, regional isolated grids - often referred to as mini-grids - are often the main source of electricity to industry and households. Electricity generation usually relies on diesel fuel, often imported over long distances. Yet generating costs can be reduced by hybridising these mini-grids with solar photovoltaic (PV) or other renewable power sources.

On the basis of seven case studies in as many countries, this report finds that hybridisation can reduce average generation costs at five of the seven sites (from 0.3 to 8 percent) - even assuming private-sector financing terms and the Energy Information Administration (EIA) mid-case scenario for oil prices. If financed with public funds at a 5 percent real discount rate, hybrid mini-grids can achieve cost reductions at all seven sites of 12 to 16 percent, with PV generation at the sites providing 31 to 40 percent of total electricity. Hybrid generating costs in this scenario represent a weighted average of diesel-only generating costs, which range from 31 to 44 U.S. cents per kilowatt-hour, and PV generating costs, which range from 16 to 23 U.S. cents per kilowatt-hour.

Increasing numbers of isolated grids are operated by independent power producers (IPP) under concession, and it is expected that hybridisation projects, which are characterised by a higher capital intensity than diesel-only plants, require further private sector involvement, in particular to ensure access to financing. Financial viability, i.e. the attractiveness of a hybridisation project from the perspective of equity investors and commercial lenders, depends on the terms and conditions of the existing or new power purchase agreement (PPA). In most cases, no such framework exists for hybridisation, and IPPs cannot change the generation technology under the existing PPA.

Where projects are economically viable, this study finds that the regulator and/or government needs to initiate the hybrid project and to set up a suitable PPA framework. Accordingly, it assesses the economic viability of renewable-based hybridisation of existing - so-called brownfield - diesel grids and provides recommendations on how economic viability can be translated into financial viability. It thereby considers two options regarding operational set-up: first, government-led investment with operation by the utility; and second, the outsourcing of operation and investment to the private sector.

This study aims to add value to the ongoing discourse by showcasing concrete examples and highlighting the differences between real-world isolated grids. The analysed projects include three physical islands (Bequia, St. Vincent & the Grenadines; Nusa Penida, Indonesia; Busuanga, the Philippines) and four remote locations that amount to "virtual islands" (Puerto Leguizamo, Colombia; Las Terrenas, Dominican Republic; Hola, Kenya; Basse Santa Su, The Gambia) far from national or other regional power grids. They were deliberately chosen to take into account the heterogeneity and complexity of remote areas in different parts of the world.

The sites represent a variety of grid sizes, number and type of customers, diesel costs, and isolation levels - all factors that can affect the technical solution as well as the economic and financial viability of the hybrid mini-grid investment. The installed diesel generation capacity ranges from 0.8 MW in Hola to 9.5 MW in Las Terrenas. The number of customers (grid connection points) ranges from 1,700 in Hola to 13,000 in Nusa Penida. The type of customers can be classified into residential (at most sites), commercial, and public categories, whereas a larger anchor customer plays a particularly important role in Puerto Leguizamo. Yet, in order to ensure a certain replication potential, the sites were selected to be representative within their respective countries and regions.

Although this study does not include purely industrial sites, the results still imply potential for PV hybridisation. Such sites are characterised by stronger demand during daytime and a less significant (or no) evening peak.

Diesel-powered grids can be hybridised using different types of system-integration technologies and renewable energy sources. This analysis compares diesel plants to a '100-percent-peak PV penetration' hybrid technology, with which existing diesel generators can be switched off during peak availability of solar radiation. The focus on this technology, however, is illustrative only, and does not imply its general advantage compared to other hybrid technologies. Likewise, solar PV was selected as only one of several options for hybridisation.

The aim of this study is to compare average generation costs of a renewable hybrid to a diesel-only power plant – not to compare different hybrid technologies or renewable power sources to each other. With PV electricity - despite rapidly falling technology costs - still representing a comparatively expensive source compared to some other renewables, this assessment provides a conservative view of the potential cost savings through hybridisation. While PV is an obvious technology (and offers the benefit of reliable resource data), site assessments may point to other renewable energy sources that would permit cheaper hybridisation.

With the selected hybrid technology, and given a suitable capacity and efficiency of PV installations at the different sites, the power demand could be fully met with PV for around four to seven hours per day (yearly average). PV thereby could cover about 30 to 40 percent of the total energy demand - leading to possible diesel savings in this range. Nevertheless, since load patterns at the selected sites are mainly residential (with peak demand occurring in the evenings at the low/no sun hours), most of the electricity would have to be generated with diesel power. Where suitable resources exist, non-PV renewable power technologies with a different output pattern could further reduce the diesel share. At industrial sites, the overlap of electricity demand and variable renewable energy supply tends to be greater.

While a hybrid power plant can be operated with significantly less diesel fuel, it also means higher investment (and replacement) costs. To combine the diesel and PV electricity, technical components for system integration are required as well. The average electricity generation costs (so-called levelised cost of electricity, or LCOE) of a hybrid system are a combination of PV and diesel LCOEs weighted with their share in the total output plus a cost component for system integration.

Since PV accounts for only about one third of total generation, the full comparative advantage of the PV portion is disguised in the average. By comparing LCOEs diesel and hybrid power and, excluding financing costs in the first step, the relative advantage of hybrid plants is significant. The current generation costs of diesel electricity - as calculated for the purpose of this analysis, including carbon costs of 50 USD/tCO_2 - range from 34 USDc/kWh in Bequia to 48 USDc/kWh in Hola. In contrast, generation costs for hybrids at the same sites are 27 USDc/kWh and 38 USDc/kWh, respectively (in other words: a 20 percent savings).

Financing costs play a crucial role in renewable energy finance and hybridisation projects. The first of two scenarios assumes that the utility and/ or government has the financial strength to deploy capital on its own, remains owner of the assets (diesel-only or diesel/renewable hybrid) and might only outsource the operation. For this scenario, a flat discount rate of 5 percent over the lifetime of the assets is assumed. Such 'public' capital costs can be achieved if, for instance, the project is financed on the balance sheet of the utility, and if it has access to concessional debt finance from international financial institutions. Adding financing costs to the generation costs reduces the above-highlighted cost advantage of hybrid systems. Generation costs can be reduced from 34 USDc/kWh to 30 USDc/kWh in Bequia and from 48 USDc/kWh to 42 USDc/kWh in Hola (a 13 percent savings).

The second scenario assumes that the utility/ government does not want to be involved in the financing (and operation) of the plants, and accepts higher generation costs that are a result of the relatively higher financing costs of the private sector. Such arrangements and PPA terms were observed during this analysis. As concessions for the operation of a site are given to the private sector - usually for a pre-defined period - a project finance capital structure was assumed. This further increases the relative share of financing costs in total generation costs, which burdens more capital-intensive hybrid projects. The economic viability of hybridisation is consequently lower in this scenario, but the analysis reveals that hybrid projects continue to enjoy a relative cost advantage at most of the sites.

Economic viability depends heavily on future oil prices. The figures above are based on the 'EIA reference' scenario, released in early 2014, which expects declining oil prices over the next several years, and a medium increase afterwards. It remains to be seen whether the oil-price decline from 115 USD/barrel in June 2014 to less than 50 USD/barrel in February 2015 is only a short-term shock, or if it will lead to an adjustment of long-term projections.

Most analysts agree that the price will increase again after several years. At the time of writing, no revised long-term projections were available from EIA. The World Bank however, released an updated forecast, in which the mid-term trend levels off close to the EIA reference in 2025. Although not directly reflecting the most recent developments, different diesel price scenarios are presented as part of the sensitivity analysis.

The LCOE was chosen as the major indicator for economic viability. While this is a common approach, it ignores the uncertainties with regard to diesel price development and its volatility, and consequently does not value the advantage of more predictable generation costs in the hybrid cases. For instance, at Basse Santa Su, EIA low and high oil-price scenarios swing the LCOE from a 16 percent reduction to 31 percent increase in a diesel-only grid, but only from 10 percent reduction to an 18 percent increase in a hybrid grid.

Among the investigated sites, the differences in estimated cost savings are mostly due to plant size, diesel costs, and solar radiation. Large plants achieve economies of scale by distributing the fixed cost of the hybrid system over more units of generated electricity. High diesel prices result in high cost savings, whereas high solar radiation allows for the generation of relatively more (cheaper) PV electricity.

Despite relatively high local diesel prices and solar radiation, hybridisation could - under conservative assumptions, including reliance on private sector finance - result in a cost increase in Hola and Basse Santa Su. The main reason is the small generation capacity, i.e. missing economies of scale. In contrast, the cost advantage at the largest site (Las Terrenas) is limited by relatively low diesel prices and solar radiation. The most viable case for hybridisation is Nusa Penida - a mid-sized plant with the highest diesel prices and relatively high solar radiation.

Demand growth has a positive effect on electricity generation costs of hybrid systems - even within a limited project lifetime of 20 years. To consider growth, additional PV capacity needs to be installed during the project's lifetime. However, the physical lifetime of these additional modules, other new components, and possibly also the initial equipment usually exceeds the 20-year economic lifetime applied in the financial model. The 'growth LCOEs' do not consider electricity generated after the twentieth year, while additional costs are distributed only over the output of the remaining years (until year 20). To mitigate the effects, it was assumed that generation assets can be sold at book value at the end of year 20.

This assessment underpins the requirement of detailed and thorough cost analyses for the specific sites before the initiation of hybridisation projects. Even though real diesel generation costs were available from some sites, the breakdown of those costs was not fully known. For this analysis, it was required to calculate alternative values in order to ensure comparability to the hybrid case. It has to be determined which elements of costs are ultimately included in diesel generation costs, and which financing conditions were applied. Once these aspects are known, hybrid generation costs have to be re-calculated based on the same assumptions.

Moreover, this analysis is limited to one renewable energy resource (solar) and one associated hybrid technology (PV). Other technologies (e.g. fuel saver, diesel spinning reserves, large battery banks for energy storage) and resources (particularly wind and biomass) should be taken into consideration when planning a real project.

The results for PV alone, however, are promising enough that stakeholders may be encouraged to invest in a more extensive analysis of hybridisation potential.

Other further-reaching aspects must be considered for project implementation. For instance, especially for countries with low-average, on-grid generation costs (and where an extension is not restricted by geographical barriers), the hybridisation option needs to be compared to the possibility of interconnecting the isolated grid with the national grid. Nusa Penida is one site where this option is currently assessed by the utility. Such interconnection will serve as a third scenario, in addition to the status quo and a hybridisation of the island grid.

The operation and optimisation of isolated grids is not necessarily at the top of the agenda of national utilities and decision makers; familiarity with hybrid technologies among relevant stakeholders is sometimes limited, and there might already be cost-reduction potential from optimising diesel-power operations and overall grid management. Fair communication is required with regard to applied assumptions, actual achievable cost savings, and hence the benefits of hybridisation.

Transparent assumptions and calculation methods in this study are intended to help policy makers and other stakeholders assess hybridisation options in each specific context, in order to make well-founded decisions that help to increase electricity access in remote areas without straying from least-cost development paths. The results for hybridisation with PV may encourage more detailed analyses with a broader renewable energy portfolio.

1. INTRODUCTION

In the context of rural electrification efforts with a focus on least-cost investment strategies, regional grids with primarily diesel generation assets – often referred to as mini-grids – have been established in remote areas or island environments. With continued technology progress on intelligent grid management of hybrid generation systems, as well as decreasing costs of renewable energy (RE) components, the replacement of diesel generation assets has become cost competitive. The addition of RE generation capacity can provide a solid basis for further grid expansion or replacement of diesel generation capacity – while reducing the consumption of diesel per unit of generated electricity.

This study assesses the economic and financial viability of RE-based hybridisation of existing – so called brownfield – diesel power plants in seven countries. The focus on brownfield assets offers the advantage of an established operational structure and management, as well as an existing track record of energy offtake and appears to present a low-hanging fruit when it comes to hybridisation.[1]

The following of section 1 gives an overview about the background of this analysis, the selected hybrid technology, and the applied technical and financial models. Section 2 briefly presents the characteristics of – and key findings from – the selected sites, before the main part of the study continues in a comparative manner. Section 3 outlines the different sites' potential for hybridisation by presenting solar irradiance, RE generation potential, actual load profiles and demand patterns, as well as potential demand growth and expansion options.

Section 4 starts with an introduction to the overall approach and assumptions applied in the economic analysis. It then discusses the impact of hybridisation on the levelised cost of electricity (LCOE) by presenting the breakdown to the elements of costs, and hence the key cost drivers of diesel and hybrid power generation. A 'base case' – including costs of carbon emissions, assuming EIA 'reference' oil price developments, and not considering demand growth – compares the impact of two different ownership and financing structures on the LCOE. It is argued that lower-than-commercial 'public sector' return expectations (financing on balance-sheet of utility, concessional debt terms) make the hybridisation viable at all sites, whereas 'private sector' return expectations (project finance structure, IPP) can burden the capital intensive hybrid systems with too high financing costs to ultimately reduce generation costs. It is further shown that – besides financing costs – sufficiently large grid size, high fuel costs and solar radiation, and the combination of these factors, respectively, are key for making the hybrid investment viable. A sensitivity analysis compares the base case to alternative fuel price scenarios, different capital costs and risk margins, changing equipment costs, decreasing PV penetration levels, and increasing customer demand.

Section 5 discusses the relevance of feed-in-tariffs, avoided costs of diesel generation, and asset ownership for financial viability of hybridisation. Using one case example, it presents cash flows, financing structures and repayment profiles of the hybrid investment, and assesses whether costs related to the generation of electricity – including financing costs for debt and equity – can be fully recovered by future revenues.

Section 6 presents the key findings and conclusions, and outlines possible implementation challenges as well as areas for further discussion. A glossary in Annex 1 presents definitions of certain technical and financial terminology. Annexes 2, 3, and 4 present technical fact sheets of the selected sites, as well as assumptions on system sizing and operations, demand growth, and possible technical upgrades.

1.1. BASIS OF DECISION MAKING

The decision making processes for the hybridisation of existing diesel power plants will vary significantly, and depends on the current ownership

[1] Completely newly set-up grids are referred to as greenfield assets.

and operating structure. In case of a utility-owned island grid, also the financial strength of the utility, government budgets and access to financing from development banks will play a role, and will determine whether they can invest capital on their own, or need to rely on private sector financing. In this case, the initial decision needs to be taken by the public sector which is expected to decide based on economic viability. Thereafter, private sector operators and investors will decide based on the offered terms. In case the private sector is already involved in the operation of the diesel power plant, a hybridisation decision needs to be taken by both parties as existing contracts are expected to include diesel electricity only.

The public sector is expected to assess different development paths for a hybrid grid based on the economic viability, i.e. minimising the overall generation costs. Investment decisions for power supply and rural electrification are not only based on project-related cost-benefit calculations. Rather, utilities have a mandate to ensure basic energy needs, and governments (usually the main shareholder of public utility companies) have an interest in taking environmental and social aspects into account. While social benefits are difficult to quantify for the hybridisation of existing grids (for instance since access to electricity is already given), the analysis of the public sector should address the question of whether hybridisation can reduce average generation costs under consideration of carbon emissions from diesel electricity generation.

Financing costs play a significant role and drive RE generation costs. In a number of PPAs for sites licensed out to the private sector, nearly 'cost-plus' PPA terms were observed. The price per kWh paid to the private sector concessionaire is adjusted to diesel price developments, i.e. the diesel price risk is allocated to the public sector, and the private sector being compensated to appropriate financing costs (although having a minor impact in the case of diesel only plants).

As a consequence, the cost per kWh depends also on the decision on whether the national utility continues to operate a plant, or whether the appropriate private sector financing costs need to be considered. An analysis of the average generation costs from the utility's/societal perspective as key criteria for the decision making follows this approach:

- One scenario assumes a private sector party investing into the plant and operating the plant, resulting in return expectations of 15 percent on equity and 8 percent on debt. Given a target debt service cover ratio (DSCR) of 1.2, a maximum debt portion of 70 percent, a debt tenor of 12 years (1-year grace period) and different local tax rates for each of the respective sites, the initial weighted average capital costs (WACC) are assumed to range between 8.7 and 9.6 percent. Since debt is repaid first and hence the capital structure becomes more equity-dominated, average financing costs increase over the project lifetime.

- The other scenario assumes a continued capital allocation from the public sector, i.e. a realisation of a project on the balance sheet of the national utility, with financing costs of 5 percent flat over the lifetime of the project.

As described above, there are diesel price adjustment clauses in the PPAs for the sites already being outsourced to private sector operators. The risk of adverse diesel price developments consequently remains with the public sector in both scenarios. The LCOE was chosen as major indicator for economic viability. While this is a common approach, it ignores the uncertainties with regard to the diesel price development and its volatility, and consequently does not value the advantage of more predictable generation costs in the hybrid cases. Applying different oil price forecasts, a range of LCOEs was calculated. This analysis reveals that an investment in hybridisation reduces this LCOE range significantly – an advantage which is not reflected in a LCOE-only assessment, but which should be considered by the public sector. Section 4.4.1 provides more details on this aspect.

The financial viability of a hybridisation project is the key determinant for making an investment decision from a private investor's perspective – in case their participation is requested. The financial viability depends on a framework and market design which allows the hybrid plant operator to realise sufficient revenues rather than the avoided costs. Against the background of the limited liquidity and low price levels on the compliance carbon markets, reduced societal costs of carbon emissions which play a role in the economic assessment, will not trigger revenues for the private sector investors. Regulators and stakeholders of the energy sector can most likely be convinced to put the required frameworks in place if the economic viability of an investment is given, i.e. if the project can help to create value for the overall economy.

Diesel power plants can be hybridised by using different types of system integration technologies and RE sources. The decision to realise a hybridisation project – as well as the technology choice – depend on various factors such as customer load requirements, and the availability of alternative energy sources. Decision makers in the target countries – as well as potential international and local investors – can use this study as an initial reference point for assessing the benefits of hybridisation. The study should be understood as a starting point for discussion and a tool for a site specific analysis. Of course, other technology options (different RE penetration levels and different RE technologies) should be considered and compared to identify the least cost option for the specific site.

The study discusses the questions if hybridisation makes sense from a societal perspective, and if it offers an attractive investment opportunity for private sector investors. It compares the LCOEs of diesel and hybrid, applying two different ownership- and financing structures: public sector return expectations, assuming that the assets will be financed on the balance sheet of the utility, and that the utility has access to concessional debt terms; and private sector return expectations, assuming that an IPP will make the investment under a project finance structure. For the latter, the study continues with an analysis of cash flows, financing structure, debt tranches, and payback periods.

Table 1: Economic vs. financial viability

Economic viability	Financial viability
Does the hybridisation make sense from a societal perspective? ■ LCOE [consumed kWh] as key decision criterion; LCOE range change depending diesel price as proxy for increased stability of hybrid option ■ Study compares two scenarios (real world would need to consider other technology options) - Diesel only - Hybridised scenario ■ Two different financing structures considered depending on financial strength of utility/ government ■ Externalities taken into account	**Does the hybridisation offer an attractive investment opportunity for a private sector investor?** ■ EIRR, payback periods, possible debt tranches ■ Based on PPA terms ■ Considers risk profile of investment

1.2. TECHNOLOGY SELECTION

The analysis compares LCOEs of current diesel assets and a '100 percent peak RE penetration' hybrid technology. This means that the hybridised plant is designed in a way that the existing diesel generators can be switched off during peak availability of the intermittent RE source (e.g. four to six hours during daytime for solar). The stability of the overall system during peak hours is managed by an automation tool and an integrated storage device (batteries) for short-term interruptions of the power supply.[2] The automation tool manages the complexity of diesel power installation with, for example, intermittent PV sources. It ensures high grid stability of PV with integrated energy storage. It also maintains power quality, and optimises the generation units based on real-time fluctuation of RE and variable load. Despite relatively high investment costs of this technology, it was selected since it ensures the maximum amount of diesel savings and carbon emission reduction during peak resource availability.

The focus on this technology, however, is illustrative only, and does not imply the general advantage of this technology compared to other hybrid technologies.[3] The study aims to demonstrate the benefits of a selected hybrid solution compared to diesel power plants. More detailed proposals and feasibility studies might be required to determine the most appropriate hybrid solution. It depends on the individual circumstances which technical configuration might be preferable.

The same applies to the selection of RE sources: While other sources were initially considered in the analysis, the main potential at all selected sites seems to be for solar energy. This is not only due to the resource availability, i.e. the relative abundance of solar radiation compared to wind, biomass, or hydro. It is also because solar data is readily available, whereas there are no long-term wind measurements or biomass supply projections (run-of river hydropower is most likely not feasible at any of the sites). Another advantage of PV compared to alternative RE technologies is the relatively low operation and maintenance (O&M) costs and complexity, as well as the relatively simple and quick installation and infrastructure requirements. Biomass power generation, for instance, depends on adequate and stable feedstock supply chains, which do not yet exist, and are probably difficult to create. Altogether, solar PV is the most commonly installed RE technology in islands and other remote sites today, and is presumably the first choice for the majority of hybridisation projects in the future. However, again, the aim of the analysis is to assess the economic and financial viability of hybridising diesel plants with a RE technology – not to compare different RE technologies against each other. Utilities are encouraged not to exclude any type of RE technology (and RE source, respectively) in their analysis as alternatives to relatively costly PV can significantly reduce generation costs.

1.3. TECHNICAL AND FINANCIAL MODELLING

The sizing of the hybrid systems and its individual technical components[4] was modelled with the Hybrid Optimisation of Multiple Energy Resources (HOMER) software,[5] which is one of the most commonly used tools worldwide for designing and analysing hybrid power systems. HOMER determines how variable RE resources can be optimally integrated into hybrid systems by applying simplified financial assumptions.

[2] In this analysis, batteries are only considered for balancing of short-term interruptions of power supply (up to 15 minutes), but – due to the still prohibitively high investment costs – not as longer-term storage devices (for instance three hours per day, to be used as electricity supply source to the grid).

[3] The study does not benchmark the 100% peak PV penetration technology with lower or higher penetration technologies. For instance, fuel-saving technologies, operating with maximum PV power ratios of 20% to 60% of the generator capacity (depending on the utilisation of batteries), achieve less diesel savings; at the same time they are less capital intensive. Further possible technical configurations are spinning reserves and larger battery banks for energy storage. Spinning reserves are diesel generation capacity that is kept up and running – not for power output, but as a standby for sudden demand increases, in order to ensure system stability. On the one hand, this reserve makes the automation tool and batteries dispensable. On the other hand, there is a need for additional diesel generation capacity (beyond actual demand), and there are less diesel fuel and emission savings compared to the peak penetration layout. Battery banks would prolong the period of PV electricity use, and could also make an automation tool unnecessary. At the same time, batteries are capital intensive, too, and more PV capacity would be required to fill the storage device.

[4] Technical fact sheets of the different hybrid power plants (including HOMER output) are presented in Annex 2.

[5] www.homerenergy.com

One of the simplifications in HOMER relates to the financing costs: only a constant discount rate can be assumed to calculate the NPVs of the different technical layouts as basis of decision making. Also, HOMER does not properly consider fluctuating diesel price forecasts, revenue streams, tax effects, or changes of the financing structure over the 20-year lifetime of the project – components that could influence financing conditions and investment decisions. Further, growth scenarios can only be simulated by modelling the optimum seizing of the RE component on a year-on-year basis in separate HOMER files.

The financial analysis of this study is hence based on a fully-fledged financial model that builds upon HOMER output and other input data (see figure 1). As both models 'optimise' based on LCOEs, this approach accepts some inaccuracy, as financial assumptions cannot be inserted into HOMER with the same level of detail as they can in the financial model. However, cross-checks for specific sensitivities have revealed that this inaccuracy remains limited.

Input data like the current (diesel) plant layout, load profile, fuel consumption and costs, and RE resource availability was gathered on site for each individual case. Assumptions for i) initial capital expenditures (CAPEX) of the hybrid system, e.g. PV modules, battery, battery converter, and automation tool; ii) component lifetime and replacement costs for PV inverter, battery converter, and diesel generators; and iii) operational expenditures (OPEX, excluding fuel) for diesel generators and PV system were provided by Siemens, and verified by IRENA. For each individual site, actual historic fuel prices (including transportation costs to the mostly remote areas) were indexed to different crude oil price forecasts to predict future diesel price scenarios case-by-case. Financing costs like equity return expectations, interest on debt, transaction costs, contingencies, and debt service coverage ratio (DSCR) were determined in workshops with international financial institutions (IFI) and private sector financiers.

The breakdown to the actual elements of current diesel LCOEs (like capital expenditures, operational expenses, fuel, financing costs, potential carbon costs etc.) was not fully known at all sites. Therefore, in order to ensure comparability to the simulated hybrid LCOEs and among the sites, alternative values of diesel LCOEs were calculated for the purpose of this analysis – based on real data from the ground, but partly using unified assumptions.

The LCOE is often defined as the total capital and operating expenditures per unit of generated electricity, discounted over the economic lifetime of the investment. Discount factor is the Weighted Average Cost of Capital (WACC); the investment lifetime of a hybridisation project is assumed to be 20 years. However, for the purpose of this analysis, it is essential to take financing cost and a changing financing structure (over economic lifetime) into account.

Figure 1: Technical and financial modelling approach

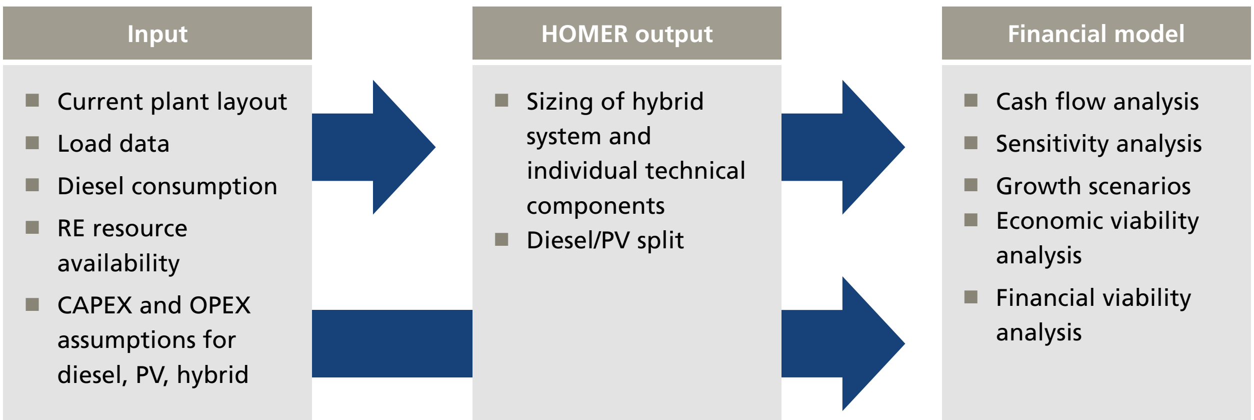
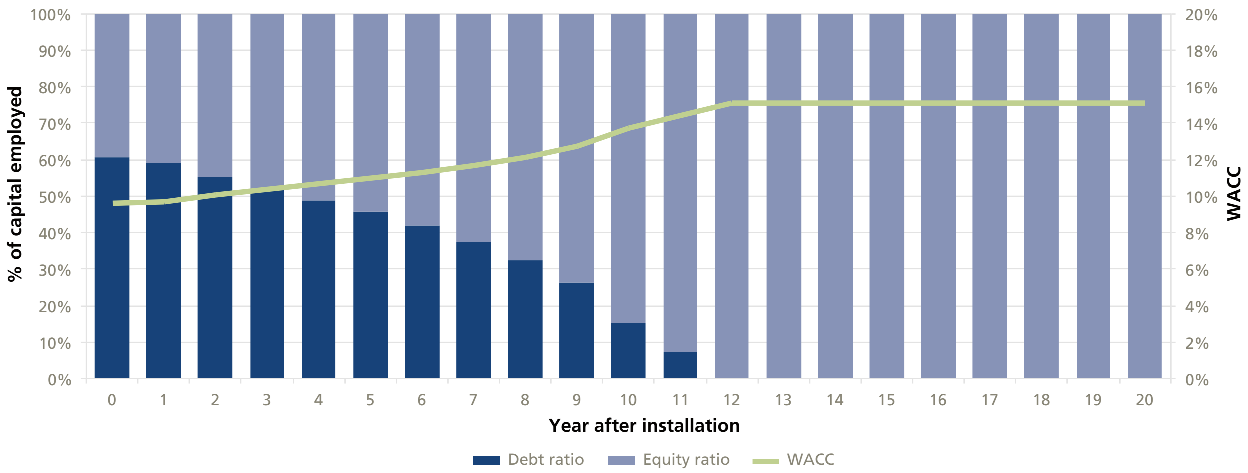


Figure 2: Typical project finance structure, NUSA PENIDA – Indonesia



In the 'traditional' LCOE calculation, investment costs, operating costs and fuel costs are discounted with a stable WACC, and divided by the discounted electricity output over the lifetime of the project. However, this does not reflect the reality of a project finance structure with changing debt-to-equity ratios, loan tenors, and cost of debt and equity. Figure 2 shows a typical project finance structure for the example of Nusa Penida. It highlights that the capital mix changes over time. That means the average financing costs increase since debt is repaid first, and consequently, the capital structure becomes more equity-dominated.

Nusa Penida for example would show an initial WACC of 8.7 percent based on an initial 70/30 debt/equity split. The WACC rises as debt is repaid, and reaches the remuneration level for equity (15 percent) after final debt repayment. Using a fixed WACC as discount rate is underestimating the financing costs and is hence leading to inaccurate results in the LCOE calculation.

A different approach is used in this analysis to reflect the financing structure more accurately. The yearly project cash flows are discounted with the WACC of the respective year. This could also be expressed with the following formula. This formula is solved for the Net Present Value (NPV) = 0 by calculating the required electricity price under the given set of financing assumptions.

From the financial model, the revenues per unit of electricity required to reach the target equity IRR of 15 percent are derived. The revenues resulting from this calculation equal the LCOE (in nominal terms, i.e. before inflation adjustment, which is calculated in a separate step).

Figure 3: LCOE calculation

$$NPV = \sum_{t=1}^{n} \frac{(El_t \times P_t - I_t - M_t - F_t - \Delta DSRA)}{(1 + (\frac{D_t}{C_t} \times \overline{r_D} \times (1-\tau) + \frac{E_t}{C_t} \times \overline{r_E}))^t}$$

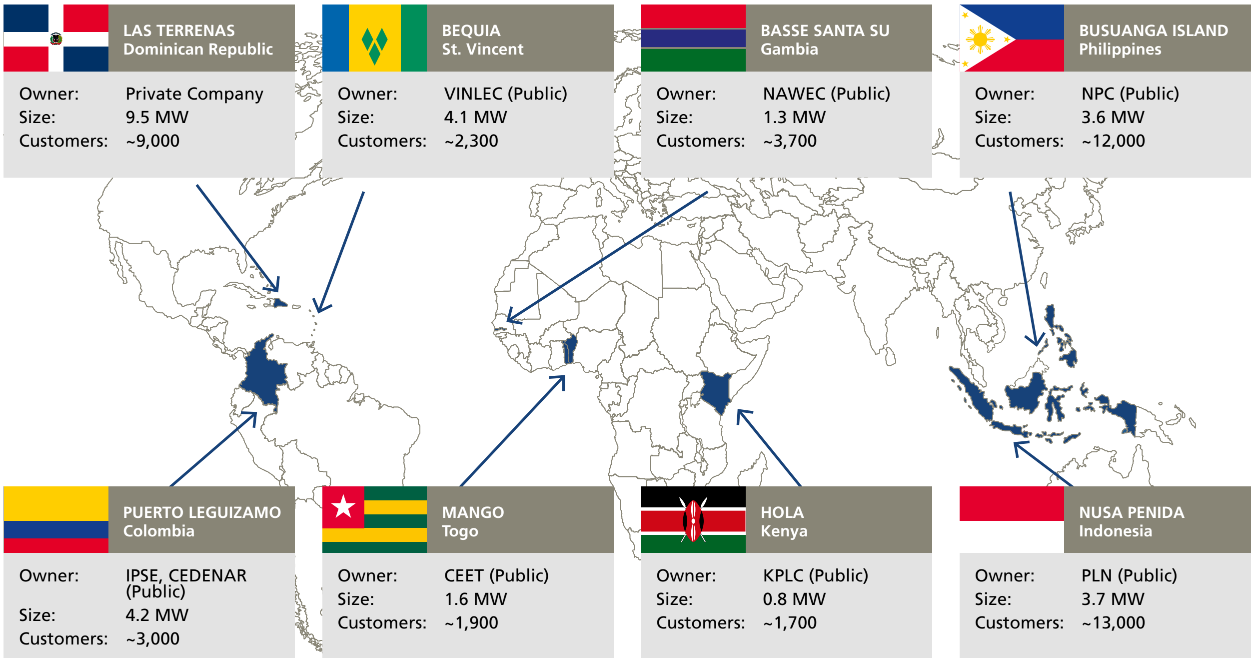
Elt = Electricity sold in kWh in t
Pt = Electricity Price in USD/kWh in t
It = Investment cost in t
Mt = O&M cost in t
Ft = Fuel cost in t
ΔDSRA = Changes in debt service reserve account

Dt = Debt amount in t
Ct = Capital employed in t
rD = Interest rate on debt
Ʈ = Tax rate
Et = equity amount in t
rE = equity return

2. SELECTED SITES

The study analyses seven (initially eight) existing sites from different parts of the world. It thereby considers the heterogeneity and individual complexity of different remote areas. The sites were selected to represent a variety of grid sizes as well as number and type of customers – determinants, which have significant impact on the technical solution and economic viability of the hybrid investment.

Figure 4: Selected sites – Ownership, installed capacity and number of customers



The installed diesel generation capacity ranges from 0.8 MW in Hola to 9.5 MW in Las Terrenas. Number of customers (grid connection points) ranges from 1,700 in Hola to 13,000 in Nusa Penida. The type of customers can be broadly classified into residential (prevailing at most sites), commercial, and public categories, whereas a larger anchor customer plays a particularly important role in Puerto Leguizamo; there are no purely industrial sites included. Last but not least, in order to ensure a certain replication potential, the sites were selected to be representative within their respective country and region.

The following gives a brief introduction to each individual site – including current status, operational environment, as well as economic and financial viability of hybridisation. A detailed comparative analysis of the sites (i.e. power demand patterns, hybridisation potential and benefits, economic and financial viability, sensitivities, growth scenarios, financial indicators) is presented in the subsequent sections.[6] Technical fact sheets for each site can be found in Annex 2.

[6] Further, individual business cases for each site were developed in parallel to this study. The business cases include more detailed information about project stakeholders, location, growth expectations, electricity tariffs, plant operation environment (e.g. organisational structure, regulatory requirements), and the financial viability analysis itself.

The case of Mango, Togo, was initially considered in the analysis. Mango is a town in the northern Savannes region, where a 1.6 MW diesel power plant supplies approx. 1,900 customers (predominantly households). In 2012, the plant generated only 2,550 MWh, averaging to 5-6 hours daily electricity service. Power generation is limited primarily by the availability and affordability of fuel. Hybridisation of the power plant certainly makes sense from an energy supply point-of-view; PV could generate additional electricity, at least during daytime. The actual economic and financial viability assessment, however, was hampered by the availability of real data. In the course of this research, the study team could not gather sufficient information from the ground to draw convincing conclusions, and to plausibly compare this case to others, respectively. Mango is therefore not further followed up in the actual analysis.

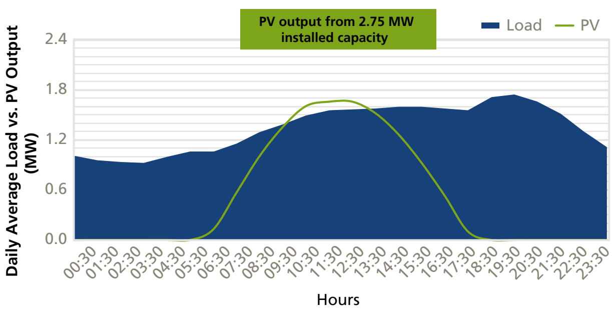
2.1. PUERTO LEGUIZAMO – COLOMBIA

Puerto Leguizamo is a municipality and town in the Department of Putumayo, Colombia. Being located around 100km from the national electricity grid, and not being part of the government's medium-term grid extension plan, it is the only municipality in Putumayo (out of 13) that belongs to the "Non-grid Connected Areas" (ZNI).[7] The city is supplied with electricity from an off-grid diesel power plant. The plant is operated by the Electricity Company of Narino (CEDENAR); the Public Utility Company of Leguizamo (EMPULEG) is responsible for distribution and sales (both public entities).

Puerto Leguizamo has about 31,000 inhabitants, one third of which live in the town. Among the 3,000 electricity customers are mainly households (93 percent of customers; 35 percent of demand), as well as some 200 businesses (hotels, restaurants, banks, shops) and public facilities (e.g. hospital, airport; 7 percent of customers; 22 percent of demand). The bulk of electricity, though, is consumed by the Navy as single anchor client (42 percent of demand).

There are five diesel generators with a maximum possible capacity of 4.2 MW.[8] In 2013, average demand was 1.4 MW, with a peak of 2.2 MW in the evenings. There were frequent power cuts and shortages from technical failures that interrupt the 24-hour service, though, ranging from a few minutes to several hours. The plant generated more than 11,000 MWh per year – consuming around 3.5 million litres of diesel fuel. The average diesel price (including transportation) was 1.05 USD/litre.

Figure 5: Daily average load vs. possible PV output (Puerto Leguizamo)



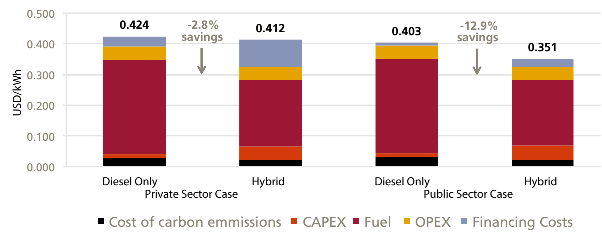
The HOMER simulation has shown that hybridising the diesel plant with 2.75 MW solar PV can lead to diesel savings of more than 1.1 million litres per year, which translates into cost savings of nearly USD 1.2 million at the diesel costs prevailing in 2013. In this case, diesel generators can be turned off for 4 hours per day, from around 9:30 to 13:30. Over the course of an average 24-hour day, the installed solar cells would generate about 31 percent of the site's electricity requirements.

Since the existing diesel assets are owned and operated by the public sector (there is no private sector involvement at all), hybridisation in the existing structure and involving further government funds appears possible. At financing costs of 5 percent, and including carbon costs, hybridisation reduces the LCOE from 40.3 to 35.1 USDc/kWh at 'EIA reference' diesel prices, representing a decrease of generation costs of 13 percent. At 'EIA high' diesel prices, the LCOE would rise to 54.1 USDc/kWh for the fully-diesel grid, but just to 44.9 USDc/kWh for the hybrid grid, boosting expected cost savings to 17 percent.

[7] The ZNI account for 52% of the Colombian territory and are defined as municipalities, towns and single countryside houses which are not connected to the National Electricity Grid of Colombia (SIN).

[8] The actual installed capacity is 5.2 MW, but not all generators can be run simultaneously.

Figure 6: LCOE breakdown for private vs. public financing costs (Puerto Leguizamo)



For the alternative structure involving private project finance, the initial WACC was estimated at 8.7 percent. At reference diesel prices, hybridisation still reduces the LCOE from 42.4 to 41.2 USDc/kWh including the costs of carbon emissions, or from 39.7 to 39.3 USDc/kWh without the costs of carbon emissions – implying a modest cost savings of 1 to 3 percent. Under a scenario of EIA high diesel prices, the LCOE, including the costs of carbon emissions, would rise to 56.2 USDc/kWh for the diesel-only grid, but just to 50.6 USDc/kWh for the hybrid grid, so the cost savings would increase to 10 percent; the savings would also rise to 10 percent excluding carbon costs.

Among the selected sites, Puerto Leguizamo is the only grid with a large anchor client. On the one hand, anchor clients per se are characterised by stable energy offtake on a relatively high level; on the other hand, there is a risk that a large share of energy offtake breaks away if the client gets lots. The latter, however, seems unlikely. The Navy plans an expansion of its facilities by four new blocks, and there are no signs that it plans to provide electricity by other or own sources.

2.2. LAS TERRENAS – DOMINICAN REPUBLIC

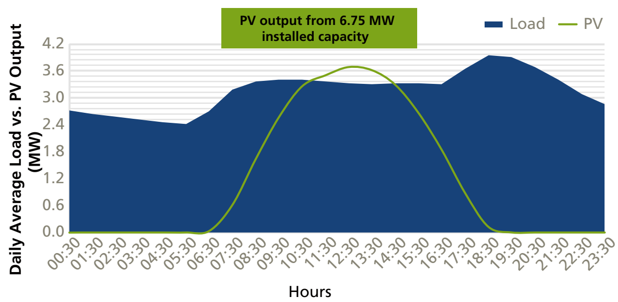
Las Terrenas is a municipality and town in Samana Province, Dominican Republic. It is one of only ten locations outside the National Electric Interconnected Grid System (SENI).[9] The off-grid power plant is operated by a private company; another private company is responsible for distribution and sales.

Las Terrenas has about 19,000 inhabitants. The local power supply system also connects El Limon, where another 7,000 people live. The region is one of the most famous tourist destinations of the Dominican Republic. Among the approx. 9,000 electricity customers are mostly low-income residents (62 percent of customers; 23 percent of demand), but also high-income residents, including holiday homes (24 percent of customers; 28 percent of demand), as well as resorts, hotels, hospitals, banks, and other businesses (14 percent of customers; 48 percent of demand).

Nine power generators are permanently connected.[10] Eight operate regularly and simultaneously. Besides four diesel generators, there are three dual fuel generators (2/3 diesel, 1/3 natural gas), and one run on heavy fuel oil (HFO). Another mere natural gas generator is only rarely used due to its low efficiency and relatively high operating cost. The installed capacity is considered as the maximum possible capacity of the nine generators (9.5 MW).

In 2013, the peak demand reached about 5.8 MW (in the evenings); average demand was 3.2 MW (24/7 service, significant daytime load for commercial activities). The total generated electricity was more than 27,000 MWh, consuming around 7.5 million litres diesel, 9,800 litres HFO, and 46,216 MMBTU natural gas. The average local diesel price was 0.89 USD/litre.

Figure 7: Daily average load vs. possible PV output (Las Terrenas)



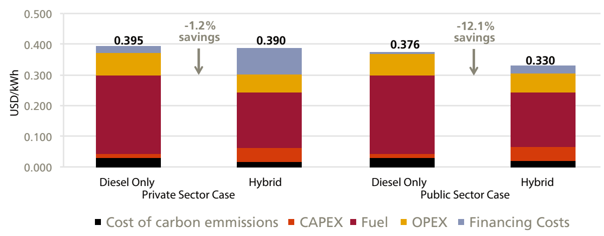
9 The Dominican Republic is mainly served by the SENI, which provides access to electricity to 96% of the population, and reaches all provinces in the country.

10 There are another five generators as back-up power. These are, if ever, only connected though during high-peak demand periods such as holiday season in July and August. Their share is less than 0.5% of the total annual electricity generation. Hence they were not considered in this analysis.

The HOMER simulation has shown that, with a hybrid solution, installing 6.75 MW PV, diesel generators can be turned off for 3.5 hours per day. Per year this saves more than 2.5 million litres of fuel – or costs of USD 2.2 million, given 2013 diesel prices.[11] Over the course of an average 24-hour day, PV would generate about 31 percent of Las Terrenas' electricity needs.

Hybridisation reduces average electricity generation costs from 39.5 to 39.0 USDc/kWh (at reference diesel price developments; including costs of carbon emissions) if the project has to be financed on commercial terms (assumed 8.6% initial WACC). The LCOE raises from 36.3 to 37.1 USDc/kWh if one does not consider carbon costs. Assuming EIA high oil price developments, the diesel LCOE including carbon costs would come in at 50.7 USDc/kWh, whereas hybrid electricity could be produced at 46.8 USDc/kWh (8 percent cost savings); savings without carbon costs would still be 5 percent.

Figure 8: LCOE breakdown for private vs. public financing costs (Las Terrenas)



Savings would be substantially greater at 5 percent WACC (public sector finance). In this case, including carbon and under medium diesel price developments, hybridisation reduces the LCOE from 37.6 to 33.0 cents per kWh, for cost savings of 12 percent. The cost advantage even increases to 16 percent (from 49.2 down to 41.2 USDc/kWh) if the high oil price scenario occurs – albeit from a much higher base.

End-user electricity tariffs in Las Terrenas are the highest among the investigated sites. One reason is that there are no government subsidies for electricity generation or the sales tariff in off-grid areas. In 2013, the grid lost one of its major hotel clients that started generating its own electricity, and residents have been increasingly concerned about high tariffs. There is an apparent need for lowering electricity generation costs – and tariffs – which can be achieved through hybridisation. The political framework can play a crucial role the feasibility of a hybridisation project.

2.3. BEQUIA – ST. VINCENT & THE GRENADINES

St. Vincent and the Grenadines (SVG) is an island state in the Caribbean, comprised of the main island St. Vincent and several Grenadine islands. The largest Grenadine island is Bequia, a popular tourist destination with approx. 4,300 inhabitants.[12] Bequia is supplied with electricity from an off-grid diesel power plant operated by state-owned VINLEC (responsible for generation, distribution and sales of electricity).

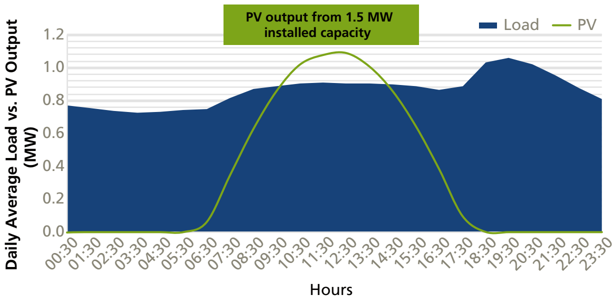
The island's electrification rate is almost 100 percent. VINLEC has approx. 2,300 customers, whereas electricity demand is almost equally distributed between 87 percent domestic and 13 percent commercial customers. There is no industrial client; two existing public street light systems only have neglectable demand.

There are six diesel generators with a total of 4.1 MW installed capacity. Demand in 2013 averaged 0.9 MW, reaching a peak of 1.5 MW in the evenings. Total generation exceeded 7,500 MWh,[13] consuming about 2.14 million litres of diesel at an average cost of 0.90 USD per litre.

Hybridising the plant with 1.5 MW PV could bring diesel savings of more than 700,000 litres per year; diesel generators could be turned off for around 5 hours per day, translating into a cost reduction of over USD 0.6 million per annum, assuming diesel costs remain at the 2013 level. On average, about 34 percent of electricity could be generated by solar power.

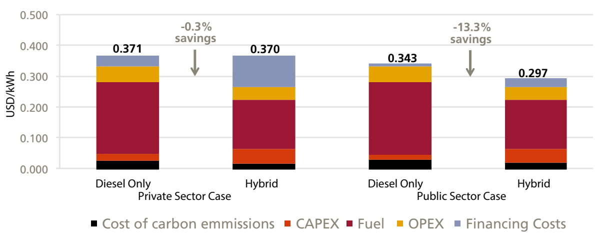
[11] For this analysis it was assumed that all generators run exclusively with diesel fuel. The cost variation between combined-fuel generation costs and diesel-only generation costs is marginal since the share of other fuels in electricity generation was only less than 10 percent in 2012-13.
[12] The estimated population of SVG is approx. 110,000 people, with almost 100,000 living on the main island St. Vincent.
[13] Another 175 kWp solar PV panels, which are connected with the Bequia grid, add to the yearly demand, but only have a negligible energy share in the grid (less than 1%). These small-scale PVs are privately owned, scatteredly placed and mainly used for self-consumption by the owners with the provision of feeding excess electricity, if any, into the grid.

Figure 9: Daily average load vs. possible PV output (Bequia)



Assuming a public sector 5 percent WACC, savings of generation costs would be substantially higher. In this case, hybridisation reduces the LCOE from 34.3 to 29.7 USDc/kWh at reference diesel prices (cost savings of 13 percent), and from 44.9 USDc/kWh to 36.9 USDc/kWh (18 percent) if diesel price increase according to the EIA high scenario.

Figure 10: LCOE breakdown for private vs. public financing costs (Las Terrenas)



The LCOE does not decrease significantly under private sector finance (8.4 percent initial WACC) and reference diesel price assumptions, where hybridisation reduces generation costs from 37.1 to 37.0 USDc/kWh (including carbon costs). In a high diesel price case, though, the LCOE including carbon costs would rise to 47.5 USDc/kWh for the diesel grid but just to 44.0 USDc/kWh for a hybrid grid, for cost savings of 7 percent (savings without carbon costs would still be 5 percent).

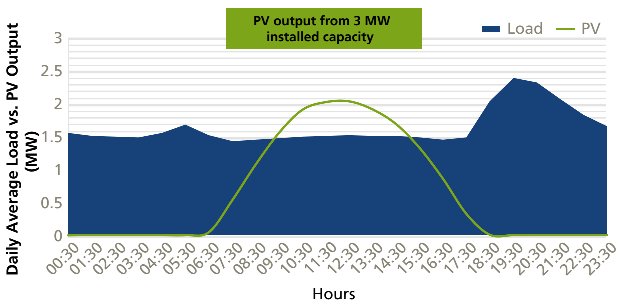
2.4. NUSA PENIDA – INDONESIA

Nusa Penida is a small island southeast of Bali, Indonesia. The nearest connection to the national grid (on Bali) is separated by sea. The island's off-grid diesel power plant is operated by PLN, a state-owned corporation responsible for generation, distribution and sales of electricity.

Nusa Penida has an estimated population of 48,000 inhabitants. The vast majority of the estimated 13,000 electricity customers are households; there are only a handful of shops, small resorts, government offices, a gas station and a local bank, adding relatively little demand. There is no unmet demand from the connected customers. However, approx. 10 percent of the population do not yet have access to electricity; around 1,500 unelectrified households are planned to be connected within the next years. In addition, increasing tourism on Nusa Penida is expected to add demand.

The total installed capacity of nine diesel generators is 3.65 MW. There are also some existing wind turbines (800kW) and PV panels (80kW) – but none are in working condition. In 2012, the peak demand reached about 2.9 MW (in the evenings); average demand was about 1.7 MW, and total generation exceeded 14,000 MWh, consuming about 4.1 million litres of diesel. The average diesel price, including transportation to the site, was relatively high at 1.16 USD per litre.

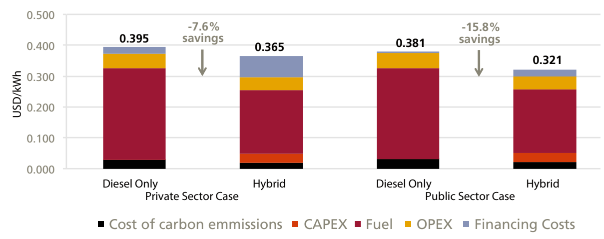
Figure 11: Daily average load vs. possible PV output (Nusa Penida)



Hybridising the diesel plant with 3 MW of PV could allow the diesel generators to be completely shut off for roughly 6 hours per day. Diesel savings of 1.2 million litres and cost savings of USD 1.4 million (given 2012 prices) could be achieved per year. Over the course of an average 24-hour day, the installed PV capacity would generate about 32 percent of the island's electricity requirements.

Given Indonesia's good access to donor funds, a 5 percent WACC case (public sector finance) seems likely. Including carbon costs, hybridisation reduces the LCOE from 38.1 to 32.1 cents per kWh at reference diesel prices, for cost savings of 16 percent. At higher diesel prices, the LCOE would rise to 51.5 USDc/kWh for the diesel grid but just 41.5 USDc/kWh for a hybrid grid, boosting cost savings to 19 percent or 10 USDc/kWh produced, although from a higher level.

Figure 12: LCOE breakdown for private vs. public financing costs (Nusa Penida)



The private sector initial WACC was assumed to be 8.7 percent. At reference diesel prices, hybridisation reduces the LCOE from 39.5 to 36.5 USDc/kWh including the costs of carbon emissions or from 36.5 to 34.6 USDc/kWh without the costs of carbon emissions, implying a cost savings of 5 to 8 percent. Under a scenario of higher diesel prices, the LCOE including carbon costs would rise to 52.3 USDc/kWh for the diesel-only grid but just 45.6 USDc/kWh for the hybrid grid, so cost savings would rise to 13 percent; savings without carbon costs would be 11 percent.

Since August 2013, there is an interconnection through submarine power cables from Bali to Nusa Penida and two other adjacent islands, Nusa Lembongan and Nusa Ceningan. The cables were initially supposed to supply a total of 20 MW to the three islands (breakdown to each island unknown). However, due to strong undercurrents of the deep sea, the cable system broke during installation, disconnecting the island from the national grid. PLN considers the replacement of the cable system and assesses this option as third option. Given private sector interest in financing larger PV installations on Nusa Penida, the island could actually become an exporter of electricity in a sea cable scenario.

The weak maintenance and resulting non-performance of the existing RE installations on Nusa Penida is a good example for minor RE additions not receiving enough attention from management. While those installations can help to build an early track record, a lacking importance of the assets compared to the diesel generators, and consequently, lacking focus of the management teams on proper maintenance of the RE assets was recognised. In the suggested hybrid scenario, the RE component would be more dominant.

2.5. BUSUANGA – PHILIPPINES

Busuanga is the second largest island in the Province of Palawan, Philippines. It is located around 400 km from the Palawan island grid. The isolated diesel power plant is owned and operated by the state-owned National Power Corporation (NPC or NAPOCOR);[14] the private utility company Busuanga Island Electric Cooperative (BISELCO) is responsible for distribution and sales.

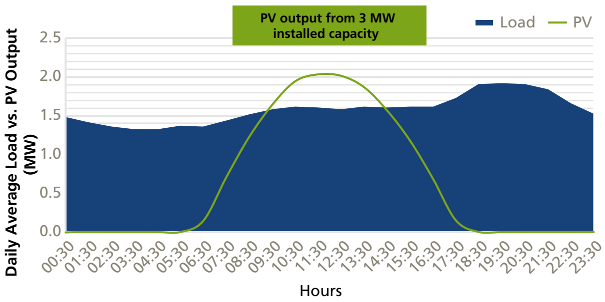
The power plant serves the municipalities of Busuanga and Coron, which together have around 66,000 inhabitants. Among the 12,000 electricity customers are mainly households (89 percent of customers; 30 percent of demand), businesses (8 percent of customers; 45 percent of demand), public facilities including street lights (2 percent of customers; 14 percent of demand), and some industry (0.04 percent of customers; 11 percent of demand).

The seven diesel generators have a maximum possible capacity of 3.58 MW.[15] Demand in 2013 averaged 1.6 MW, with a peak of 2.6 MW in the evenings. The plant generated more than 13,800 MWh over the course of the year, consuming around 5.8 million litres of diesel fuel at an average price of 0.96 USD per litre.

[14] A new concession with private operator CIPC (the Calamian Islands Power Corporation) is in progress.

[15] CIPC is expected to expand the net-dependable generation capacity to 7.7 MW by purchasing new diesel generators. Nevertheless, this hybridisation analysis was done for the existing gen-sets, not least due to the availability of real historic data for load, customer demand, and fuel consumption.

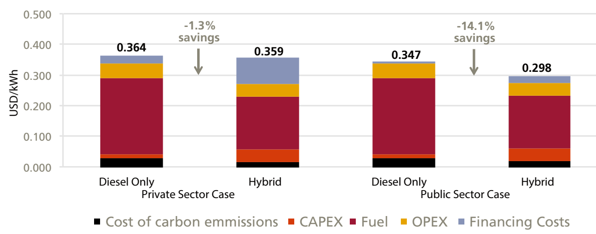
Figure 13: Daily average load vs. possible PV output (Busuanga)



Hybridising the diesel plant with 3 MW of solar PV could reduce the diesel consumption by more than 1.2 million litres per year (nearly 1.2 million cost savings at current fuel prices). Diesel generators could be turned off from around 9:30 to 14:30. On an average day, about 33 percent of the island's electricity requirements could be generated by PV.

Cost savings would be significant if public sector financing costs can be applied. Hybridisation reduces the LCOE from 34.7 to 29.8 USDc/kWh (14 percent) at 5 percent WACC, reference diesel prices, and considering carbon emissions. At EIA high diesel prices, the LCOE would rise to 46.0 USDc/kWh for the fully diesel grid but to just 37.6 USDc/kWh for the hybrid grid, boosting expected cost savings to 18 percent.

Figure 14: LCOE breakdown for private vs. public financing costs (Busuanga)



For an alternative case, the private sector initial WACC was assumed to be relatively high at 9.4 percent. In this case, given reference diesel price developments and including carbon costs, average electricity generation costs would reduce from 36.4 to 35.9 USDc/kWh, for a slight cost decline of 1 percent; the LCOE would rise from 33.5 to 34.1 USDc/kWh without consideration of carbon costs. If one assumes high oil price developments, hybridisation results in a more significant cost advantage of 9 percent; the LCOE rises to 47.3 USDc/kWh for the diesel grid, but just to 42.8 USDc/kWh for the hybrid.

A new concession with private operator CIPC (the Calamian Islands Power Corporation) is in progress. It is understood that they are in the process of installation new generation assets. The existing diesel generators owned by NPC will be relocated to another island. The new PPA with CIPC is based the assumption that the electricity will be produced by diesel generators. CIPC is compensated for their financing costs. Under this PPA, CIPC would not have the option to replace diesel with PV electricity but would require an amendment to the PPA. While it appears unlikely that CIPC will change their plans regarding generation assets and the technical layout of the plant, there seems potential for hybridisation of comparable sites in the Philippines. Financial viability would require a restructuring of existing PPAs and/or a negotiation of an appropriate new PPA in case of the issuance of new concessions to allow the concessionaires to combine PV and diesel.

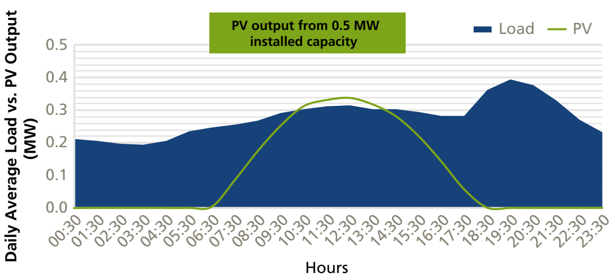
2.6. HOLA – KENYA

Hola is the capitol town of the Tana River County, Kenya. Although the closest connection point is only some 50km away, there is no interconnection plan to the national electricity grid. Instead, the Hola power plant is one of seven off-grid stations in Kenya that has been hybridised already (very little, though) – and that is planned for further expansion of diesel and RE-generation capacity. The power station is operated and managed by Kenya Power and Lighting Company (KPLC), a state-owned company responsible for transmission, distribution and retail supply of electrical energy to end users.

Hola has an estimated population of 7,000. Its electricity grid also connects through transmission lines two nearby towns (Masalani and Bura, with a combined population of 45,000) and an agricultural irrigation scheme. The latter requires around 10 percent of the total generated electricity, and operates day and night. Yet there are no noteworthy commercial or industrial facilities connected. A nearby juice factory operates its own diesel generator. So far the grid only supplies some 1,700 customers (mostly households) due to its limited generation capacity, amongst other things. Most of the customers pay the bottom-of-the-pyramid electricity tariff which is cross-subsidised by other ratepayers. As a consequence, the Hola grid itself is heavily loss-making and the financial understanding and awareness of its managers is very limited.

The existing diesel capacity of 800 kW is provided by two 400 kW generators. In 2012, there were 60kW PV added, providing around 4 percent to the electricity mix. In 2013, average demand was 300kW (peak of 600 kW) – however, the current load profile does not necessarily reflect the potential customer demand in and around Hola. The installation of another 500kV diesel generator is already in progress; Government and KPLC are planning to upgrade the PV capacity, i.e. to maximise the PV penetration.

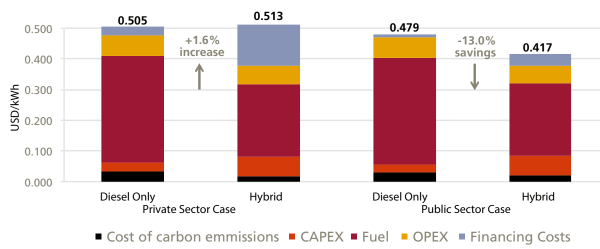
Figure 15: Daily average load vs. possible PV output (Hola)



Total electricity generation in 2013 was about 2,460 MWh, consuming some 700,000 litres of diesel at an average price of 1.12 USD per litre. Hybridisation with another 500 kW PV system could lead to diesel savings of around 300,000 litres per year; HOMER simulates that diesel generators could be turned off for as long as 5 hours per day. This would mean cost savings of over USD 0.3 million per year at the diesel costs prevailing in 2013. During an average day, solar cells would generate about 34 percent of Hola's electricity.

Savings would be substantial if public sector financing costs can be applied. At 5 percent WACC, including carbon costs, hybridisation lowers the LCOE from 47.9 to 41.7 USDc/kWh at EIA reference diesel prices, and from 63.8 to 52.4 USDc/kWh at EIA high diesel prices. Depending on fuel price developments, cost savings of 13 to 18 percent can be achieved.

Figure 16: LCOE breakdown for private vs. public financing costs (Hola)



The private sector WACC was assumed to be 8.8 percent initially. At reference diesel prices, hybridisation then increases the LCOE from 50.5 to 51.3 USDc/kWh including the costs of carbon emissions, or from 47.2 to 49.5 USDc/kWh without carbon costs, implying a cost increase of 2 to 5 percent. Under a scenario of higher diesel prices, however, the LCOE including carbon costs would rise to 65.8 USDc/kWh for the diesel-only grid but just 61.6 USDc/kWh for a hybrid grid, bringing cost savings to 6 percent; without carbon costs, savings would be 4 percent.

Beyond Hola, there is a national strategy for hybridisation, including a pipeline of 24 existing and under-construction mini-grids, as well as 44 greenfield sites. Financing from international donors can most likely be secured. For instance, the French Development Agency AFD has committed EUR 30 million to fund the retrofitting of existing mini-grids, including expansion of existing hybrids.

2.7. BASSE SANTA SU – GAMBIA

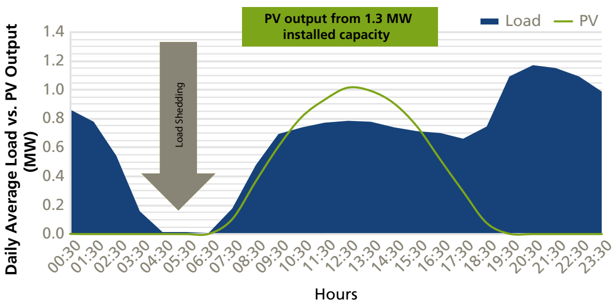
Basse Santa Su is located 375km east of Banjul, in the Upper River Region of Gambia – the least developed administrative area of the country. The Basse region has the second-largest of the six regional diesel-powered mini-grids in the country. The power plant is operated by the National Water and Electricity Company (NAWEC), a state-owned company responsible for generation, transmission and distribution of electricity.

Basse is the major trading centre for the upper reaches of the Gambia River. The region has an estimated population of 230,000.[16] The 100 km transmission network connects the communities of Basse, Fatoto, Sabi, and Koima. The number of electricity customers, though, is limited to 3,660. Amongst them are mainly households and a few (larger) commercial customers like bank, health centre, ice plant, bakery and cement factory – all of which have additional own generation capacity. The UK's Medical Research Council has a research station in Basse which is not connected to the regional grid since power fluctuations would not allow their sensitive equipment to operate reliably. There is no anchor load or large industry – largely because of the limited power supply.

There are 6 diesel generators with a total capacity of 5.3 MW, but 4 are not operational, bringing dependable capacity down to 1.3 MW. In 2012, potential demand was estimated at around 6 MW, requiring significant load shedding at nights and in the afternoons.[17] Due to high costs and limited fuel,[18] the plant normally operates for only 9 to 12 hours a day.

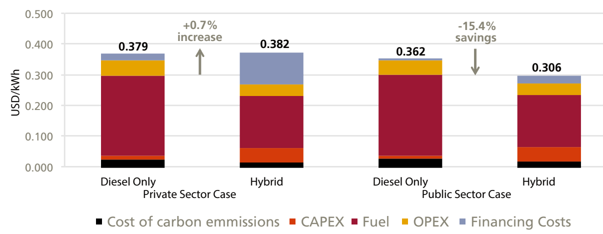
In 2012, total electricity generation was around 4,800 MWh, consuming about 1.3 million litres of diesel fuel at a cost of 1.10 USD per litre. The HOMER analysis shows that hybridising the plant with 1.3 MW of PV could allow the diesel generators to be turned off for around 6 hours per day. Assuming that afternoon load shedding could be avoided, there could be fuel savings of more than 500,000 litres per year, with annual cost savings of well over USD 0.5 million. Solar cells, on average, would produce about 37 percent of Basse's electricity requirements.

Figure 17: Daily average load vs. possible PV output (Basse Santa Su)



The absence of reliable power is restricting economic growth and employment in both manufacturing and services. Since a hybridisation project, through extended access to electricity, would come along with significant social benefits, International Financial Institutions might possibly provide concessional financing. If so, at a 5 percent WACC, and considering carbon costs, hybridisation reduces the LCOE from 36.2 to 30.6 USDc/kWh at reference diesel prices – for cost savings of 15 percent or 5.6 USDc/kWh produced. At higher diesel prices, the LCOE would rise to 48.3 USDc/kWh for the fully-diesel grid, but just to 38.5 USDc/kWh for a hybrid grid, boosting expected cost savings to 20 percent or 9.8 USDc/kWh.

Figure 18: LCOE breakdown for private vs. public financing costs (Basse Santa Su)



16 It is estimated that the population has grown from 183,000 in 2003 (last census) to 230,000 in 2014.

17 The afternoon load shedding is not shown in figure 17 since, for this analysis, it was assumed that the (certainly existing) customer demand at this time of the day can be mostly met by PV. Further, in the mornings, generators are turned off completely and much quicker than visible from the load curve. The seemingly long periods and remaining load are owed to the fact that the shut-down times can vary, and that the curve presents a yearly average.

18 Basse is the furthest grid from the coast so also has the highest transportation costs for fuel delivery in Gambia.

If the project had to be financed on private sector terms (assumed 9.6 percent initial WACC), at reference diesel prices, hybridisation raises the LCOE from 37.9 to 38.2 USDc/kWh (including costs of carbon) and from 35.1 to 36.5 USDc/kWh (without carbon costs), respectively – raising costs by 1 to 4 percent. Under a scenario of higher diesel prices, the picture looks different as the LCOE including carbon costs would raise to 49.5 USDc/kWh for the diesel grid but just to 44.9 USDc/kWh for a hybrid grid (9 percent cost savings; without carbon costs, the savings would still be 7 percent).

3. HYBRIDISATION: POTENTIAL AND BENEFITS

The potential to replace parts of the diesel with PV is mainly determined by solar irradiance, demand (and how these two overlap), design and costs of the hybrid system, and cost savings that result from reduced diesel consumption. Diesel savings is probably the most tangible and substantial argument for utilities that consider a hybrid investment. High diesel costs often make the operation of a power plant uneconomic, and jeopardise the security of electricity supply.

This section presents for each of the selected sites:

- The current electricity demand and supply, showing that the actual customer demand is not always met by the power generated;
- The solar irradiance and seasonal climate conditions as key determinants for the expected output and sizing of a PV-hybrid system;
- The PV generation potential and PV/diesel electricity mix based on the HOMER simulation, as well as possible diesel savings and number of hours when there is no diesel power required.

3.1. STATUS QUO: CURRENT DEMAND AND SUPPLY

Figure 19 presents the current load profiles (i.e. the variation of power demand over one day, yearly averages) of the existing diesel generators at the selected sites.[19] The average demand over a longer term is one of the most important input factors for the HOMER tool to design an appropriate hybrid system, i.e. to determine the size of the PV component. It goes without saying that, in general, the actual load can differ:

- during the day, e.g. fluctuating demand for business activities, cooling, and other inconstant energy needs;
- for individual days, e.g. less economic activities on the weekend; fluctuating household demand due to travel (work, family visits) and other inconstant energy needs;
- between months, due to changing temperatures or tourist season;
- according to load management, e.g. load shedding at certain days or times of the day to save fuel costs;
- due to technical problems, power cuts, and grid instability.

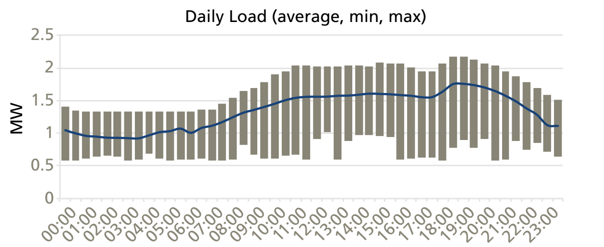
There are two main drivers for the shape of the load curves: a) the level of economic activity and, consequently, the mix of customers (residential vs. commercial, industrial, possible anchor customers); b) the (non-) availability and affordability of diesel fuel that can lead to power shortages and load shedding. There is not a standard load pattern for residential, commercial or industrial customers. However, typically residential load patterns reach their peak at the evening hours and have a relatively low load factor (ratio between average and peak power demand) throughout the day. On the other hand, commercial loads tend to be higher during daytime (08:00 to 18:00). Typical industrial loads tend to run continuously (depending on the local working time), have a higher average demand and, consequently, a higher load factor. An industrial load pattern follows the economic activity, and shows a peak and relatively stable demand during the day.

[19] Load profiles were available for the following periods: Nusa Penida (January – December 2012), Hola (January – November 2013), Basse Santa Su (January – December 2012), Puerto Leguizamo (April 2011 – April 2014), Las Terrenas (January 2011 – December 2013), Busuanga (January – December 2013), Bequia (January 2011 – December 2013). The analysis of average loads was done based on output data of the diesel generation assets. Only for selected sites was it possible to cross-check the output data with actually billed electricity. Assuming some technical losses as well as overproduction, the actual LCOE per kWh supplied would come in at a higher level. This would, however, not distort this relative analysis. In the following it is assumed that the output is equal to the demand.

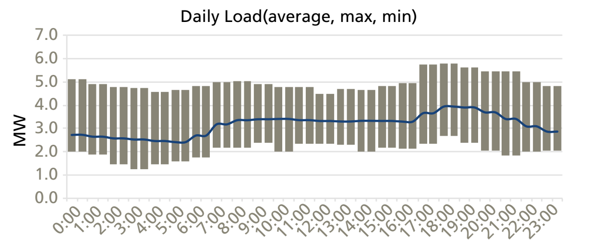
The load profiles for the selected sites vary in terms of demand (average, min, max), fluctuation, and shape. The Las Terrenas power station, for instance, has an average demand of 2.9 MW, compared to 0.3 MW in Hola. However, each site shows basic characteristics of a residential load pattern. Peak demand occurs in the early evening hours between 18:00 to 20:00, which means during the very low irradiance (or no sun) hours.

Figure 19: Load profiles (daily average, min, max)

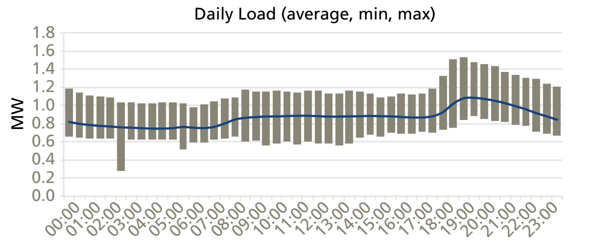
PUERTO LEGUIZAMO – Colombia



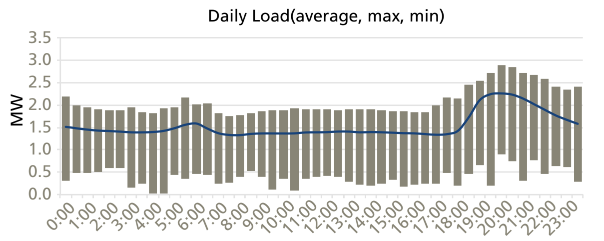
LAS TERRENAS – Dominican Republic



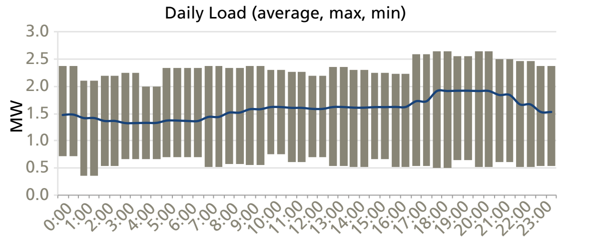
BEQUIA – St. Vincent and the Grenadines



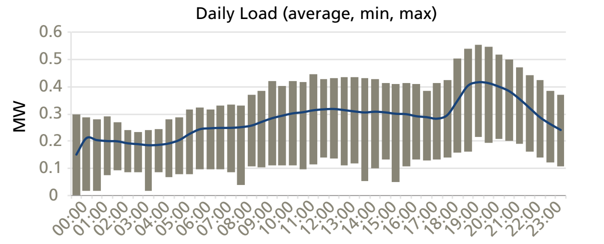
NUSA PENIDA – Indonesia



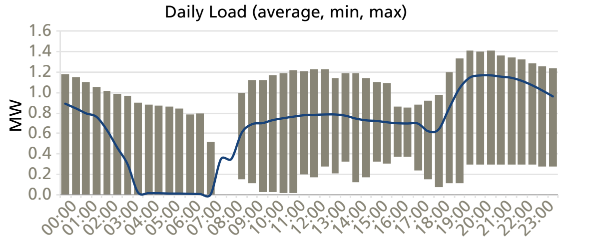
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia



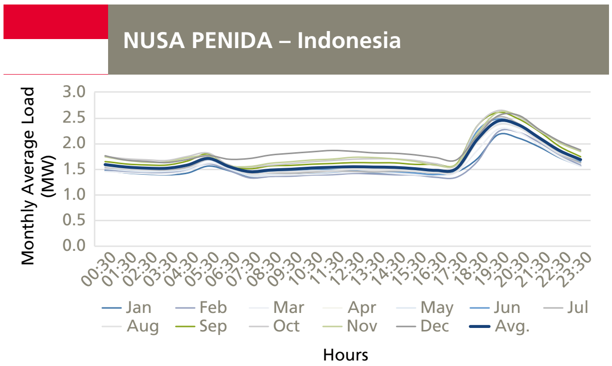
Despite this common (residential) trend, some sites also have noteworthy demand from other customers. In Puerto Leguizamo, a significant share of electricity is consumed from the commercial and public sectors (22 percent) as well as the Navy (42 percent). Compared to the other sites, there is relatively high demand during daytime (1.53 MW in the afternoon, compared to 1.67 MW in the evening). The load profiles for Las Terrenas and Bequia, both famous tourist destinations, also show relatively high demand in the morning and afternoon – compared to Nusa Penida and Hola, where basically all demand comes from private households, and where the evening peak is much more distinct.

In Basse Santa Su, the limited availability and affordability of fuel requires significant load shedding. The plant normally operates for only 9 to 12 hours a day; diesel generators are shut down for several hours in the early mornings and late afternoons.[20] The afternoon load shedding is not shown in the curve though since, for this analysis, it was assumed that the (certainly existing) customer demand at this time of the day can be met by PV.[21] Furthermore, the actual demand (average and peak) is assumed to be much higher than shown in the graph; it is suppressed though due to the limited dependable generation capacity of 1.3 MW.

The pattern of the load curves varies very little between days and months. In other words, the shape of the curves over a 24-hour interval usually looks very similar. What differs between months though is the total demand (at all sites). For example, the load profile of Nusa Penida (figure 20) shows the monthly variation of total demand, while the pattern remains unchanged.

It is difficult to determine the reasons and influencing factors behind this monthly variation. It can be assumed that it is mostly load management on the part of the utility (e.g. availability and affordability of diesel fuel), power failures, and fluctuating household demand that – more or less randomly – determine the load. Household demand does not necessarily fluctuate according to seasonality. It can be more accidental or sporadic instances that determine the demand – like temporarily broken household appliances or travel.

Figure 20: Daily average load variation per month



On the contrary, more predictable factors like seasonality do not seem to play a significant role. Looking at Nusa Penida, there is hardly any tourism (except few guest houses), and temperatures do not change enough throughout the year to argue that people need different levels of heating or cooling. Solar radiation differs greatly between November and December. The power production in these two months was almost equal though.

In any case, most people at the target sites do not have heating or air conditioning. The range of household appliances is rather limited – and so is the load per household. In Nusa Penida, most households pay the lowest electricity tariff, which in turn puts a cap of 450W on their power demand. This cap does not appear to be reached by most households who only use some lighting (e.g. 5 x 10 W), a fan (15 W), a small TV (50 W) and maybe a small water pump (50 W).

Load management, i.e. the shift of loads from the evening peak to times with high solar radiation and, consequently, lower generation costs, can be a driver for the economic viability of a hybridisation. During this assessment, however, no obvious loads were found that have significant size and that could be actively managed at a reasonable cost (e.g. water pumping stations with storage).

[20] Generators are turned off completely and much quicker than visible from the load curve. The seemingly long periods and remaining load are owed to the fact that the shut-down times can vary, and that the curve presents a yearly average only.
[21] Hence, contrary to the other sites, the case of Basse Santa Su is not a mere status quo analysis, but goes one step further in order to facilitate the analysis of PV generation potential in section 3.3.

Demand profiles were therefore not adjusted in this analysis (expect for Basse Santa Su where the afternoon load shedding was avoided).

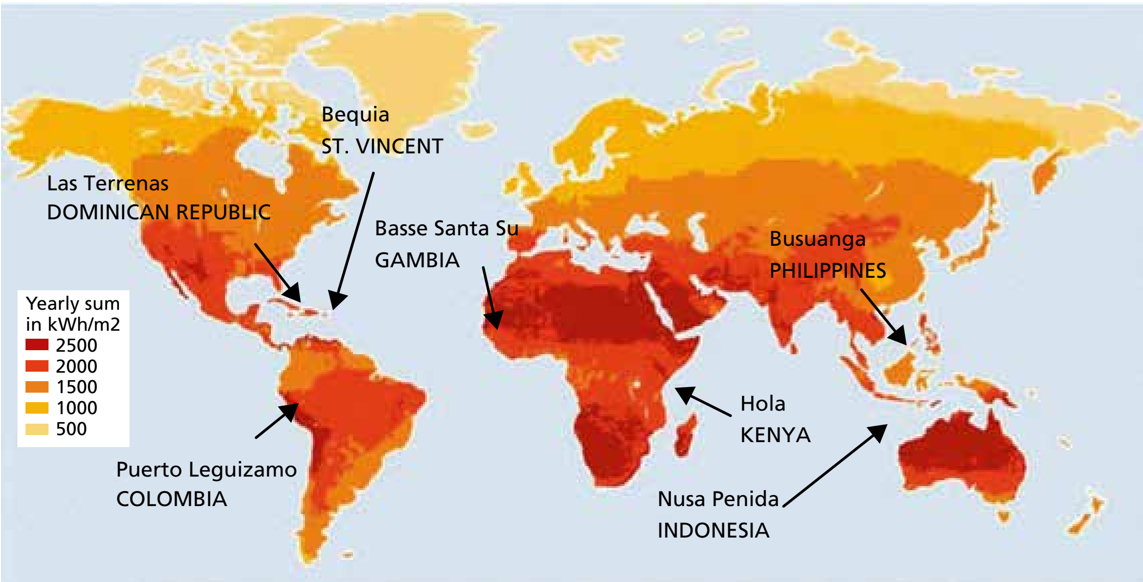
3.2. SOLAR RADIATION AND SEASONALITY

The actual PV generation potential mainly depends on the solar radiation at the location and other atmospheric conditions (e.g. ambient temperature, dust, shading, etc.) throughout the seasons. Solar radiation varies from one place to another and changes throughout the year. Although all target countries are located in the tropical climate zone, there are varieties in terms of precipitation[22] and sun hours.

Figure 21[23] shows the global radiation levels, with the dark red areas highlighting the regions with the highest radiation. Among the selected sites, Bequia receives the highest annual solar radiation (2,102 kWh/m2/year). Puerto Leguizamo, despite receiving the lowest annual solar radiation (1,477 kWh/m2/year), is still favourable for PV power production.

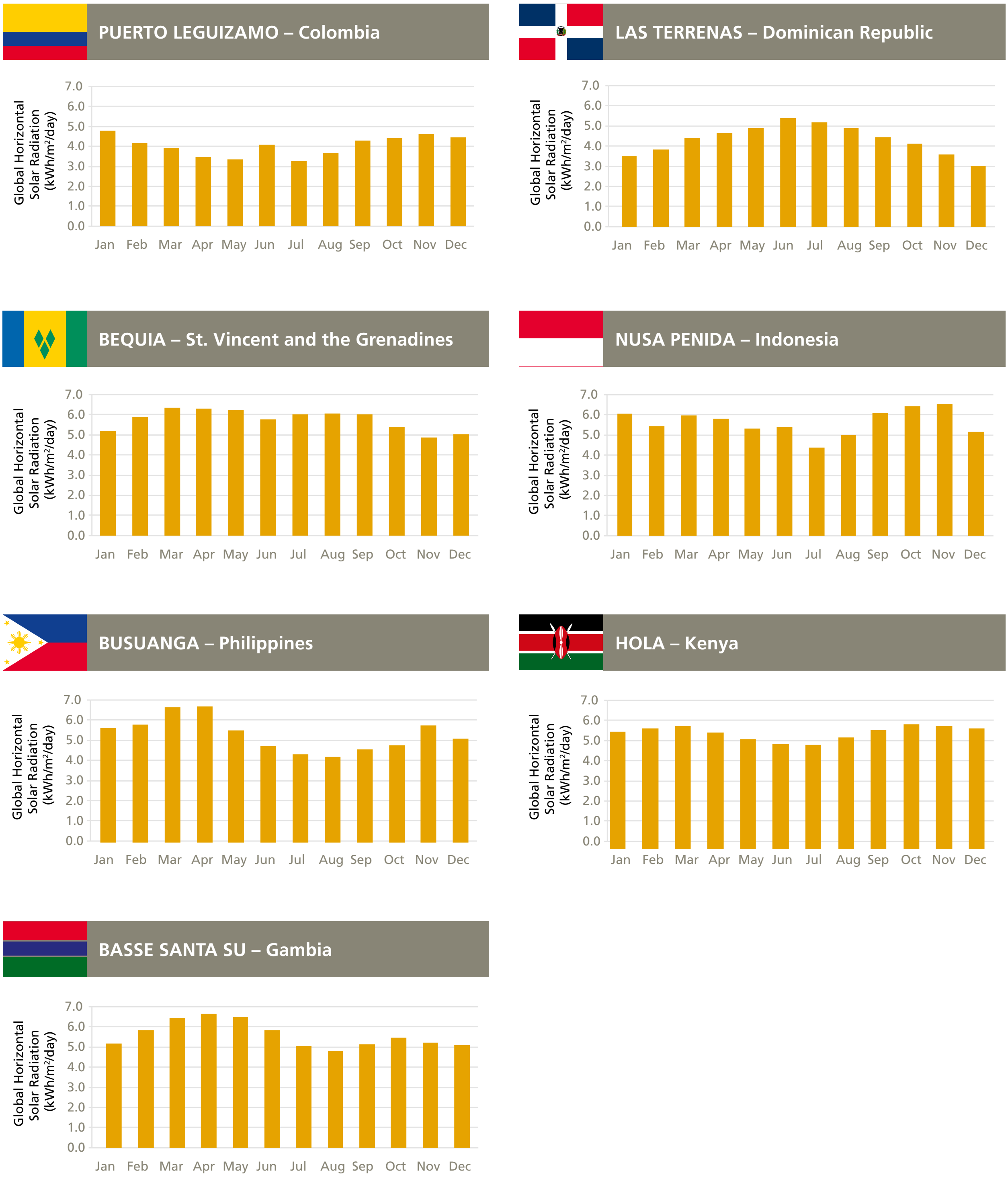
Daily average solar radiation differs between months; the month-wise daily average global horizontal solar radiation (kWh/m2/day) at each site is as follows: Puerto Leguizamo: 3.3 to 4.8 (4.1 average); Las Terrenas: 3.0 to 5.4 (4.3 average); Bequia: 4.9 to 6.3 (5.8 average); Nusa Penida: 4.4 to 6.5 (5.6 average); Busuanga: 4.3 to 6.8 (5.4 average); Hola: 4.9 to 5.9 (5.5 average); Basse Santa Su: 4.8 to 6.6 (5.6 average). The following charts show the seasonal variation of daily average solar radiation[24] at the selected sites for each month of the year. HOMER considers these seasonalities when analysing the most appropriate technical layout.

Figure 21: Global horizontal radiation map



[22] This includes rain, snow, dew, etc., formed by condensation of water vapour in the atmosphere.
[23] Source: http://www.creativhandz.co.za/images/solar_radiation.jpg
[24] Data for solar radiation at the target sites is taken from the HOMER tool, which is based on data from the National Renewable Energy Laboratory (NREL) of the United States Department of Energy. Actual PV electricity production data is available for Hola where a 60 kW system is already installed by the utility. In Hola, the actual PV generation sometimes varies from the expected output due to technical problems with the inverter. A limited focus on maintenance, cleaning of the modules, and monitoring could be additional reasons for the under performance. In Bequia, a total of 175 kW PV systems exist which are all privately owned and distributed all over the island. These PV systems are mainly used for self-consumption, and excess energy is fed into the grid by the user.

Figure 22: Global horizontal radiation at selected sites



3.3. DEMAND AND PV-GENERATION POTENTIAL

The PV generation potential and PV/diesel electricity mix in this section were calculated over a project lifetime of 20 years, without consideration of future demand growth. It is a mere status quo analysis, in line with the actual methodology of the HOMER tool that designs the hybrid system according to the present load profile and other current conditions. Demand growth is discussed in sections 3.4 (assumptions and technical options) and 4.4.6 (financial sensitivity analysis).

The study assesses the viability of a '100 percent peak PV penetration' technology. Depending on power demand, the PV component is sized in a way that the diesel generator can be switched off during peak solar availability. Figure 23 presents the current load profiles[25] of the existing diesel generators (blue area), and the PV generation potential (green curve) at the selected sites (per day, yearly average). Both were modelled with the HOMER tool.

The blue area under the green curve shows the amount of PV electricity that can actually be supplied to meet the given demand (again, all values have to be understood as yearly averages). The PV capacity has to be sufficiently large to ensure that – during peak sun hours – solar power can fully replace diesel power.

Theoretically, there can be excess electricity from PV generation (white area under the green curve) which can neither be utilised nor stored.[26] However, in reality, this excess is usually quite limited. PV modules degrade over time, and there are wiring and electrical losses. Also, the system needs to cater to seasonal fluctuations of PV radiation, leading to a certain amount of excess electricity in times of higher radiation, while in times of lower radiation the excess electricity will be lower. Furthermore, even a presumably 'over-sized' PV solution can be cost-effective; additional diesel savings in the mornings and afternoons (compared to a smaller-size solution) can result in lower average electricity generation costs.

Given a suitable capacity and efficiency of PV installations at the different sites, the demand could be fully met with PV power for around four to six hours per day. In terms of energy, PV power meets approx. 30 to 40 percent of the total energy demand. It has to be noted that the load pattern of the sites are mainly residential types, where peak demand occurs in the evening hours (or at the low/no sun hours), which means diesel generators shall fully operate to meet the evening peak demand. The benefits of the analysed technology are higher the more the blue area and the green curve overlap. All load occurring outside the sunshine hours – or possibly exceeding the amount of electricity produced by the PV system – needs to be covered by diesel generators.[27]

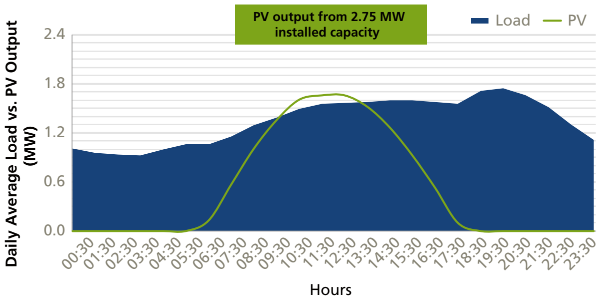
At all selected sites there is a mismatch between maximum resource availability and maximum demand, leading to lower than expected benefits for the hybrid solution. This would be different if industrial sites would have been analysed. Assuming that the major part of the load cannot be shifted (i.e. the evening peak will always be in the evening, since electricity for lighting is required when the sun is not shining), that mismatch represents a major burden for the attractiveness of the technical solution described in this study, since the system is still dominated by the share of the diesel electricity.

In Nusa Penida, for example, a PV system of 3 MW capacity could supply approx. 12.7 MWh per day (blue area under green curve) – enough electricity to shut down the diesel generators from roughly 9:00 to 15:00 During these 6 hours, the PV produces 12.7 MWh, compared to 10.7 MWh demand (18.0 percent excess). The average daily PV generation is 1.3 MW (peak at 2.1 MW, whereas only for a few minutes on certain days, depending on the irradiance, the system can generate up to almost the installed capacity of 3 MW).[28] Nusa Penida has a total electricity demand of 14,692 MWh per

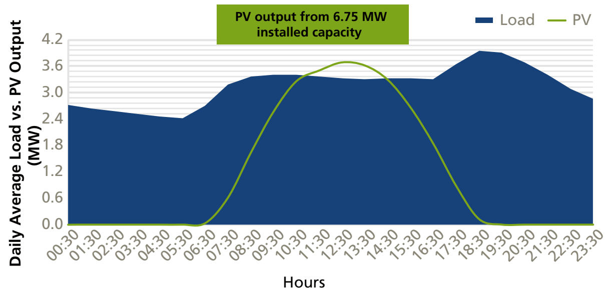
[25] A special case in Basse Santa Su, where power demand during the afternoon load shedding time was modelled as a result of the availability of PV electricity. Load shedding in the early mornings was kept in the analysis due to non-availability of PV electricity in the early hours of the day.
[26] With the considered technology, the installed batteries do not ex¬tend the period of availability of PV-generated electricity; they only bridge short-term reduction in PV production (up to 15 minutes), as for instance driven by cloud movements.
[27] Alternatively, more storage capacity could be added to match the peak PV output with the peak load. However, given the high prices for batteries, this aspect was not included in the analysis.
[28] Yet, the 3 MW PV capacity was chosen since i) it can adequately meet the peak load on the days and hours of the highest demand (the peak load between the sun hours of 06:30 to 18:30 varies from 1.76 MW to 2.47 MW), and ii) the average electricity generations costs of the hybrid system are lowest at this capacity.

Figure 23: Daily average load vs. possible PV output

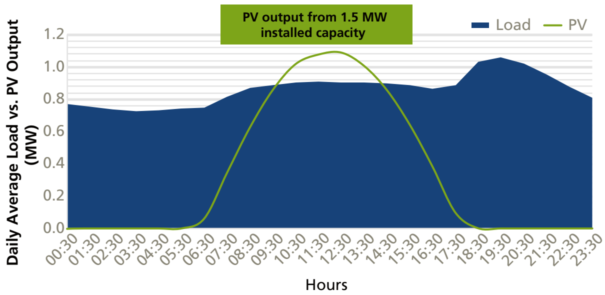
PUERTO LEGUIZAMO – Colombia



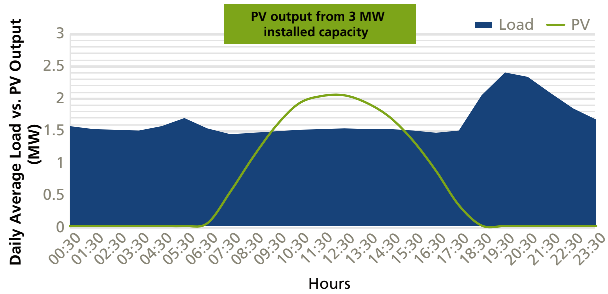
LAS TERRENAS – Dominican Republic



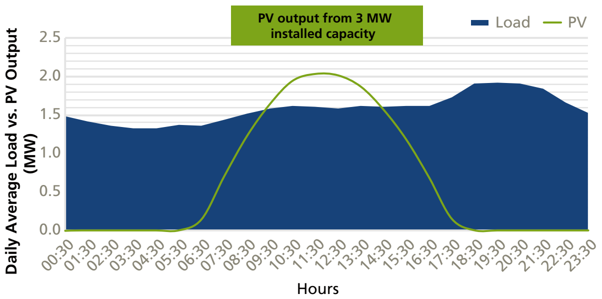
BEQUIA – St. Vincent and the Grenadines



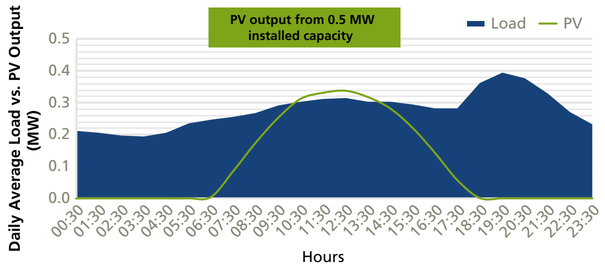
NUSA PENIDA – Indonesia



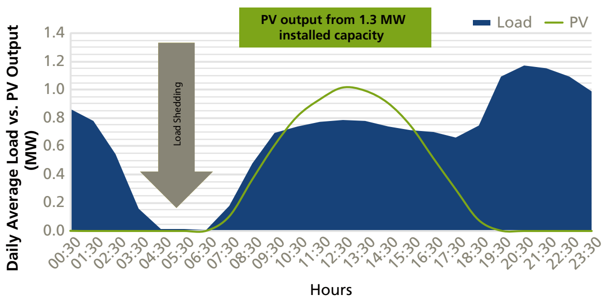
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia



year – of which 4,649 MWh (32 percent) could be provided by PV. Hence, hybridisation could lead to yearly diesel savings of 1.2 million litres.

As mentioned in the status quo analysis (section 3.1), special case is Basse Santa Su, where the utility turns off the diesel generators for several hours in the early mornings and late afternoons. PV-electricity could not only replace diesel-generated electricity (5.9 MWh per day, blue area under the green curve); the PV system could generate additional electricity in the late afternoon to increase the total power output of the plant. Hence, for this analysis, the PV system was sized larger in order to also meet the currently suppressed demand. Furthermore, the historic load profile might not necessarily be a good basis to assess the actual demand and design of an appropriate PV system. However, as mentioned above, the HOMER analysis – and initial sizing of hybrid systems, respectively – is generally based on historical data of diesel-generated electricity. In Basse Santa Su, power demand during the afternoon load shedding time was modelled as a result of the availability of PV electricity.

Table 2: Energy demand, PV share, and possible savings of hybridisation

Town/Island	Total generation capacity[29] (MW; diesel/PV)	Total energy demand (MWh/year)	Avg. daily PV supply (MWh/day)	PV share of total demand	100% PV penetration per day (~hours)	Possible diesel savings (litres/year	Possible cost savings[30] (USD/year)
Puerto Leguizamo	6.95 (4.2/2.75)	11,810	10.0	31%	4 (9:30- 13:30)	1,114,775 (29%)	854,000 - 1,924,000
Las Terrenas	16.25 (9.5/6.75)	27,703	23.6	31%	3.5 (11:00-14:30)	2,584,002 (30%)	1678,000 – 3,780,000
Bequia	5.6 (4.1/1.5)	7,554	7.0	34%	5 (9:30-14:30)	702,830 (32%)	461,000 – 1,040,000
Nusa Penida	6.1 (3.1/3.0)	14,693	12.7	32%	6 (9:00- 15:00)	1,239,320 (30%)	1,049,000 – 2,363,000
Busuanga	6.36 (3.36/3.0)	13,864	12.4	33%	5 (9:30-14:30)	1,224,073 (31%)	857,000 – 1,931,000
Hola	1.3 (0.8/0.5)	2,458	2.3	34%	5 (9:30-14:30)	274,101 (32%)	224,000 – 505,000
Basse Santa Su	2.8 (1.5/1.3)	5,789	5.9	37%	6 (10:00-16:00)	542,388 (35%)	434,000 - 977,000

[29] Slightly higher/lower diesel generation capacities were used for Basse Santa Su, Nusa Penida and Busuanga, sufficient to meet the current demand (not considering demand growth).
[30] Depending on the selected diesel price forecast (see section 4.1).

Figure 24: Diesel/PV split (capacity and output)

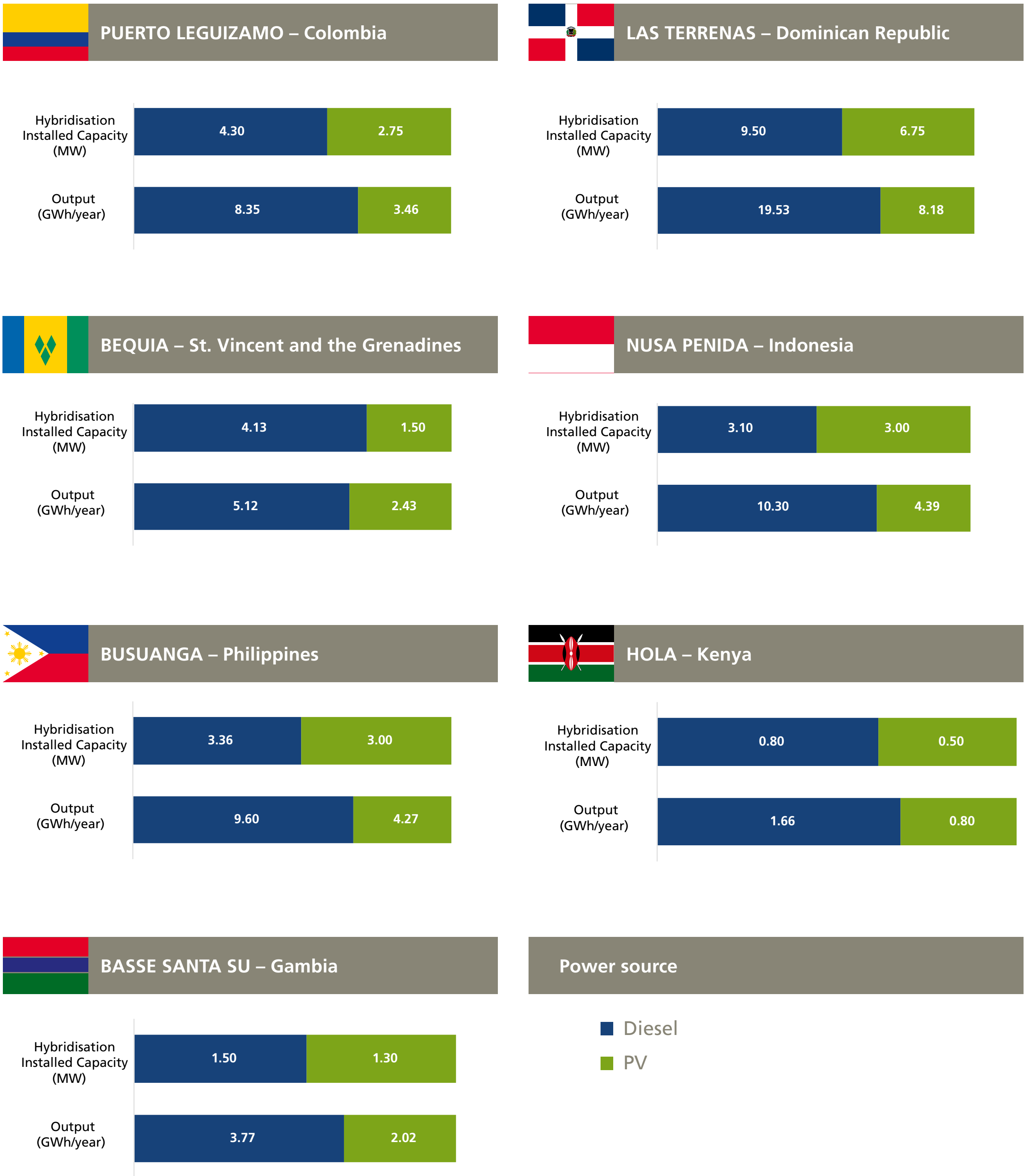


Figure 24 illustrates the installed capacity and output of the PV and diesel component. Both bars are normalised to 100 percent. Although the installed PV capacity comes in most cases close to the level of the installed diesel capacity, the capacity factor of the PV comes in lower than for the diesel (there is no radiation at night and variation from low to high radiation throughout the day). The capacity factor of the PV system ranges from 17.1 percent in Las Terrenas to 23.6 percent in Basse Santa Su,[31] whereas the capacity factor of diesel generators comes in much higher. A new diesel generator can reach up to 80 percent. However, in the plant layout, the existing diesel generators were kept as currently installed on-site (in terms of number and size), leading to lower-than-usual capacity factors (approx. 30-50 percent). At some sites, especially in Bequia, the existent generators are oversized, considering the current demand. Approx. 30-40 percent of the electricity output is derived from PV, which reduces the diesel consumption by approx. the same rate. The fraction of solar PV power to current demand would range from 31 percent to 37 percent at the selected sites.

Figure 25 (page 38) shows the most cost-efficient load share (and hence electricity mix) between diesel generators and PV systems in different months. The monthly average power production is based on real (historic) load data from the respective site. At each site, the possible monthly average PV production (in green, including excess electricity) clearly follows the trend of monthly average solar radiation (see section 3.2). The blue part of the bars presents the diesel power requirement to provide the total demand.

While the monthly load profiles show that there is fluctuation in demand, one should not overvalue the significance of these trends. In most cases, the monthly profiles are based on historical load data from one year; it is not proven that there is a clear monthly (or seasonal) demand pattern behind these numbers. The relevance of these graphs is rather the possible share of PV in average power production (bar on the right). This share is the basis for designing and sizing the hybrid system, and one of the main inputs for the economic analysis (section 4).

3.4. DEMAND GROWTH AND EXPANSION OPTIONS

The analysis above (and most of the cost analysis in section 4) is based on status quo assumptions, i.e. it neglects future growth of electricity demand. This is owed to the fact that the HOMER tool (as other common hybrid design and sizing softwares) designs the hybrid system according to the present load profile and other current conditions. Yet, some of the sites have shown considerable demand growth during recent years.

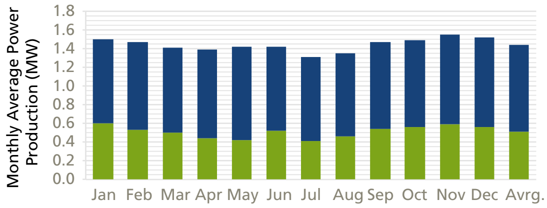
Demand growth during the sun hours can be covered by the hybrid system, whereas growth outside the sun hours requires more diesel power. For the selected sites, peak demand occurs in the evening hours, during no sun or very low solar irradiance periods. With the exception of Nusa Penida, it was assumed that demand growth will not affect the shape of the load curve (i.e. it will not shift evening demand towards daytime), and that the requirements for diesel and PV power generation will increase at an equal level (not exponentially more for diesel to cover above-average growing evening peaks).

Growth assumptions are primarily based on historical load developments, population growth (country level), and, if available, the utilities' own demand projections and plans for new connection points. For all sites, it was assumed that the growth rate – being relatively high in initial years – will decrease over project lifetime. Forecasts were derived by factoring the growth rate assumed from historical growth at every 30-minute intervals.

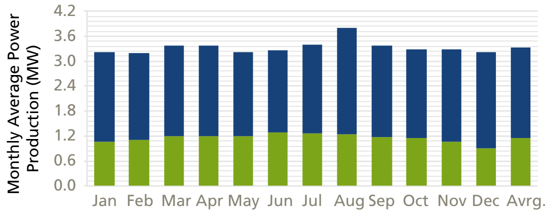
[31] Variation is due to differences in sun hours and radiation levels at the locations. For Puerto Leguizamo, average (historic) load is 1.35 MW, the select 2.75 MW PV can provide a mean output of 0.513 MW (capacity factor 18.7 percent). For Las Terrenas, average (historic) load is 3.16 MW, the select 6.75 MW PV can provide a mean output of 1.15 MW (capacity factor 17.1 percent). For Bequia, average (historic) load is 0.92 MW, the select 1.5 MW PV can provide a mean output of 0.336 MW (capacity factor 22.4 percent). For Nusa Penida, average (historic) load is 1.67 MW, the select 3 MW PV can provide a mean output of 0.650 MW (capacity factor 22 percent). For Busuanga, average (historic) load is 1.58 MW, the select 3 MW PV can provide a mean output of 0.631 MW (capacity factor 21 percent). For Hola, average (historic) load is 0.31 MW, the select 0.5 MW PV can provide a mean output of 0.105 MW (capacity factor 21 percent). For Basse Santa Su, average (historic) load is 0.66 MW, the select 1.3 MW PV can provide a mean output of 0.307 MW (capacity factor 23.6 percent). Mean output is the average power output from a PV system at the given solar radiations over the year (8760 hours). Capacity factor is the ratio between PV mean out put and rated capacity. In case of PV power, only day-time availability of solar radiation limits the capacity factor of PV.

Figure 25: Diesel/PV load share in different months

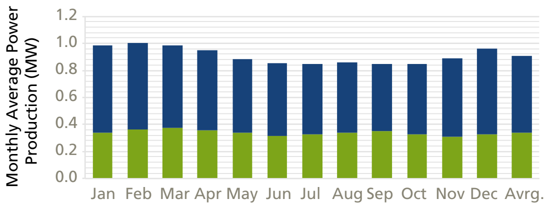
PUERTO LEGUIZAMO – Colombia



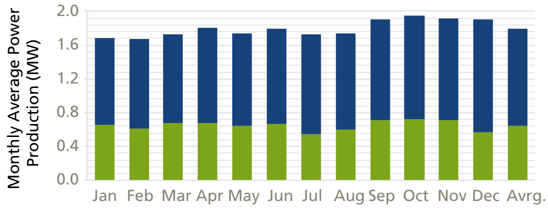
LAS TERRENAS – Dominican Republic



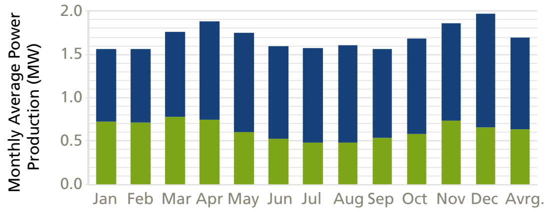
BEQUIA – St. Vincent and the Grenadines



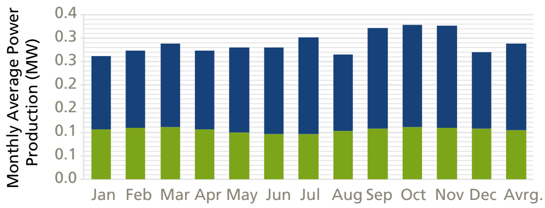
NUSA PENIDA – Indonesia



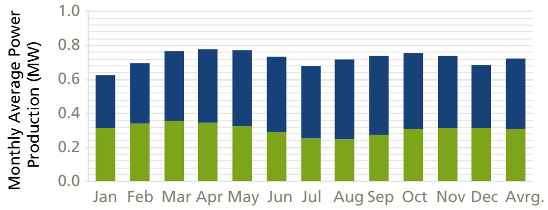
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia



Power source

- Diesel (MW)
- PV (MW)

Along with the growth of electricity demand over 20 years, the required technical upgrades (i.e. the installation of additional PV, battery, inverter, and diesel generators) should be done in phases.[32] This will ensure an optimal share of PV in power supply over economic project life time. Phase-wise technology upgrading will also ensure optimised O&M costs, diesel savings, and proper utilisation of the generation assets. Generator replacement considers 48,000 operating hours after which each generator needs to be replaced in order to maintain the efficiency and operating costs at an optimum level. At some sites it would also be required to expand the diesel generation capacity along with the PV-upgrades.[33]

Figure 26 shows the load curves of the growth scenario (changes from year 1 to 20) compared to the zero-growth case (dark blue line at the bottom of each graph).

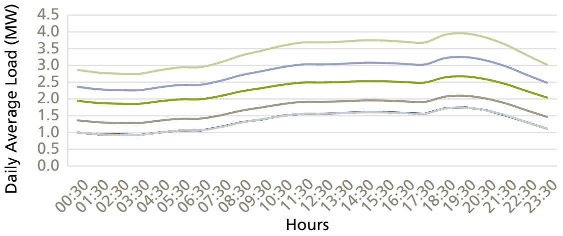
Accordingly, as shown in figure 27, the expected demand growth (in blue) was taken as basis to simulate the phase-wise PV-upgrade (in green) and the fuel savings (in yellow, average in red) over project life time. Due to the upgrades, long-term average fuel savings remain between 29% (Las Terrenas) to 34% (Hola).

[32] The base case, assuming constant demand over the next 20 years, allows calculating a single optimum (sizing of hybrid, diesel PV split). For considering growth in HOMER, one could model 20 scenarios with 1 year project lifetime, and yearly changing demand to find the respective optimum. However, suggesting 20 investments, one per each year, is of course not a rational choice. Therefore, in this study, a longer period of growing demand was approximated to shorter sequences of time with constant demand. This allows for a decent balance between precision of the optimum and reduction of transaction costs, typically opting for 1 to 3 expansions over 20 years. Supposing that the initial hybrid layout (year 0) results in a PV share of 32% as an average over the first 5 years, the same layout will only contribute a PV share of 21% in year 10 if demand grows constantly. This share, though, is far below the HOMER optimum for a base case scenario. A number of system expansions keep the overall PV share as close as possible to the HOMER optimum. It is important to note that the automation tool (as part of the assessed hybrid technology, managing the power generated from different sources) does not need to be up graded for expansions of PV and diesel capacity.

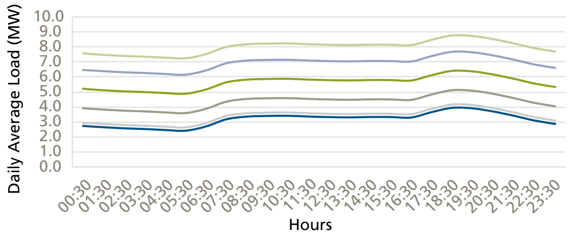
[33] Assumptions for demand growth and technical upgrades at each site are presented in Annex 4.

Figure 26: Load profiles for growth scenario

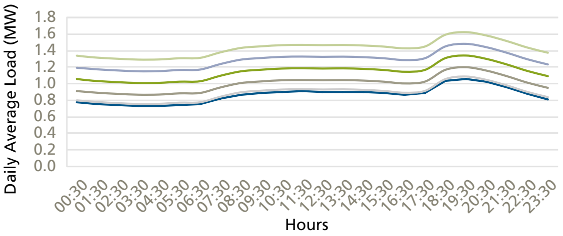
PUERTO LEGUIZAMO – Colombia



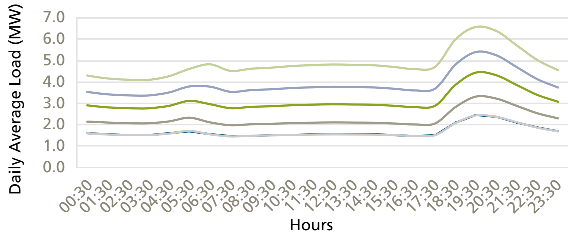
LAS TERRENAS – Dominican Republic



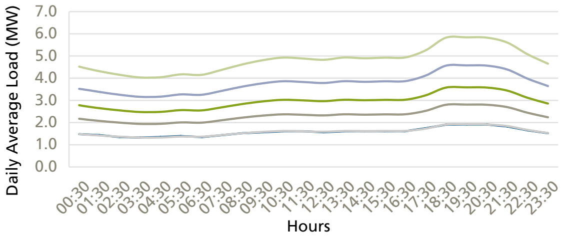
BEQUIA – St. Vincent and the Grenadines



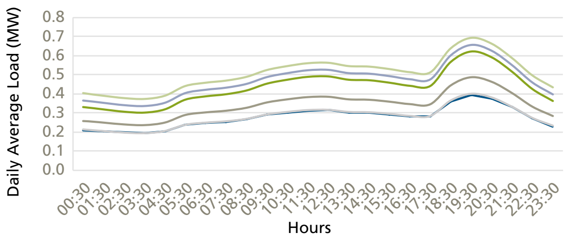
NUSA PENIDA – Indonesia



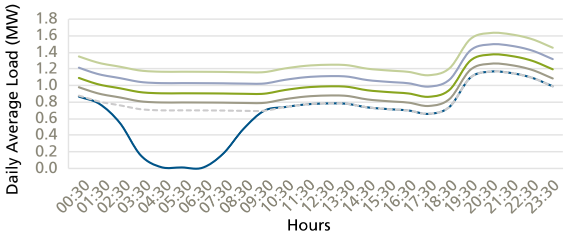
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia

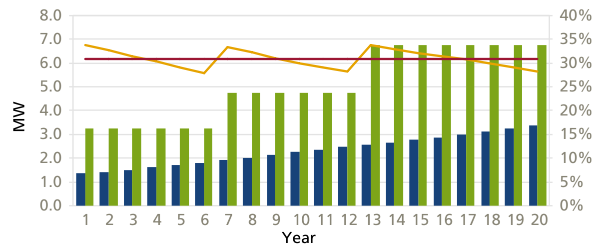


Load in respective year

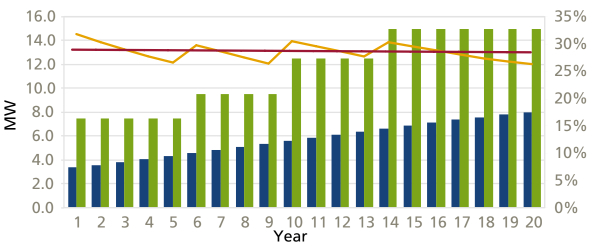
- Zero Growth
- Year 1
- Year 5
- Year 10
- Year 15
- Year 20

Figure 27: Growth and expansion plan

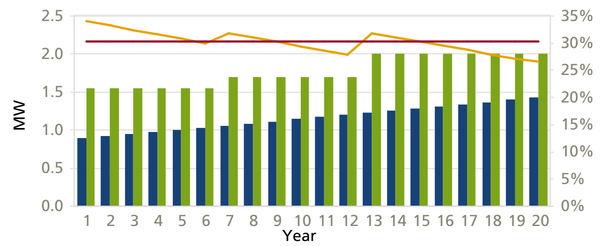
PUERTO LEGUIZAMO – Colombia



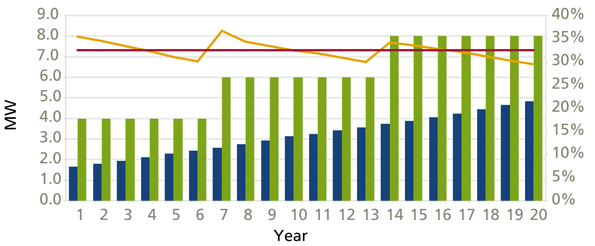
LAS TERRENAS – Dominican Republic



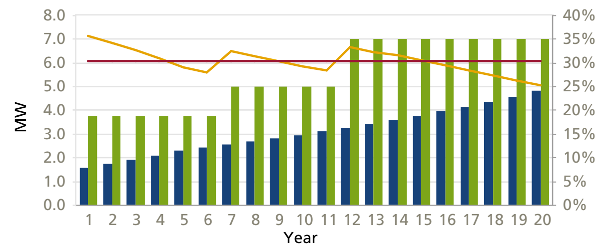
BEQUIA – St. Vincent and the Grenadines



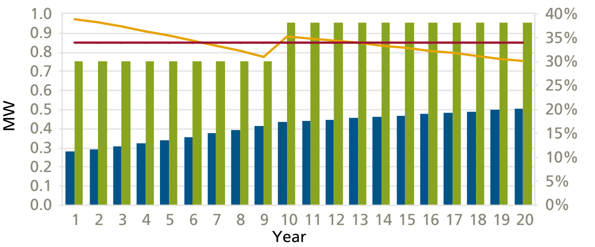
NUSA PENIDA – Indonesia



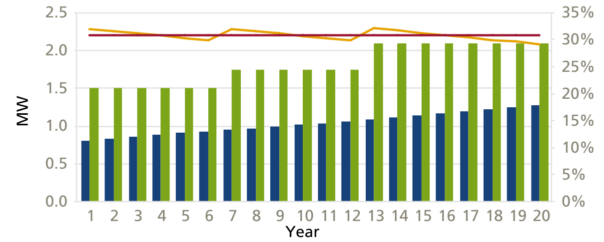
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia



Average demand, installed PV, and fuel savings

- Average demand
- Installed PV
- % fuel saving
- Average fuel saving

4. ECONOMIC VIABILITY ASSESSMENT

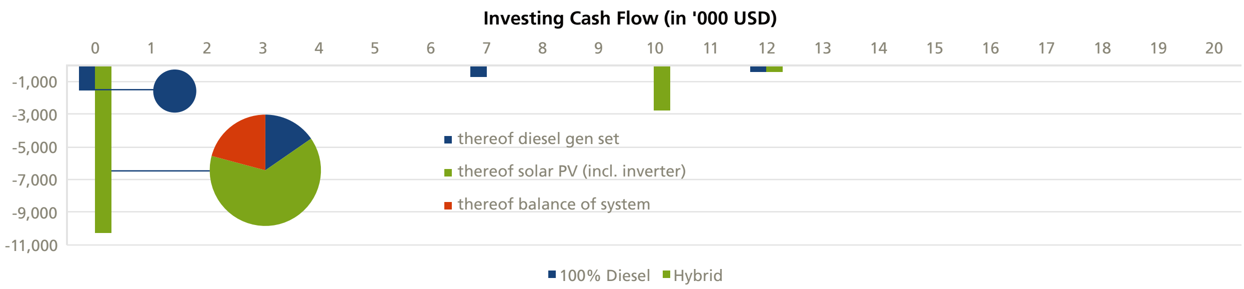
This section can be considered as the main part of this study. It explains why it is misleading to compare electricity generation costs of diesel and PV only; why it is important to differentiate between electricity sold and produced; and what cost components are included in the LCOE definition applied for this analysis. It then compares the LCOEs of diesel-electricity and hybrid-electricity at all sites – demonstrating the impact of fuel savings, carbon emissions, and alternative financing costs, and highlighting the relevance of plant size, solar radiation, and diesel prices. Sensitivity analyses were carried out for different diesel price scenarios, lower-than-commercial financing costs (so-called public sector or 'social' discount rates), different risk margins for more capital-intensive investments, varying PV penetration levels, changing capital and operational expenditures, as well as growing customer demand and system expansion.

4.1. APPROACH AND ASSUMPTIONS

4.1.1. INVESTMENT NEEDS AND COST STRUCTURE

To help understand the components of an LCOE it is important to understand the cost structure of both the diesel and hybrid systems. Investment requirements and cost structure for diesel and hybrid differ significantly. An example from Nusa Penida (figure 28) is representative for other sites as well. While the diesel is characterised by a relatively low upfront investment, the hybrid system is quite capital intensive. Some replacements of diesel engines, inverters, converters and battery take place during the assumed 20-year economic lifetime of both systems.

Figure 28: Investment cash flows of diesel and hybrid (in USD '000)



Ongoing expenditures over project lifetime also have to be considered (figure 29). The diesel system suffers from very high expenditures on fuel. The hybrid is burdened by diesel costs as well, although to a lesser degree due to the achieved reduction in diesel consumption.

Figure 29: Operating costs of diesel and hybrid (in USD '000)

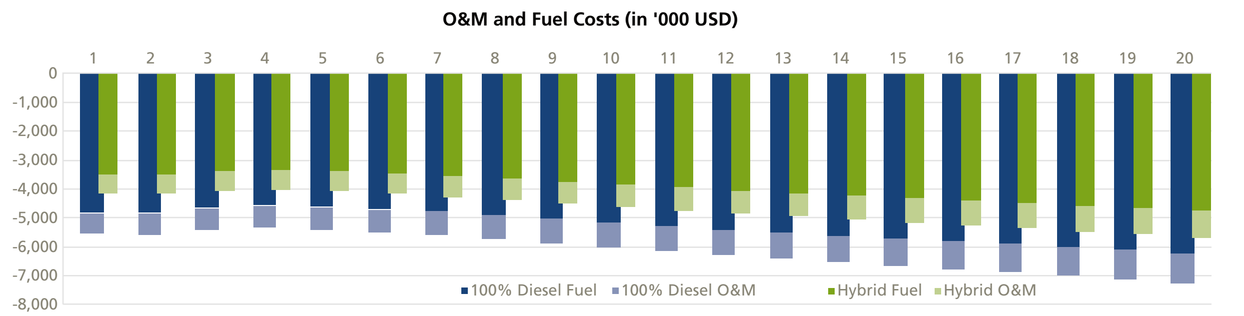


Table 3: Cost components of diesel and hybrid

Component	100% diesel case	Hybrid case
Initial and replacement investment in equipment	■ Diesel generators; new investment and some replacement required over 20-year economic lifetime.	■ Diesel generators (new investment and replacement) ■ PV-panels (replacement of inverters included in O&M) ■ Converter (replacement required) ■ Battery (replacement required) ■ Automation tool (no replacement required)
O&M	■ Change of filters, spare parts, lube oils, etc.	■ Diesel generators: see left ■ PV-panels: cleaning, mowing lawn, replacement of inverters, etc. ■ Converter ■ Battery
Fuel consumption	■ Derived from specific fuel consumption of diesel generators; based on required output of diesel electricity	

Table 3 shows the relevant cost components for the 100 percent diesel and hybrid configurations. For both cases, in order to ensure comparability, it was assumed that all existing diesel generators are replaced with new ones in 'year 0' of the investment (same generation capacity). Further diesel replacements are required over the project lifetime – earlier and possibly more often in the 100 percent diesel case due to the more intensive utilisation. Costs for the existing diesel electricity generation and for the hybrid scenario are calculated based on real economic costs. This is primarily relevant for fuel costs, which are often subsidised, not fully reflected in the utilities' profit and loss statements, and which need to be adjusted to real levels.

4.1.2. HYBRID LCOE = WEIGHTED DIESEL/PV LCOE?

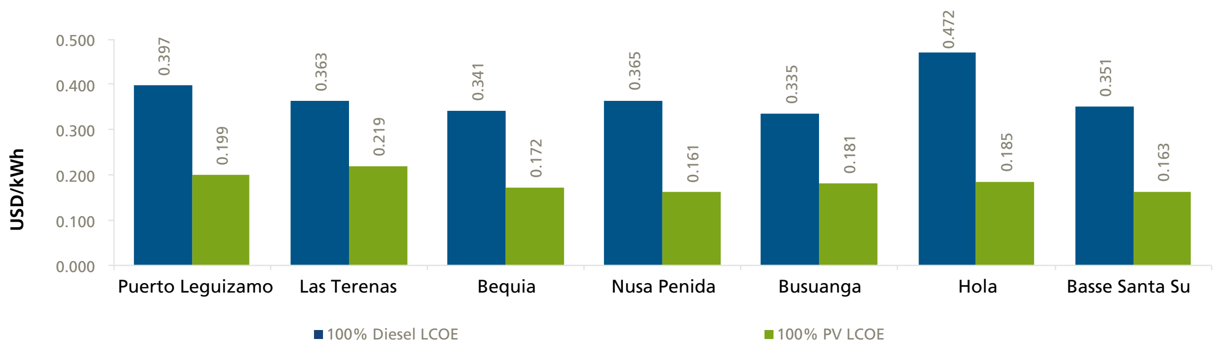
At the selected sites, the LCOE for PV-electricity comes in between 16-22 USDc/kWh (if every single kWh can be sold, and no specific demand curve needs to be serviced). Keeping the relatively high LCOE of diesel systems in mind (approx. 33-48 USDc/kWh, excluding carbon costs), a significant decrease in the LCOE of a hybrid system could be expected. Figure 30 shows the LCOEs for the 100 percent diesel case and a 100 percent PV plant.

However, this approach is misleading, since hybrid technologies still employ diesel generators for a major share in the total electricity production. Further, as hybridisation and integration of intermittent RE in an isolated grid requires additional investments, the above-shown generation costs of diesel and PV cannot be directly compared. The inconsistent use of LCOE per kWh produced (as an indicator to compare different renewable and fossil fuel based technologies) often confuses involved stakeholders, and raises unreachable expectations.

The LCOE of a hybrid system is a mix of PV and Diesel LCOEs – weighted with their share in the total output. Since – in order to derive the overall LCOE of the hybridised system – the specific cost of PV-generation gets averaged with the cost of the remaining diesel generation (approx. 1/3 to 2/3), the full advantage of the PV portion is disguised in the results.

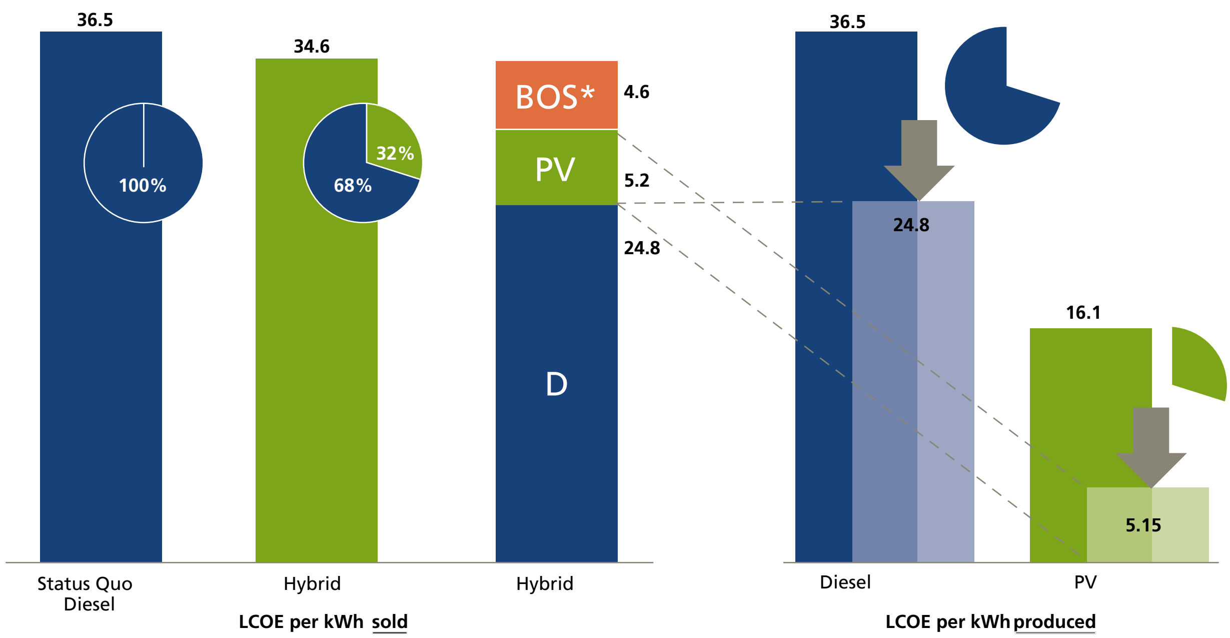
This effect is shown in figure 31 for Nusa Penida, where 32 percent of electricity demand can be covered by PV. In a 100 percent diesel-powered grid, the LCOE comes in at 36.5 USDc/kWh. Weighted with the residual 68 percent, the diesel has a share of 24.8 USDc/kWh in the hybrid LCOE. In a 100 percent PV-powered grid, the LCOE per kWh produced comes in at 16.1 USDc/kWh. While the LCOE for the PV system comes in much lower, its relatively small share in the overall output yields an equally low share in the hybrid LCOE (5.2 USDc/kWh). The equipment needed for the system integration of the hybrid is presented as 'balance of system' (BOS), including investment and replacement cost for automation tool, battery, converter and the corresponding O&M. The diesel LCOE includes the fuel cost, investment and replacement CAPEX, and O&M.

Figure 30: LCOEs – Diesel vs. PV



It is important to differentiate between the LCOE per kWh produced and sold. The LCOE per kWh produced also includes excess electricity for which the owner of the plant is not reimbursed by the respective off-taker. The LCOE per kWh sold only includes the electricity units that are sold, thus it is higher than the LCOE of kWh produced. The analysis in this study focuses on average generation costs of electricity sold, since the existing demand curve needs to be covered by the hybrid system, and since during daytime there is some excess PV electricity which cannot be used if the demand curve does not change.

Figure 31: Simplified illustration of LCOE per kWh sold and produced (Nusa Penida)[34]



[34] Balance of System (BOS) includes: cost of automation solution, batteries, converters, lower diesel efficiency, excess electricity from PV, and changes in capital structure.

4.1.3. FINANCIAL ASSUMPTIONS

The following table presents the financial assumptions applied in the project finance structure of the financial model. It is important to note that equity return expectations (15 percent) and interest on debt (8 percent) – although already on the lower end – reflect private sector market conditions. Yet, lower-than-commercial financing costs (and other changes in financial assumptions) are discussed in section 4.2 and as part of the sensitivity analysis.

The debt capacity was derived based on the available net operating cash flow and a target debt service coverage ratio (DSCR) of 1.2 – and capped at a maximum portion of 70 percent. A debt tenor of 12 years with a 1-year grace period was assumed. Different local tax rates were considered for each of the respective sites (see Annex 3). For the base case, the capital costs were not varied between diesel and hybrid systems, except for the debt/equity split as determined by the debt capacity. All calculations are based on a project lifetime of 20 years.

Table 4: Financing assumptions

Component	Assumption
Transaction cost (legal documentation, due diligence, set-up of SPVs etc.)	2% of total initial CAPEX
Contingencies (buffer for changes in equipment costs)	5% of total initial CAPEX
Interest	8% on debt, 2% on cash (nominal cost)
Equity IRR	15% (nominal cost)
Debt/equity split	Debt capacity to meet DSCR of 1.2, based on net operating cash flow, capped at max. debt portion of 70%[35]
Debt tenor	12 years + 1 year grace period
DSRA	6 months debt service
Inflation, cost escalation	2% assumed inflation on revenues and cost components (including cost of carbon), similar to inflation in the US since the whole model is based on USD
Project lifetime	20 years
Currency	All values are based in USD, to avoid unnecessary currency mismatches and make different sites comparable

4.1.4. DIESEL PRICE ASSUMPTIONS

The development of diesel prices for the individual sites are based on real prices from the site (including transportation) and indexed with crude oil price forecasts of EIA[36] and World Bank[37]. EIA uses three scenarios – low (1), reference/medium (3), and high (5) – of which the reference scenario was taken as base case for the following LCOE and sensitivity analyses. Another projection (4) was added, removing the decrease of oil prices as it is predicted over the next few years in the EIA reference scenario. Prices in nominal terms were used to consider inflation.

[35] Resulting in a minimum WACC of 0.7*8%+0.3*15% = 10.1% before consideration of tax shield of debt. The tax shield can lower the WACC to 8.4% (like in the case of Bequia). In general, lower debt portions lead to higher WACC.
[36] EIA World Energy Outlook 2014; http://www.eia.gov/forecasts/aeo/er/index.cfm
[37] At the time of the analysis, the World Bank price forecast for crude oil (October 2013) was available only until 2015, and was further projected until 2040

The significant oil price decline towards end of 2014 (down to around 50 USD/barrel) is not reflected in the applied forecasts. At the time of writing, no revised long-term projections were available from EIA. Only World Bank released an updated mid-term forecast in which the price is expected to reach 74 USD/barrel by 2020 and 103 USD/barrel by 2025 – i.e. in the range between EIA low- and reference scenarios.

Figures 32 and 33 show the five crude oil price forecasts and the adjustment to the site-specific diesel price in Nusa Penida, and the current local diesel prices at all sites, respectively. The current difference between local diesel price and crude oil price (2014 data) is kept stable for projecting future on-site diesel prices.

Figure 32: Crude oil and local diesel price forecasts

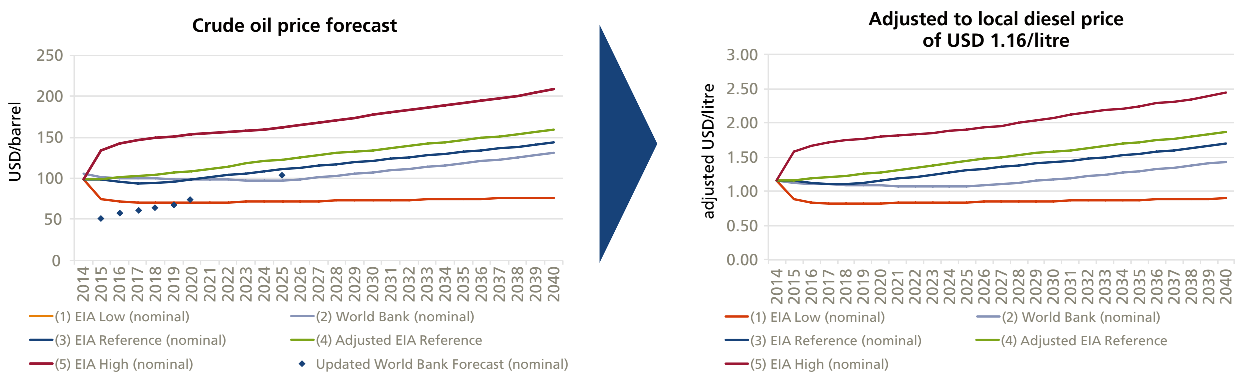
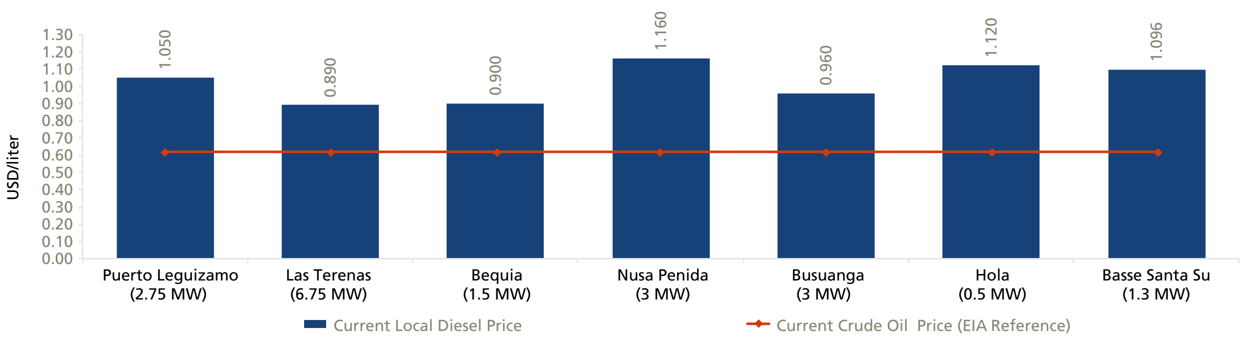


Figure 33: Current local diesel prices and EIA reference crude oil price



4.2. LEVELISED COST OF ELECTRICITY – BASE CASE

This section presents the starting point for the comparison of levelised generation costs. It includes initially decreasing diesel prices (EIA reference), and does not consider demand growth. The sensitivity analyses in the subsequent sections present diesel and hybrid LCOEs under different assumptions (most importantly other fuel price developments), and under the consideration of demand growth.

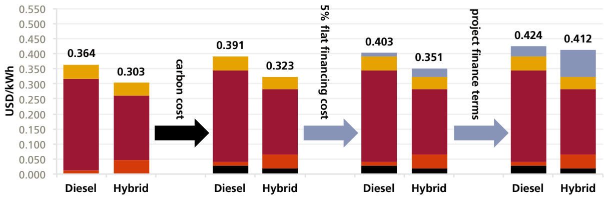
Figure 34 illustrates the cost components of hybrid and diesel LCOE (with/without carbon costs[38], and for different financing costs), and help identifying the respective cost drivers. At each site, there are two obvious – and opposite – effects.[39]

[38] Costs of carbon were assumed at 50 USD/tCO2; carbon emissions depend on the efficiency degree of diesel generators; the average for existing generators at the selected sites was calculated at 0.75 tCO_2/MWh diesel electricity.

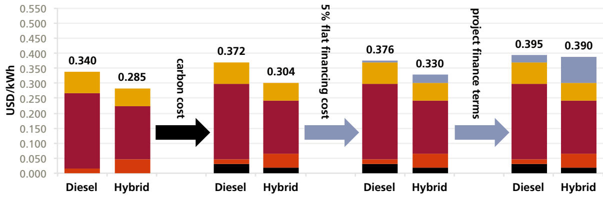
[39] Figure 53 presents the LCOE breakdown for a project finance structure excluding costs of carbon.

Figure 34: LCOE breakdown with/without carbon and financing costs

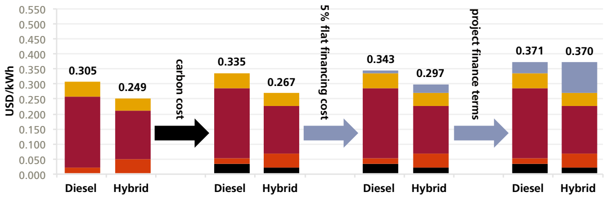
PUERTO LEGUIZAMO – Colombia



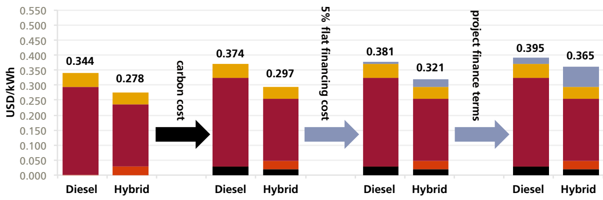
LAS TERRENAS – Dominican Republic



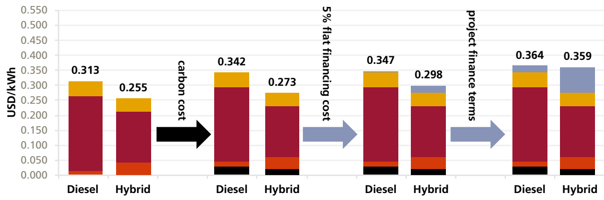
BEQUIA – St. Vincent and the Grenadines



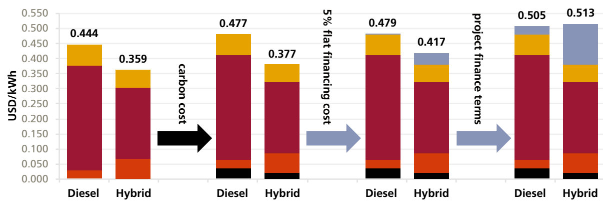
NUSA PENIDA – Indonesia



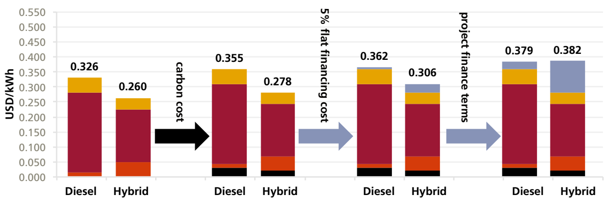
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia



LCOE – elements of costs

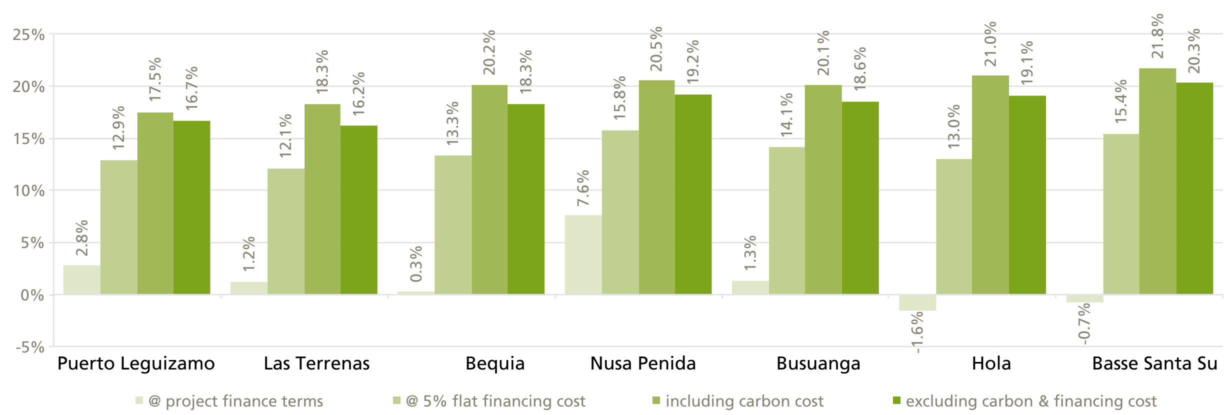
- Cost of carbon
- CAPEX
- Fuel
- OPEX
- Financing costs

On the one hand, although diesel generators still represent the major share in total electricity production, hybridisation leads to significant fuel savings. The hybrid LCOE comes in much lower than the diesel LCOE if only capital expenditures (CAPEX, including PV equipment, system integration, and replacement), operational expenditures (OPEX), and fuel costs are considered (two left bars). The reduction of fuel costs (approx. 30 percent) over-compensates the relatively higher CAPEX of the hybrid. The cost advantage of the hybrid even increases if carbon costs are taken into account (two bars second from left), which, obviously, are higher for the 100 percent diesel case.[40]

On the other hand, due to the higher capital intensity, generation costs of hybrid electricity include a higher portion of financing costs. The hybrid requires longer repayment periods and thus higher interest expenses. Still, for all sites, the hybrid LCOE is lower than the diesel LCOE if the project can be financed at public sector return expectations (assumed 5 percent flat; two bars second from right). Lower-than-commercial financing costs can be achieved, for instance, through balance sheet finance and borrowing at concessional terms. However, under private sector return expectations (assumed 15 percent on equity, 8 percent on debt), financing costs become a significant cost driver of the hybrid LCOE (two right bars), lowering the relative cost advantage (compared to the diesel) in five of seven cases, and even overcompensating the positive effect of fuel savings in Hola and Basse Santa Su. Private sector financing costs can be expected if an IPP will make the investment under a project finance structure.

Figure 35 summarises the relative cost advantage of hybridisation. At 5 percent financing costs, generation cost savings of 12.1 to 15.8 percent can be achieved at the different sites. If the projects have to be financed on commercial (project finance) terms, only Nusa Penida could achieve relevant savings, while savings at other sites are moderate and negative, respectively. In Hola and Basse Santa Su, hybridisation would increase electricity generation costs – with or without consideration of carbon costs. These two relatively small grids are affected stronger by fix costs of hybrid system integration components, and on-site diesel prices are not sufficiently high to over-compensate this effect (see next section for the relevance of plant size and diesel prices).

Figure 35: Relative cost advantage of hybridisation

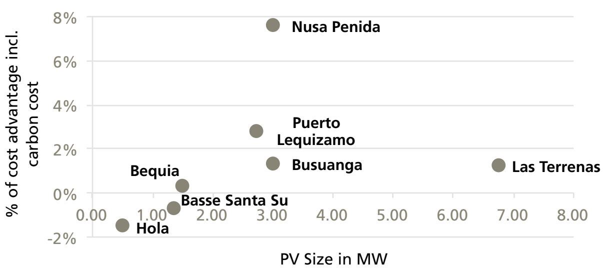


[40] Not all of the diesel-produced electricity can be replaced by PV, though; PV electricity can cover around 30-40 percent of the annual demand (different for each site). That means the hybrid scenario also leads to carbon emissions, but in a reduced amount (approx. 70 percent of the diesel-only case).

4.3. RELEVANCE OF PLANT SIZE, SOLAR RADIATION AND DIESEL PRICES

Under private sector financing conditions (project finance case), and applying EIA reference oil price forecasts, the relative cost advantage of PV-hybridisation can greatly depend on plant size, solar radiation, and local diesel price premium. Figures 36 to 38 show that a certain trend can already be observed from looking at the impact of each determinant separately.

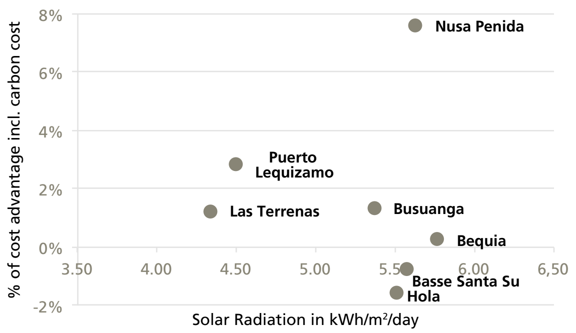
Figure 36: Relation of PV size and LCOE



Given the hybridisation technology applied in this analysis ('100 percent peak PV penetration', including automation tool and an integrated storage device), hybridisation gets more attractive with increasing plant size. The cost advantage is bigger for larger plants, where, consequently, more PV gets installed, and where the fixed cost of the automation tool is spread over more units of electricity produced (kWh). Accordingly, for smaller sites, the cost advantage of hybridisation is smaller or even negative, since fixed costs are spread over fewer units of electricity.

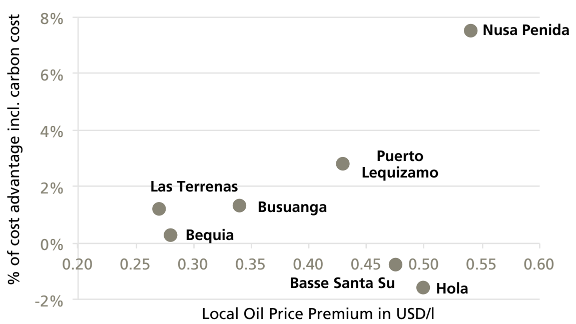
The three smallest sites (Hola, Basse Santa Su and Bequia) show no or only a small cost advantage, whereas the four larger sites show a relatively high cost advantage. However, it can also be observed that the largest site – Las Terrenas – does not show the highest benefit. It is the medium-sized sites Nusa Penida and Puerto Leguizamo that achieve the largest LCOE reduction.

Figure 37: Relation of solar radiation and LCOE



One reason why Las Terrenas does not achieve the highest cost savings is its relatively little solar radiation. Nusa Penida benefits from relatively high radiation. However, it can also be seen that even at sites with high radiation – Hola, Basse Santa Su and Bequia – hybridisation does not necessarily (or only slightly) reduce generation costs, due to the above mentioned missing scale effects, amongst other things.

Figure 38: Relation of local diesel price and LCOE



A third factor has to be considered to get a clearer picture. It goes without saying that high local diesel prices imply high potential for diesel cost savings. For instance, despite relatively little radiation, Puerto Leguizamo shows a higher cost benefit than the similarly large Busuanga. This is due to the higher diesel prices in Puerto Leguizamo. However, figure 38 also shows that hybridisation at two sites with high diesel prices (Hola and Basse Santa Su) does not automatically lead to a lower LCOE.

Consequently, one needs to analyse the correlation of the three – and possibly more – factors to determine their combined impact on generation costs. The two sites where hybridisation – under rather 'conservative' assumptions – could result in a cost increase (Hola and Basse Santa Su) have by far the smallest generation capacity, and even relatively high local diesel prices and solar radiation cannot compensate the missing scale. On the contrary, the cost advantage at the largest site (Las Terrenas) is limited by relatively low diesel prices and solar radiation. The most viable case for hybridisation is Nusa Penida – a mid-sized plant with the highest diesel prices and relatively high solar radiation.

Figures 39 and 40 put the LCOEs (decrease or increase, resulting from hybridisation) in context with two of these three influencing factors at a time. The boxes for each site show the impact of hybridisation on the LCOE, e.g. a cost reduction of 7.6 percent in the case of Nusa Penida (incl. carbon externalities).

Figure 39: Correlation of PV size and solar radiation

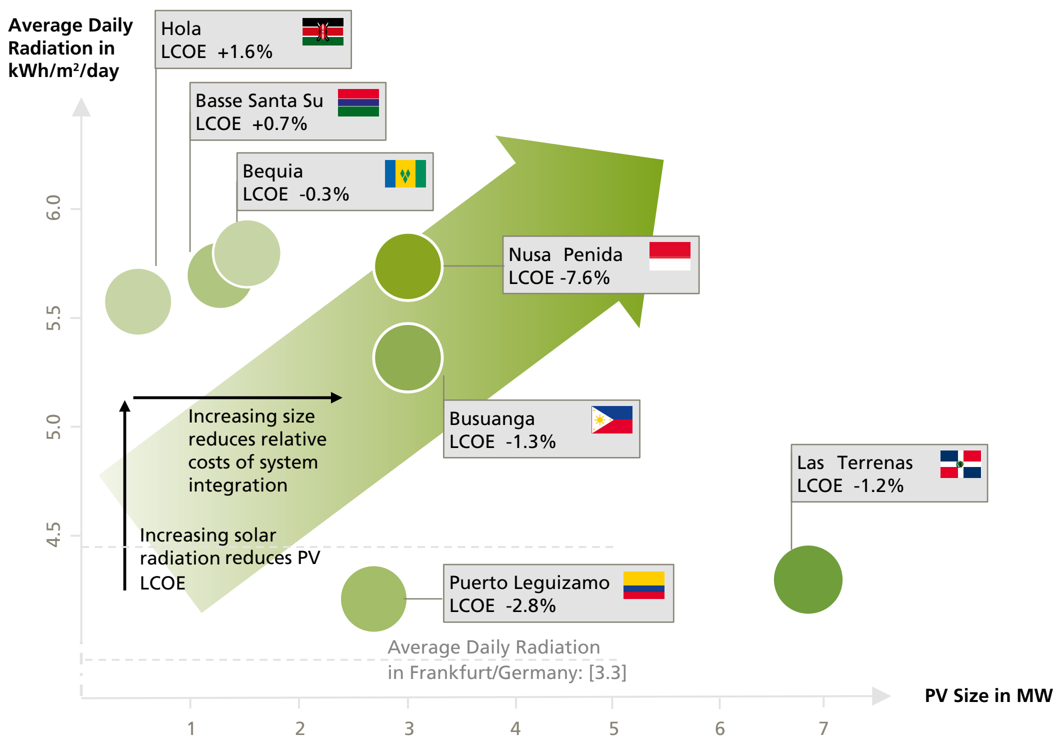
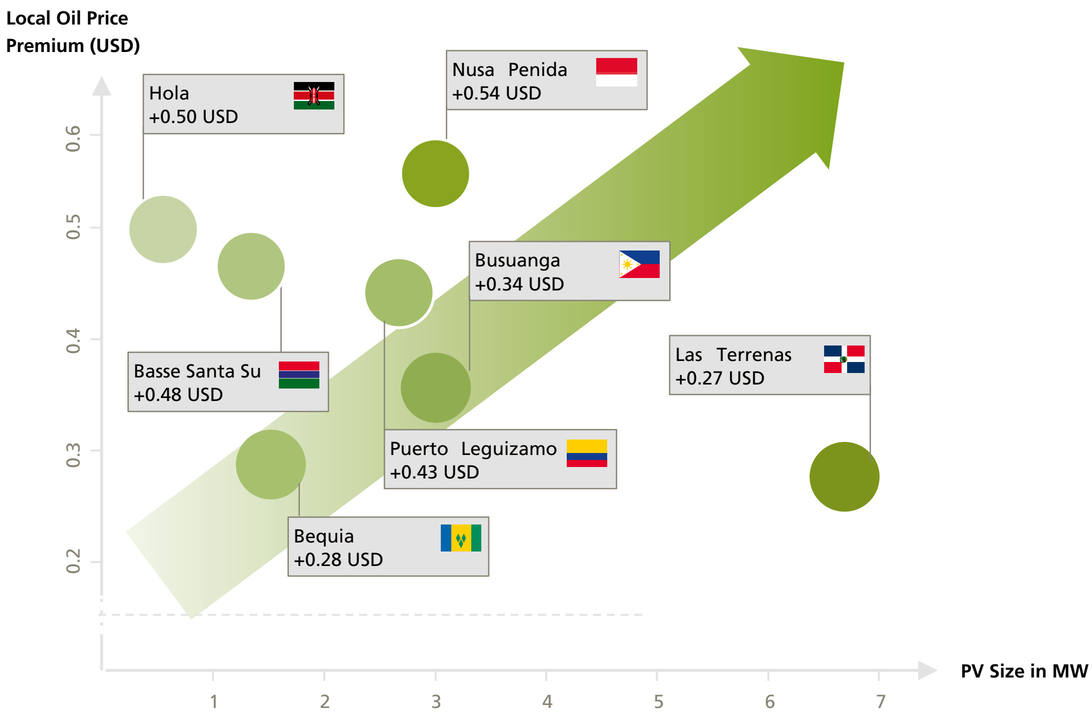


Figure 40: Correlation of PV size and local diesel price



4.4. SENSITIVITY ANALYSIS

The project finance case (private sector return expectations) and the EIA reference oil price forecast were also used as starting point for the following sensitivity analysis.

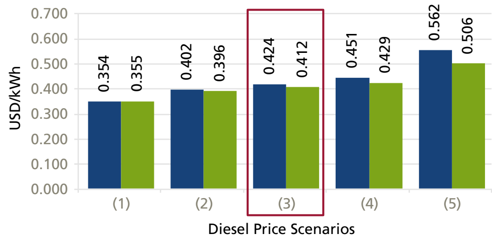
4.4.1. IMPACT OF DIESEL PRICE DEVELOPMENT

A major driver for economic viability is the expectations for crude oil, and hence, diesel price development. Figure 41 shows the LCOE (incl. carbon externality) of the hybrid and diesel-only case for the different diesel price scenarios introduced in section 4.1.4 (EIA low, reference, high, EIA adjusted, and World Bank).

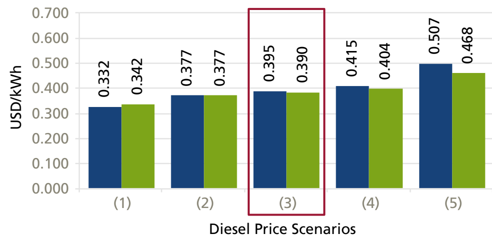
Scenario 1 shows the LCOEs for the "EIA low" crude oil price projection. In this scenario, except for Nusa Penida, diesel prices will not increase sufficiently to justify the hybrid investment (hybrid LCOE > diesel LCOE). The base case (EIA reference, as discussed in the sections above) is framed in red. For the highest plausible diesel price development assumed (scenario 5, EIA high) – other assumptions remaining constant – hybridisation results in LCOE reductions ranging from 3.5 USDc/kWh in Bequia to 6.7 USDc/kWh in Nusa Penida.

Figure 41: LCOEs for different diesel price scenarios

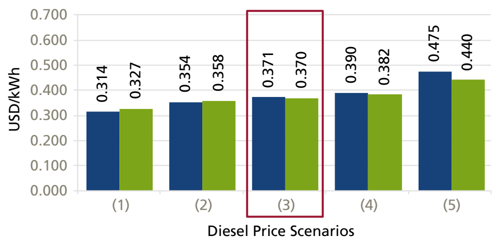
PUERTO LEGUIZAMO – Colombia



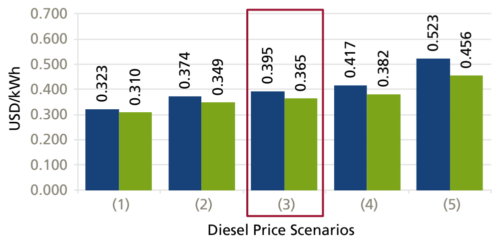
LAS TERRENAS – Dominican Republic



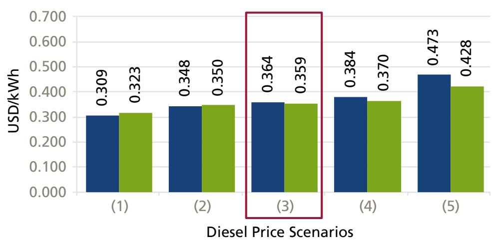
BEQUIA – St. Vincent and the Grenadines



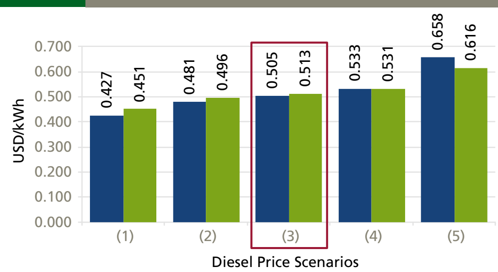
NUSA PENIDA – Indonesia



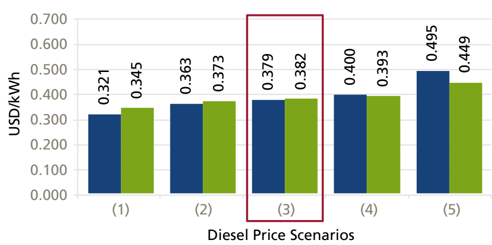
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia



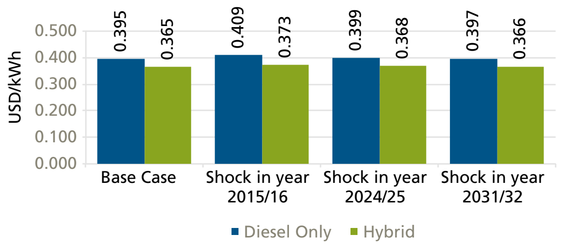
Power source

- Diesel only
- Hybrid

The diesel price forecasts used above show a relatively stable trend. Apart from that, unexpected short-term diesel price shocks might occur. Figure 42 shows the impact of a diesel price increase of 20 percent over 2 years at the beginning, the middle, and the end of project lifetime in Nusa Penida. The difference is relatively low, due to the fact that this short-term shock is averaged by the remaining 18 years of project lifetime. Due to the discounting effect, shocks in the near future burden the viability more than shocks in later years.

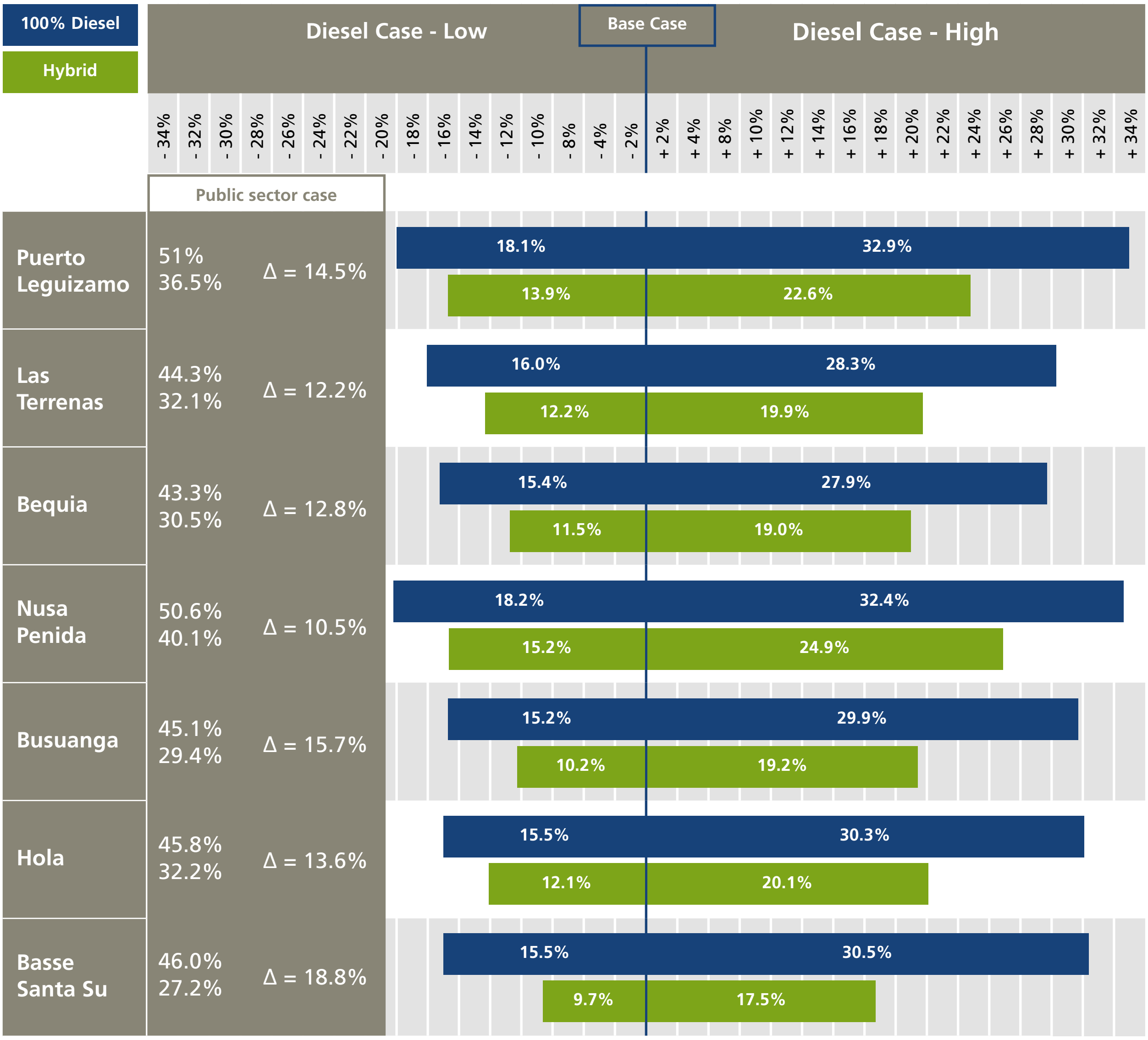
Figure 42: Impact of diesel price 'shocks' on LCOE

NUSA PENIDA – Indonesia



As mentioned above, the LCOE concept does not properly reflect the advantage of a reduced exposure to diesel price volatility. Starting from the base case (scenario 3) figure 43 shows the percentage range of LCOE changes from the lowest (1) to the highest diesel price scenario (5). Among the sites, the range of changes for the hybrid LCOE is between 27.2 in Basse Santa Su and 40.1 percent in Nusa Penida, whereas the range of the diesel LCOEs is higher, from 43.3 percent in Bequia to 51.0 percent in Puerto Leguizamo. These numbers again highlight that the hybrid systems are less vulnerable against diesel price changes and serve as a natural partial hedge against diesel price changes.

Figure 43: Volatility of LCOEs for different diesel price scenarios



Following the same logic, figure 44 shows the detailed LCOE ranges in USD/kWh for hybrid and diesel for the example of Nusa Penida under the 5 diesel price scenarios (incl. cost of carbon). The lower end of the bar indicates the LCOE for the lowest diesel price scenario, whereas the upper end of the bar shows the LCOE for the highest diesel price scenario.

Figure 45 shows the range of cost benefits between hybrid and diesel system from the lowest (1) to the highest (5) diesel price scenario, further depicting the increasing cost benefit of a hybrid over a diesel system under higher diesel prices. The upper end of the bar indicates the cost benefit under the highest diesel price scenario whereas the lower end of the bar indicates that most cases show no benefit over current generation cost at the lowest diesel price scenario.

Figure 44: LCOE volatility for different diesel price scenarios (Nusa Penida)

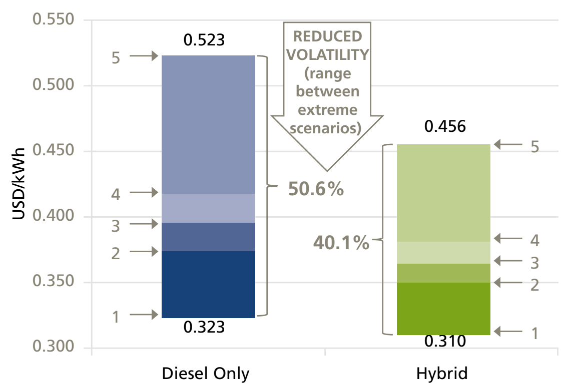
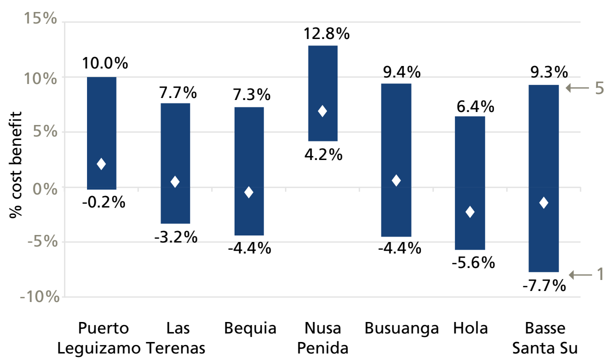


Figure 45: LCOE ranges for different diesel price scenarios



4.4.2. IMPACT OF FINANCING COSTS

For the calculation of financing cost, the debt capacity was derived based on the available net operating cash flow and a target debt service coverage ratio (DSCR) of 1.2 – and capped at a maximum portion of 70 percent. Different local tax rates were considered for each of the respective sites. Based on these assumptions the following initial WACCs were derived and applied as the base case. As described above, the average financing costs increase as debt is repaid and the capital structure becomes more equity dominated.

Figure 46 shows the impact of financing costs on the hybrid and diesel LCOEs (including carbon costs), assuming an initial 70/30 debt-equity split. The red line indicates the break even, that is the initial WACC for which both LCOEs match. The hybrid investment is viable if financing costs less than the respective break-even WACC can be secured.

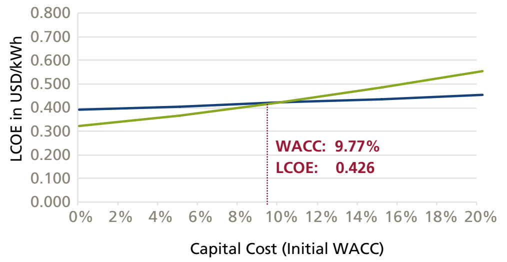
The maximum financing costs for making the hybrid investment viable vary from site to site. As already demonstrated in the base case analysis of section 4.2, in most cases (except Hola and Basse Santa Su) even commercial return expectations can be applied to make the hybrid case viable (since they are lower than the break-even initial WACCs presented in the graphs below). In Nusa Penida, viability is given for initial financing costs up to 12.7 percent, whereas there is particularly little scope in Hola with a maximum initial WACC of 8 percent.

Table 5: Financing costs at selected sites

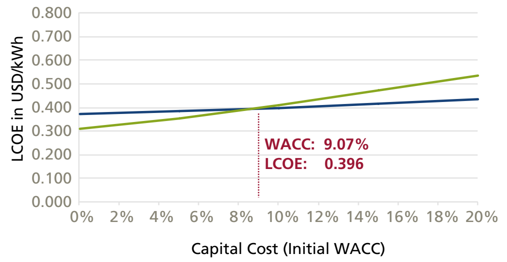
Town/Island	Tax Rate	WACC @ 70/30 D/E	D/E split based on debt capacity	Resulting WACC
Puerto Leguizamo	25%	8.7%	70/30	8.7%
Las Terrenas	27%	8.6%	63/37	9.3%
Bequia	30%	8.4%	60/40	9.3%
Nusa Penida	25%	8.7%	60/40	9.6%
Busuanga	30%	8.4%	51/49	10.2%
Hola	30%	8.4%	61/39	9.3%
Basse Santa Su	31%	8.4%	51/49	10.1%

Figure 46: LCOE as a function of financing costs (break-even WACC)

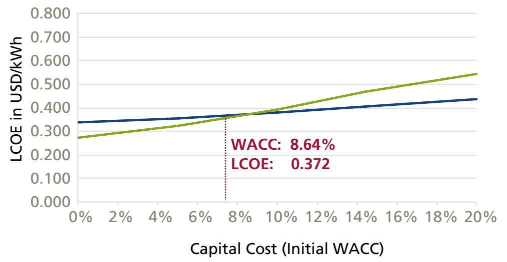
PUERTO LEGUIZAMO – Colombia



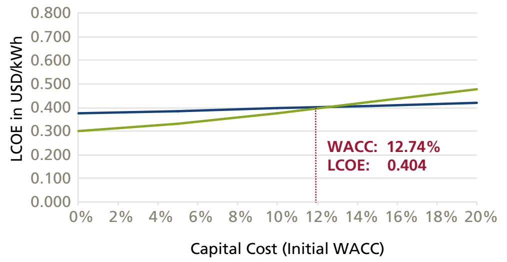
LAS TERRENAS – Dominican Republic



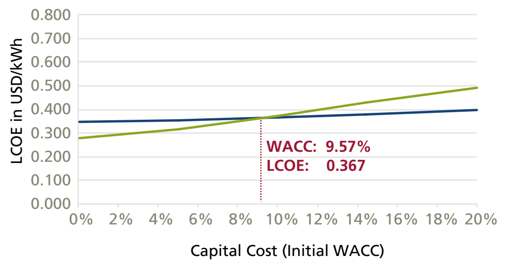
BEQUIA – St. Vincent and the Grenadines



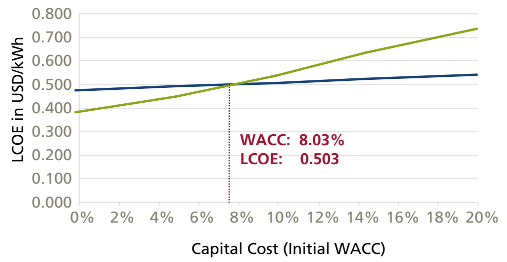
NUSA PENIDA – Indonesia



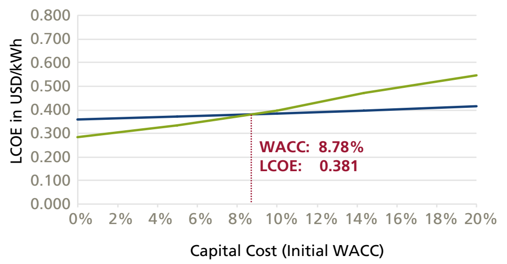
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia

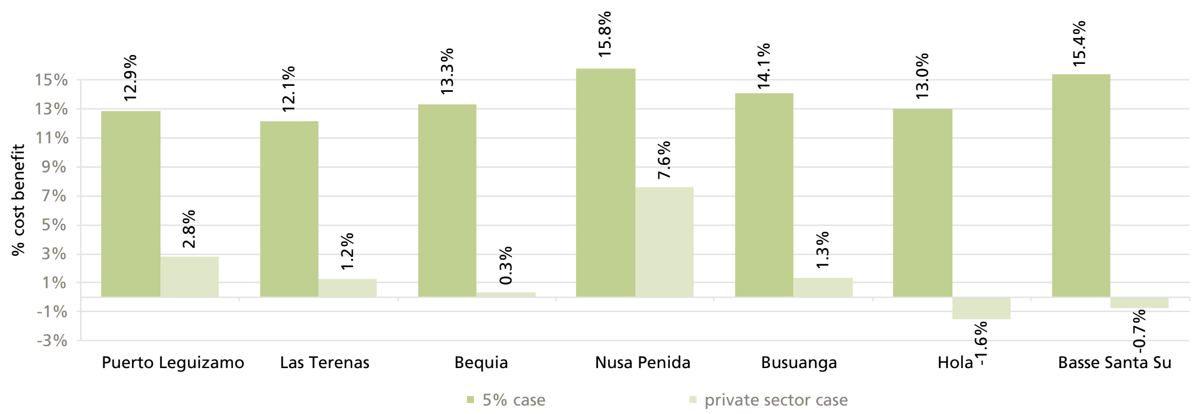


Power source

- Diesel only
- Hybrid

Perhaps, as discussed already in section 4.2, the WACC at individual sites can be lowered for instance by i) financing the hybrid project on the balance sheet of the utility, with presumably lower equity return expectations than an IPP which was assumed at 15 percent in the financial model; ii) concessional debt finance with interest rates lower than the assumed 8 percent. Figure 47 compares for each site the cost benefit of diesel and hybrid for the private sector case (project finance structure, WACC changing over project lifetime as debt is repaid) to a public sector case with an assumed WACC of 5 percent over the entire project lifetime. In the 5 percent case, average generation costs can be lowered from 12.1 percent in Las Terrenas to as much as 15.8 percent in Nusa Penida. The lower discount rate results in a significant reduction of financing costs as part of the hybrid LCOE.

Figure 47: Cost advantage of hybridisation with private and public financing costs



Financing costs are driven by the interest rate on debt (including risk margin), the loan tenor, the initial debt/equity ratio as well as the equity return expectations. The base case analysis kept margin and loan tenor stable, and calculated the debt capacity (i.e. the initial debt/equity ratio) based on the debt service cover ratio (DSCR). As a result, the safety cushion for the commercial lender remained stable in different scenarios, and the risk margin did not need to be adjusted. The hybrid system, however, is burdened by higher capital intensity, and thus a longer payback period. Due to this 'loss of flexibility' (i.e. increased capital commitment), it can be perceived as financially more risky, resulting in a higher risk margin.[41]

Figure 48 therefore compares the hybrid LCOEs under consideration of increasing risk margins (plus 2 percent, 4 percent, 6 percent) to a constant diesel case. The initial WACC results from the given private sector financing assumptions, and differs for each site due to local tax rates. The scenarios show the effect of increasing financing costs for the hybrid case (diesel remains stable). Financing costs for the hybrid system can be increased up to the 'intersecting' WACC; for higher financing costs, economic viability of the hybrid investment is no longer given. Contrary to the 'intersecting WACC', the 'break-even WACC' (discussed above) is based on the assumption that financing costs for both diesel and hybrid increase equally at the same level.

[41] Besides reduced financial flexibility, the hybrid system, in general, also comes along with a limited flexibility to react to decreasing demand. Output and hence variable costs of diesel generators can easily be reduced (close to zero), whereas the hybrid always (at least) produces the PV share of electricity. At the selected sites, however, it is not expected that the demand will decrease to a level where the PV-generated electricity exceeds the actual demand, i.e. where there are operational and financing costs without revenues.

Figure 48: Impact of different risk margins on LCOE

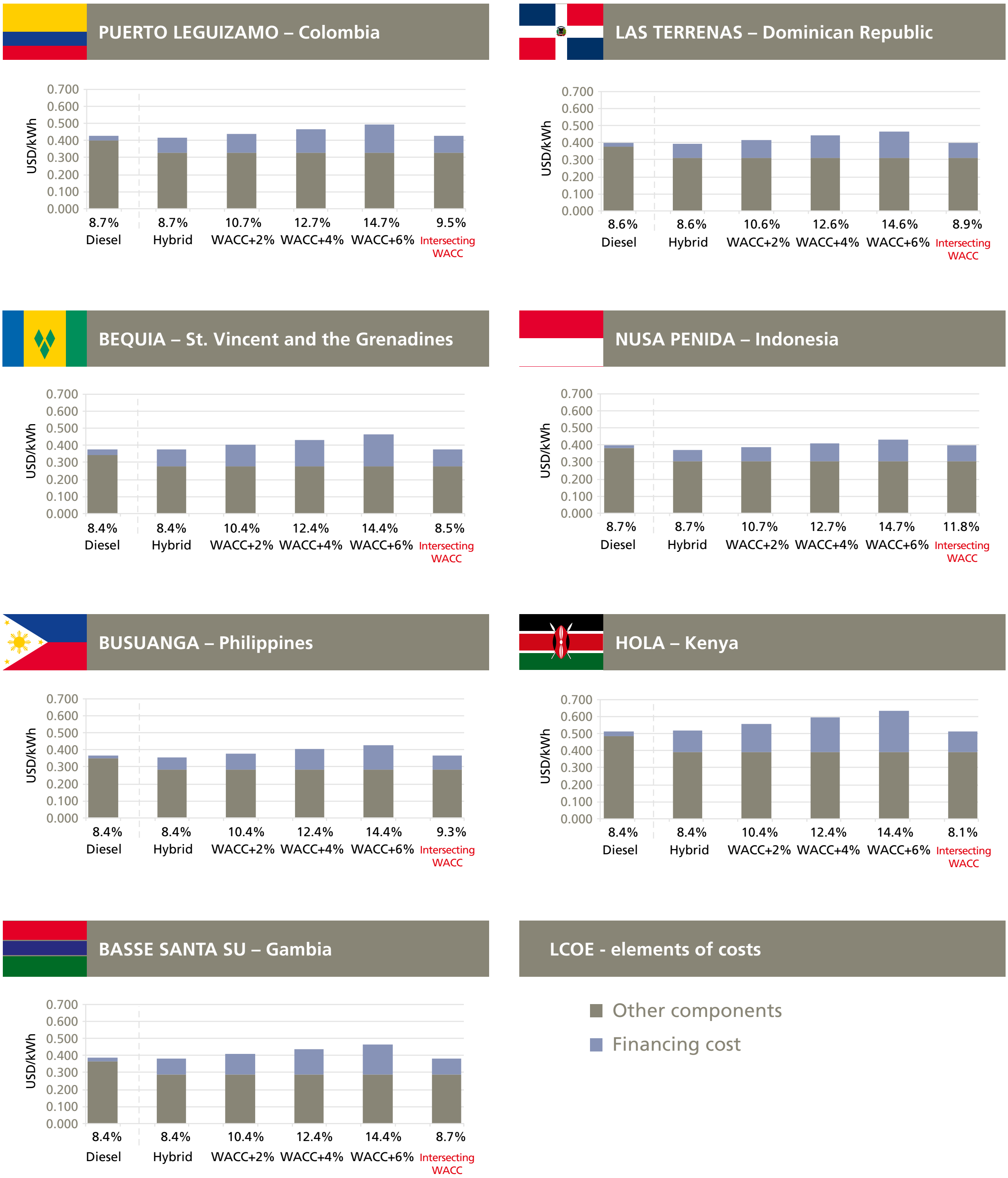


Table 6: Increase of financing costs at intersection

Town/Island	WACC increase at intersection
Puerto Leguizamo	1.4%
Las Terrenas	0.3%
Bequia	0.1%
Nusa Penida	3.1%
Busuanga	0.9%
Hola	-0.3%
Basse Santa Su	0.3%

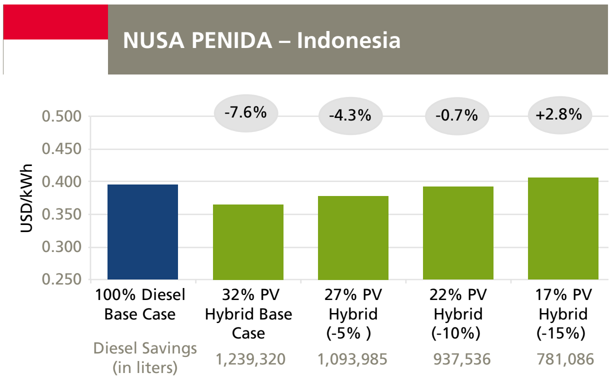
The same effect is shown in table 6. Among the selected sites, depending on the base-case cost advantage of the hybrid system, a WACC increase between 0.1 percent and 3.1 percent for the hybrid system could be tolerated for retaining a cost advantage. This highlights again that a different set of financing assumptions for diesel and hybrid system can have a major impact.

4.4.3. IMPACT OF ACHIEVED PV PENETRATION LEVEL

The (economic) viability of a hybrid system furthermore depends on the achieved PV penetration level. For Nusa Penida, the HOMER tool calculated a PV penetration of 32 percent, or 4,649 MWh of 14,692 MWh annual electricity generation.

Figure 49 shows the hybrid LCOE under reduced PV penetration levels (minus 5%, 10%, and 15%). Although the solar irradiance level is well predicable over one year and the project lifetime, respectively, externalities like dirt, clouds, or losses in cables can decrease the PV output. Accordingly, the diesel generators have to be utilised to a larger extent, reducing diesel savings.

Figure 49: Impact of PV penetration on LCOE



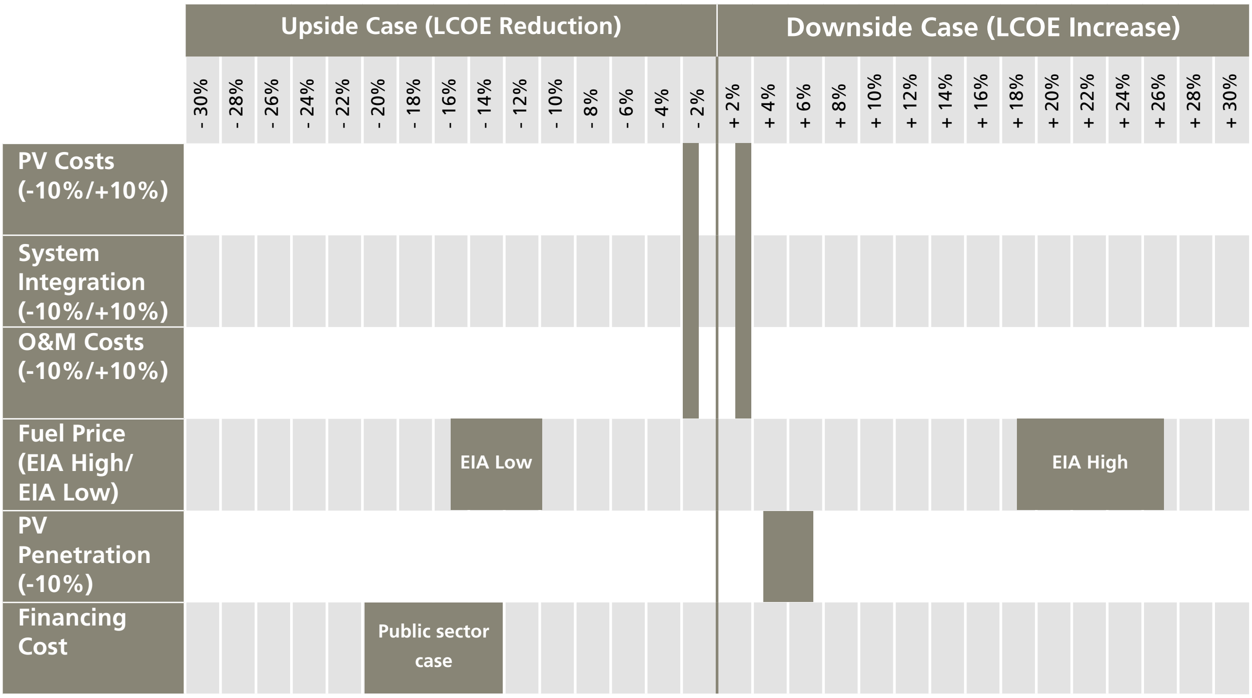
4.4.4. IMPACT OF CAPEX AND OPEX CHANGES

The impact of a 10 percent increase/decrease of CAPEX and OPEX (other than diesel) is shown in table 7. A variance of 10 percent in equipment cost in each of the components only leads to changes in the overall LCOE by up to 2 percent. Also a 10 percent change in operational expenses influences the LCOE only marginally by maximum 1.5 percent.

Table 7: CAPEX and OPEX sensitivities

Town/Island	Current assumptions	Impact of +10% on LCOE	Impact of -10% on LCOE
	Puerto Leguizamo		
PV Costs	5.61m/2.75MW 2.04m/1MW	1.7%	-1.7%
Balance of System	3.02m	0.7%	-0.7%
Average OPEX p.a.	0.49m	1.0%	-1.0%
	Las Terrenas		
PV Costs	13.77m/6.75MW 2.04m/1MW	1.9%	-1.9%
Balance of System	5.78m	0.6%	-0.6%
Average OPEX p.a.	1.65m	1.5%	-1.5%
	Bequia		
PV Costs	3.06m/1.5MW 2.04m/1MW	1.8%	-1.8%
Balance of System	2.2m	1.0%	-1.0%
Average OPEX p.a.	0.31m	1.1%	-1.1%
	Nusa Penida		
PV Costs	6.12m/3MW 2.04m/1MW	1.6%	-1.6%
Balance of System	3.22m	0.7%	-0.7%
Average OPEX p.a.	0.6m	1.1%	-1.1%
	Busuanga		
PV Costs	6.12m/3MW 2.04m/1MW	2.0%	-2.0%
Balance of System	3.03m	0.7%	-0.7%
Average OPEX p.a.	0.59m	1.2%	-1.2%
	Hola		
PV Costs	1.02m/0.5MW 2.04m/1MW	1.3%	-1.3%
Balance of System	1.65m	1.9%	-1.9%
Average OPEX p.a.	0.15m	1.2%	-1.2%
	Basse Santa Su		
PV Costs	2.652m/1.3MW 2.04m/1MW	2.0%	-2.0%
Balance of System	2.22m	1.2%	-1.2%
Average OPEX p.a.	0.22m	1.0%	-1.0%

Figure 50: Summary of sensitivities



4.4.5. SUMMARY OF SENSITIVITIES

Figure 50 shows the ranges of sensitivities across all sites. As described above, changes in the fuel and financing costs have the largest impact.

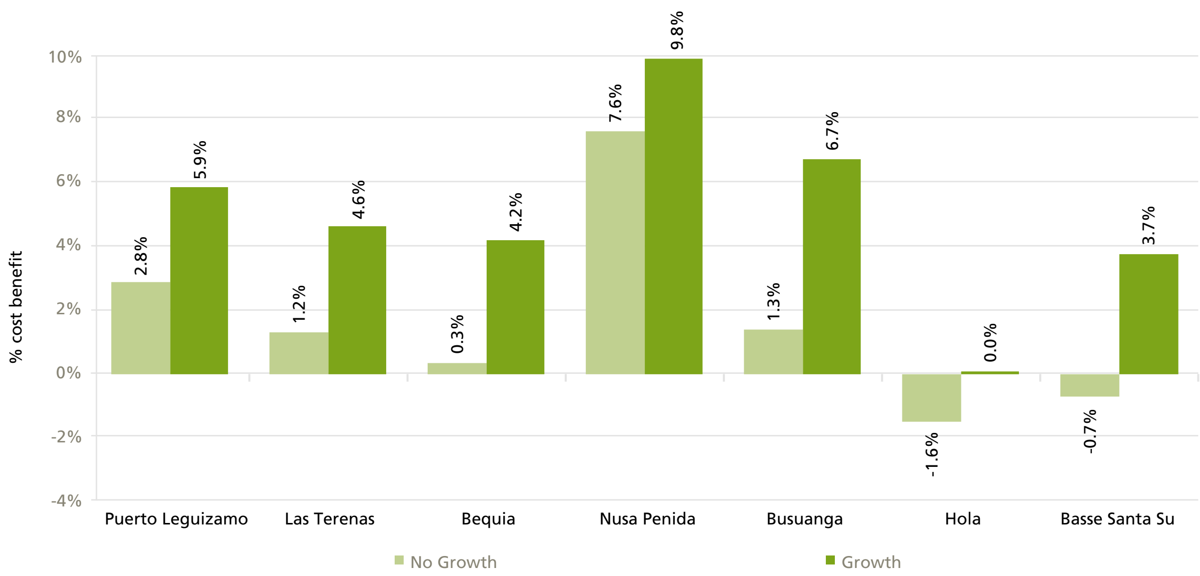
4.4.6. IMPACT OF DEMAND GROWTH

To consider demand growth, additional PV capacity needs to be installed over project lifetime (see section 3.4 for details on system sizing). The lifetime of these additional modules (and other new components), however, exceeds the 20 year timeframe applied in the financial model. The 'growth LCOEs' do not consider electricity generated after year 20, while additional costs are distributed only over the output of the remaining years (until year 20).

Further, the approach for modelling growth (i.e. the regulatory framework) was simplified in a way that no residual values of PPAs were considered. Concessions are typically provided over 20 years. When installing additional components in later years, PPAs actually had to be revised (i.e. extended). In the financial model, though, it was assumed that PPAs end after 20 years lifetime of the initial investment. To mitigate the effects, it was assumed that the generation assets can be sold at book value at the end of year 20.

Figure 51 shows that – even over the limited 20 years project lifetime – demand growth already has a positive effect on most hybrid LCOEs. For instance, in Las Terrenas, the relative cost advantage of hybridisation increases from 1.2% (no growth case) to 4.6% (growth case) – again ceteris paribus. The 'actual' growth LCOEs (considering output of additional PV after year 20) are most likely lower than the ones shown in the graph, with an additional relative cost-advantage of the hybrid.

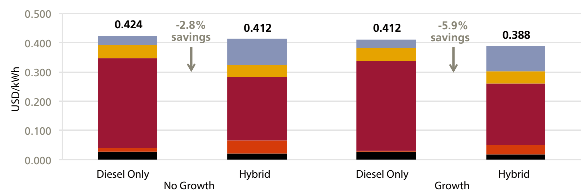
Figure 51: Cost advantage of hybridisation with and without growth



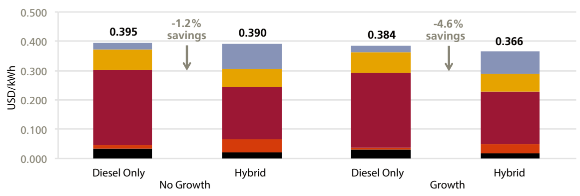
A detailed breakdown of the different sites' LCOEs with and without demand growth is shown in figure 52.

Figure 52: LCOEs with/without demand growth

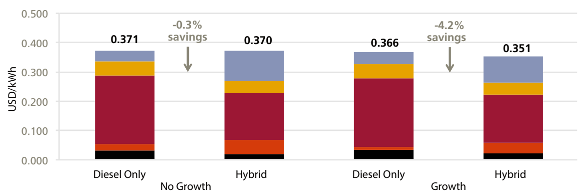
PUERTO LEGUIZAMO – Colombia



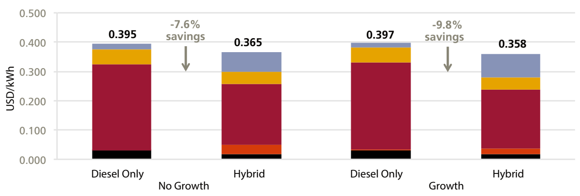
LAS TERRENAS – Dominican Republic



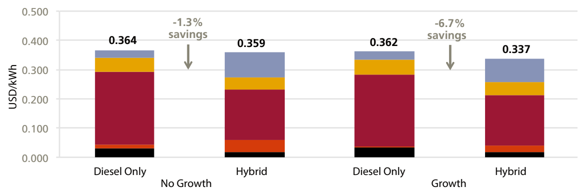
BEQUIA – St. Vincent and the Grenadines



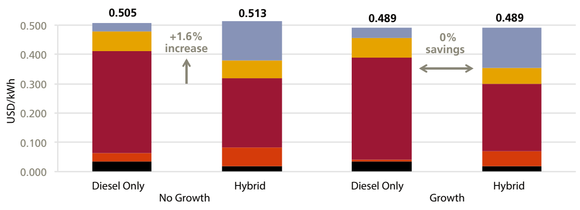
NUSA PENIDA – Indonesia



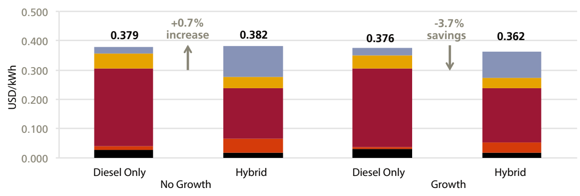
BUSUANGA – Philippines



HOLA – Kenya



BASSE SANTA SU – Gambia



LCOE - elements of costs

- Cost of carbon emissions
- CAPEX
- Fuel
- OPEX
- Financing costs

5. FINANCIAL VIABILITY ASSESSMENT

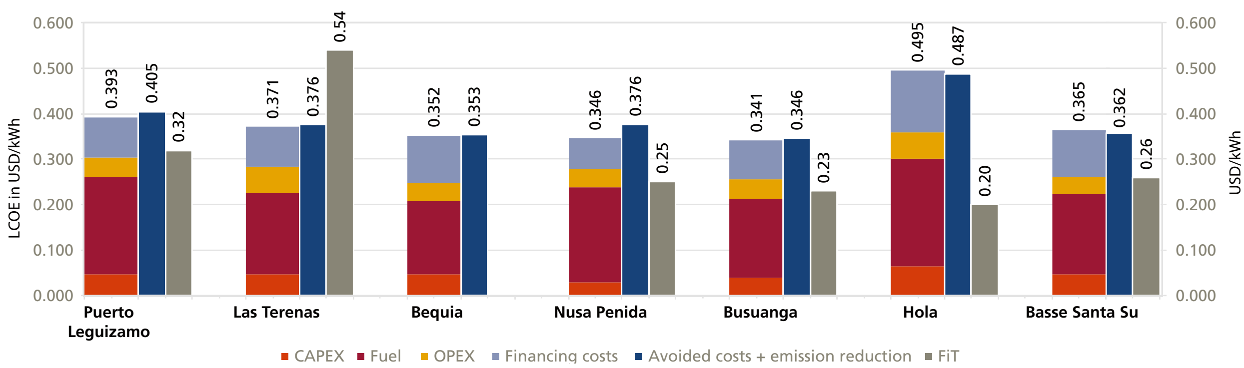
Financial viability is given if a hybridisation project offers an attractive investment opportunity for the private sector, i.e. if revenue streams are high enough to generate sufficient cash flows to pay for all costs, including cost of capital. The requested risk margins will be heavily influenced by the risk profile of the investment opportunity. The required regulatory frameworks for hybrid mini-grids are still to be created, to enable crowding in of private sector financiers. Financial indicators like project return[42] and equity return[43] expectations, payback periods and possible debt tranches are calculated based on the revenues generated from the sale of the electricity, and provide a basis for investment decisions. If the remuneration per kWh is lower than the LCOE, the project is not financially viable, since the project owner would incur ongoing losses. As a consequence a PPA or other framework needs to ensure sufficient revenues that allow for cost recovery.

In case of an IPP, the operator has entered into a PPA and/or concession agreement with the government, which guarantees them a predictable cash flow. Diesel price risk is absorbed by the public sector which makes the risk profile for the IPP more appealing. It is understood that under the current PPAs/concession agreements, none of the IPPs could switch directly from diesel to a hybrid generation asset, i.e. financial viability of a hybridisation is not given. Also, existing FiT regimes cannot be applied, and FiT levels would not be sufficient to compensate not only for the PV output but also the system integration costs. Nevertheless, there is a chance that PPAs could be renegotiated to create financial viability.

Considering externalities in the economic viability assessment is best practice. From the perspective of a potential private sector investor, this effect needs to be excluded as carbon emissions are public goods rather than private ones (not triggering concrete cash flows) and it is unlikely that the existing carbon market mechanism result in sufficient cash flows. Governments would consequently price in this market failure.

Revenues in the amount of the hybrid LCOE (excluding carbon cost), represent the minimum required remuneration under the given financing assumptions. This analysis can be used to illustrate debt repayment schedules and equity cash flow profiles. The EIRR will come in at the target level. If the hybrid LCOE comes in below the current LCOE, which is the case for most systems, this should be the basis for price discussions. In the case of a utility-owned system, the utility could accrue the cost savings to itself and reduce required subsidies.

Figure 53: LCOE for hybrid systems excluding cost of carbon under no-growth scenario



[42] Only the project cash flows (i.e. the net operating and investing cash flow before financing cash flows -disbursement of debt, debt service) are considered in the calculation of the IRR.

[43] Financing cash flows are also included in the calculation.

Revenues can also be based on current LCOE of the diesel scenario plus the cost for the reduced carbon emissions (the 'avoided cost'), i.e. the hybrid system would be compared to the costs that are currently incurred by the 100 percent diesel system plus an additional top up for the emission reduction.

Figure 53 shows the LCOE excluding carbon cost and also the avoided cost of diesel (diesel LCOE plus top up for emission reduction). Five out of seven sites are viable at avoided cost, Hola and Basse Santa Su show a gap of 7.8 USDc/kWh and 2.8 USDc/kWh, respectively.

Table 8: Asset ownership

All assets under one ownership	PV under separate ownership
All generation assets and associated equipment are owned by a single entity and financed by the owner - in most cases the utility. However, there might also be cases in which the utility sells all of the existing diesel generators to an IPP, which then generates electricity and sells it to the utility under a PPA. Depending on whether the assets are owned by the utility or a private sector IPP, the financing costs vary. The majority of grids are owned by public utilities. Private finance sector investment would require the implementation of IPP laws and a sale of the existing diesel generator to the hybrid IPP under the single ownership model. In most cases the current PPAs or available FiT regimes do not adequately address the specifics of hybrid grids nor incentivise owners to reduce generation costs. For initial projects the negotiation of such a framework would involve additional transaction costs (and transaction risk). The technology introduced in this study requires an integrated management of the diesel and renewable energy generation capacity. As a result, existing diesel assets would need to be sold or leased to the private sector player in case of an IPP structure. It is expected that private sector investors would demand a risk premium as a consequence of the longer payback period and the given level of technology risk which could, in principle, make it unattractive for the public sector to enter into IPP contracts. Rather the public sector might want to outsource the operation only and make use of attractive international concessional financing for the initial projects.	In this scenario, a new (private sector) investor owns the PV plant only, while the utility owns the balance of system equipment and diesel generators. The PV IPP would finance the PV modules only, whereas the utility would have to finance the remaining parts. The PV IPP and utility would enter into a "take-or-pay" contract, in which the utility would pay for every kWh of electricity produced by the PV plant, regardless of whether or not it is used. The price would be the PV LCOE since it comes in far below the avoided cost of diesel. The utility could then reduce the production from diesel-based electricity by the amount of electricity received from the PV IPP and incur respective cost savings (price paid to PV IPP vs. avoided cost of diesel). Local FiT for PV electricity could be the basis for price discussions for the cases were the PV portion of the plant is split out. Since the PV IPP would not be burdened by the high diesel costs nor the capital costs of the balance of system equipment, it may prove more attractive to private sector investors. The utility, however, would incur additional costs for the remaining portion of the hybridisation equipment as well as the cost for the purchased electricity. These added costs need to be weighed against the savings from reducing the diesel-based electricity. To get the full picture and to not over-estimate the viability of this solution, both views need to be analysed together.

5.1. OWNERSHIP STRUCTURES

A hybridisation project can be financed by the utility, currently owning the brownfield asset (most likely a public body) or by the private sector. The operational structure is somewhat independent from the financing structure, and the implementation and operation of a hybrid plant can be tendered out even if the assets remain in the ownership of the public sector.

The different ownership structures - as outlined in table 8 - impact the projects' key performance indicators and hence the willingness of different types of financiers to offer funding. The party owning (though not necessarily operating) the equipment would have to seek financing. Only electricity generation – not distribution – is considered. Acknowledging that the '100 percent peak penetration' technology requires a combined and aligned management of both generation assets, this study focuses on structures with all assets under one ownership, either owned by the utility or an IPP.

5.2. CASH FLOW ANALYSIS – NO-GROWTH CASE

Using the example of Nusa Penida, this section analyses the cash flows of the hybrid project for both no-growth and growth cases. All other sites show similar investment profiles and financing structures. The project IRR for all sites is presented in table 9.

For Nusa Penida, not considering growth, the total initial investment is USD 10.3 million, with additionally required replacements of USD 2.7 million and USD 0.4 million in years 10 and 12, respectively (see table 10). The net operating cash flow is the revenues (based on hybrid LCOE of 34.6 USDc/kWh, excluding carbon costs) less fuel costs, other operational expenditures, and taxes.

Considering a project finance structure and its related transaction costs (for instance for due diligence and setting up a special purpose vehicle), the total investment volume of USD 10.3 million (translating in a lending volume of USD 6.2 million) represents a relatively low ticket size. Similarly, the investment volume of the other sites – ranging from USD 3.0 million in Hola to USD 22.8 million in Las Terrenas, would only result in a relatively low ticket size for a project finance transaction (maximum lending volume of USD 14.3 million for Las Terrenas).

Table 9: Project IRR with/without growth

Town/Island	Project IRR no growth	Project IRR growth[44]
Puerto Leguizamo	13.0%	12.4%
Las Terrenas	13.0%	12.4%
Bequia	13.0%	13.1%
Nusa Penida	13.3%	11.0%
Busuanga	13.6%	12.0%
Hola	13.0%	12.9%
Basse Santa Su	13.5%	12.8%

For the base case, the net operating cash flow increases in the initial years as the diesel price is expected to decline (EIA reference scenario), while revenues remain stable on a real basis (see figure 54). Taking capital investments into account, the project reaches simple payback in year 7 (project IRR = 13.3 percent).

Project finance structures require predictable cash flows. The project finance terms as applied in this model would require a hedging of the diesel price risk or allocation of this risk to the public sector. Diesel price increases above the projected increase would reduce the cash flow available for debt service, leading to lower initial loan amounts or a requirement for longer loan tenors.

Based on stable revenues, above mentioned private sector return expectations, and taking into account the minimum DSCR of 1.2, the debt capacity comes in at 60.5 percent (excluding carbon costs).

[44] To consider demand growth, additional generation capacity needs to be installed in later years. The lifetime of these additional components, however, exceeds the 20 year timeframe applied in the financial model. The 'growth project IRRs' do not consider electricity generated after year 20, while additional costs are distributed only over the output of the remaining years (until year 20). To mitigate the effects, it was assumed that the generation assets can be sold at book value at the end of year 20. Hence, the actual project IRRs under growth assumptions are expected to be higher than shown in the table.

The initial investment would be financed with USD 6.2 million debt and USD 4.1 million equity (figure 56). The debt ratio goes down over the lifetime of the project; the project remains 100 percent equity-financed once the debt is fully repaid after the assumed 12 years loan tenor (1 year grace period). Any requirements for an accelerated repayment of debt are not considered.

Table 10: Hybrid investment costs (in USD, Nusa Penida)

Components	Initial Costs	Replacement Costs Year 10	Replacement Costs Year 12
Diesel Gen-Sets	1,475,600	734,400	367,200
PV-Panels	6,120,000		
Balance of system (converter, battery, automation tool)	1,999,200	1,985,600	
Capital Investment	9,594,800	2,720,000	367,200
Contingencies (5%)	479,740		
Transaction Costs (2%)	191,896		
Total Initial Investment	10,266,436		

Figure 54: Net operating cashflow (in USD '000, Nusa Penida)

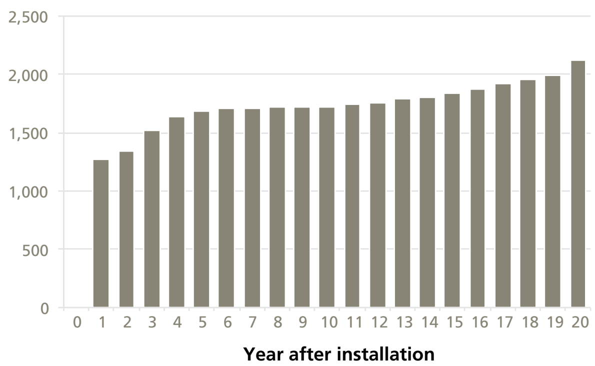
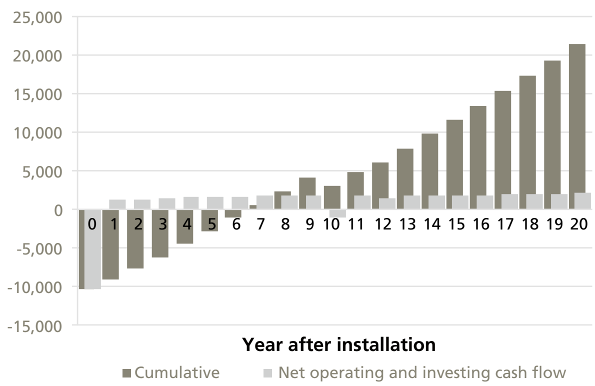


Figure 55: Net operating & investing cashflow (in USD '000, Nusa Penida)



After debt service (figure 57), the remaining cash flows are distributed to equity investors (figure 58). Dividend payments are suspended in year 1 and 2 due to minimum cash requirements and beginning of debt repayment; they start in year 3 at a relatively low level. Also, equity investors are not paid dividends in year 10 due to replacement investments of USD 2.7 million. Once the debt is fully repaid, and all replacements have been installed, the dividend level increases towards end of the project lifetime. Equity investors achieve simple payback in year 8. The chosen financing structure incentivises the equity investor to properly manage and operate the project over the loan tenor and beyond, since the equity return reaches attractive levels only after debt is repaid. The equity IRR increases after the loan is repaid, stays flat in year 10 due to replacement investments and then increases further until reaching the targeted 15 percent in year 20.

Figure 56: Debt/equity ratio over project lifetime (in USD '000, Nusa Penida)

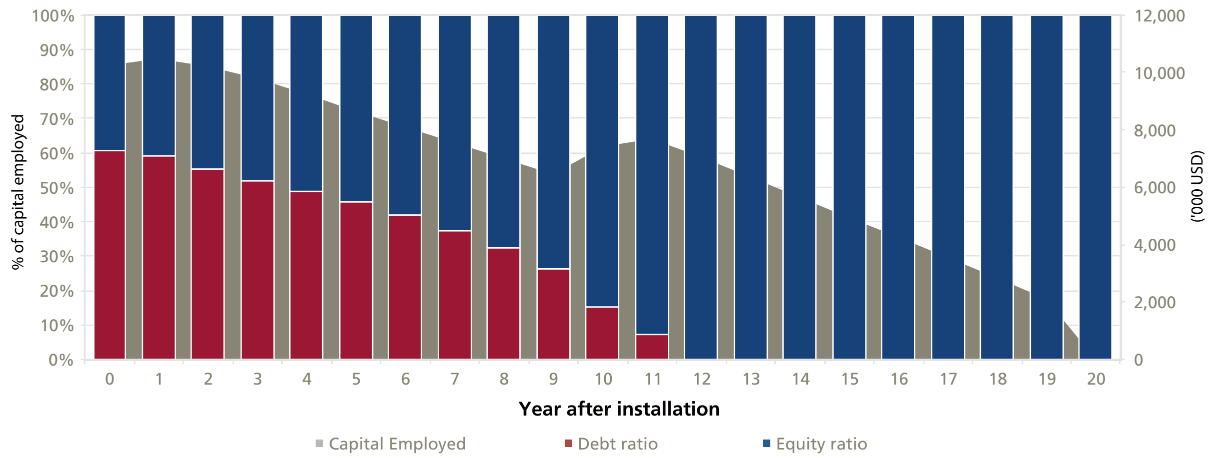


Figure 57: Debt repayment (in USD '000, Nusa Penida)

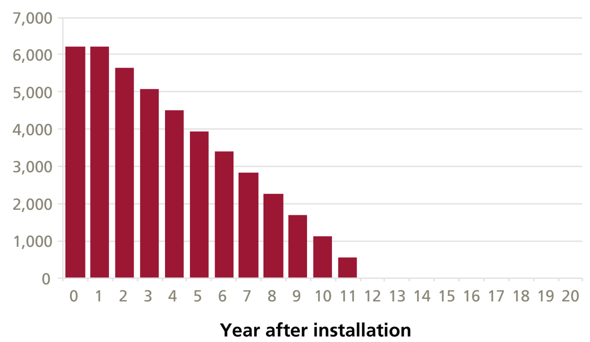
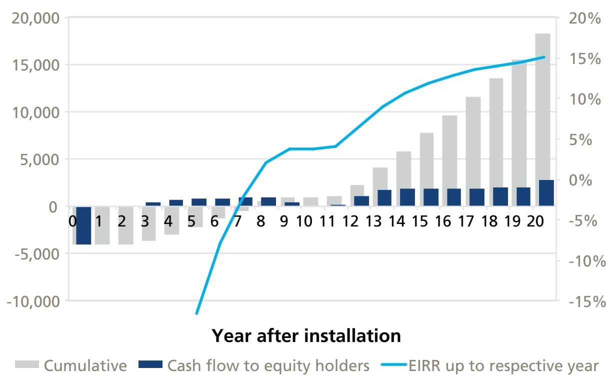


Figure 58: Equity payback (in USD '000, Nusa Penida)



5.3. CASH FLOW ANALYSIS – GROWTH CASE

Project financing typically focusses on one concrete project. The growth case could be considered as a series of several projects, which is a more entrepreneurial approach. For each increase in generation capacity, the existing underlying contracts would need to be amended or separate contracts for the additional capacity need to be negotiated. For the purpose of this study, it was assumed that additional debt can be sourced during the expansion of the project.

Taking demand growth into account, it is assumed that revenues equal the hybrid LCOE of 34.1 USDc/kWh (excluding carbon costs). Figures 59 and 60 present the net operating and investing cash flow. Project IRR is 13.5 percent.

As shown in figure 61, the initial investment (USD 14.1 million) would be financed with 56.7 percent debt (USD 7.96 million) and 43.3 percent equity (USD 6.1 million). Besides replacement investments in years 14 (USD 1.6 million), new debt and equity injections are required to finance additional (extension) investments in years 7 (USD 5.8 million – only equity), 13 (USD 2.6 million) and 14 (USD 3.6 million). The second and third debt tranches are assumed to be paid back at the end of the 20-year project lifetime (figure 62). Any requirements for an accelerated repayment of debt are not considered.

Figure 59: Net operating cashflow; growth case (in USD '000, Nusa Penida)

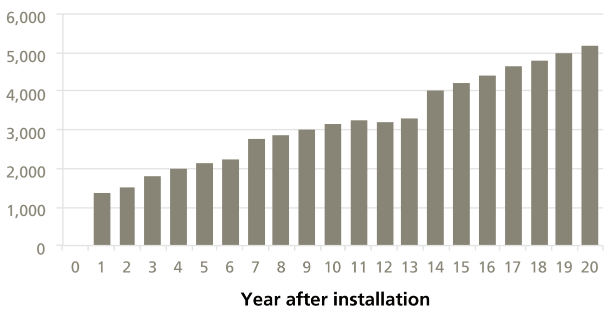


Figure 60: Net operating & investing cashflow; growth case (in USD '000, Nusa Penida)

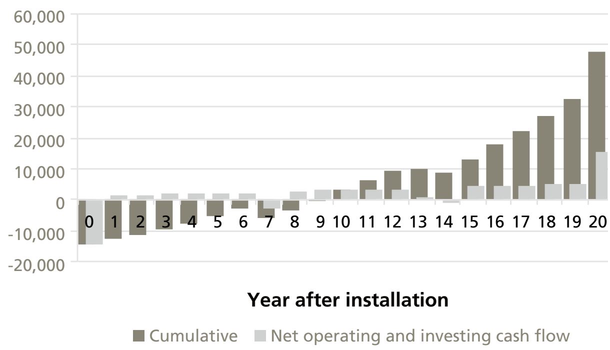


Figure 63 shows that equity investors are not paid dividends in year 1 and 2 due to minimum cash requirements and beginning of debt repayment.

Payback of equity is in year 11. The equity IRR increases as debt is repaid, reaching the targeted EIRR of 15 percent in year 20.

Figure 61: Debt/equity ratio over project lifetime; growth case (in USD '000, Nusa Penida)

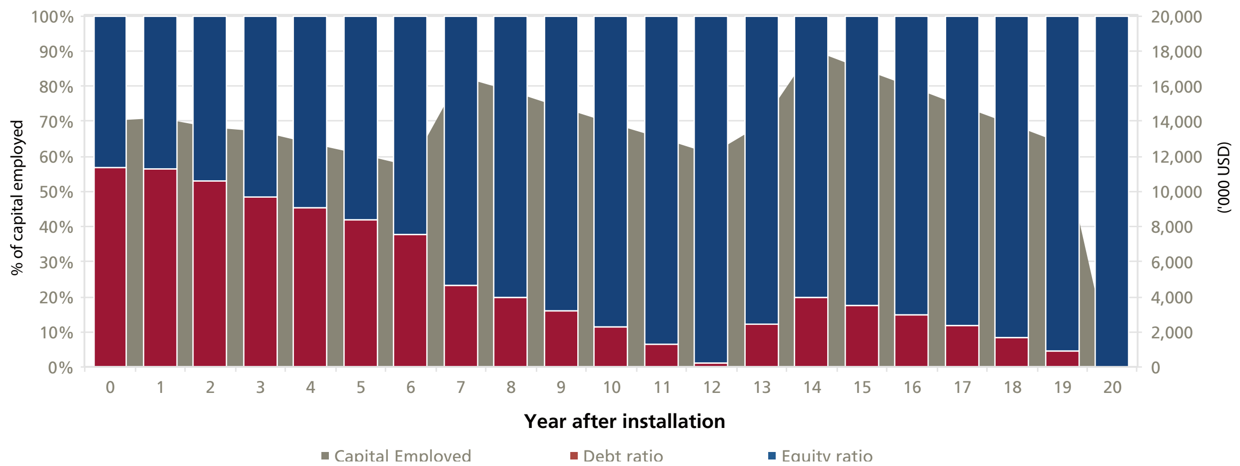


Figure 62: Debt repayment; growth case (in USD '000, Nusa Penida)

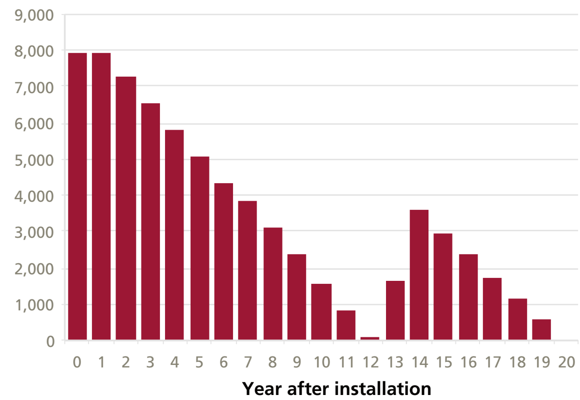
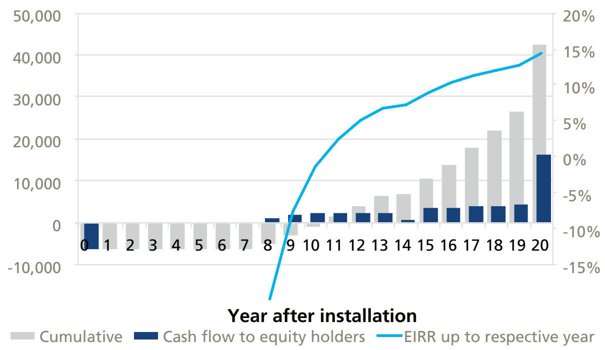


Figure 63: Equity payback; growth case (in USD '000, Nusa Penida)



6. CONCLUSIONS

Based on case studies in seven countries, hybrid mini-grids that combine electricity generation from RE sources with existing diesel generation have potential to reduce energy costs and boost energy security in a wide variety of situations around the world.

The current diesel-only average generation costs at the chosen sites (without carbon externalities and financing costs) range from 31 to 44 USDc/kWh. They are driven mainly by the high cost of diesel fuel – in particular – in island settings today. Often, end-customer tariffs do not come in at a cost-reflective level, and the operation of remote grids represent a burden to the national utilities and hinder accelerated grid expansion. In addition, the current reliance on diesel fuel exposes utilities and governments to diesel price volatility, with diesel-only generating costs increasing by up to 33 percent in case of 'EIA high' oil price projections. Hybridisation projects can help to reduce average generation costs and exposure to diesel price volatility.

PV power can generate electricity at much lower costs at all sites studied, which are located in regions with high solar radiation. The average generation cost for PV – assuming that every kWh produced can be used – is 16 USDc/kWh to 23 USDc/kWh. Where biomass and/or wind resources can be utilised, the average generation costs may be even lower.

Because the hybridisation and integration of intermittent RE in an isolated grid require additional investment, the above-stated generation costs (diesel vs. PV) cannot be directly compared. The inconsistent use of LCOE per kWh produced (as an indicator to compare different renewable and fossil-fuel based technologies) rather than system LCOEs (LCOEs per kWh sold) confuses stakeholders and raises unrealistic expectations. In a hybrid system, investors swap a part of the costs for diesel with financing costs and depreciation of the initial investment in renewables capacity. This margin drives economic viability. Not taking into account financing costs, the average generation cost in the hybrid systems come in below the current generation costs in all cases.

Financing costs are a major driver of achievable cost savings. Among other things, the level of financing costs is determined by the chosen ownership structure. Assuming a hybridisation project is financed on the balance sheet of the utility, and access to concessional finance is given, the assumption of a 5-percent flat discount rate appears realistic. In this case, the hybridisation of diesel grids with PV would yield significant cost savings. Savings at the seven sites (including costs of carbon emissions) range from 12 to 16 percent under a mid-case scenario for oil prices, and from 16 to 20 percent at high-case oil price projections – although PV at the sites accounts for just 31 to 40 percent of overall electricity generation. And, since PV is more costly than other renewable options such as wind, hydro, or geothermal power that may be available, these estimates of savings are conservative.

If hybridisation is financed by the private sector through an IPP, the PPA needs to compensate for higher financing costs (owing to higher refinancing costs as well as a mix of real and perceived risks associated with investing in power generation assets in developing countries). Since hybrid grids are more capital intensive than diesel grids, this decreases the attractiveness of the hybrid solution. Nevertheless, even with private finance, hybridisation reduces electricity generation costs at five of the seven sites.

The appetite of private-sector lenders for hybrid mini-grid investments is likely limited by their small size, which results in high transaction costs relative to anticipated revenues (of course varying from market to market). In many developing countries, it is hard to obtain commercial financing even for medium-scale RE projects on larger grids. Hybrid mini-grids are small and more complex. For the initial transactions it is therefore believed that concessional financing from international financial institutions will be required to leverage private investments in mini-grids – at least until more experience is gained, risks are better understood, and private financing costs decline.

Among the investigated sites, the differences in estimated cost reduction are mainly due to differences in plant size, on-site diesel costs, and solar radiation. Larger plants can achieve economies of scale by distributing the fixed cost of the hybrid system (like the automation tool required for the hybrid technology applied in this study) over more units of generated electricity. High diesel prices result in high cost savings and allow hybrid systems to offer partial insurance against the risk of rising fuels costs. Higher solar radiation allows each unit of PV capacity to produce more (cheaper) electricity. The two sites where hybridisation could result in a cost increase (Hola and Basse Santa Su) have by far the smallest generation capacity, and even relatively high local diesel prices and solar radiation cannot compensate the missing scale. In contrast, the cost advantage at the largest site (Las Terrenas) is limited by relatively low diesel prices and solar radiation. The most viable case for hybridisation is Nusa Penida, a mid-sized plant with the highest diesel prices and relatively high solar radiation.

There is limited evidence that significant load management can easily take place that could reshape the demand curve in a way that it becomes more compatible with the PV output curve. Realising economic potential from such load management would require some on-site activity and appropriate incentive structures. It remains, however, an upside potential that should not be ignored when preparing for a concrete project.

The risk of adverse diesel-price developments remains with the public sector, irrespective of whether the sites are operated by the public sector or outsourced to private sector operators (through PPAs with diesel-price-adjustment clauses). Hybrid systems mitigate the public sector's exposure to diesel-price volatility and serve as a natural partial hedge against diesel price changes. Given the results of this analysis, public sector stakeholders should be encouraged to analyse the potential for hybridisation – also with other technologies – in more detail. If realisation is not possible on the utility's balance sheet, they should support the creation/change of PPAs/concessions in a way that the relative cost advantage of hybrid plants can be realised by the private sector.

Some additional observations relate to potential implementation challenges:

The absence of up-to-date and reliable cost and performance data for RE technologies is often a significant barrier to their uptake. This can lead to inefficient policy making, and undermine public support for renewables and hence hybrid power systems. Accurate, transparent, and reliable data would ensure that decision makers and the public are adequately informed, as well as help convince investors and financial institutions that the risks of RE investments are limited.

Before implementing the hybrid project at any of the sites, another more thorough cost analysis needs to take into account all site-specific details (to be disclosed by the utilities). It has to be determined, for instance, which elements of costs are ultimately included in current diesel generation costs, and which financing conditions were applied. Once these aspects are known, the hybrid generation costs have to be re-calculated, based on the same assumptions.

Analysis should be performed of alternate technical configurations for hybridisation as well as different mixes of RE resources and potential connection to the main grid. This study compares electricity generating costs of existing diesel power plants to those of simulated PV-diesel hybrid grids, applying a '100-percent peak PV penetration' solution. At particular sites, however, another hybrid configuration and other renewable resources might be even more cost-effective. Other hybrid system configurations – for example using diesel spinning reserves or larger battery banks to balance fluctuations in solar power output – could be the subject of follow-up analyses. And for sites not far from the main grid, where generating costs are generally lower than in isolated areas because there is a wider mix of generating options, analysis of extending the grid is critical.

The level of familiarity with hybrid technologies among stakeholders, in particular in environments dominated by residential consumption, is often limited. Technology providers need to develop appropriate technology-guarantee mechanisms, for example with regard to possible RE penetration, which heavily impacts the relative cost advantage of a hybrid solution. The latter, however, is not straightforward as PV penetration is also heavily dependent on the underlying demand patterns. Smart risk allocation would aim to allocate demand-pattern-related risks to the public sector, and technology-related risks to original equipment manufacturers as well as engineering, procurement and construction-management companies.

A significant increase in understanding RE and hybrid business models, and a higher level of transparency among technology providers, will be necessary to create mutual trust (required to allocate resources for project assessment) and to implement such innovative projects. This also calls for fair communication with regard to achievable cost savings and financing assumptions. This analysis has revealed that findings from the commercial application of hybrid technologies (for example in the mining industry) can only partially be transferred to primarily residential applications. Nevertheless, they are often used to 'convince' stakeholders on the ground, who then become disappointed at a later stage. Also, one has to distinguish clearly between generation costs (and cost savings) per kWh sold and kWh produced.

The operation and optimisation of isolated grids is not necessarily at the top of the agenda of national utilities, as they are often too small to receive much attention in the national context. Even if isolated grids are heavily loss-making, their low relative contribution to the overall (financial) utility results rarely triggers significant management attention. Also, operators on the ground often lack the broader perspective and awareness to drive a discussion around hybridisation. Required data to properly analyse the economic viability of a hybrid project needs to be compiled from different stakeholders. For instance, local contacts (on-site at the isolated grid) often lack access to data on the volume of electricity sold or actual diesel spending. On the other hand, experts and managers at the utility headquarters are rarely aware of optimisation potential on site. Private-sector operators of isolated grids are regularly compensated on a cost-plus basis, which does not create significant incentive to consider hybrid solutions.

The limited scalability and replication potential (driven by a required site-specific technical layout of hybrid plants) represents a barrier for implementation. There are few countries with a significant number of (comparable) isolated grids. Consequently, countries with a large number of similar isolated grids might be particularly interesting to look at. This is the case in Kenya, where – although the expected cost advantage of hybridisation is relatively limited in Hola – a pipeline of similar brownfield projects for hybridisation already exists.

For many sites, the current, diesel-dominated operation is not yet optimised, and cost-reduction potential can also be expected on this side. Furthermore, in the current environment, a (fact-based and highly accurate) approach towards economic viability of hybridisation might be rational, but not necessarily convincing for local stakeholders.

Given the site-specific nature of the hybridisation technology, and the relatively marginal emission savings (from a global perspective), it may prove difficult to access climate funds, which prefer to focus on low-hanging fruits that will contribute to rapid emissions reductions. This kind of climate finance may be better classified as development intervention.

Reality is more complex and less rational than a financial model. 'Walking the talk' will be challenging for projects at first, and will involve significant additional (and in this study not reflected) transaction costs for setting up an appropriate framework. Nevertheless, the learning-curve can be steep, and additional initial efforts will pay off if a pipeline of projects is ready for realisation.

ANNEX 1: Glossary

100% Peak Renewable Energy Penetration Technology	A Hybrid Power System designed with a 100 percent peak penetration of renewable is a system that is allowed to rely totally on the renewable energy source at any moment this source is available at sufficient level. On the example of a PV-Diesel hybrid system designed this way, the operator is allowed to switch off the diesel engines when the sun is shining at peak.
Average solar radiation (kWh/m2/day)	Amount of electromagnetic energy (solar radiation) incident on the surface of the earth. Also referred to as total or global solar radiation.
Average PV supply	Amount of PV energy supplied to the grid on a daily average basis.
Avoided costs	The avoided cost of electricity produced in the current diesel grid.
Capacity factor	The ratio of the total amount of energy the plant produces during a period of time, to the amount of energy the plant would have produced at full capacity.
Carbon externalities/cost of carbon emissions	An estimate of the economic damages associated with a small increase in carbon dioxide (CO_2) emissions, conventionally one metric ton, in a given year. In the study, cost of carbon emissions of 50 USD/tCO_2 was considered. It is derived from the diesel consumption and multiplied with cost of carbon emissions.
Converter (inverter)	An electronic device that takes DC input from the solar module and converts it into AC electricity.
Debt capacity	It refers to an assessment of the amount of debt that the hybrid project can repay within a specified period of time. Based on the available net operating cash flow and a target debt service cover ratio (DSCR) of 1.2, the debt capacity for private sector debt was derived, but capped at a maximum debt portion of 70 percent
Debt Service Cover Ratio (DSCR)	It is defined as the earnings before interest, taxes, depreciation and amortisation divided by the debt service (the payment of interest and repayment of principal). It needs to be ≥ 1 to provide some safety cushion for the lenders.
Economic LCOE	Economic Levelised Cost of Electricity that also considers cost of carbon emissions over the investment lifetime.
Economic viability	It considers hybridisation from a pure economic perspective. It takes into account whether hybridisation can reduce average generation costs, considering carbon emissions from diesel electricity generation as a component of the economic levelised cost of electricity (LCOE). Costs for the existing diesel electricity generation and for the hybrid scenario are calculated based on real economic costs.

EIA	U.S. Energy Information Administration. It is the principal energy agency of the U.S. Federal Statistical System and a part of U.S. Department of Energy responsible for collecting, analysing and disseminating information.
Equity IRR	Rate of return on equity invested in the project. When using the Equity IRR as a discount rate, the Net present Value of the equity cash flows would equal 0.
Feed-in-Tariff (FiT)	A policy mechanism designed to accelerate investment in renewable energy technologies. It offers long-term contracts to renewable energy producers, typically based on the cost of generation of each technology.
Financial LCOE	Financial Levelised Cost of Electricity that does not consider costs of carbon emissions over the investment lifetime.
Financial viability	It considers the perspective of equity investors and commercial lenders, i.e. whether the respective project presents an attractive investment/lending opportunity. Financial viability depends inter alia on stability/riskiness of cash flows, achievable revenues/returns and payback periods of the project.
Fully-fledged financial model	A comprehensive excel based financial model that assesses the viability of a hybrid project. The model analyses how a hybrid project will react to different economic situations or events, and estimates the outcome of financial decisions. It includes cash flow projections, depreciation schedules, debt service, balance sheet, income statement, growth scenarios etc. over the lifetime of the project. It provides all the key assumptions and allows the user to run sensitivity analysis by changing one or several assumptions at one time and see the overall results on the projected numbers.
HOMER	Hybrid optimisation modelling software, developed by National Renewable Energy Laboratory (NREL), USA.
Hybridisation	The 'Hybridisation' combines at least two different kinds of technologies for power generation and distributes electricity to several customers through an independent grid. Thus, the hybrid technology is supplied by a mix of renewable energy sources, and a generator, generally supplied with diesel, used as a back-up/base load.
IPP	Independent Power Producer, a company owning and operation electricity generation facilities and selling the output to the local utility or the end users.

Investment lifetime	The total lifetime of the project starting from construction until end of operation. In this study the investment lifetime of a hybridisation project is assumed to be 20 years.
Levelised Cost Of Electricity (LCOE)	The LCOE is the total capital, operating (incl. fuel) costs and financing cost per unit generated electricity, discounted over the investment lifetime. Typically, the discount factor is the Weighted Average Costs of Capital (WACC). In the financial model used in this study, the LCOE is calculated with a goal seek on the required revenues per unit of electricity to reach a certain equity IRR. Thus the financing structure is reflected much more accurate than in the “traditional” LCOE calculation. The LCOE is the price per unit electricity that makes an investment break even, i.e. if the revenues per unit electricity is below the LCOE, the owner of the facility will not be able to recover its cost from the electricity production without subsidies.
LCOE produced	The levelised cost of produced electricity i.e. total capital and operating costs per unit generated electricity over the investment lifetime. Excess electricity is included here. Thus the LCOE per kWh produced is lower that the LCOE per kWh sold.
LCOE sold	The levelised cost of sold electricity i.e. total capital and operating costs per unit sold electricity over the investment lifetime. Excess electricity which cannot be sold, is exluded here. Thus the LCOE per kWh sold is higher than the LCOE per kWh produced.
Load pattern	It exhibits electricity consumption behaviour into various customer classes (residential, commercial, and industrial).
Load profile	Total energy demanded from a power system over a specific period of time (e.g. hours, days, etc).
Load shedding	A power blackout/failure condition that occurs when the site is forced to shut down due to limitations in fuel supply, maintenance of the generators, or inadequate supply of power demand.
PPA	Power Purchase Agreement. It is a contract defining the terms of electricity sale between the buyer and seller of electricity.
PV mean output	Average power output from a PV system at the given solar radiations over the year (8760 hours).
PV penetration	It is defined as the ratio of total peak PV power to the peak load power of the grid.

Suppressed demand	Unmet power demand caused by the enforcement of load shedding by the power utility.
System integration	Electrical systems with multi-functional features that control voltage, frequency, power of a grid and regulate operation of the energy sources (PV, generator, battery) in it. It continuously monitors the grid, determines the cost-optimal working condition for each energy source and gives the necessary set points, calculates necessary operating reserve and allocates this to the different energy sources.
Weighted Average Costs of Capital (WACC)	It is defined as the sum of the cost of each capital component (debt, equity) multiplied by its proportional weight and adjusted by the tax shield on debt. It is the average expected return on the entire project.

ANNEX 2: Technical fact sheets

PUERTO LEGUIZAMO – Colombia

Technical data

ENERGY DEMAND

Present energy demand: 11,810 MWh/year

Growth of demand: 6% in year 1-10; 4% in year 11-20.

HYBRIDIZATION POTENTIAL (NO GROWTH)

2.75 MW PV

4.2 MW diesel generators

1.2 MW converter (DC-AC/AC-DC)

170 kWh battery (10-15 minutes emergency backup)

Control system

PV POWER SUPPLY AND CONSUMPTION

Daily average radiation: 4.05 kWh/m²/day

Average daily PV power production:
12.32 MWh/day

Average daily PV power consumption: 10 MWh/day

31% fraction of PV in the actual demand

Peak PV output: 3.4 MW

Average PV output: 1.03 MW

Mean PV output: 0.51 MW

Yearly sun hours: 4,358 hours/year

Capacity factor: 18.7%

DIESEL GENERATOR POWER SUPPLY

Daily generator power production: 22.32 MWh/day

Specific fuel consumption: 0.322 litre/kWh

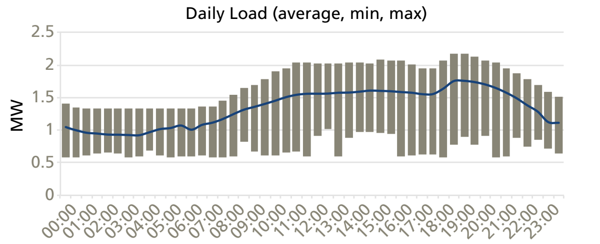
Mean electrical efficiency: 31.8%

EMISSIONS AND SAVINGS

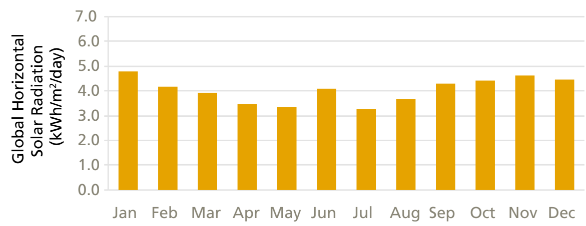
Diesel savings of 1,114,775 litre/year

Average Savings of 2,596 tCO_2/year

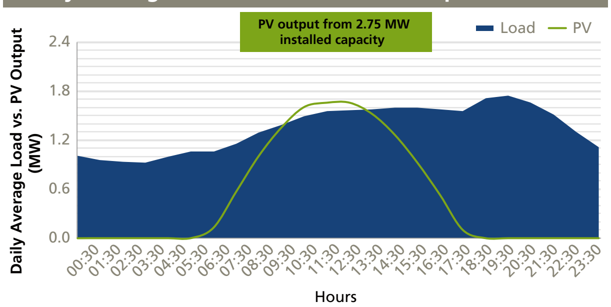
Daily Load Profile



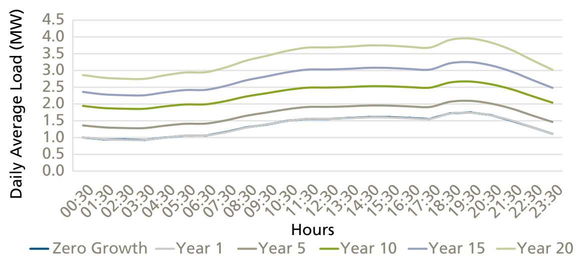
Global Horizontal Solar Radiation



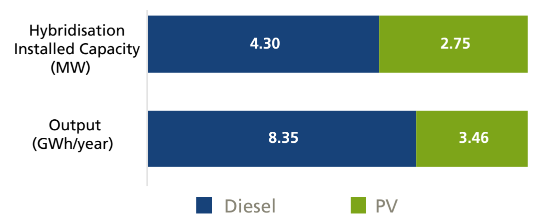
Daily Average Load Vs. Possible PV Output



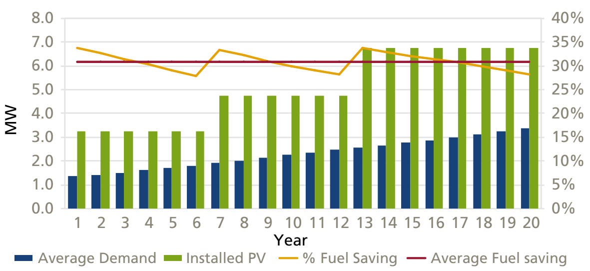
Load Profile for Growth Scenario



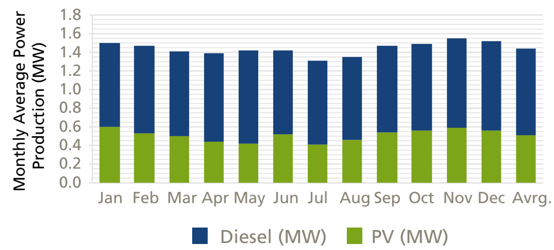
Diesel-PV Split (Capacity and Output)



Growth and Expansion Plan



Diesel-PV Load Share in Different Months



LAS TERRENAS – Dominican Republic

Technical data

ENERGY DEMAND

Present energy demand: 27,703 MWh/year

Growth of demand: 7% in year 1-3; 6% in year 4-7; 5% in year 8-11; 4% in year 12-15; 3% in year 16-19; 2% in year 20

HYBRIDIZATION POTENTIAL (NO GROWTH)

6.75 MW PV

9.5 MW diesel generators

2.5 MW converter (DC-AC/AC-DC)

455 kWh battery (10-15 minutes emergency backup)

Control system

PV POWER SUPPLY AND CONSUMPTION

Daily average radiation: 4.34 kWh/m²/day

Average daily PV power production: 27.68 MWh/day

Average daily PV power consumption: 23.64 MWh/day

31% fraction of PV in the actual demand

Peak PV output: 6.7 MW

Average PV output: 2.3 MW

Mean PV output: 1.15 MW

Yearly sun hours: 4,367 hours/year

Capacity factor: 17.1%

DIESEL GENERATOR POWER SUPPLY

Daily generator power production: 52.25 MWh/day

Specific fuel consumption: 0.316 litre/kWh

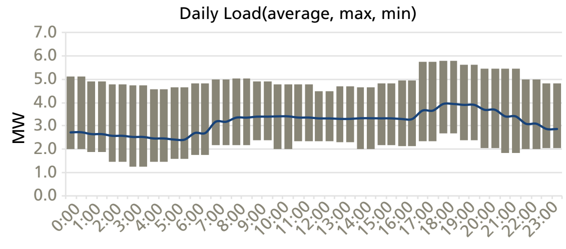
Mean electrical efficiency: 31.68%

EMISSIONS AND SAVINGS

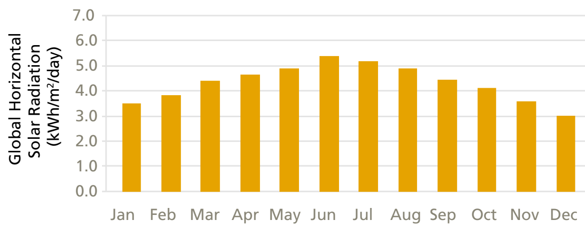
Diesel savings of 2,584,002 litre/year

Average Savings of 6,131 tCO_2/year

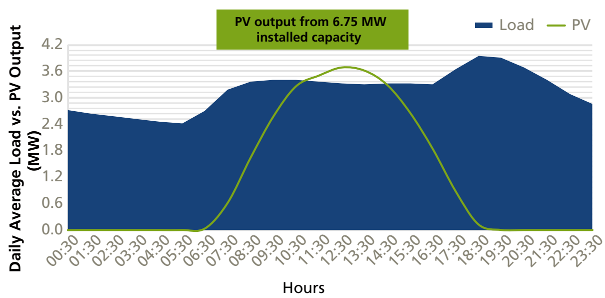
Daily Load Profile



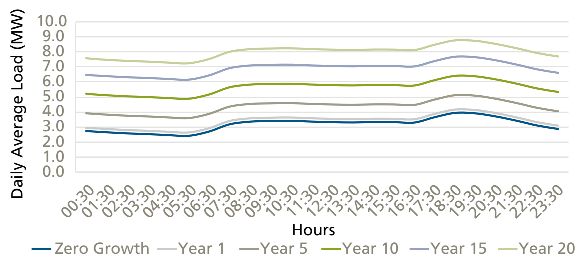
Global Horizontal Solar Radiation



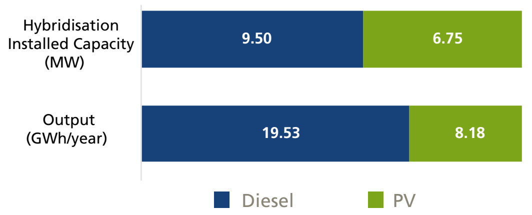
Daily Average Load Vs. Possible PV Output



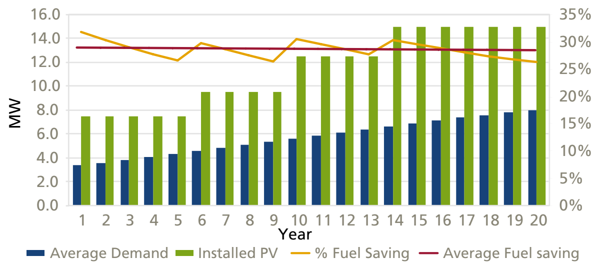
Load Profile for Growth Scenario



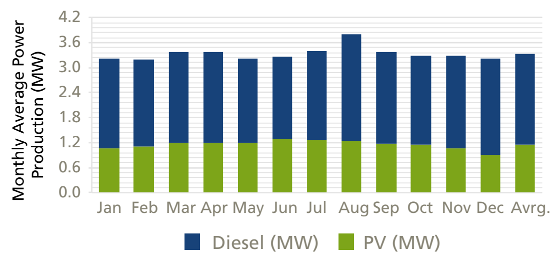
Diesel-PV Split (Capacity and Output)



Growth and Expansion Plan



Diesel-PV Load Share in Different Months



BEQUIA – St. Vincent and the Grenadines

Technical data

ENERGY DEMAND
Present energy demand: 7,554 MWh/year
Growth of demand: 3% in year 1-10; 2% in year 11-20

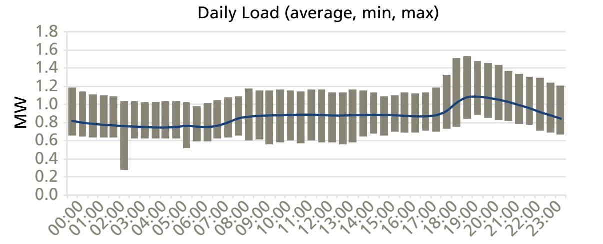
HYBRIDIZATION POTENTIAL (NO GROWTH)
1.5 MW PV
4.1 MW diesel generators
0.7 MW converter (DC-AC/AC-DC)
114 kWh battery
(10-15 minutes emergency backup)
Control system

PV POWER SUPPLY AND CONSUMPTION
Daily average radiation: 5.76 kWh/m²/day
Average daily PV power production: 8.06 MWh/day
Average daily PV power consumption: 7.0 MWh/day
34% fraction of PV in the actual demand
Peak PV output: 1.4 MW
Average PV output: 0.67 MW
Mean PV output: 0.34 MW
Yearly sun hours: 4,353 hours/year
Capacity factor: 22.4%

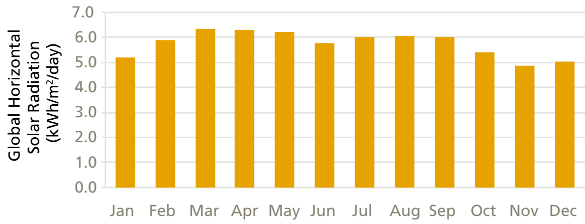
DIESEL GENERATOR POWER SUPPLY
Daily generator power production: 13.67 MWh/day
Specific fuel consumption: 0.289 litre/kWh
Mean electrical efficiency: 34.9%

EMISSIONS AND SAVINGS
Diesel savings of 702,830 litre/year
Average Savings of 1,823 tCO_2/year

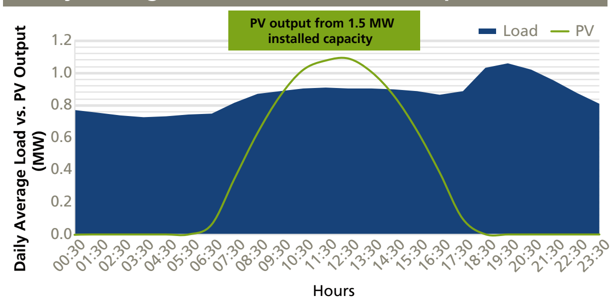
Daily Load Profile



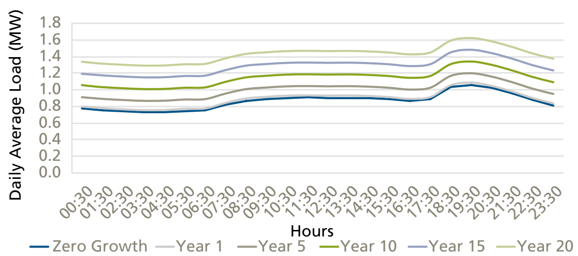
Global Horizontal Solar Radiation



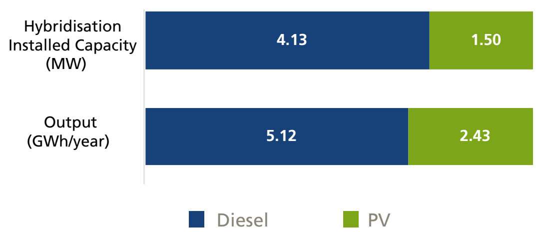
Daily Average Load Vs. Possible PV Output



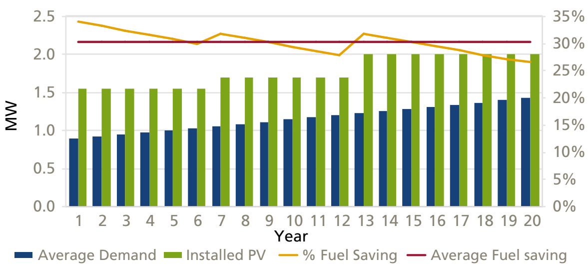
Load Profile for Growth Scenario



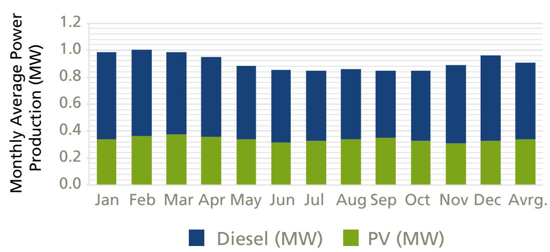
Diesel-PV Split (Capacity and Output)



Growth and Expansion Plan



Diesel-PV Load Share in Different Months



NUSA PENIDA – Indonesia

Technical data

ENERGY DEMAND

Present energy demand: 14,693 MWh/year

Growth of demand: 8% in year 1-5; 6.5% in year 6-10; 4.5% in year 11-20.

HYBRIDIZATION POTENTIAL (NO GROWTH)

3.0 MW PV

3.1 MW diesel generators

1.2 MW converter (DC-AC/AC-DC)

227 kWh battery

(10-15 minutes emergency backup)

Control system

PV POWER SUPPLY AND CONSUMPTION

Daily average radiation: 5.63 kWh/m²/day

Average daily PV power production: 15.6 MWh/day

Average daily PV power consumption: 12.7 MWh/day

32% fraction of PV in the actual demand

Peak PV output: 3.0 MW

Average PV output: 1.3 MW

Mean PV output: 0.65 MW

Yearly sun hours: 4,343 hours/year

Capacity factor: 21.7%

DIESEL GENERATOR POWER SUPPLY

Daily generator power production: 27.5 MWh/day

Specific fuel consumption: 0.282 litre/kWh

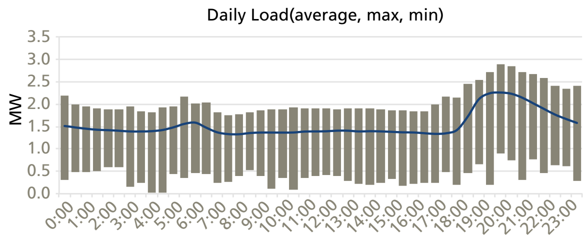
Mean electrical efficiency: 36.3%

EMISSIONS AND SAVINGS

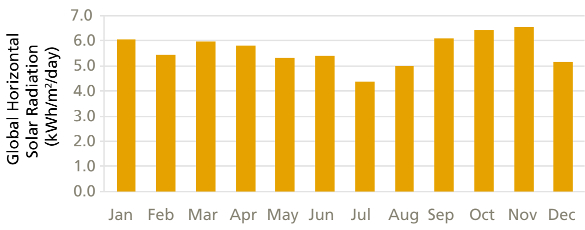
Diesel savings of 1,239,320 litre/year

Average Savings of 3,295 tCO_2/year

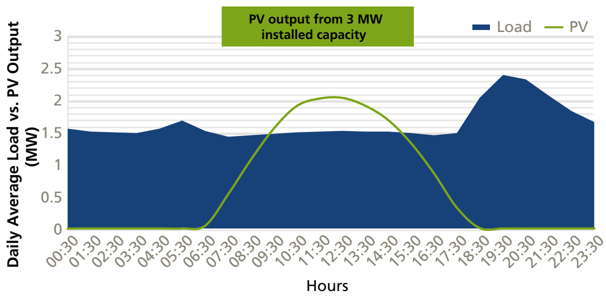
Daily Load Profile



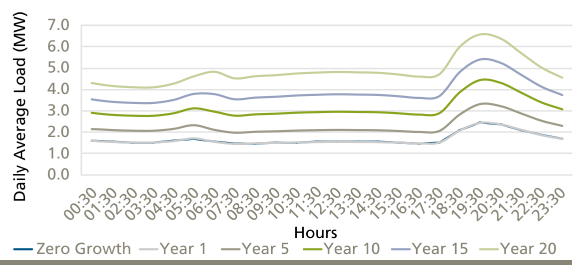
Global Horizontal Solar Radiation



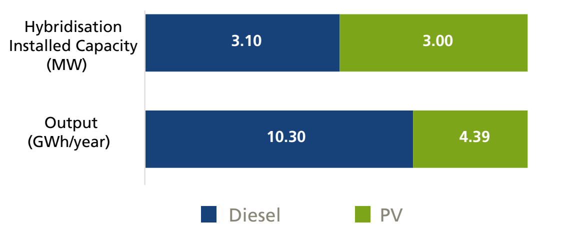
Daily Average Load Vs. Possible PV Output



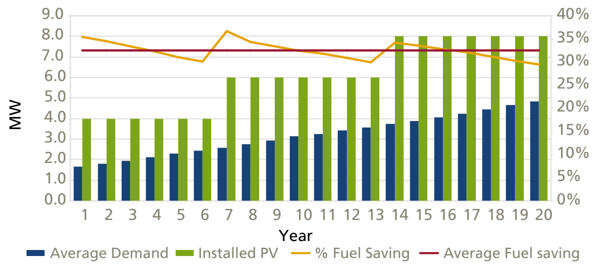
Load Profile for Growth Scenario



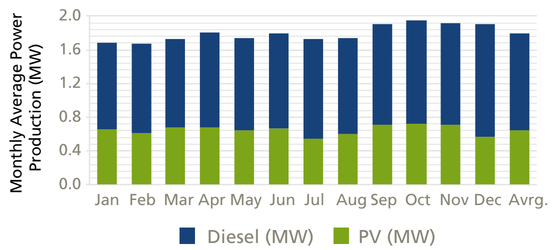
Diesel-PV Split (Capacity and Output)



Growth and Expansion Plan



Diesel-PV Load Share in Different Months



BUSUANGA – Philippines

Technical data

ENERGY DEMAND
Present energy demand: 13,864 MWh/year
Growth of demand: 10% in year 1-5; 5% in year 6-20

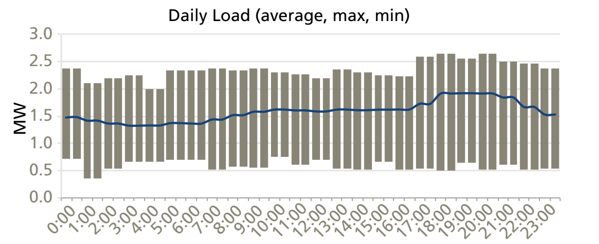
HYBRIDIZATION POTENTIAL (NO GROWTH)
3.0 MW PV
3.36 MW diesel generators
1.0 MW converter (DC-AC/AC-DC)
170 kWh battery
(10-15 minutes emergency backup)
Control system

PV POWER SUPPLY AND CONSUMPTION
Daily average radiation: 5.37 kWh/m²/day
Average daily PV power production: 15.15 MWh/day
Average daily PV power consumption: 12.36 MWh/day
33% fraction of PV in the actual demand
Peak PV output: 3.0 MW
Average PV output: 1.3 MW
Mean PV output: 0.63 MW
Yearly sun hours: 4,341 hours/year
Capacity factor: 21.0%

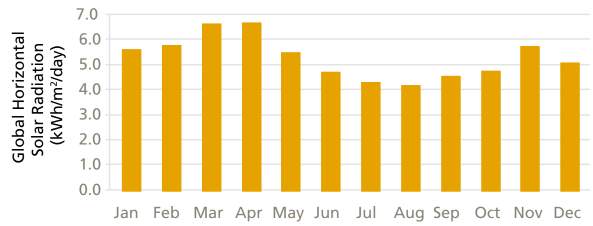
DIESEL GENERATOR POWER SUPPLY
Daily generator power production: 25.62 MWh/day
Specific fuel consumption: 0.287 litre/kWh
Mean electrical efficiency: 35.13%

EMISSIONS AND SAVINGS
Diesel savings of 1,224,073 litre/year
Average Savings of 3,198 tCO_2/year

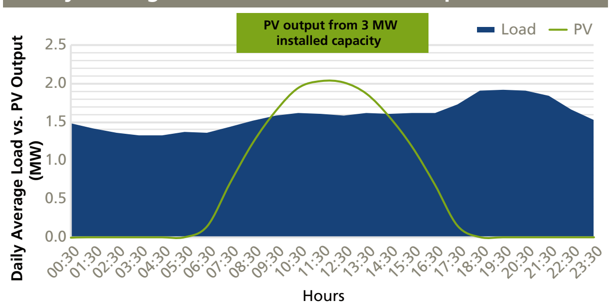
Daily Load Profile



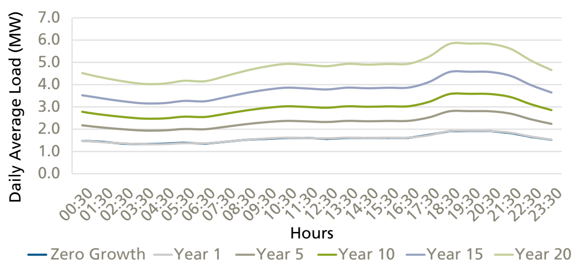
Global Horizontal Solar Radiation



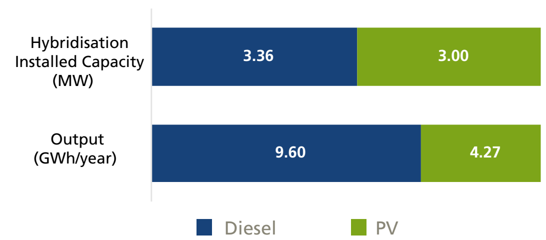
Daily Average Load Vs. Possible PV Output



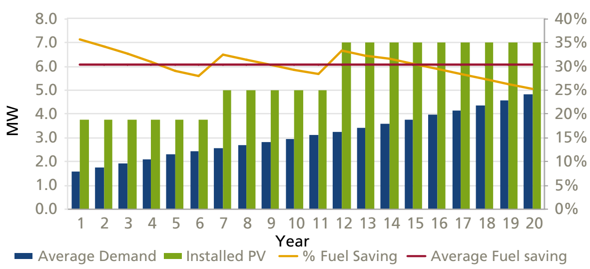
Load Profile for Growth Scenario



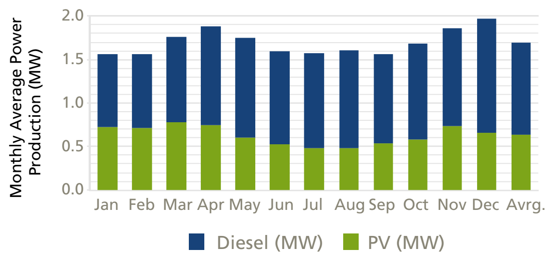
Diesel-PV Split (Capacity and Output)



Growth and Expansion Plan



Diesel-PV Load Share in Different Months



HOLA – Kenya

Technical data

ENERGY DEMAND

Present energy demand: 2,458 MWh/year
Growth of demand: 5% in year 1-9; 2% in year 10-20

HYBRIDIZATION POTENTIAL (NO GROWTH)

0.5 MW PV
0.8 MW diesel generators
0.25 MW converter (DC-AC/AC-DC)
170 kWh battery
(10-15 minutes emergency backup)
Control system

PV POWER SUPPLY AND CONSUMPTION

Daily average radiation: 5.50 kWh/m²/day
Average daily PV power production: 2.52 MWh/day
Average daily PV power consumption: 2.30 MWh/day
34% fraction of PV in the actual demand
Peak PV output: 0.47 MW
Average PV output: 0.21 MW
Mean PV output: 0.11 MW
Yearly sun hours: 4,364 hours/year
Capacity factor: 21.0%

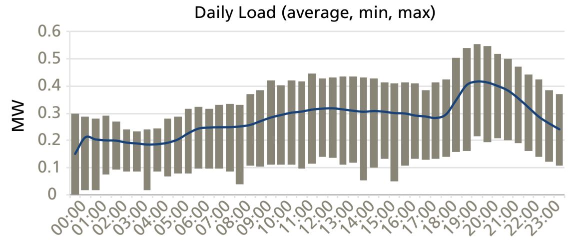
DIESEL GENERATOR POWER SUPPLY

Daily generator power production: 4.41 MWh/day
Specific fuel consumption: 0.344 litre/kWh
Mean electrical efficiency: 28.7%

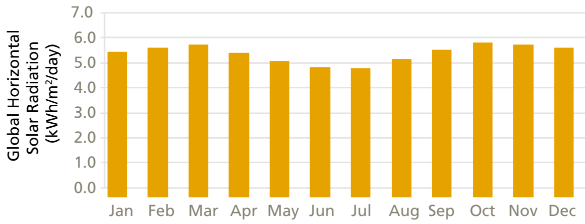
EMISSIONS AND SAVINGS

Diesel savings of 274,101 litre/year
Average Savings of 579 tCO_2/year

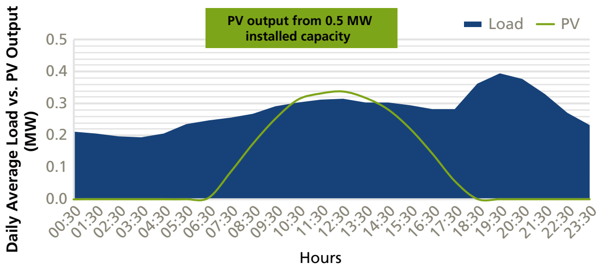
Daily Load Profile



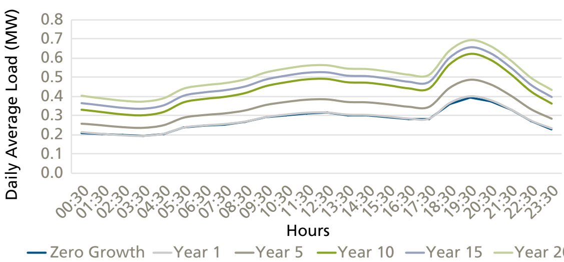
Global Horizontal Solar Radiation



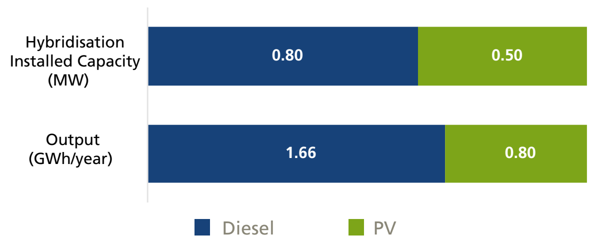
Daily Average Load Vs. Possible PV Output



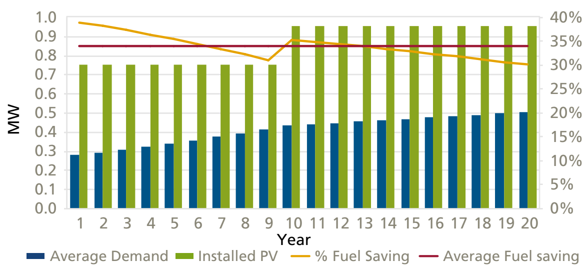
Load Profile for Growth Scenario



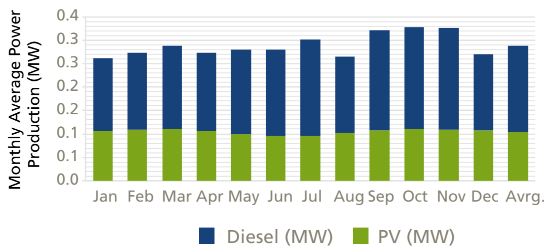
Diesel-PV Split (Capacity and Output)



Growth and Expansion Plan



Diesel-PV Load Share in Different Months



BASSE SANTA SU – The Gambia

Technical data

ENERGY DEMAND
Present energy demand: 5,789 MWh/year

Growth of demand: 5.5% in year 1-10; 4.5% in year 11-20.

HYBRIDIZATION POTENTIAL (NO GROWTH)
1.3 MW PV

1.5 MW diesel generators

0.6 MW converter (DC-AC/AC-DC)

114 kWh battery

(10-15 minutes emergency backup)

Control system

PV POWER SUPPLY AND CONSUMPTION
Daily average radiation: 5.56 kWh/m²/day

Average daily PV power production: 7.4 MWh/day

Average daily PV power consumption: 5.9 MWh/day

37% fraction of PV in the actual demand

Peak PV output: 1.4 MW

Average PV output: 0.80 MW

Mean PV output: 0.30 MW

Yearly sun hours: 4,387 hours/year

Capacity factor: 23.6%

DIESEL GENERATOR POWER SUPPLY
Daily generator power production: 10.0 MWh/day

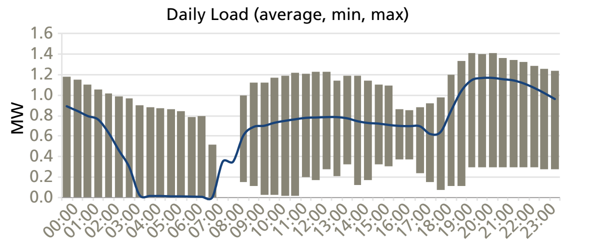
Specific fuel consumption: 0.269 litre/kWh

Mean electrical efficiency: 36.8%

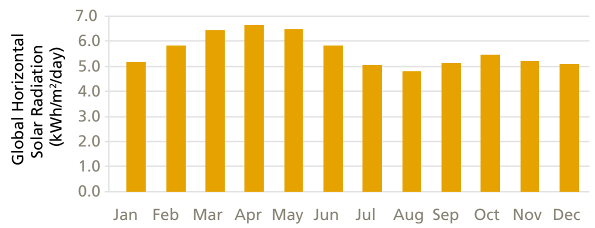
EMISSIONS AND SAVINGS
Diesel savings of 542,388 litre/year

Average Savings of 1,512 tCO_2/year

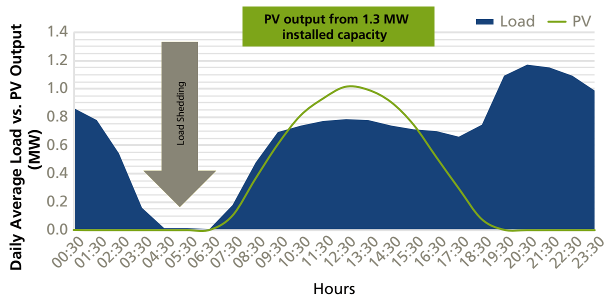
Daily Load Profile



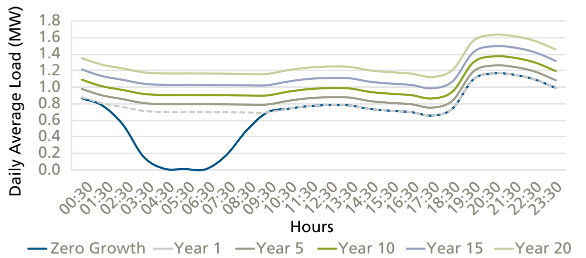
Global Horizontal Solar Radiation



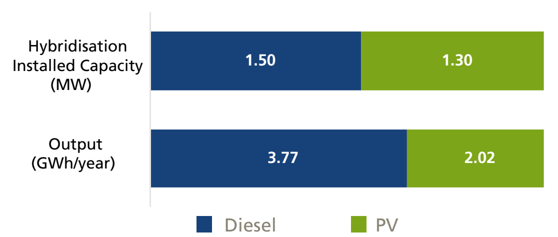
Daily Average Load Vs. Possible PV Output



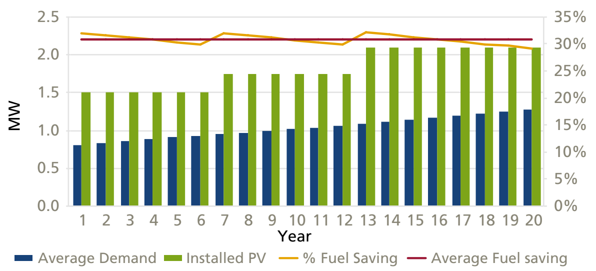
Load Profile for Growth Scenario



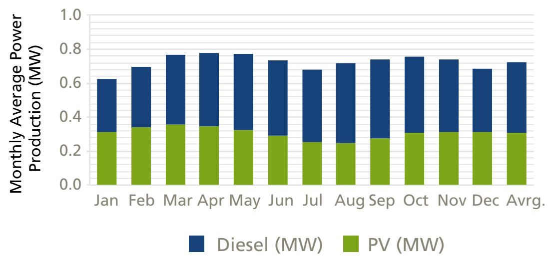
Diesel-PV Split (Capacity and Output)



Growth and Expansion Plan



Diesel-PV Load Share in Different Months



ANNEX 3: Technical assumptions

Town/Island	Initial CAPEX Diesel GenSets (USD)	Initial CAPEX PV panels (USD)	Initial CAPEX other components (USD)	Replacement CAPEX Hybrid Case (USD)	Replacement CAPEX Diesel Case (USD)
Puerto Leguizamo	2.05m/4.3MW 0.48m/1MW	5.61m/2.75M 2.04m/1MW	Balance of RE systems 1,897,200	Diesel Genset: 1.142m (yr 12) Balance of RE Systems: 1.815m (yr 10)	Diesel Genset 1.142m (yr 10)
Las Terrenas	4.52m/9.5MW 0.48m/1MW	13.77m/6.75MW 2.04m/1MW	Balance of RE systems 3,026,000	Diesel Genset: 3.876m (yr 12) Balance of RE Systems: 4.318m (yr 10)	Diesel Genset 0.612m (yr 10), 3.264m (yr 12)
Bequia	1.96m/4.125 MW 0.48m/1MW	3.06m/1.5MW 2.04m/1MW	Balance of RE systems 1,557,200	Diesel Genset: 0.367m (yr 10), 0.261m (yr 12) Balance of RE Systems: 1.075m (yr 10)	Diesel Genset 0.293m (yr 7), 0.404m (yr 10), 0.489m (yr 13
Nusa Penida	1.48m/3.1MW 0.48m/1MW	6.12m/3.0MW 2.04m/1MW	Balance of RE systems 1,999,200	Diesel Genset: 0.734m (yr 10), 0.367m (yr 12) Balance of RE Systems: 1.985m (yr 10)	Diesel Genset 0.696m (yr 7), 0.367m (yr 12)
Busuanga	1.6m/3.36MW 0.48m/1MW	6.12m/3.MW 2.04m/1MW	Balance of RE systems 1,802,000	Diesel Genset: 1.37m (yr 11) Balance of RE Systems: 1.836m (yr 10)	Diesel Genset 0.653m (yr 7), 0.718m (yr 12), 0.653m (yr 14)
Hola	0.38m/0.8MW 0.48m/1MW	1.02m/0.5MW 2.04m/1MW	Balance of RE systems 1,445,000	Diesel Genset: 0.326m (yr 10) Balance of RE Systems: 0.510m (yr 10)	Diesel Genset 0.326m (yr 6,10,12)
Basse Santa Su	0.71m/1.5MW 0.48m/1MW	2.652m/1.3M 2.04m/1MW	Balance of RE systems 1,509,600	Diesel Genset: 0.612m (yr 12) Balance of RE Systems: 0.911m (yr 10)	Diesel Genset 0.367m (yr 10), 0.245m (yr 12

OPEX Hybrid Case (USD)	OPEX Diesel Case (USD)	Diesel Consumption (Liter/MWh)	Current Local Diesel Price (USD/Liter)	Corporate Tax Rate
Diesel: 401,570 RE Systems: 88,672	547,948	322	1.05	25%
Diesel: 1,429,189 RE Systems: 215,832	1,968,853	316	0.89	27%
Diesel: 265,362 RE Systems: 49,368	373,599	289	0.90	30%
Diesel: 501,673 RE Systems: 97,376	707,443	282	1.16	25% (if Revenues < USD 417000;12.5%)
Diesel: 493,831 RE Systems: 94,112	693,280	287	0.96	30%
Diesel: 124,554 RE Systems: 21,012	168,161	344	1.12	30%
Diesel: 179,145 RE Systems: 43,248	282,487	269	1.096	31%

ANNEX 4: Assumptions for growth and technical upgrades

Site	Growth and Technical Upgrade – Assumptions
Puerto Leguizamo	■ **Growth:** decreasing from 6% to 4%; 6% p.a. for the first 10 years, 4% in the following years. ■ **Electricity demand:** Increases from present annual ~11,000 MWh to ~30,000 MWh in year 20. Average demand increases from present 1.3 MW to 3.3 MW by end of project lifetime. ■ **Technical upgrades:** PV capacity can be gradually upgraded from initially 3.25 MW in the beginning to 6.75 MW in year 13. For diesel generators, 0.9 MW capacities need to installed in year 11, in addition to existent 4.2 MW, thus increasing the the net capacity to 5.1 MW. ■ Replacements: The 4.2 MW generators need to be replaced with the same capacity over the project lifetime of the generators.
Las Terrenas	■ **Growth:** decreasing from 7% to 2%; 7% in year 1-3; 6% in year 4-7; 5% in year 8-11; 4% in year 12-15; 3% in year 16-19 and 2% in year 20. ■ **Electricity demand:** Increases from present annual ~27,000 MWh to ~70,000 MWh in year 20. The average demand would increase from present 3.3 MW to 8.0 MW by end of project lifetime. ■ **Technical upgrades:** PV capacity can be gradually upgraded from initially 7.5 MW in the beginning to 15 MW in year 14. For diesel generators, the existing 9.5 MW capacity shall be sufficient to meet the demand for the first 7 years. The net diesel generator capacity needs to increase to 10.5 MW in year 8 and further to 11.2 MW in year 12 – sufficient to meet the demand for 20 years. ■ **Replacements:** in year 8, old diesel generators of 2 MW capacity need to be replaced with 3 MW capacity and in year 12, another 2.8 MW old generators need to be replaced with new 3.5 MW generators.
Bequia	■ **Growth:** decreasing from 3% to 2%, 3% in year 1-10; 2% in year 11-20. ■ **Electricity demand:** Increases from present annual 7,554 MWh to 12,482 MWh in year 20. The average demand would increase from present 0.9 MW to 1.4 MW. ■ **Technical upgrades:** PV capacity can be gradually upgraded in three phases from initially 1.55 MW in the beginning to 1.7 MW in year 7 and 2 MW in year 13. For diesel generators, the existing 4.15 MW capacity shall be sufficient to meet the growing demand over 20 years. ■ **Replacements:** 0.9 MW old diesel generators need to be replaced with the same capacity in year 13, keeping the net installed capacity at the same level.

Site	Growth and Technical Upgrade – Assumptions
Nusa Penida	■ **Growth:** decreasing from 8% to 4.5%, 8% in year 1-5; 6.5% in year 6-10; 4.5% in year 11-20. Plus demand shift towards daytime due to some expected economic growth from new guest houses. The demand shift forecasts two different rates of (decreasing) demand growth during day and night, which is modelled for every 30 minutes interval for each year. For day time (06:30-18:30), 8% increase in year 1-5, 7% increase in year 6-10, and 5% increase in year 11-20 is modelled. For night/early morning time (18:30 to 06:30) 8% increase in year 1-5, 6% increase in year 6-10, and 4% increase in year 11-20 is modelled. ■ **Electricity demand:** Increases from present annual ~14,000 MWh to ~42,500 MWh in year 20. The average demand would increase from present 1.7 MW to 4.8 MW. ■ **Technical upgrades:** PV capacity can be gradually upgraded in three phases from initially 4 MW in the beginning to 6 MW in year 7 and 8 MW in year 14. For diesel generators, a total 4.1 MW generators are recommended to be installed in the beginning to meet the growing demand for the first 6 years. The net diesel generator capacity needs to increase to 7.1 MW in year 7 and further to 9 MW in year 12 -sufficient to meet the demand for 20 years. ■ **Replacements:** In year 12, the 4.1 MW old generators, installed in the beginning, need to be replaced and upgraded with new 6 MW generators.
Busuanga	■ **Growth:** decreasing from 10% to 5%,10% in year 1-5; 5% in year 6-20. ■ **Electricity demand:** Increases from present annual ~13,800 MWh to ~42,200 MWh in year 20. The average demand would increase from present 1.6 MW to 4.8 MW by end of project lifetime. ■ **Technical upgrades:** PV capacity can be gradually upgraded in three phases from initially 3.75 MW in the beginning to 5 MW in year 7 and 7 MW in year 12. For diesel generators, a total 4.4 MW generators are recommended to be installed in the beginning to meet the growing demand for the first 6 years. The net diesel generator capacity needs to increase to 4.6 MW, 6.1 MW, 7.1 MW, 8.3 MW in year 7, 8, 13 and 14 -sufficient to meet the demand for 20 years. ■ **Replacements:** 6.9 MW old generators, need to be replaced over the project life time of 20 years (48,000 operating hours per generator).
Hola	■ **Growth:** decreasing from 5% to 2%, 5% in year 1-9; 2% in year 10-20. ■ **Electricity demand:** Increases from present annual 2,460 MWh in 2013 to 4,438 MWh in year 20. The average demand would increase from present 0.3 MW to 0.5 MW by end of year 20. ■ **Technical upgrades:** PV capacity can be gradually upgraded in two phases from initially 0.75 MW in the beginning to 0.95 MW in year 10. For diesel generators, 0.5 MW capacities need to installed in year 7, in addition to existent 0.8 MW, thus increasing the net capacity to 1.3 MW. ■ **Replacements:** The 1.3 MW generators need to be replaced with the same capacities in year 12 and 14.

Site	Growth and Technical Upgrade – Assumptions
Basse Santa Su	■ **Growth:** decreasing from 5.5% to 4.5%,5.5% in year 1-10; 4.5% in year 11-20. Plus demand shift towards daytime and afternoon due to availability of solar radiation. ■ **Electricity demand:** Increases from present annual 5,789 MWh to 11,186 MWh in year 20. The average demand would increase from present 0.7 MW to 1.3 MW. ■ **Technical upgrades:** PV capacity can be gradually upgraded in three phases from initially 1.5 MW in the beginning to 1.75 MW in year 7 and 2.1 MW in year 13. For diesel generators, 0.3 MW capacities need to installed in year 7 and 13, in addition to existent 1.6 MW, thus increasing the net capacity to 1.9 MW. ■ **Replacements:** The 1.9 MW generators need to be replaced with the same capacity as soon as each generator's operation exceeds 48,000 hours.

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