Confidential

Energy Master Plans for the Federated States of Micronesia

Final Report to the Department of Resources and Development

April 2018

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Acronyms and Abbreviations

ADB	Asian Development Bank
BESS	Battery Energy Storage Systems
COL	Concessional OCR loans
CO_2	Carbon dioxide
CPUC	Chuuk Public Utility Corporation
DSM	Demand-side management
EE	Energy Efficiency
EPA	Environmental Protection Agency
ESS	Energy storage systems
FSM	Federated States of Micronesia
GCF	Global Climate Fund
GHG	Greenhouse gas
IBRD	International Bank for Reconstruction and Development
IDA	International Development Association
IMF	International Monetary Fund
INDC	Intended Nationally-Determined Contribution
IPP	Independent power producer
JICA	Japanese International Cooperation Agency
KUA	Kosrae Utilities Authority
LRMC	Long-run marginal cost
LV	Low-voltage
MD	Maximum Demand
MDB	Multilateral Development Bank
MFD	Maximising Funds for Development
MFAT	New Zealand Ministry of Foreign Affairs and Trade
MV	Medium-voltage

NEP	National Energy Policy
NEW	National Energy Workgroup
NGO	Non-government organisation
NPV	Net Present Value
O&M	Operations and maintenance
ODA	Overseas Development Assistance
OCR	Ordinary Capital Resources
PPA	Power Purchase Agreement
PSC	Public section comparator
PUC	Pohnpei Utilities Corporation
PV	Photovoltaics
R&D	Research & development
RE	Renewable energy
SEW	State Energy Workgroup
SHS	Solar home system
tCO_2-e	Tonnes of CO_2 equivalent
TOR	Terms of reference
US$	United States dollars
VfM	Value for money
YSPSC	Yap State Public Service Corporation

Executive Summary

This report presents the Energy Master Plans for each of the Federated States of Micronesia (FSM), and for the nation. The Master Plans have been developed during the period of unprecedented technological change. The last few years have seen remarkable and disruptive improvements in renewable energy (RE) technologies and battery storage. Further expected reductions in the costs of these technologies provide FSM with an opportunity to combine achievement of its environmental targets with ensuring that electricity production remains affordable.

At the same time, FSM faces a significant challenge of delivering electricity to people living on outer islands. At present, there is significant social and economic divide: people living on the four main islands enjoy almost universal access to the main electricity grids. By contrast, people on outer islands and in outlying communities have almost no access to electricity. The Master Plans are designed to address this divide in a financially and socially sustainable way.

The modeled plans can be fully funded and financed and will achieve the National Vision Statement for Energy

The plans will provide **electricity access**, at good quality service standards, to more than 80 percent of FSM households by 2020 and to almost every household by 2023. We define access as the practical ability of each household to be able to receive affordable electricity

The plans achieve FSM's **RE, diesel reduction, and emissions reduction** objectives.

Figure ES.1: Summary of National-level Outcomes of State Energy Master Plans

Electricity Access (HH)	RE Percentage	Diesel Use (million gallons)	Electricity CO_2 Emissions (tonnes)
2018: 67%	2018: 19%	2018: 4.2	2018: 43,490
2020: 82%	2020: 44%	2020: 2.9	2025: 21,980*
2027: 100%	2027: 63%	2027: 2.1	2027: 21,980
2037: 100%	2037: 84%	2037: 1.5	2037: 15,769

*We show 2025 for comparison with UNFCCC emissions target for 2025.

The plans were developed using two types of modeling:

- HOMER modeling, incorporating best available information on the current and future costs of various technologies, as well as the technical characteristics of various generation units, was used to develop the optimal generation fleet and distribution network
- Financial modeling was used to estimate the annual cash needs of all utilities, on the expectation that cash revenues would fully cover operating and maintenance costs (including fuel costs) and the costs of debt service (interest payments and repayment of principal), as well as provide a cushion for contingencies.

RE, emissions, and diesel reduction objectives can be achieved at no extra cost to consumers (compared to meeting demand using diesel)

The generation mixes we propose in the plans exceed the state-level and national RE generation targets at a lower cost than any other generation mix (including greater use of diesel) and without compromising reliability. In all states, increasing RE generation is the least-cost way to meet future electricity demand (with support from diesel generation and storage to ensure reliability). The reduction in the use of diesel more than compensates for the additional investment cost. As a result, from 2019, the Master Plans together achieve an overall national RE contribution of over 40 percent (against a national target of 30 percent by 2020).

Although diesel will continue to play an important role in ensuring security of supply, the use of diesel for electricity generation falls by over 60 percent. There is a corresponding decline in carbon emissions.

Our analysis, presented in the Appendices and the accompanying models, demonstrates that there is no longer a trade-off between least-cost electrification and achieving climate change and RE targets.

The State Energy Master Plans set out a technically feasible, financeable, and implementable pathway for each state to provide a reliable and environmentally sustainable electricity service to all residents

Our proposed investment strategy has four limbs:

- Some new diesel generation capacity to ensure security of supply
- A large amount of new solar PV capacity (with storage) to reduce reliance on diesel and meet demand growth. This also lowers the cost of generating electricity
- Re-investment to sustain the distribution network, along with minor expansions to connect new customers
- Investment to serve unelectrified communities.

The electricity tariffs required to fund the implementation of the Master Plans will depend on two factors:

- The cost of finance—The total financing package for the initial implementation of the Master Plans (for the period to 2023) will need to be assembled during 2018. While some donors have already made commitments to grant funding, the final financing package may consist of a mix of grants, concessional loans and commercial finance (including independent power producers, IPPs). The cost of finance will depend on the composition of the financing package
- The rate of transition from the current reactive maintenance to full planned maintenance and planned asset replacement.

We have modeled several financing scenarios on the common assumption of immediate transition to planned maintenance and replacement, as well as building in a financial "cushion" for contingencies. Based on these reference scenarios, Yap and Pohnpei would be able to fully fund the implementation of the Master Plans while gradually reducing tariffs over time.

Kosrae will need to manage the transition to planned maintenance and asset replacement more carefully, but generally will be in a position to fully fund the implementation of the Master

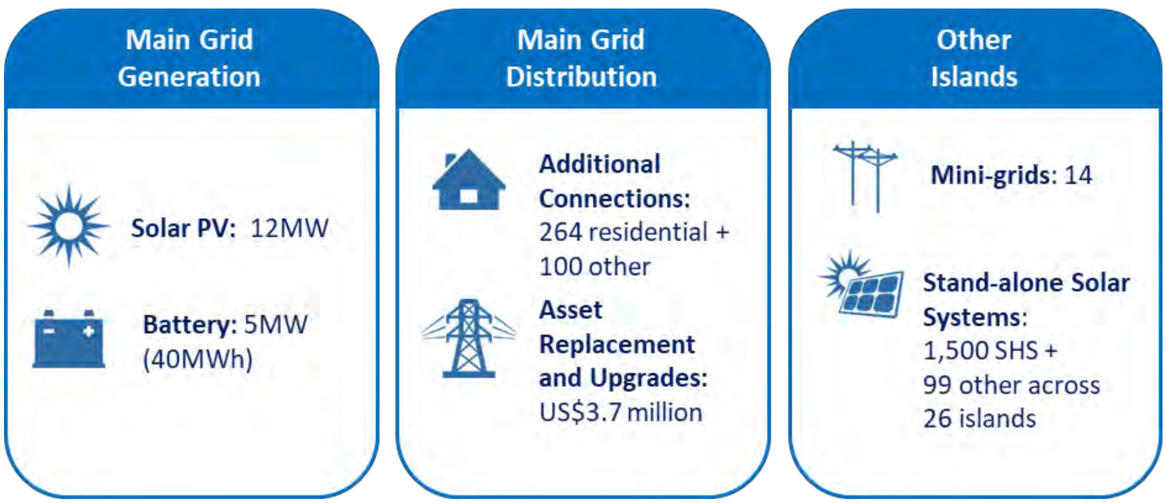
Plan at the current level of tariffs in real terms. Tariffs could be reduced over time with greater reliance on concessional finance.

Chuuk faces the greatest challenge as it has the highest proportion of unelectrified households on isolated outer islands. Once they are electrified, they will be costly to serve. Even with full grant funding for the roll-out of mini-grids to isolated communities, Chuuk may need to consider small tariff increases over the next 4 to 5 years. Over time, growth in demand will enable tariffs to return to their current levels. As a better option, we recommend that the FSM Government work with donors and consider application of its own grant funds to cover the initial operating costs of the new mini-grids. Such transitional funding would enable Chuuk to keep tariffs at a stable level in real terms.

Chuuk

Our modeling suggests that Chuuk will need to invest US$86.0 million in new and replacement electricity infrastructure over the next 20 years. New infrastructure includes adding renewable generation capacity on Weno, adding grid connections on Weno, and developing electricity infrastructure in other regions of Chuuk (Figure ES.2).

Figure ES.2: Summary of New Infrastructure in Chuuk Technical Investment Plan



The total investment requirement will be:

Table ES.1: Capital Expenditure Requirements for Chuuk (US$ million 2016)

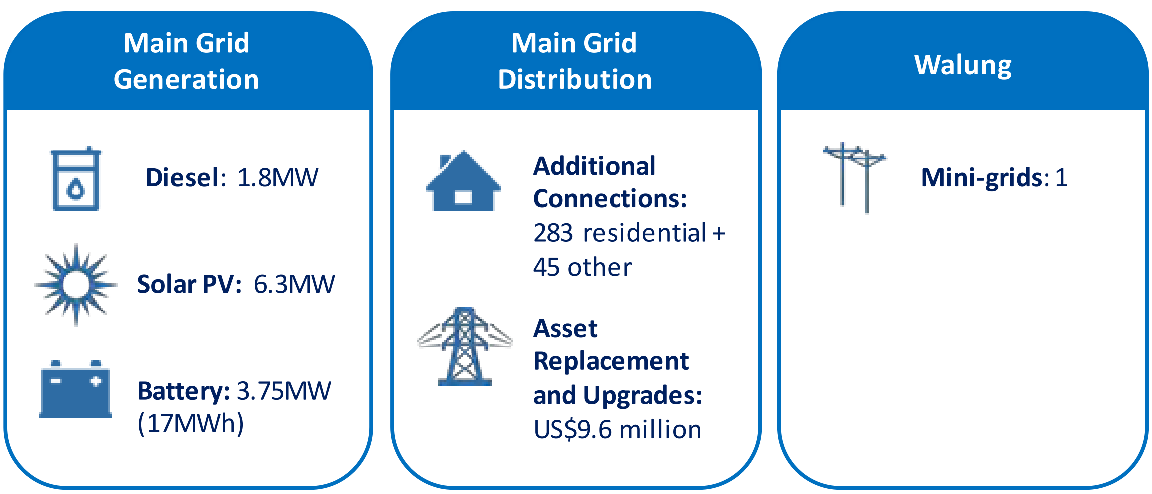
	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
New Main Grid Generation	0.00	11.48	12.62	7.05	7.05	38.21
Main Grid Generation Replacement	0.58	1.34	1.65	2.48	3.39	9.43
Main Grid Distribution	0.03	0.34	0.61	1.77	1.53	4.28
Mini-grids	0.00	20.90	1.51	1.22	1.88	25.51
Stand-alone Solar Systems	0.00	4.29	0.00	4.29	0.00	8.58
Total	0.61	38.35	16.39	16.81	13.85	86.00

Implementing the plan will enable the electrification of all households and public facilities in Chuuk by 2023. Chuuk's RE generation percentage would exceed the state's 30 percent target.

Kosrae

Our modeling suggests that Kosrae will need to invest US$37.3 million in new and replacement electricity infrastructure (see Figure ES.3) over the next 20 years. New infrastructure includes adding renewable generation capacity on to the main grid, adding grid connections on the main grid, and developing electricity infrastructure in Walung (Figure ES.3).

Figure ES.3: Summary of New Infrastructure in Kosrae Technical Investment Plan



The total investment requirement will be:

Table ES.2: Capital Expenditure Requirements for Kosrae (US$ million 2016)

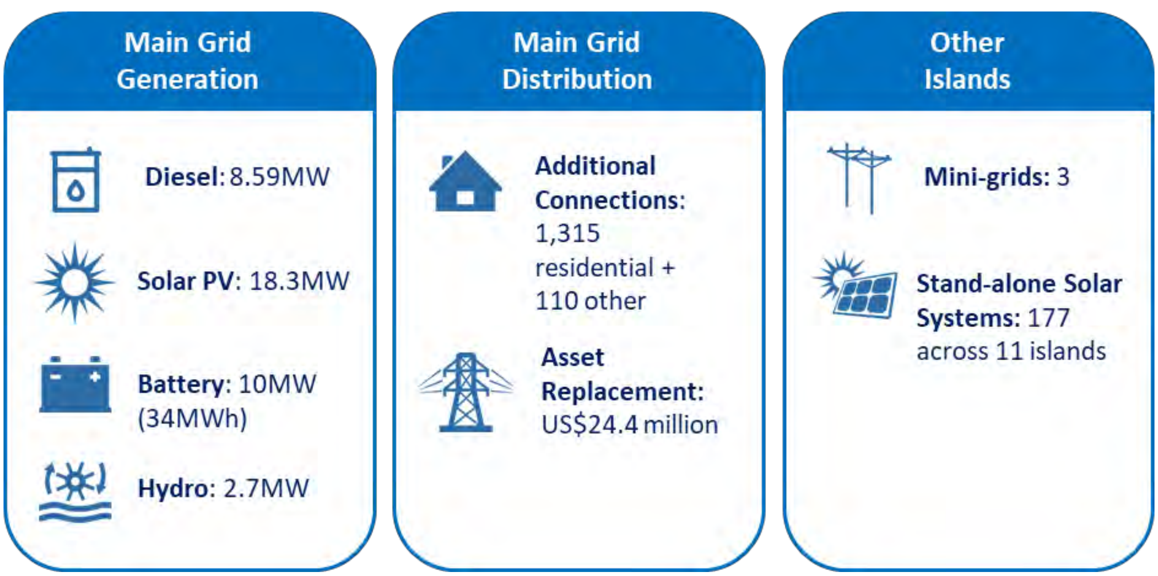
	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
New Main Grid Generation	2.49	6.42	6.71	3.18	2.67	21.47
Main Grid Generation Replacement	0.00	0.50	0.16	1.75	2.57	4.97
Main Grid Distribution	0.28	4.64	1.74	1.86	1.61	10.12
Mini-grids	0.00	0.47	0.04	0.08	0.11	0.70
Total	2.77	12.03	8.64	6.86	6.96	37.26

The objective is to ensure that by the end of 2019 Walung consumers have access to electricity. The share of RE in Kosrae's electricity generation would be above 80 percent from 2019 onwards. Kosrae would also reach its target of doubling solar PV capacity.

Pohnpei

Our modeling suggests that Pohnpei will need to invest US$114.0 million in new and replacement electricity infrastructure over the next 20 years. New infrastructure includes adding renewable generation capacity on Pohnpei Proper, adding grid connections on Pohnpei Proper, and developing electricity infrastructure in other regions of Pohnpei State (Figure ES.4).

Figure ES.4: Summary of New Infrastructure in Pohnpei Technical Investment Plan



The total investment requirement will be:

Table ES.3: Capital Expenditure Requirements for Pohnpei (US$ million 2016)

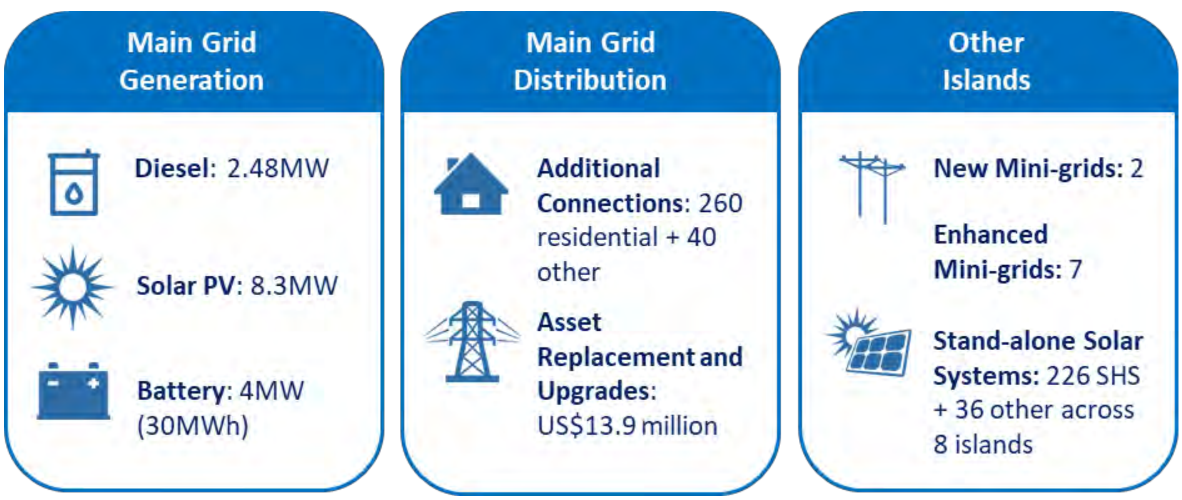
	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
New Main Grid Generation	1.78	26.38	12.73	11.82	19.89	72.59
Main Grid Generation Replacement	0.00	0.00	0.00	5.41	4.81	10.22
Main Grid Distribution	1.07	7.36	6.53	6.98	6.03	27.96
Mini-grids	0.00	1.37	0.72	0.02	0.08	2.19
Stand-alone Solar	0.00	0.53	0.00	0.53	0.00	1.06
Total	2.85	35.63	19.97	24.76	30.80	114.02

The Master Plan would provide all households in Pohnpei with electricity access from 2025. From 2019 onwards, the share of RE in Pohnpei's electricity generation would be over 50 percent.

Yap

Our modeling suggests that Yap will need to invest US$58.9 million in new and replacement electricity infrastructure over the next 20 years. New infrastructure includes adding renewable generation capacity on Yap Proper, adding grid connections on Yap Proper, and developing electricity infrastructure in other regions of Yap State (Figure ES.5).

Figure ES.5: Summary of New Infrastructure in Yap Technical Investment Plan



The total investment requirement will be:

Table ES.4: Capital Expenditure Requirements for Yap (US$ million 2016)

	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
New Main Grid Generation	$0.00	$6.80	$6.94	$9.15	$5.95	$28.83
Main Grid Generation Replacement	$0.70	$0.00	$1.69	$1.65	$4.17	$8.20
Main Grid Distribution	$0.45	$6.31	$2.74	$2.93	$2.63	$15.06
Mini-grids	$0.12	$1.36	$1.33	$0.89	$0.17	$3.86
Stand-alone Solar	$0.00	$0.63	$0.53	$1.16	$0.63	$2.94
Total	$1.27	$15.09	$13.22	$15.77	$13.55	$58.90

The Master Plan would provide all households in Yap with electricity access from 2025. From 2019 onwards, the share of RE in Yap's electricity generation would be about 50 percent or above.

1 Introduction

This Report presents the Energy Master Plans for each of the Federated States of Micronesia (FSM), and for the nation.

The State Energy Master Plans contribute to the National Vision Statement for Energy: to "improve the life and livelihood of all FSM residents with affordable, reliable and environmentally sound energy". They set out what investments are required to achieve this vision in the electricity sector over the next 20 years, and how the investments will be financed and implemented.

These plans were developed in close collaboration with the Department of Resources and Development and the four State Energy Workgroups. A wide range of government, private sector, community, and other stakeholders from all four states also provided valuable input throughout the process (see Appendix A).

The main body of this report:

- Describes our approach to developing the Master Plans (Section 2)
- Presents the National Energy Master Plan (Section 3)
- Presents the four State Energy Master Plans:
  - Chuuk (Section 4)
  - Kosrae (Section 5)
  - Pohnpei (Section 6)
  - Yap (Section 7).

The appendices set out supporting information, including the underlying assumptions, methodologies, and context underlying the investment plans. All data are available in an electronic format.

2 Approach

Each State Energy Master Plan includes a Technical Plan, a Financing Plan, and an Implementation Plan. These components of the Master Plans were produced after several iterations based on consultations and other feedback. In this section we outline the approach used to develop the components of the Master Plans and the inputs used. Details of the inputs and calculations are provided in the appendices and in the accompanying spreadsheets.

It is important to emphasize that master planning should be seen as a process, rather than as a one-off exercise for the next 20 years. All plans should be regularly updated to reflect the best available information and to incorporate the lessons from implementation. The State Energy Master Plans are forward-looking documents, based on load forecasts, expected technological developments (including the costs of various technical components), diesel price projections, and the forecasts of future economic and financial conditions. Inevitably, the future will not be quite as forecast. For this reason, the models, inputs, and calculations that have been provided to the FSM counterparts are designed to be easily and regularly updated.

Finally, while the Energy Master Plans set out the development of FSM's electricity sector over the next 20 years, the focus is on the next 4 to 5 years. While there will be both the need and the opportunity to revisit and revise the Plans for the period after 2023, the Energy Master Plans for the 2019-2023 period require immediate commitment and implementation.

2.1 Technical Plan

We developed a technical generation and distribution plan for each of the four states of the FSM. The plans are least-cost solutions to meet each state's access, reliability, social, and environmental objectives. We separated each state into three service areas: main grids, mini-grids, and stand-alone solar systems, to provide cost effective and implementable electrification solutions across the FSM.

The main grids are located on the main island of each of the four states. We developed least-cost generation plans for the main grids using HOMER. Key inputs for the main grid HOMER modeling were: natural energy resources, energy forecasts, peak demand forecasts, agreed reliability targets and generation planning criteria, diesel price projections, generation asset capital costs, operating costs, and maintenance costs. The technical distribution plans were developed through expert engineer judgment based on data from similarly islanded grids, and information on existing and planned distribution networks provided by utilities. Details of inputs to the main grid generation and distribution plans are available in Appendix B.

We recognize that these technical plans are being developed during a period of unprecedented technological change in the electricity sector. The costs and the reliability of RE technologies, particularly solar PV and battery storage, have been undergoing disruptive changes. Only a few years ago, governments faced a trade-off between achieving environmental and other social objectives through promoting the use of new technologies, and keeping the costs of electricity systems at affordable levels. For countries such as the FSM, where least-cost reliable generation was previously provided by diesel, this trade-off no longer exists. Combination of solar PV and battery storage is now economically competitive with diesel generation.

On current projections of future diesel prices and battery storage costs, the Master Plans still recommend some new and replacement investment in diesel capacity to ensure security of supply. However, these projections will need to be kept under constant review. Further disruptive changes, such as greater than expected declines in battery storage costs or unexpected spikes in diesel prices may make it more economic to achieve reliability through greater use of battery storage capacity. The analytical tools provided as part of these Master Plans will allow such decisions to be made in the future.

For areas outside the main grids, we recommend either mini-grids or stand-alone solar systems. The decision on whether mini-grids or stand-alone solar system were best for each island and/or village were based on factors such as the size of the community, population density, and the availability of regular transport to deliver fuel supplies. In assessing these factors, we relied on a combination of geospatial analysis, census data, and engineering judgment.

We developed least-cost generation plans for mini-grid areas using HOMER. Key inputs for the main grid HOMER modeling were: energy forecasts, peak demand forecasts, agreed reliability targets and generation planning criteria, diesel price projections, generation asset capital, operating costs, and maintenance costs. For all mini-grids we recommend hybrid diesel and solar with storage generation to provide cost-effective generation while maintaining security of supply. Distribution plans for each mini-grid were developed through expert engineer judgment. Details of inputs to the mini-grid generation and distribution plans are available in Appendix B. As with the main grids, the requirement for diesel capacity will need to be kept under review as technology costs and diesel prices change. However, the Master Plans envisage that most of the proposed mini-grids will be rolled out over the period to 2023. In practice, this means that investment decisions on the components of the mini-grids will need to be made based on the best currently available information.

Generation plans for stand-alone solar systems include one system per household, school, dispensary, and other community buildings. We sized household systems based on World Bank energy access tiers. Systems for other buildings were sized to allow for their requirements, and school systems given additional capacity to allow for other community uses. Details of inputs to the stand-alone solar generation plans are available in Appendix B. No distribution network is required in areas with stand-alone solar systems.

2.2 Financing Plan

Achieving the objectives of the Master Plans will require upfront capital investment in new generation and distribution capacity, and ongoing operations and maintenance (O&M) spending to keep the system functioning. Capital investment cost must either be paid for by grant funding or be spread over time through financing.

The Master Plans are not mere wish lists. They are designed to be financially viable. Financial viability means that the plans can be fully funded and financed within the means available to the Government and consumers of the FSM.

Our approach to confirming the financial viability of the Master Plans is based on developing a financial model for each state to estimate the annual cash requirement by the electricity utility to cover the costs associated with the Master Plans.

We note that FSM utilities are not profit-making organizations. It is common for non-profit utilities, such as consumer cooperatives, to set tariffs on the "cash need" basis. For example, this is the approach adopted in the United States and in the Philippines. Cash need should cover all costs as well as providing any required financial "cushion" for the on-going stable operation of the utilities.

The annual cash need consists of the sum of the operating expenses and any debt service payments. Operating expenses include O&M expenses for generation and distribution assets, administration and general expenses[1], and fuel cost. Our assessment is that FSM utilities generally need to spend more on maintenance of their existing assets. We develop an estimate of maintenance expenses based on a move from the current reactive maintenance to scheduled maintenance. For all new assets added as part of the Master Plans, we estimate the costs of scheduled maintenance. We also include an O&M contingency to account for FSM-specific challenges in maintaining assets in isolated locations.

The estimated revenue requirements are significantly influenced by the rate of transition from reactive to planned maintenance and by the degree of "cushion" required, including contingencies. This allows for a degree of financial flexibility and will help utilities smooth their cash flow requirements.

Estimates of capital investment and operating expenses (including fuel costs) for generation and distribution assets come from the technical modeling outlined in Section 2.1. We also incorporate the costs of new connection and internal house wiring into the investment program, to enable consumers to pay off connection costs over time. Administration and general expenses are estimated based on current spending and growth in consumption. Expected power sales in each state are based on the electricity consumption forecasts we developed. Details of inputs to the financial model are available in Appendix C.

Debt service payments cover the total amount required each year to service outstanding loans taken for capital investment. We have included a debt service coverage margin on top of debt service coverage payments because many lenders will require a minimum debt service coverage ratio to secure loans.

Some multilateral and bilateral donors have already indicated commitments to provide some grant funding over the next 4 to 5 years. The Government of the FSM also has some resources that can be made available to the electricity sector. However, the full financing package for the initial implementation of the Master Plans—that is, the investment program to 2023—will need to be assembled over the remainder of 2018 in close consultation with donors, lenders, and potential investors.

We modeled several financing scenarios based on different levels of grant funding and on different combinations of concessional and commercial financing. The financing package will have a material effect on the cash need of the utilities. Details of our financing assumptions are available in the State Energy Master Plans and in Appendix C.

Cash in is estimated as tariff multiplied by the forecast electricity consumption, adjusted for the level of collection. The Master Plans are viable if cash need is fully covered by cash in. Overall, we find that the Master Plans are viable over a broad range of financing scenarios:

- For Pohnpei and Yap, the implementation of the Master Plans will unambiguously lead to lower tariffs over time
- For Kosrae, full reliance on commercial financing may require an increase in tariffs over the medium-term. However, we discuss options for Kosrae to achieve the implementation of the Master Plan without an increase in tariffs

[1] Administration and general costs include fixed costs such as staff salaries and training.

- Chuuk faces the greatest challenge as it has the highest proportion of unelectrified population. Some increase in tariffs may be unavoidable. However, we consider various options that may allow Chuuk to keep any such increase to a minimum
- The current tariffs are affordable, in the sense that consumers are demonstrably able and willing to pay those tariffs.

In considering the financial viability of the Master Plans, we are mindful of the desire of the FSM and State Governments to achieve a reduction in electricity tariffs. Clearly, paying less for electricity would be beneficial for consumers. Lower tariffs would also enable businesses to expand production. At the same time, tariffs must continue to cover the full cost of the electricity system. Increased grants from donors would enable tariffs to be lowered and could have a material effect on the economic well-being of FSM.

However, if the increased grants are not available, FSM would still be better off fully implementing the proposed Master Plans with more expensive sources of financing than constraining the implementation to the available grant funding.

We assume that the current tariff structure between customer segments will be maintained. We have considered time-of-use and seasonal tariffs. However, we found that the electricity consumption pattern is relatively flat both during each 24-hour period and across the seasons. There is relatively little to be gained from smoothing consumption further. The additional cost of more sophisticated metering infrastructure required to implement a more complex tariff structure does not appear to be justified.

Within the current tariff structure, we recommend a uniform tariff that would be paid by all consumers in a customer segment (residential, commercial, and government) in that state—regardless of location. While this involves a cross-subsidy from consumers on the main grid to consumers on outer islands, we believe that a uniform tariff would:

- Ensure that consumers on outer islands can afford to pay for electricity, and hence provide for meaningful access
- Create a sense of social solidarity, and hence improve collections on outer islands
- Give residential consumers on outer islands access to the same level of cross-subsidy from government and commercial users as is currently enjoyed by the residential consumers on the main grid.

We note that over time, FSM utilities should consider changes in the structure of the tariffs to reduce cross-subsidies from commercial to residential consumers. We also recommend that Yap consider including a variable fuel charge component into its tariff structure to make fuel price adjustments more automatic and less politically complex.

2.3 Implementation Plan

The Master Plans rely on more than just money flowing in. If that money cannot be used in an efficient and timely way, the objectives of the Plans will not be met.

We consider three aspects of implementation:

- Rollout of physical capital
- Implementation roles and capacity
- Implementation risks.

In Appendix H, we also discuss implementation approaches, such as outsourcing. Functions would not be outsourced because the utility doesn't have the resources, but rather because outsourcing can deliver superior value for money (VfM) than the utility performing the function internally.

Rollout of physical capital

We separate activities to be carried out over the 20-year period of the Master Plans into generation capital projects and distribution improvements. We then create a rollout plan that outlines the sequencing of these activities.

The rollout plan includes all the projects that the utilities have already committed to. We then add the new generation and distribution projects from the technical plans. On the main grids, we use the timing and sequencing of projects that our modeling recommends. For unelectrified islands, we start with the most accessible islands first to test out the technology, billing, logistics, and management approach before rolling out to less-accessible islands. For stand-alone solar systems in particular, it will be important to test out and monitor a prepayment system in an accessible location first. In all cases, community buy-in will be critical, with at least a majority of households in the community ready and willing to receive, pay for, and make the best use of, the infrastructure.

If stakeholders prefer different sequencing, the costs and benefits of this would need to be carefully considered. Providing electricity to all schools and dispensaries first may be a priority, but it will be much more efficient to electrify whole communities at once due to fixed costs like training staff and transporting materials.

Implementation roles and capacity

We have carefully reviewed the utilities' current engineering, planning, and financial analysis capabilities. We discuss the roles of the utilities and others in implementing the Master Plans, and what additional capacity they are likely to need to successfully perform those roles. The costs we have estimated for implementing the State Energy Master Plans reflect the additional human capacity required. In the National Energy Master Plan, we include a budget allowance for technical assistance and various coordination, monitoring and evaluation, and administrative functions related to Master Plan implementation.

Implementation risks

We highlight state-specific risks that exist because of the use of specific technologies (for example, additional hydropower in Pohnpei) or the state's particular geographic or social context. In Appendix E, we then discuss risks that are common to all four states. Common risks arise from states using similar technologies, infrastructure, and institutional arrangements.

2.4 Outcomes

We show how the Master Plans achieve state and national targets for: electricity access, reliability, the proportion of electricity generated from renewable sources, lower diesel reliance, and lower greenhouse gas (GHG) emissions.

3 National Energy Master Plan

The National Energy Master Plan focuses on the roles and responsibilities of the National Government. While the technical aspects of the Master Plans depend on the circumstances of each state, so that the National Technical Plan is an aggregation of the state investment programs, the National Government will play a key role in:

- Coordinating and supporting the Financing Plan for each state
- Supporting the implementation of the State Energy Master Plans.

The outcomes of each state Plan combine to deliver the national policy objectives such as achievement of the GHG emission targets (and the associated renewable generation targets) and energy efficiency (EE) targets, as well meeting the electrification targets. While the National Objectives will ultimately be achieved through the state-level actions, national-level actions will also be required.

3.1 Outcomes

Figure 3.1 summarizes the outcomes of the State Master Plans in terms of four key national policy objectives: electricity access, percentage of electricity generated from renewable sources, diesel use, and carbon dioxide (CO_2) emissions. The State Master Plans allow all the desired outcomes to be met.

Figure 3.1: Summary of National-level Outcomes of State Energy Master Plans

Electricity Access (HH)	RE Percentage	Diesel Use (million gallons)	Electricity CO_2 Emissions (tonnes)
2018: 67%	2018: 19%	2018: 4.2	2018: 43,490
2020: 82%	2020: 44%	2020: 2.9	2025: 21,980*
2027: 100%	2027: 63%	2027: 2.1	2027: 21,980
2037: 100%	2037: 84%	2037: 1.5	2037: 15,769

*We show 2025 for comparison with UNFCCC emissions target for 2025.

The National Energy Policy (NEP) sets six main targets:

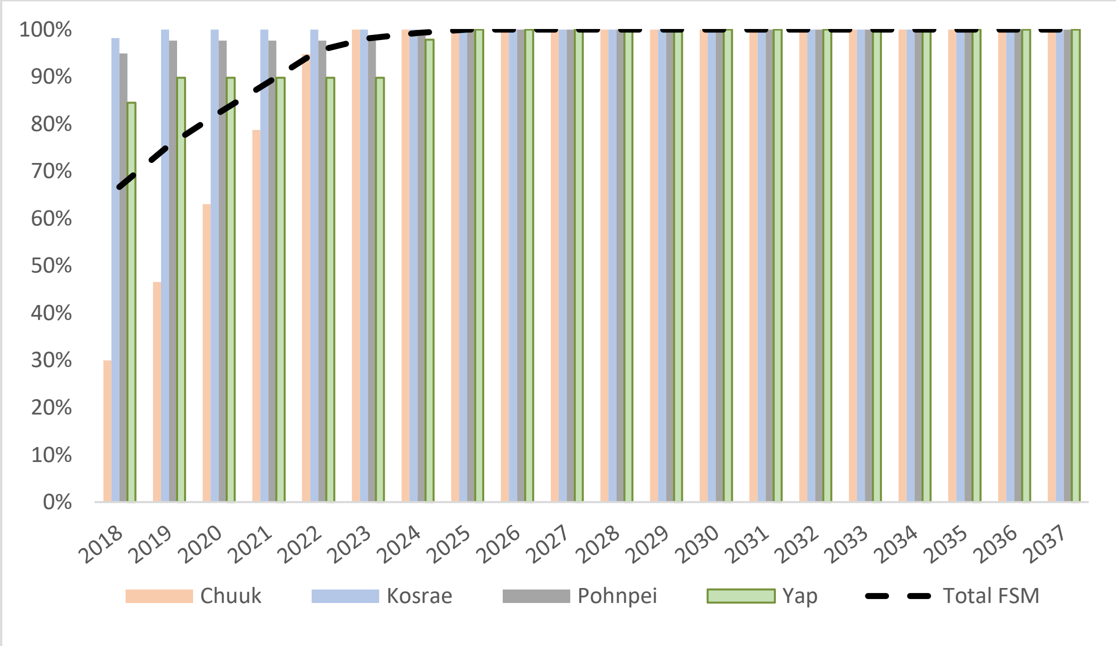
- Obtain 30 percent of energy supply from RE by 2020[2]
- Increase overall EE by 50 percent by 2020
- Ensure a safe, reliable, and affordable supply of conventional energy
- Electrify 80 percent of rural public facilities by 2015
- Electrify 90 percent of rural households by 2020
- Enhance the supply side EE of the FSM utilities by 20 percent by 2015.

[2] This target is widely interpreted by sector stakeholders in FSM as meaning 30 percent of national electricity generation (rather than primary energy supply).

Electrification

The state investment plans described in subsequent sections have been designed to achieve more than 95 percent access to electricity over the next 5 years, and 100 percent electrification of all households and public facilities by 2025. However, our analysis suggests that it is unfortunately not practical to achieve the NEP objective of 90 percent electrification by 2020. Figure 3.2 shows the planned electricity access rates in each state, and the average for FSM.

Figure 3.2: Electricity Access - Households



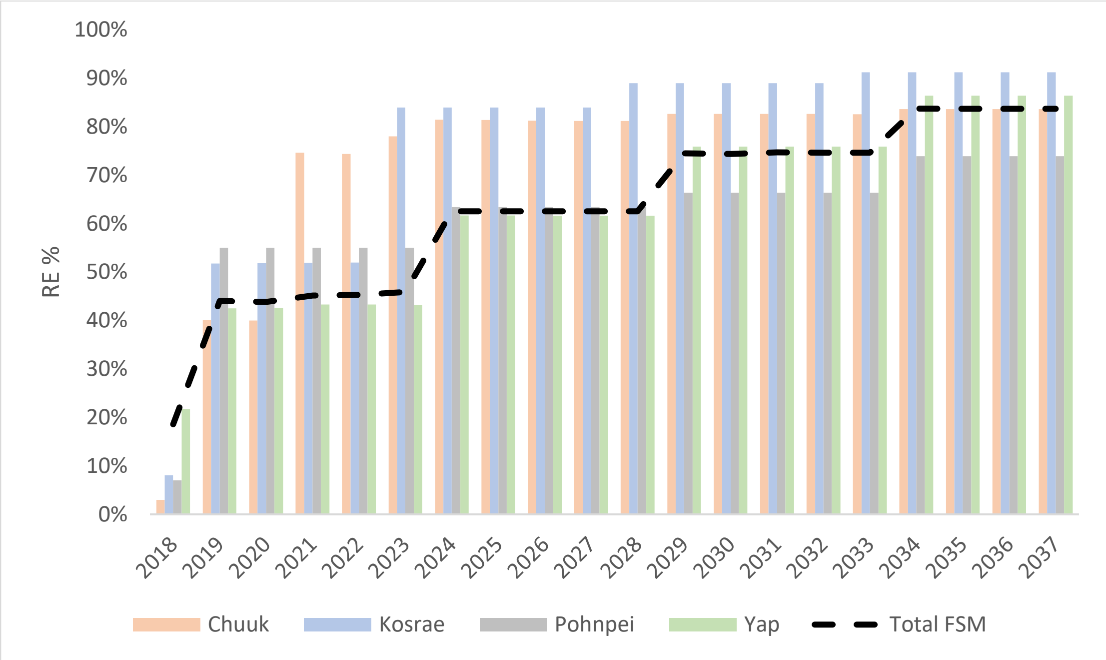
All states would have 100 percent electricity access by 2025. 100 percent access would start in Kosrae in 2019 (after the Walung mini-grid is built), followed by Chuuk in 2023, and Pohnpei and Yap in 2025.

By 2020, 82 percent of households in FSM would have electricity access (32 percent of households outside the four main islands). However, if rural households on the main islands were also included, the percentage of rural households with electricity access by 2020 would be higher.

RE generation percentage

Together, the state-level reference case investment plans far exceed the national RE target of 30 percent (Figure 3.3).

Figure 3.3: RE Percentage of Total Generation



Energy security

Relying on imported diesel for electricity generation puts the utilities—and, hence, consumers—at the mercy of volatile international prices. The investment plans address this by facilitating an increasing contribution of domestic, RE resources for electricity generation (see Figure 3.3).

With current technology, even in 2037 diesel still plays an important role in electricity generation, and FSM will need to import 1.5 million gallons of fuel. However, this is 64 percent lower than the expected amount in 2018 (Table 3.1)—representing a major achievement in reducing FSM's vulnerability to imported fossil fuels. The Master Plans should be regularly revised and updated. As technology changes, it may become economic to reduce reliance on diesel generation even further, without compromising reliability.

Table 3.1: Average Diesel Use, Gallons per Year

	2018	2019–2023	2023–2027	2028–2033	2034–2037
Chuuk	1,249,211	805,942	525,701	418,935	346,879
Kosrae	458,107	277,498	92,406	74,971	75,251
Pohnpei	1,787,333	1,269,637	1,112,939	1,150,808	947,475
Yap	713,745	531,801	395,833	270,186	156,349
Total FSM	**4,208,397**	**2,884,877**	**2,126,880**	**1,914,900**	**1,525,954**

GHG emissions

FSM's Intended Nationally-Determined Contribution (INDC) commits the country to unconditionally reduce its GHG emissions by 28 percent by 2025, compared to 2000. It also has a conditional target to reduce emissions by up to 35 percent in 2025, compared to 2000 (subject to the availability of additional financial, technical, and capacity building support from the international community).

In 2000, GHG emissions were 150,000 tonnes of carbon dioxide equivalent (tCO2e). Electricity generation accounted for 42 percent of this (64,000 tCO2e).[3]

The Master Plans result in an estimated 21,980 tonnes per year of carbon emissions (not including other GHGs like methane or nitrous oxide) from electricity generation in total across the four states in the 2023-2027 period (Table 3.2). This is about 65 percent below the electricity sector's total emissions in 2000. Even with other GHGs added, this would allow the electricity sector to meet much more than its proportionate share of emissions reductions required to meet both FSM's conditional and unconditional INDC targets for 2025.

Table 3.2: CO_2 Emissions, Annual Average Tonnes

	2018	2019–2023	2023–2027	2028–2033	2034–2037
Chuuk	12,910	8,329	5,433	4,329	3,585
Kosrae	4,734	2,868	955	775	778
Pohnpei	18,471	13,121	11,501	11,893	9,791
Yap	7,376	5,496	4,091	2,792	1,616
Total FSM	**43,490**	**29,813**	**21,980**	**19,789**	**15,769**

Energy efficiency

FSM aims to increase overall EE by 50 percent by 2020, and enhance the utilities' supply side EE by 20 percent by 2015. The deadline for the second objective has expired and, although data are lacking, we understand that sufficient progress on the first objective has not been made. Given this, we believe the National Government should reconsider EE its objectives and implementation plans.

It is important to recognize that overall EE has two key drivers. First, demand-side efficiency, represented by improved EE of appliances and commercial/industrial equipment and reduced non-technical losses such as theft and under-recovery of delivered energy. Second, supply-side efficiency, represented by improved EE of generation assets and reduced technical losses on the network.

Demand-side

On the demand-side, the key drivers of EE are:

- Changes in appliances, such as light fittings, towards more energy efficient solutions which provide the same service but with lower energy requirement
- Changes in behavior to reduce energy use while maintaining the same level of welfare.

Modern appliances are increasingly more energy efficient. Consumers are incentivized to purchase more energy efficient appliances. While many manufacturers provide information on EE of their appliances, some products do not have adequate information and it may be difficult for consumers to make informed choices. The national Government already promotes EE, but more can be done. We discuss this below.

[3] FSM's INDC under the UNFCCC.

There is significant potential for behavioral changes, particularly from the government consumers. In particular, office air conditioning can be set at slightly higher temperatures and it is not necessary to air condition offices overnight.

Overall, on the demand-side, the load forecasts underlying the investment plans reflect two main EE assumptions:

- **EE improvements across all user groups**—The load forecast escalates the expected energy consumption from the different user groups (and the rate of increase in overall demand) over time at the same rate as the expected increase in GDP. International experience suggests that countries at this stage of development usually see energy consumption growing at a faster rate than GDP. The assumption used in our load forecast therefore implicitly reflects a gain in EE for all users.
- **Additional EE improvement for government**—We have factored in an additional EE improvement of 30 percent from government customers, recognizing that they are likely to have the greatest potential to achieve EE gains quickly.

We have also considered the effects of introducing demand-side measures into the overall management of the energy system. However, our analysis of the type of commercial and industrial load in FSM suggests that there are limited efficiencies to be gained from active demand-side management. The Master Plans are based on a concept of combining diesel and renewable generation capacity to enable an increased proportion of energy to be produced from renewable sources while ensuring security of supply. This design principle, however, also ensures that the system will always have sufficient capacity to meet additional demand at very low marginal cost. Hence, within the specific context of the FSM's power system, the marginal cost of demand-side management is generally likely to exceed the marginal cost of additional generation.

In addition, many of the Master Plan investments will improve supply-side EE. The Plans include improvements in generation efficiency over time through the implementation of more fuel-efficient diesel generators, retirement of less fuel-efficient diesel generators, and the rapid incorporation of solar PV, BESS, and a new hydropower plant on Pohnpei. The Master Plans also document some measures to reduce technical losses, such as YSPSC replacing or upgrading about 21 miles of 13.8kV MV overhead lines, and Kosrae relocating and upgrading around 6 miles of 13.8kV MV overhead lines. Both these projects will make incremental improvements in line losses.

To improve EE further—in order to meet the NEP targets—will require additional funding and policy intervention

Appendix I discusses the potential for further EE improvement on the demand-side. Particular areas of potential are:

- Improving the design, procurement, operation/running times, and maintenance of air conditioning systems in government buildings
- Improving the design and deployment of commercial refrigeration and freezing plants, especially to get rid of trailer-mounted reefer containers that are commonly seen beside major stores and supermarkets across the FSM, in favor of purpose-built cold storage rooms
- Improving the design standards for commercial and residential buildings, to take advantage of the natural environment of the FSM rather than building in a requirement for air conditioning

- Implementing star rating systems for appliances, and programs to encourage retailers to only provide high-efficiency appliances to the market
- Providing incentives for commercial and residential customers to replace older, low-efficiency refrigeration and air conditioning units with modern, high-efficiency inverter-controlled air conditioners and refrigerators/freezers

We have considered the benefits of time-of-use (TOU) energy tariffs, which may encourage energy consumers to switch the use of non-time critical appliances to non-peak times of the day or week. However, we believe there is unlikely to be significant benefit from TOU tariffs in the FSM because:

- The daily load profile is relatively flat, so that the savings from load shifting will not be material
- Highest daily demand is during the hours of daylight. With increased reliance on solar generation, this will lead to greater coincidence of generation and consumption. Measures to shift the time of consumption could run the risk of increasing the requirement for battery storage
- The cost of rolling out the metering infrastructure required to implement TOU tariffs is unlikely to be justified.

Achieving more ambitious EE scenarios would require a clear government policy and state-level commitment to implementing policies and actions to promote DSM (such as those in the State Energy Action Plans), and encouraging consumers to use energy efficient products and behaviors through information and incentives. These actions would involve a cost. This cost would need to be compared to the benefits from DSM (for example, it may allow some capital investments in generation and distribution infrastructure to be deferred).

Both the National and State Governments have a role to play in improving EE. Better coordination of activities across states could provide momentum and allow states to share knowledge and benefit from economies of scale in program design and implementation.

3.2 Implementation Plan

Successful implementation of the Master Plans will require effective state and national institutions with sufficient capacity. It will also require a total capital investment across the FSM of about US$300 million over the 20-year Master Plan timeframe.

3.2.1 Capital Expenditure Requirement

We recommend a combination of grant funding, concessional financing, and IPPs be used to cover the capital expenditure required to implement the Master Plans. We anticipate that the national capital requirement to implement the Master Plans is larger than available grants. A total of about US$296 million of capital expenditure will be required over the 20-year timeframe of the Master Plans. This includes about US$101 million in the first 5-year planning period (Table 3.3).

For practical reasons when carrying out the modeling, we divided the 20-year Master Plan timeframe into 5-year blocks. This has created somewhat artificial boundaries between time periods. For the purposes of obtaining finance, we recommend that all electricity access investments—including those currently scheduled for implementation early in the second 5-year period—be considered as a single package that would be financed as part of the first phase of Master Plan implementation.

Table 3.3: National Capital Expenditure Requirement (US$ million 2016)

	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
Chuuk	0.61	38.35	16.39	16.81	13.85	**86.01**
Kosrae	2.77	12.03	8.64	6.86	6.96	**37.26**
Pohnpei	2.85	35.63	19.97	24.76	30.80	**114.02**
Yap	1.27	15.09	13.22	15.77	13.55	**58.90**
Total	**7.5**	**101.10**	**58.22**	**64.20**	**65.16**	**296.18**

3.2.2 Institutional responsibilities and coordination

Implementing the National Energy Master Plan (and the individual State Energy Master Plans) successfully will require close coordination between various parties in the states, as well as the national government.

Tasks will include:

- Monitoring and evaluating implementation and how the Master Plans are contributing to state and national goals
- Liaising with donors and other potential financiers, and allocating grants and concessional loans between states and projects
- Developing and enacting policies that will facilitate Master Plan implementation
- Procuring goods and services.

The existing institutions do not have sufficient capacity to fulfil all the required functions

We have reviewed the roles and the capabilities of the national institutions.

The National Energy Workgroup (NEW) has staff members in Palikir and the SEWs have three to four people in each state, including a representative from each utility. The Energy Division includes a Director, a part-time Energy Advisor funded through the World Bank Energy Sector Development Program, and an Accountant.

However, the Master Plans will involve a significant expansion in the activities required to coordinate energy sector development in FSM and, hence, the workload for local institutions. Furthermore, successful implementation of the Master Plans will require a range of technical expertise (including monitoring and evaluation; applying for donor funding, and procurement), much of which is not currently available.

Training may be needed on how to keep the Master Plan a live document and the Energy Division or other institutions may need to seek policy advice from consultants, or other government departments, in specific areas. For example, transactions advice for public-private partnerships.

In addition, to carry out its monitoring and coordination functions, the Energy Division will need additional staff.

The Master Plans include a budget for coordination and technical assistance

We assume that FSM will need an additional 5 percent on top of the total capital expenditure requirement in Table 3.3 (a total of about US$15 million over 20 years) to provide for the additional capacity and technical assistance that will be required. We do not include this in the tariffs discussed in the State Energy Master Plans as we assume such costs—which will relate to functions like coordinating and monitoring the implementation of the Master Plans and updating the plans as circumstances change—will be covered by grants.

The National Government, State Governments, Energy Workgroups, and utilities will need to decide how to allocate different roles and responsibilities for Master Plan implementation, and the budget for it.

We anticipate that the Department of R&D (Energy Division) will play a key role in monitoring how all the individual projects feed into the Master Plan and the National Energy Policy objectives. It will also coordinate requests for overseas development assistance and keep track of financial flows. Both the national and state governments will be in charge of enacting policies that facilitate implementation of the Master Plans.

3.2.3 Policy support

Successful implementation of the Master Plans will require supportive policies from the National and State Governments. We have identified the following specific areas where there may be a need to review and/or enact policies and regulations (there may be others):

- **Promoting explicit IPP laws and procedures**—Pohnpei is the only state with an explicit legal provision for PPPs, although we understand that IPPs are implicitly permitted in Chuuk. The other states may wish to consider the potential role of IPPs in implementing the Master Plans (see Appendix H), and what policies may be needed to support this.

  Utilities would likely need transaction support to design, execute, and manage IPP arrangements. Through the Strengthening the Energy Sector Regulatory Framework project, the Asian Development Bank (ADB) supported the development of guidance materials, a template request for proposals (RfP) that FSM states can use to contract with IPPs for RE generation projects, and a model PPA. The budget included in the Master Plans for project implementation (whether this by the utility or through an IPP) is intended to fund the required support.

  More centralized implementation of IPPs through coordinated procurement at the national level could increase economies of scale and achieve further savings relative to the currently modeled costs.

- **Net metering**—With the Master Plans envisaging large increases in solar PV capacity in all states, and potential land access constraints in some, there may be a role for distributed solar capacity on the roofs of commercial or government buildings. Since buildings with rooftop generation will still require connection to the grid for security of supply, the utilities will need to implement one of two policies:

  – Charge users who take advantage of net metering for the cost of connection. Low level of net purchases from the grid, while attractive to the building owners, would mean that the current per kWh tariff would not cover the cost of connection

– Require users to sell solar PV output into the grid at IPP prices, and then re-purchase power from the grid at consumer tariffs.

To facilitate distributed solar PV, the states of FSM are currently developing net metering legislation. Pohnpei State has a Net Metering Act but has faced challenges to implementing it. SPC is funding a consultant to develop net metering bills for the other three states and to identify ways to overcome the implementation challenges in Pohnpei. This work is expected to be completed by early-2018.

If net metering is implemented, it will need to be done in a way that is practical for the utilities and balances the interests of different parties.

- **EE**—The National and State Action Plans include a large number of policy and regulatory actions related to demand-side EE, many of which have yet to deliver results. It may be possible to accelerate EE gains by focusing policies and incentives on a smaller number of high-potential areas for EE (such as those highlighted above)
- **Safe battery disposal**—We understand that the national government has recently introduced a new policy requiring donors providing new generation to dispose of the batteries from previous donor projects. During our consultations, some stakeholders expressed concern that this policy may act as a disincentive to, or burden for, donors. They suggested that utilities could identify their own strategies for battery disposal or recycling.

4 Chuuk State Energy Master Plan

The Chuuk State Energy Master Plan provides a least-cost strategy to achieve the state's energy goals. By 2023 the state will achieve its goal of 100 percent electrification, and its 30 percent RE target. Total capital investment required over the 20 years of the Master Plan is US$86 million. The Master Plan has three core components:

- A **Technical Plan** that outlines the generation and distribution assets that need to be purchased for the state to be able to provide a reliable, sustainable electricity service to all residents at least-cost
- A **Financing Plan** that outlines how the Technical Plan can be feasibly financed and funded
- An **Implementation Plan** that discusses key considerations and risks for rolling out the Technical Plan.

Figure 4.1 summarizes the Master Plan's components and their outcomes.

Figure 4.1: Summary of the Chuuk State Energy Master Plan

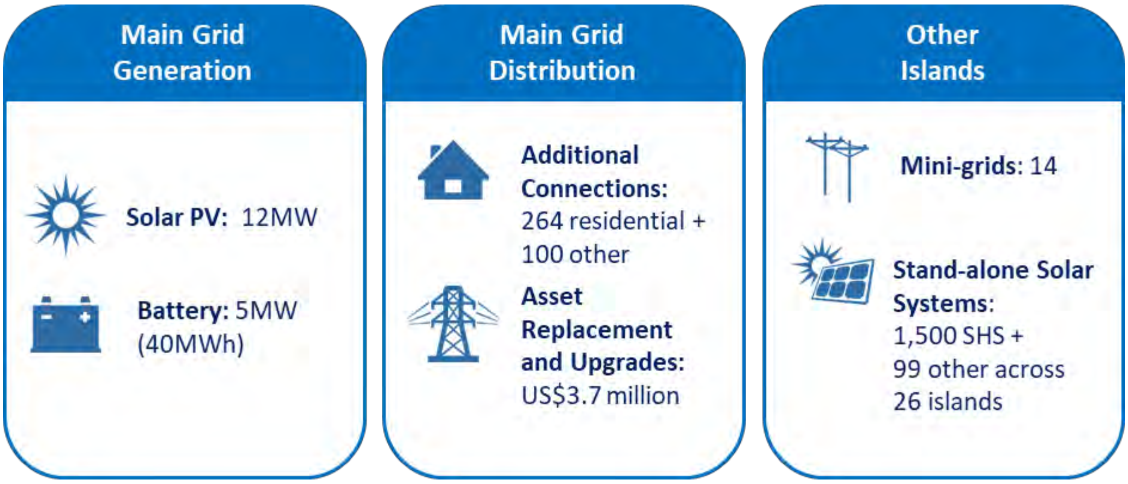
Technical Plan	Financing Plan	Implementation Plan	Outcomes
Main Island: 12MW new solar 5MW new batteries (40MWh) Various generation and distribution refurbishments and enhancements **Other Islands:** 14 mini-grids + 1,599 stand-alone solar systems	**Total Capital Expenditure:** US$86.0 million 2018: US$0.61m 2019-2023: US$38.4m 2024-2028: US$16.4m 2029-2033: US$16.8m 2034-2037: US$13.9m	**2019-2023:** Provide mini-grids and stand-alone solar systems to all unelectrified communities **2019-2037:** Invest in new solar PV and batteries **2029-2037:** Replace mini-grid components and stand-alone solar systems	**Electricity Access: (HH)** 2018: 30% 2020: 63% 2027: 100% 2037: 100% **RE Generation %:** 2018: 3% 2020: 40% 2027: 81% 2037: 84%

4.1 Technical Plan

The Technical Plan outlines required upgrades and improvements to the grid on Weno, and the least-cost options for achieving the desired level of service on all other islands in Chuuk. On Weno, the plan includes investment in new solar photovoltaic (PV) capacity to reduce the cost of electricity. Distribution asset replacements and upgrades are needed to improve system reliability, while connections on the main grid are for households not currently connected as well as the growth we have forecast for number of households and new businesses. Outside Weno, the plan includes the construction of 14 mini-grids, and provision of stand-alone solar systems on the remaining 26 inhabited islands in Chuuk.

Figure 4.2 summarizes the new infrastructure required in Chuuk (not including replacements of existing generation infrastructure).

Figure 4.2: Summary of New Infrastructure in Chuuk Technical Investment Plan



4.1.1 Chuuk main grid

Over the 20-year Master Plan period, the main-grid on Weno needs investment in: new generation capacity, replacement or refurbishment of existing generation assets, extension of the distribution network to connect new customers, and replacement of existing distribution assets.

We have labelled recommended generation capacity 'new' if the assets change the makeup of the generation system. All other capital is included as 'replacement', and includes totally replacing an asset, large asset refurbishment, and replacing major components of an asset. Diesel generators are categorized as 'new' if they add additional generation capacity or are purchased when a generator of different capacity comes offline. Capital investment in diesel generators is categorized as 'replacement' when a like for like replacement of a generator is made or when a major refurbishment of an existing generator is undertaken. Table 4.1 shows the new generation capacity our modeling suggests is required. In the text we explain the new generation investments, as well as discuss when replacements or refurbishments are required.

Investments in new solar PV and storage capacity will reduce the cost of energy

Over the 20 years of the Master Plan, we recommend that 12MW of new solar PV generation capacity is installed alongside 40MWh of battery storage. New solar PV capacity will reduce the average cost of electricity by reducing Chuuk Public Utility Corporation's (CPUC) diesel fuel use and therefore expenditure on diesel fuel. The upfront capital cost of solar PV will be either paid for through grants or smoothed over time with cheap concessional financing so the cost per kWh will be lower than that provided by diesel generation. Refurbishments and replacements of existing diesel generation capacity are required to ensure security of supply.

Table 4.1: Chuuk New[4] Generation and Storage Capacity for Main Grid

	2018	2019–2023	2024–2028	2029–2033	2034–2037
Diesel	-	-	-	-	-
Solar PV	-	4MW	4MW	2MW	2MW
Battery inverter	-	1MW	2MW	1MW	1MW
Battery storage	-	7MWh	13MWh	10MWh	10MWh

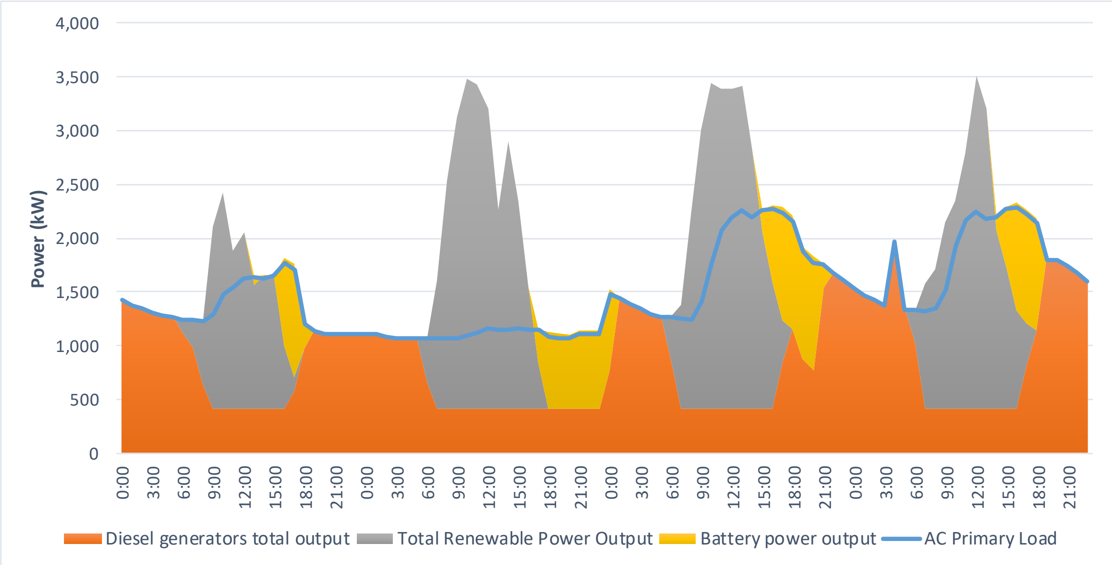
In the period 2019–2023, our modeling suggests that:

- There should be a major overhaul of the existing diesel gensets #4 and #5
- 4MW of solar PV capacity should be developed. This will help reduce the cost of energy by reducing the use of diesel. The feasibility study on integrating new solar PV to the grid on Weno will review possible locations for this and the other solar PV capacity we recommend on Weno (below), and the commercial arrangements that might be used
- Energy storage should be deployed at the Weno power station, to provide 1MW of capacity and 7MWh of storage to manage integration of the PV plants and increased use of RE. The battery energy storage system (BESS) can be used for spinning reserve, stability management, and additional security (n-2)[5], as well as load shifting
- The recommended investments in solar and storage will meet a large proportion of Weno's demand in 2023, reducing the use of diesel and therefore the cost of electricity (Figure 4.3). However, the system is set to keep one genset running at all times—that is, there is no diesel-off mode in this period.

[4] New only includes new generation assets that change the generation mix. Like for like replacement of retired assets is not included.

[5] n-2 redundancy is defined as having one of the two largest gensets off-line for maintenance, and losing the next largest genset on Fault, and still supplying the Maximum Demand.

Figure 4.3: Weno Load Duration Curve and Contribution of Generation Sources, 2023



In the period 2024–2028:

- Diesel genset #3 should be replaced
- 4MW of solar PV should be developed to offset increasing use of diesel generation as loads increase. This capacity could be added to an existing solar site or deployed behind the meter on government or commercial buildings
- Energy storage should be deployed at the Weno power station, to provide 2MW of capacity and 13MWh of storage to manage integration of the PV plants and increased use of RE. BESS can be used for spinning reserve, stability management, and additional security (n-2), as well as load shifting
- Diesel-off mode is allowed in this period and occurs sometimes during the day.

In the period 2029–2033:

- Diesel genset #4 should be replaced
- Battery inverters and batteries installed in the 2019-2023 period should be replaced
- 2MW more solar PV and 10MWh more battery storage should be added as the battery price continues to fall
- Diesel genset #5 should be retired as it is no longer needed to achieve n+2 now that the battery bank can provide redundancy.

In the period 2034–2037:

- Battery inverters and batteries installed in the 2024-2028 period should be replaced
- 2MW more PV and 10MWh more battery should be added. The battery price is assumed to have flattened and the increases are mainly due to higher fuel prices.

Replacement capital is needed to maintain generation

The current solar PV plants will reach the end of their lives during the period of the Master Plans, and our modeling suggests they should be replaced. We assume energy storage will achieve a 10-year life and will be replaced at least once during the Master Plan timeframe. Diesel gensets will likely need to be replaced, depending on the duty cycle and level of RE contribution.

The spreadsheets that will be shared as part of data handover break down the replacement capital needed over the 20-year period.

New connections are needed as the number of households increase

Weno currently has a 90 percent household connection rate.[6] We assume the other 10 percent of households are connected between 2019 and 2028. New connections will also be needed to cater to an increase in the number of households.[7] This rate of new connections seems feasible based on the CPUC Business Plan 2017–2021.

We have also planned for five new commercial or government entities being connected each year on average. Table 4.2 shows the new residential, commercial, and government connections. The costs of these connections are provided in the accompanying spreadsheets.

Table 4.2: Average Annual New Connections

	2018	2019–2023	2024–2028	2029–2033	2034–2037
New Residential Household Connections	37	37	3	3	3
New Commercial & Government Connections	5	5	5	5	5

The existing distribution network will need upgrades and maintenance

General network and demand growth includes minor feeder extensions and updating transformers as peak demand gradually increases and the expenditure cannot be tied to any specific large customer load project. Our analysis suggests that this will cost about US$200,000 every 5 years.[8]

We used the asset register to make replacement estimates (see Table 4.3). As the network on Weno is new, we do not forecast any asset replacement in the first 10 years. Details of asset lifespans and replacement costs are in Appendix B.

[6] We calculated the percentage of electrified households by comparing the number of residential connections to the forecast number of households in 2018.

[7] Based on growth in the number of households between 1994 and 2010 in Weno, we forecast a further increase in households over the next 20 years.

[8] The network expansion requirement is likely to be quite limited due to network layout and because Weno is a small island. However, to be conservative we include a general allowance for some expansion/augmentation that is not specifically directed to one customer or project.

Table 4.3: Distribution Network Asset Replacement (average annual figures, US$)

	2018	2019–2023	2024–2028	2029–2033	2034–2037
Age-based Asset Replacement	0	0	54,650[9]	285,795	305,573

4.1.2 Chuuk lagoon and outer islands

Based on the numbers and distribution of households, our analysis suggests that Chuuk should construct 14 mini-grids. These would cover the following municipalities:

- **Southern Nomoneas**: Tonoas, Fefen, Uman (one mini-grid for all three)
- **Faichuk**: Tol, Polle, Wonei, Patta, Udot, Romanum, Fanapanges
- **Mortlocks**: Lekinoch, Satowan, Nema
- **Northwest**: Nomwin, Houk, Onoun.[10]

We find that stand-alone solar systems are the least-cost option for all the other islands in Chuuk.

We assume that all infrastructure is new. However, where schools already have solar, the panels could be reused.

Mini-grids

Each mini-grid will require a mixture of diesel and solar generation, as well as storage. The capacity of each of these asset types is in Table 4.4. The diesel is to meet the reliability standards. The amount of solar PV and storage capacity changes between mini-grids based on electricity demand. Most mini-grids rely primarily on RE, with the diesel generators used as backup.

Generation for the Tonoas, Fefen, and Uman mini-grid would come from the Vital IPP. We understand that CPUC has signed an agreement with Vital for the Coconut for Life project. The project will include the IPP plant and an integrated coconut processing facility was officially launched at the site in October 2017.

Because of household distribution on Udot, the least-cost option is for some of the island to be serviced by a mini-grid and some with stand-alone solar systems. Our initial analysis suggests that 80 households should be connected to the mini-grid and 160 should have solar home systems (SHS). The forthcoming feasibility study for the Udot mini-grid will review this recommendation in light of additional information on geographic and institutional conditions on Udot, and adjust it if appropriate.

[9] All in 2028 (we assume age-based replacement starts after 10 years).

[10] Although Onoun has fewer than the threshold of 100 households we have used to select islands for mini-grids, we assume for now that it will have a mini-grid as the Government plans to carry out a detailed feasibility study for a mini-grid in Onoun.

Table 4.4: Chuuk Mini-grid Generation Capacity 2018–2037[11]

Location	Diesel generation	Solar Generation	Storage	Converter
Tonoas, Fefen, Uman	900kW	300kW	200kWh	200kW
Tol	100kW	100kW	200kWh	60kW
Polle	100kW	40kW	100kWh	20kW
Wonei	100kW	40kW	100kWh	20kW
Patta	100kW	40kW	100kWh	20kW
Udot	100kW	100kW	200kWh	70kW
Romanum	100kW	60kW	180kWh	40kW
Fanapanges	100kW	60kW	180kWh	40kW
Lekinoch	100kW	50kW	140kWh	30kW
Satowan	100kW	50kW	140kWh	30kW
Nema	100kW	40kW	120kWh	30kW
Nomwin	100kW	50kW	140kWh	30kW
Houk	100kW	50kW	140kWh	30kW
Onoun	100kW	40kW	100kWh	30kW

For distribution, we recommend that all islands except the Tonoas group have low-voltage (LV) underground networks. For LV, the costs are similar for above or below ground, so we recommend underground to increase weather resistance.

The Tonoas, Fefen, Uman mini-grid requires a 13.8kV medium-voltage (MV) overhead network plus a LV underground network. The overhead line runs around the perimeter of the island to join up the major household areas. The mini-grid also requires two short submarine cables connecting the islands.

The estimated distribution costs for each mini-grid are in the accompanying spreadsheets.

Stand-alone solar systems

For the remaining islands, our analysis suggests that stand-alone solar systems are the most cost-effective option due to the lower number of households, and the distribution of households.

Table 4.5 shows the number of stand-alone solar systems required. These numbers include residential, schools, dispensaries, and other facilities.[12] The sizes assumed are:

- 200W/1.2kWh for home systems[13]

[11] The variability in solar/diesel contribution in different islands is mainly due to fuel costs being lower on the more accessible islands and to differences in the sunk costs.

[12] Other facilities may include commercial entities or community centers.

[13] For the purposes of the Master Plan we assume that all households use 200kW systems. However, we recognize that some households may want larger sizes. As an illustration, Appendix B outlines the additional cost for two larger sizes of SHS.

- 10kW systems for schools
- 2kW systems for other users such as dispensaries and shops.

Table 4.5: Number of Stand-alone Solar Systems by Customer Type

Location	Household	School	Dispensary	Other
Chuuk	1,500	18	27	54

A break-down of the number of stand-alone solar systems for specific locations is in Appendix B.

The entire system will need to be replaced about every 8 years (provided it is well-maintained). We have factored in quarterly trips to each island for maintenance.

4.2 Financing Plan

The total amount needed to cover capital expenditure across the lifespan of the Master Plan is US$86.0 million

Almost half of the capital expenditure over the 20-year Master Plan period is on new generation capacity for the grid on Weno (Table 4.6). We recommend ongoing investment in solar PV with storage to lower the cost of generation and reduce reliance on diesel generation. Required expenditure for the main grid distribution network includes network upgrades currently being planned by CPUC. Based on requests from stakeholders during consultations, the Master Plans provide for all mini-grids and stand-alone systems to be rolled out between 2019 and 2023.

Table 4.6: Capital Expenditure Requirements (US$ million 2016)

	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
New Main Grid Generation	0.00	11.48	12.62	7.05	7.05	38.21
Main Grid Generation Replacement	0.58	1.34	1.65	2.48	3.39	9.43
Main Grid Distribution	0.03	0.34	0.61	1.77	1.53	4.28
Mini-grids	0.00	20.90	1.51	1.22	1.88	25.51
Stand-alone Solar Systems	0.00	4.29	0.00	4.29	0.00	8.58
Total	0.61	38.35	16.39	16.81	13.85	86.00

Operating expenses include:

- Weno generation O&M cost
- Weno distribution O&M cost
- Weno fuel cost
- Mini-grid generation O&M cost
- Mini-grid distribution O&M cost

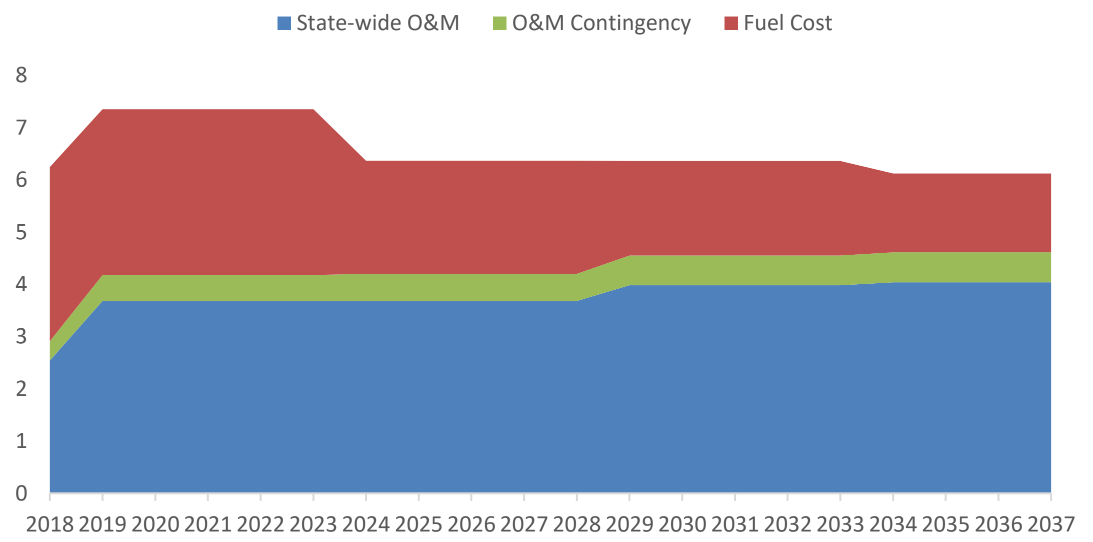
- Mini-grid fuel cost
- Stand-alone solar O&M cost
- Administration and general fixed costs
- A 15 percent contingency on all technical O&M expenditure
- Project preparation costs (5 percent of total capital investment) for new capital projects (includes owner's engineer, procurement, and so on).

Operating expenses fall by US$2.4 million a year between 2018 and 2037 because of a reduction in diesel use

State-wide operating expenses increase from 2018 to 2023 as new mini-grids and stand-alone solar systems come online. Falling fuel use on Weno offsets this increase by 2024 (Figure 4.4).

Fuel cost makes up 60 percent of total operating expenses on Weno in 2018. As new RE capacity comes online, fuel consumption declines and fuel cost falls to less than 20 percent of operating expenses. The shift from diesel to renewables also leads to a fall in generation O&M costs on Weno because of lower run hours for diesel generators. State-wide operating expenses—excluding the fuel cost—increase over the Master Plan period. This increase is because administration and general costs, and distribution costs on Weno, grow with load growth; and operating expenses for new mini-grids and stand-alone solar systems are added. The net effect of lower fuel cost and growing O&M costs on Weno is a reduction in operating expenses each year of US$2.4 million from 2018 to 2037.

Figure 4.4: Estimated State-wide Operating Expenses, US$ million



The financial spreadsheet provided to CPUC and the FSM Department of Resources and Development includes a more detailed breakdown.

We calculate debt service payments for three scenarios

The debt service payment made each year will include a repayment of the principal of the loan(s) (capital amortization) as well as an interest payment (cost of financing). We have calculated debt service payments for three scenarios:

- Scenario 1: All capital expenditure is paid for with grant funding

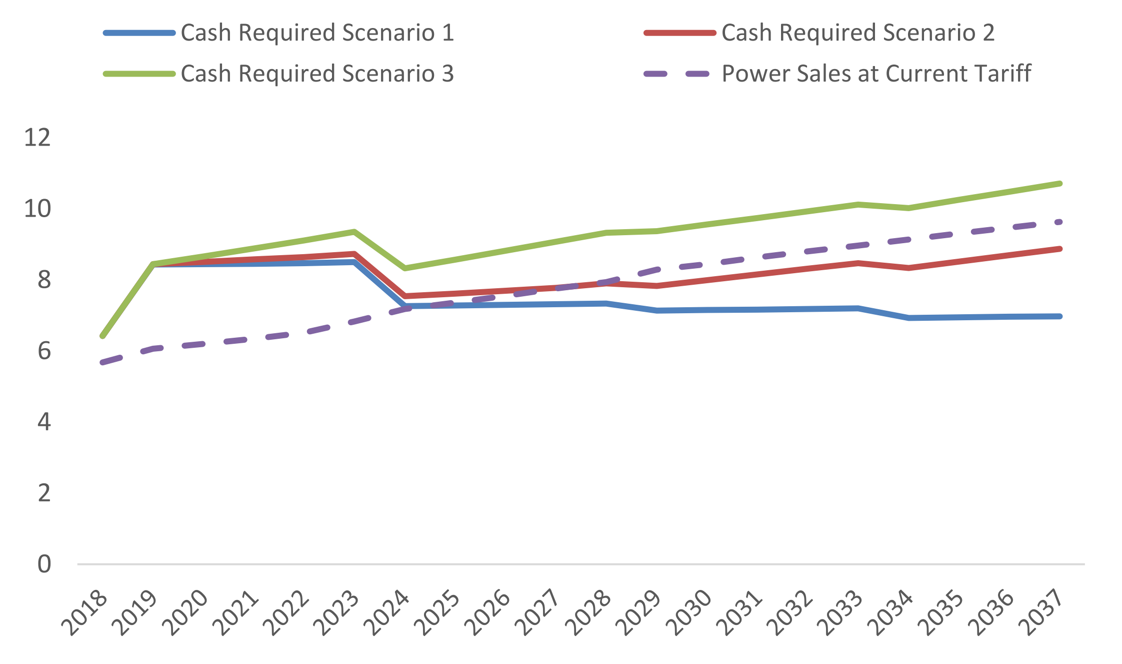
- Scenario 2: Capital expenditure on mini-grids and stand-alone solar systems is paid for with grant funding. Capital expenditure on Weno is financed with concessional loans. Details of assumed loan terms offered by donor organizations are available in Appendix B
- Scenario 3: Capital expenditure on the mini-grids and stand-alone solar systems is paid for with grant funding. Capital expenditure on Weno is financed with loans from commercial banks. (This scenario approximates the cost of getting IPPs for solar and storage as well as of CPUC financing the replacement of the network on its own balance sheet). Details of assumed loan terms offered by commercial banks are available in Appendix B.

Current tariffs will not be sufficient to cover CPUC's cash requirements over the 20-year Master Plan period

Chuuk faces the greatest financial challenge of all FSM states since it has the highest proportion of currently unelectrified households living in remote locations. For Chuuk, the current tariffs will not be sufficient to cover the costs of the electricity system even if all new investments were grant-funded.

The net present value (NPV) of net cashflow over the 20 years of the Master Plan is negative in all three scenarios if tariffs are kept at their current level. Cash required exceeds the expected revenue from current tariffs in all years to 2024. However, from 2024 onward, as revenue grows with electricity demand and new renewable investment lowers operating expenses, expected revenue exceeds cash required in all years.

Figure 4.5: Cash Requirements in the Three Financing Scenarios, US$ million



There are two key implications for Chuuk

- Scenario 3—that is, reliance on commercial financing for the entire Master Plan—is not viable in the medium-term. This is consistent with the expectations of donors. We believe there is high probability that the electrification on outer islands will be funded by donor grants

- Scenarios 1 and 2 are viable over the medium-term, but even under those scenarios Chuuk needs to consider a temporary increase in tariffs over the next 4 years.

Table 4.7: Average Tariff Required to Cover Cashflows by 5-year Period and Customer Segment, US$ per kWh[14]

	Current[15]	2018	2019–2023	2024–2028	2029–2033	2034–2037
Scenario 1						
Residential	0.41	0.46	0.54	0.40	0.34	0.30
Commercial	0.44	0.50	0.58	0.43	0.37	0.33
Government	0.46	0.52	0.61	0.44	0.38	0.34
Scenario 2						
Residential	0.41	0.46	0.55	0.42	0.39	0.38
Commercial	0.44	0.50	0.59	0.45	0.42	0.40
Government	0.46	0.52	0.62	0.47	0.43	0.42
Scenario 3						
Residential	0.41	0.46	0.57	0.48	0.46	0.45
Commercial	0.44	0.50	0.61	0.51	0.50	0.49
Government	0.46	0.52	0.64	0.54	0.52	0.51

In general, we consider that significant variations in tariffs over time should be avoided. Stable electricity tariffs allow users to plan, and in particular help commercial and industrial users to make their own medium-term investment decisions. In addition, stable electricity tariffs provide potential investors in the power system, such as IPPs, with the confidence to commit to long-term contracts.

For this reason, we recommend that Chuuk works with donors and financiers to develop a medium-term tariff path. This will either require donor grant support for some operating expenses in the short-term or may require financing to carry CPUC over the period before cost reductions from RE investment begin to kick in. For example, if donors were to support operating expenses of the new mini-grids over the initial 2 to 3 years, CPUC would be able to maintain the current tariffs over the medium-term.

4.3 Implementation Plan

Here, we discuss the rollout of investments, and what additional capacity within CPUC will be needed to implement and maintain these investments. We also discuss project risks.

The funding and financing plan ensures CPUC has all the resources it needs to successfully implement the investment plan. However, outsourcing is a possibility if it provides greater value for money. This is discussed in Appendix H.

[14] We assume tariff structure across customer segments is unchanged, and adjust current tariffs for each segment by a constant percentage to calculate the tariff requirements.

[15] Current tariffs include a US$0.04 per kWh cross-subsidy for water and sewer. Our calculated future tariffs are for power only.

4.3.1 Rollout of physical capital projects

We separate activities to be carried out over the 20-year period of the Master Plan into generation capital projects and distribution improvements. The rollout plan outlines the sequencing of these activities (Table 4.8).

We include new connections in the rollout plan. On top of this, asset-based replacement and general network upgrades will be needed as peak demand increases. These distribution upgrades are not listed in the table.

The proposed schedule allows for all of Chuuk to be electrified within 5 years. The electrification program—which involves 14 mini-grids and 1,599 stand-alone solar systems across 26 islands—is a significant undertaking. However, CPUC has advised us that it is possible in this timeframe.

Construction of all mini-grids and provision of stand-alone solar systems will occur between 2019 and 2023. Within these 5 years, we suggest CPUC start with the lagoon, followed by the Mortlocks, and then the Northwest islands. Doing the most accessible islands first will test out the technology, billing, logistics, and management approach before rolling out to less-accessible islands.

Table 4.8: Rollout Plan for Chuuk

Year	2018	2019–2023	2024–2028	2029–2033	2034–2037
Main Grid[16]	**Additional connections** ▪ 37 new residential connections a year ▪ 5 new commercial connections a year	**Generation capital projects** ▪ 4MW solar ▪ 1MW battery inverter ▪ 7MWh battery storage **Additional connections** ▪ 37 new residential connections a year ▪ 5 new commercial connections a year	**Generation capital projects** ▪ 4MW solar ▪ 2MW battery inverter ▪ 13MWh battery storage **Additional connections** ▪ 3 new residential connections a year ▪ 5 new commercial connections a year	**Generation capital projects** ▪ 2MW solar ▪ 1MW battery inverter ▪ 10MWh battery storage **Additional connections** ▪ 3 new residential connections a year ▪ 5 new commercial connections a year	**Generation capital projects** ▪ 2MW solar ▪ 1MW battery inverter ▪ 10MWh battery storage **Additional connections** ▪ 3 new residential connections a year ▪ 5 new commercial connections a year
Mini-grid: Tonoas, Fefen, Uman		**Mini-grid construction** ▪ 2x450kW diesel genset ▪ 300kW solar ▪ 200kWh storage ▪ 200kW converter ▪ 13.8kV overhead network plus LV underground network		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converter
Mini-grid: Tol		**Mini-grid construction** ▪ 100kW diesel genset ▪ 100kW solar ▪ 200kWh storage ▪ 60kW converter		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converter

[16] Generation capital projects for the main grid show new capacity but not replacements, overhauls, or retirements of existing capacity.

Year	2018	2019–2023	2024–2028	2029–2033	2034–2037
		▪ LV underground network			
Mini-grid: Polle/Wonei/ Patta		**Mini-grid construction (per mini-grid)** ▪ 100kW diesel genset ▪ 40kW solar ▪ 100kWh storage ▪ 20kW converter ▪ LV underground network		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converter
Mini-grid: Udot		**Mini-grid construction** ▪ 100kW diesel genset ▪ 100kW solar ▪ 200kWh storage ▪ 70kW converter ▪ LV underground network		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converter
Mini-grid: Romanum/ Fanapanges		**Mini-grid construction (per mini-grid)** ▪ 100kW diesel genset ▪ 60kW solar ▪ 180kWh storage ▪ 40kW converter ▪ LV underground network		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converter
Mini-grid: Lekinoch/		**Mini-grid construction (per mini-grid)**		**Replacement** ▪ Replace gensets	**Replacement** ▪ Replace converter

Year	2018	2019–2023	2024–2028	2029–2033	2034–2037
Satowan		▪ 100kW diesel genset ▪ 50kW solar ▪ 140kWh storage ▪ 30kW converter ▪ LV underground network		▪ Replace batteries	
Mini-grid: Nema		**Mini-grid construction** ▪ 2x50kW diesel genset ▪ 40kW solar ▪ 120kWh storage ▪ 30kW converter ▪ LV underground network		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converter
Mini-grid: Nomwin/ Houk		**Mini-grid construction (per mini-grid)** ▪ 100kW diesel genset ▪ 50kW solar ▪ 140kWh storage ▪ 30kW converter ▪ LV underground network		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converter
Onoun		**Mini-grid construction** ▪ 2x50kW diesel genset ▪ 40kW solar ▪ 120kWh storage ▪ 30kW converter		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converter

Year	2018	2019–2023	2024–2028	2029–2033	2034–2037
		▪ LV underground network			
Stand-alone solar systems		**Stand-alone solar systems installation** ▪ Install 476 stand-alone solar systems on lagoon islands ▪ Install 580 stand-alone solar systems on Mortlocks ▪ Install 543 stand-alone solar systems on Northwest islands		**Replacement** ▪ Replace 308 stand-alone solar systems in lagoon ▪ Replace 580 stand-alone solar systems in Mortlocks ▪ Replace 543 stand-alone solar systems on Northwest islands	

4.3.2 Implementation capacity

To implement the Master Plans, CPUC will need additional staff

We have considered whether CPUC has the capacity to implement the activities required in the plan. As this is a large and complex investment plan (especially given the need to roll out infrastructure to many households on multiple islands), CPUC will need additional capacity (Table 4.9).

The requirements relate to ongoing operational, managerial, and maintenance functions and do not include building the new infrastructure (for which we assume contractors will be engaged). The table shows when these staff would need to be engaged or trained. Once engaged, they would continue their work throughout the whole Master Plan period (and beyond), unless otherwise stated. The costs of this extra capacity are included in the total cost of implementing the Master Plans.

Table 4.9: Capacity Requirements for CPUC

	1–5 Years
Weno	1 new engineer hired and trained in RE skills and control-system skills. Current staff trained to deal with the new grid-based generation and control system **Support for outer islands** New staff to support mini-grids and stand-alone solar, including: 1 electrification program manager (first 5 years only), 1 engineer, 1 technician, and 2 administration and billing assistants 2 linesmen trained for the 13.8kV network 2 additional new technical managers on Weno to provide support to outer islands
Mini-grid: Tonoas, Fefen, Uman	1 skilled 13.8kV linesman and 1 trainee linesman 1 skilled power station supervisor 4 operators, of which at least 1 is a skilled mechanic and at least 1 is an electrical technician. Additional casual workers for vegetation management may be required 1 billing assistant (Cashpower sales and admin) (casual)
Other mini-grids	For each island as it comes online, CPUC will need to hire 4 operators for each island, including at least 1 skilled mechanic and 1 skilled electrical technician The power station does not need to be manned 24/7 as these mini-grids have relatively low diesel run-time Additional casual workers for vegetation management may be required
Stand-alone solar systems	For each island as it comes online, CPUC will need to hire 1 casual assistant for each island. Additional support technicians on Weno to be hired as needed to service the additional islands.

In addition to various technical positions, we recommend that CPUC appoint a dedicated Electrification Program Manager. This person would have explicit responsibility for coordinating the rollout of infrastructure outside Weno. The need for this reflects the scale and complexity of, and timeframe for, the electrification program in Chuuk. The person appointed would track progress, and use experience with the first phase of the rollout to refine the approach to the remaining islands. This person would be needed for the first 5 years of the Master Plan (during the core period for rolling out infrastructure beyond Weno), or until the nature of the work became routine and operational, rather than project-based.

CPUC will take lead responsibility for implementing the Master Plan investments. Even if CPUC chooses to outsource some project implementation tasks, it would still need to manage these contracts and oversee implementation.

The State Energy Workgroup (SEW) has an interest in providing strategic guidance and in monitoring progress and results to ensure that the desired state-level policy outcomes are met. SEW does not have the capacity to fulfil this role (neither does the State Project Management Unit).

The Master Plan includes a budget for technical assistance to fulfil the various monitoring, coordinating and administrative functions (the National Energy Master Plan provides more details). We assume this will be covered by a grant, so do not include it in the tariff calculation.

4.3.3 Implementation risks

Here we discuss some risks specific to Chuuk. Appendix E highlights various risks associated with the types of technology and investments proposed in this Plan. Many of these are common to all states using the same technology.

Land availability could be a constraint on installing new generation capacity on Weno

The 12MW of recommended solar generation will need 80,000m^2 (about 861,000 square feet) of land or roof area. Some of this area can be on rooftops, but this will be a very small fraction of the required area. To house the full capacity, larger blocks of land, or large areas of protected unused fresh water or seawater, will be needed.

Ideally the 12MW solar PV will be housed on one, or a few, large sites. Concentrating the solar PV generation capacity will make control and management of the system easier. If possible, the site(s) will be located close enough to the power station to connect directly to the power station's MV (13.8kV) switchboard, as this provides the best opportunity for the daytime peak solar PV generation to match as closely as possible Weno's maximum daytime peak load. Otherwise, sites should be located as close to a MV feeder as possible, preferably to a feeder with a high daytime peak load. In addition to the solar PV, it is desirable for the BESS to be located at the power station and connected to the MV switchboard, to enable optimum control and management. The next best alternative for the BESS location is on the same site as the solar generation capacity.

Leasing or purchasing land from private land owners could be expensive and time consuming. Sites that are large enough to house the solar generation are all privately owned. In some cases, sites will be owned by multiple parties, making negotiations more difficult.

Potential sites will need to have a geotechnical assessment to ensure suitability. Land needs to be sufficiently flat and stable to be suitable for housing solar panels. The geotechnical assessment will also inform additional foundation work that may need to be done and which could increase project cost.

An area of protected seawater just to the East of the main Weno township, known as Pou Bay, may be suitable for a large, floating PV installation.

The forthcoming feasibility study for integrating new solar PV capacity into the Weno grid will assess the available space, and identify potential sites for solar PV capacity.

Land for mini-grids will need to be considered on a case-by-case basis

We assume that mini-grid generation units on other islands will be located on public land or buildings (such as schools), but this would need to be confirmed through more detailed assessment before building on each island. The requirements for land access for mini-grid distribution lines would need to be considered carefully in the local context and depending on the specific route involved.

If mini-grids cannot be built on public land, our research and consultations suggest it may be problematic in some locations to acquire land. Leasing is an option as the owner then gets to retain title. However, people can be wary of leases due to past arrangements where they have only received the first payment.

The eminent domain law requires that lease options must be exhausted before the Governor can apply to take the land.

CPUC has agreed a lease for land in Tonoas for a water project at the government rate.

The forthcoming feasibility study for the mini-grid in Udot will consider land availability.

Installing and managing electricity infrastructure on multiple islands in a short timeframe brings significant implementation risks

One of the main risks for Chuuk—more so than for the other states—is the institutional and implementation risks associated with electrifying so many unserved islands. Risks include payment collection, logistics, and maintenance, as well as the short timeframe involved.

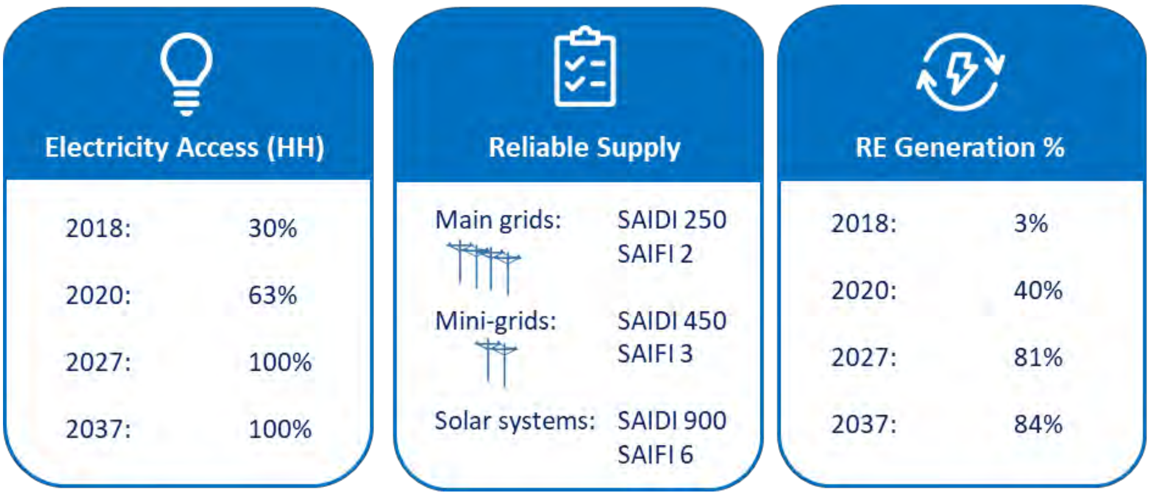
The Master Plan provides for all consumers with both mini-grids and stand-alone systems to use Cashpower meters—this reduces the risks around payment collection.[17] We have also identified particular human resource requirements to help mitigate these risks and that of timely implementation. We have also identified technical solutions for pre-paid meters on islands that do not currently have mobile telephony.

4.4 Outcomes

If Chuuk implements the above plans it can expect to meet its main energy sector objectives. Figure 4.6 summarizes the outcomes the plans will help Chuuk achieve.

[17] For islands that do not have adequate telecommunications services, we recommend providing radios. They can be used to communicate Cashpower transactions, as well as to report faults on systems.

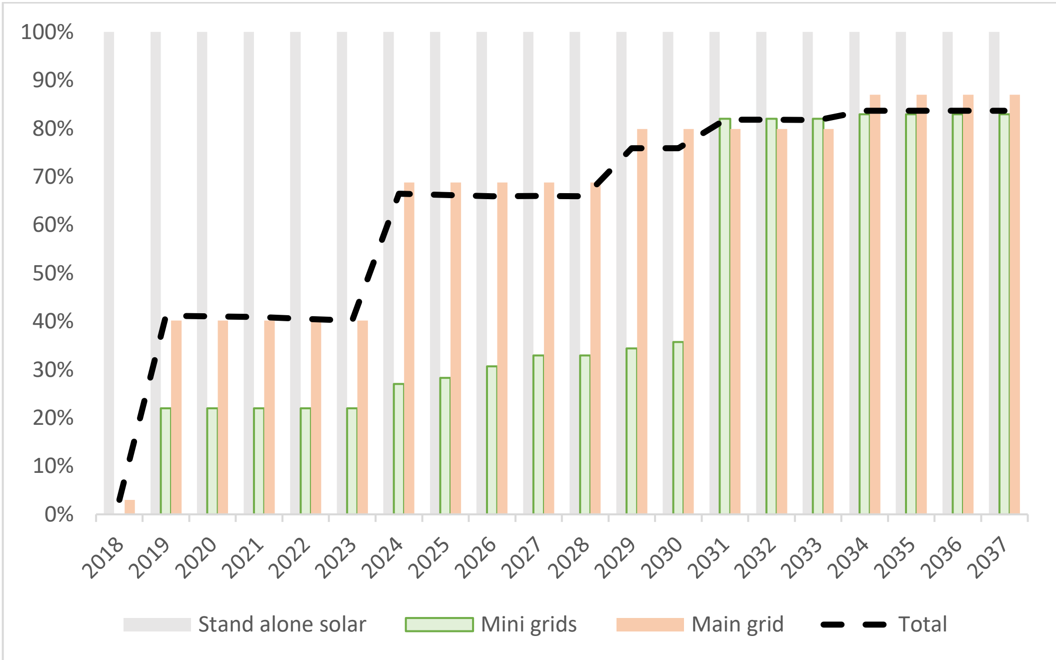
Figure 4.6: Summary of Outcomes of the Chuuk State Energy Master Plan



The main outcome of the Master Plan is that, by 2023, 100 percent of households, businesses, and public facilities in Chuuk will have access to a reliable, affordable electricity service. In addition, during the 20 years of the Master Plan the percentage of electricity generated from renewable sources will increase, and CO_2 emissions and diesel use will fall.

The Master Plan exceeds Chuuk's target of 30 percent RE generation by the end of 2019. Exceeding the target is possible without extra cost for consumers because our modeling determined that investing in new RE capacity would increase the amount of RE generation at the same time as reducing the overall cost of energy. Figure 4.7 shows the percentage of RE for the stand-alone solar systems, mini-grids, and main grid. The 'total' line is the weighted average of all three.

Figure 4.7: RE Percentage of Generation for Chuuk



CO_2 emissions and fuel use decrease by 72 percent by the end of the Master Plan period (see Table 4.10).

Table 4.10: Chuuk Emissions and Diesel Use

	2018	2019–2023	2024–2028	2029–2033	2034–2037
CO_2 emissions (tonnes/year)	12,910	8,329	5,433	4,329	3,585
Fuel use (gallons/year)	1,249,211	805,942	525,701	418,935	346,879

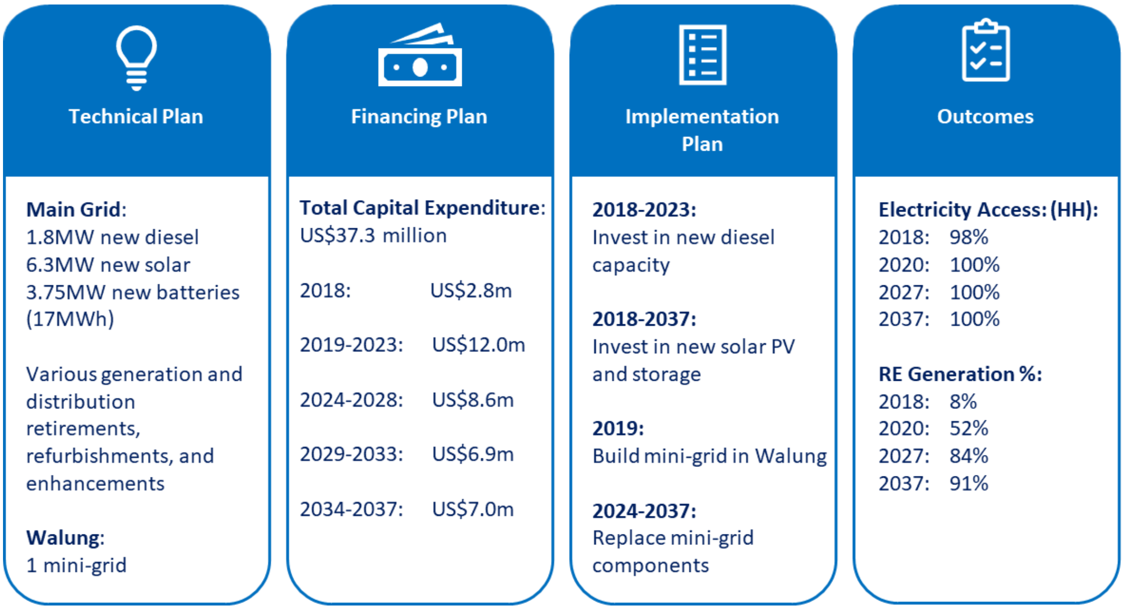
5 Kosrae State Energy Master Plan

The Kosrae State Energy Master Plan provides a least-cost strategy to achieve the state's energy goals. By 2019, the state will achieve its goal of 100 percent electrification. It will achieve the national target of 30 percent RE by 2023. Total capital investment required over the 20 years of the Master Plan is US$37.3 million. The Master Plan has three core components:

- A **Technical Plan** that outlines the generation and distribution assets that need to be purchased for the state to be able to provide a reliable, sustainable electricity service to all residents at least-cost
- A **Financing Plan** that outlines how the Technical Plan can be feasibly financed and funded
- An **Implementation Plan** that discusses key considerations and risks for rolling out the Technical Plan.

Figure 5.1 summarizes the Master Plan's components and their outcomes.

Figure 5.1: Summary of the Kosrae State Energy Master Plan

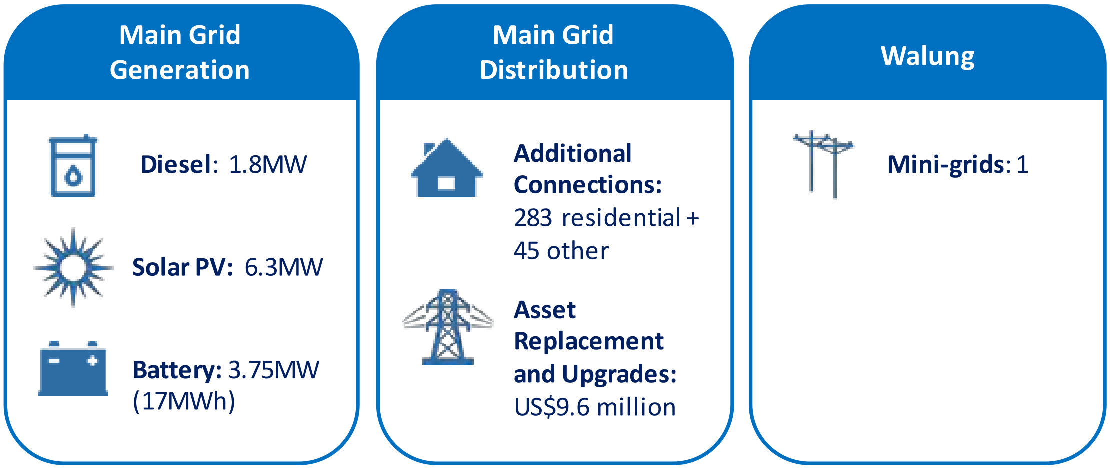


5.1 Technical Plan

The Technical Plan outlines required upgrades and improvements to the grid on Kosrae. In addition, we recommend a mini-grid as the least-cost option for achieving the desired level of service in Walung. On the grid, the plan includes investment in new solar PV capacity to reduce the cost of electricity, as well as in new diesel capacity to ensure security of supply. Distribution asset replacements and upgrades are needed to improve system reliability, while connections on the main grid are for the growth we have forecast for number of households and new businesses. There is also a need to move part of the distribution inland because of coastal erosion. We have incorporated this project into the Master Plan.

Figure 5.2 summarizes the new infrastructure required in Kosrae (not including replacements of existing generation infrastructure).

Figure 5.2: Summary of New Infrastructure in Kosrae Technical Investment Plan



5.1.1 Kosrae main grid

Over the 20-year Master Plan period the main grid on Kosrae needs investment in: new generation capacity, refurbishment and replacement of existing generation assets, refurbishment and replacement of existing distribution assets, and shifting the distribution network inland to account for coastal erosion.

We have labelled recommended generation capacity 'new' if the assets change the makeup of the generation system. All other capital is included as 'replacement', and includes totally replacing an asset, large asset refurbishment, and replacing major components of an asset. Diesel generators are categorized as 'new' if they add additional generation capacity or are purchased when a generator of different capacity comes offline. Capital investment in diesel generators is categorized as 'replacement' when a like for like replacement of a generator is made or when a major refurbishment of an existing generator is undertaken. Table 5.1 shows the new generation capacity our modeling suggests is required. In the text we explain the new generation investments, as well as discuss when replacements or refurbishments are required.

Upgrades to the existing diesel generation capacity are already under way

Three diesel gensets are currently being installed in the new Kosrae power station. We assume that these will come online in 2018 or 2019, along with 0.3MW of solar PV. This new capacity (combined with the existing diesel and RE capacity) is sufficient to meet electricity demand on the main island over the 20-year period of the Master Plan, and allows the existing diesel gensets to be retired over the life of the Plan, as the new RE assets are progressively installed.

New RE capacity provides an opportunity to reduce overall costs

Over the 20 years of the Master Plan, we recommend that 6.3MW of new solar PV generation is installed alongside 17Wh of battery storage. The proposed mix of storage and solar PV in Kosrae is slightly different to the other states.

New solar PV capacity will reduce the average cost of electricity by reducing the Kosrae Utilities Authority's (KUA) diesel fuel use and therefore expenditure on diesel fuel. The upfront capital cost of solar PV will be either paid for through grants or smoothed over time with cheap concessional financing so the cost per kWh will be lower than that provided by diesel generation. Investment in diesel generation in 2018 is still required to ensure security of supply.

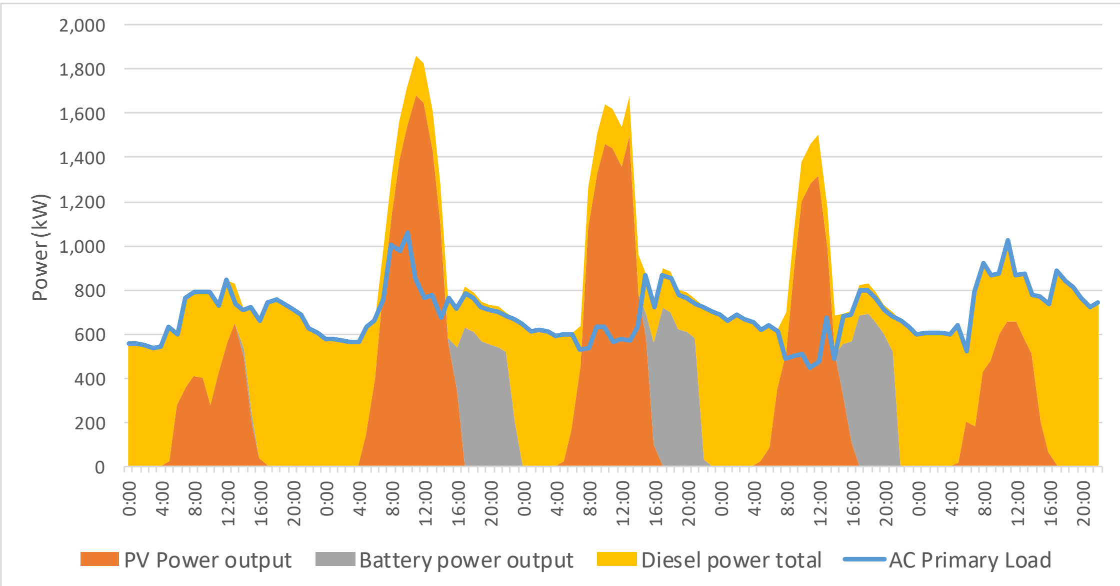
Table 5.1: Kosrae New[18] Generation and Storage Capacity for Main Grid

	2018	2019–2023	2024–2028	2029–2033	2034–2037
Diesel	1.8MW	-	-	-	-
Solar PV	0.3MW	2MW	2MW	1MW	1MW
Battery storage		1.25MW	1.25MW	0.75MW	0.5MW
Battery inverter	-	5MWh	8MWh	3MWh	1MWh

In the period 2019–2023:

- 2MW of PV should be developed at one or more solar sites. Some of the capacity could be deployed behind the meter on government or commercial buildings
- Energy storage should be deployed at the Kosrae power station, providing 1.25MW of capacity and 5MWh of storage to manage integration of the PV plants and increased use of RE
- The recommended investments in solar and storage will meet a large proportion of Kosrae's demand in 2023, reducing the use of diesel and therefore the cost of electricity (Figure 5.3)
- Genset #4 should be retired in 2020.

Figure 5.3: Kosrae Load Duration Curve and Contribution of Generation Sources, 2023



In the period 2024–2028:

- Genset #8 should be retired in 2024

[18] New only includes new generation assets that change the generation mix. Like for like replacement of retired assets is not included.

- 2MW of PV should be developed at one or more solar sites. This could also be deployed behind the meter on government or commercial buildings
- The battery inverter capacity should be increased by 1.25MW and 8MWh of storage to address load growth and maintain reliability standards.

In the period 2029–2033:

- 1MW of solar PV capacity should be developed to offset increasing use of diesel generation as loads increase. This capacity could be developed at a new site, added to an existing solar site, or deployed behind the meter on government or commercial buildings
- The battery inverter capacity should be increased by 0.75MW and storage capacity by 3MWh to address load growth and maintain reliability.

In the period 2034–2037:

- Genset#6 should be retired in 2034
- 1MW of solar PV capacity should be developed
- The battery inverter capacity should be increased by 0.5MW and storage capacity by 1MWh.

Replacement capital will also be needed to maintain existing generation capacity

The current PV solar plants will reach the end of their lives during the period of the Master Plan, and our analysis suggests they should be replaced. We assume energy storage capacity achieves a 10-year life and so will need to be replaced during the Master Plan timeframe. Diesel gensets will likely need to be replaced, depending on the duty cycle and level of RE contribution.

The spreadsheets that will be provided as part of data handover break down the replacement capital needed over the 20-year period.

New connections will be needed as the number of households increase

Apart from Walung, Kosrae is completely electrified. However, our forecast shows that the number of households will increase by about 1 percent each year, which will require new connections.

We assume two new commercial and government connections each year, except in the period between 2019 and 2023, when we expect an extra connection from the refurbishment of a water bottling plant.

Table 5.2 shows the new residential, commercial, and government connections. The costs of these connections are provided in the accompanying spreadsheets.

Table 5.2: Average Annual New Connections

	2018	2019-2023	2024-2028	2029-2033	2034-2037
New Residential Household Connections	13	13	14	15	15
New Commercial & Government Connections	2	3	2	2	2

The existing distribution network will need upgrades and maintenance

General network and demand growth includes minor feeder extensions and updating transformers as peak demand gradually increases and the expenditure cannot be tied to any specific large customer load project. Our analysis suggests that this will cost US$200,000 every 5 years.[19]

We used the asset register to make replacement estimates (see Table 5.3). Details of asset lifespans and replacement costs are in Appendix B.

Table 5.3: Distribution Network Asset Replacement (average annual figures, US$)

	2018	2019–2023	2024–2028	2029–2033	2034–2037
Age-based Asset Replacement	252,000	263,569	283,939	305,883	327,052

We are aware that the KUA plans to relocate part of the 13.8kW distribution lines further inland, to reduce the risk of damage from coastal erosion. We assume 10km (6.2 miles) of line is relocated, at a cost of US$3 million.

5.1.2 Walung mini-grid

We recommend a mini-grid for Walung. We compared connecting Walung to the main grid versus building a mini-grid, and found that the mini-grid was the least-cost option.[20]

A mini-grid will be more expensive than stand-alone solar systems (given the small number of households), but is expected to provide a higher quality of service. It can help achieve a balance between cost and stakeholders' desire for Walung (the only unelectrified community in the state) to have a service level closer to that experienced by the rest of Kosrae.

We recommend a mixture of diesel, solar, and storage for the mini-grid (see Table 5.4), as the least-cost way to meet the demand at the required service standards.

[19] The network expansion requirement is likely to be quite limited due to network layout and because Kosrae is a small island. However, to be conservative we include a general allowance for some expansion/augmentation that is not specifically directed to one customer or project.

[20] The capital cost of the line was nearly double that of the mini-grid, and the operating costs would also be higher with the cable. However, there may be some advantages to KUA to managing an integrated network.

Table 5.4: Walung Mini-grid Capacity 2018–2037

Asset Type	Capacity
Diesel	2x 20kW
Solar	40kW
Storage	120kWh
Converter	15kW

We suggest an LV underground network for distribution. The initial costs are higher than an above-ground network, but less maintenance is needed and it is more weather resistant. The estimated cost is US$110,000.

5.2 Financing Plan

The total amount needed to cover capital expenditure across the lifespan of the Master Plan is US$37.3 million

Over half of the capital expenditure over the 20-year Master Plan period is on new generation capacity for the main grid (Table 5.5). We recommend ongoing investment in solar PV with storage to lower the cost of generation and reduce reliance on diesel generation. Required expenditure for the main grid distribution network includes the US$3 million cost of moving part of the distribution network inland.

Table 5.5: Capital Expenditure Requirements (US$ million 2016)

	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
New Main Grid Generation	2.49	6.42	6.71	3.18	2.67	21.47
Main Grid Generation Replacement	0.00	0.50	0.16	1.75	2.57	4.97
Main Grid Distribution	0.28	4.64	1.74	1.86	1.61	10.12
Mini-grids	0.00	0.47	0.04	0.08	0.11	0.70
Total	2.77	12.03	8.64	6.86	6.96	37.26

Operating expenses include:

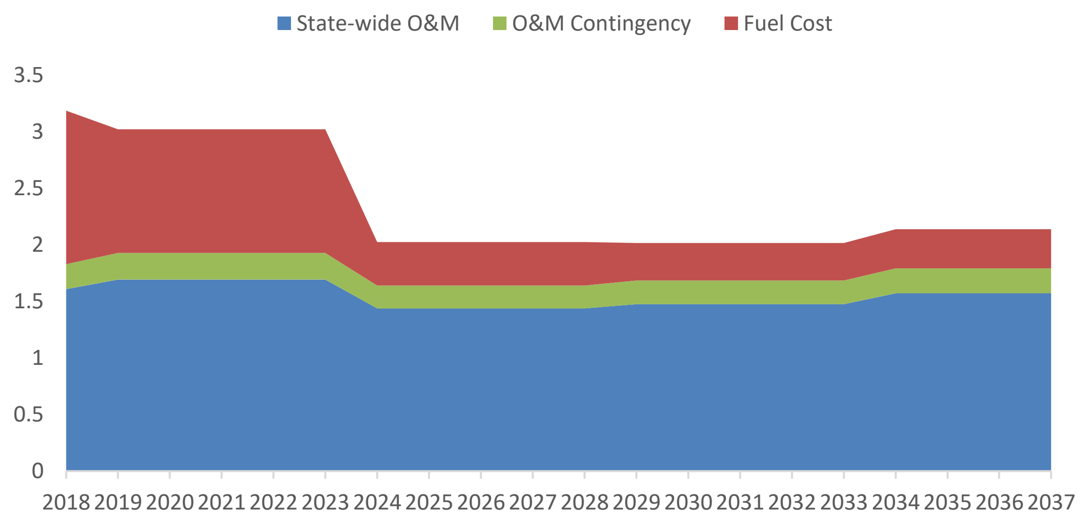
- Main grid generation O&M cost
- Main grid distribution O&M cost
- Main grid fuel cost
- Walung mini-grid generation O&M cost
- Walung mini-grid distribution O&M cost
- Walung mini-grid fuel cost
- Administration and general fixed costs
- A 15 percent contingency on all technical O&M expenditure

- Project preparation costs (5 percent of total capital investment) for new capital projects (includes owner's engineer, procurement, and so on).

Operating expenses fall by US$1.05 million a year between 2018 and 2037 because of a reduction in diesel use

Fuel cost makes up almost 50 percent of total operating expenses in 2018. As new RE capacity comes online, fuel consumption declines and fuel cost falls to less than 20 percent of operating expenses. The shift from diesel to renewables also leads to a fall in generation operating and maintenance costs on Kosrae because of lower run hours for diesel generators. State-wide operating expenses (excluding the fuel cost) increase from 2024 onward. This is because administration and general costs, and distribution costs on Kosrae, grow with load growth; and operating expenses for the new Walung mini-grid are added. The net effect is a reduction in operating expenses of US$1.05 million per year from 2018 to 2037.

Figure 5.4: Estimated State-wide Operating Expenses, US$ million



The financial spreadsheet provided to KUA and the FSM Department of Resources and Development includes a more detailed breakdown.

We calculate debt service payments for three scenarios

The debt service payment made each year will include a repayment of the principal of the loan(s) (capital amortization) as well as an interest payment (cost of financing). We have calculated debt service payments for three scenarios:

- Scenario 1: All capital expenditure is paid for with grant funding
- Scenario 2: Capital expenditure for the mini-grid in Walung is paid for with grant funding. Capital expenditure on the Kosrae main grid is financed with concessional loans. Details of assumed loan terms offered by donor organizations are available in Appendix C
- Scenario 3: Capital expenditure for the mini-grid in Walung is paid for with grant funding. Capital expenditure on Kosrae's main grid is financed with commercial loans. (This scenario approximates the cost of getting IPPs for solar and storage as well as of KUA financing the replacement of the network on its own balance sheet.) Details of assumed loan terms offered by commercial banks are available in Appendix C.

In Scenario 1 and Scenario 2, the power sales revenue earned from keeping tariffs at their current level covers the cash requirements over the 20-year Master Plan period

The net present value (NPV) of net cashflow over the 20 years of the Master Plan is positive in Scenario 1 and approximately zero in Scenario 2 if tariffs are kept at their current level in real terms. Cash required exceeds the expected revenue from current tariffs in all years to 2024. From 2024 onward, as revenue grows with electricity demand and new renewable investment lowers operating expenses, expected revenue exceeds cash required in all years.

Unlike other states, Kosrae is not expecting a significant increase in demand. For this reason, in Scenario 3 the NPV of net cashflow over the 20 years is negative if tariffs are kept at their current level in real terms.

Figure 5.5: Cash Requirements in the Three Financing Scenarios, US$ million

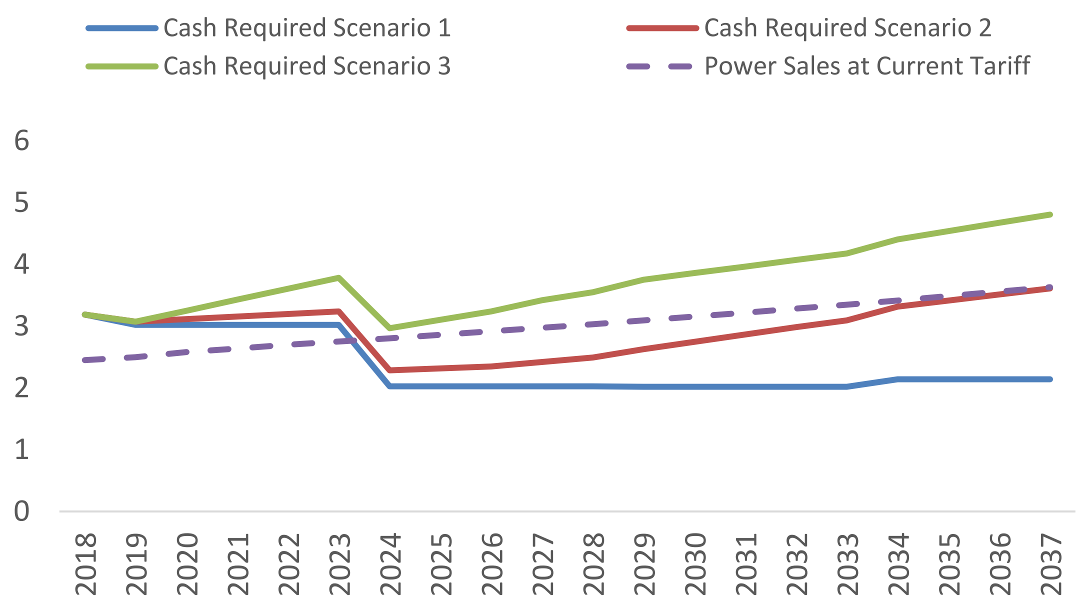


Table 5.6: Average Tariff Required to Cover Cashflows by 5-year Period and Customer Segment, US$ per kWh[21]

	Current	2018	2019–2023	2024–2028	2029–2033	2034–2037
Scenario 1						
Residential	0.44	0.57	0.50	0.31	0.28	0.27
Commercial	0.48	0.62	0.55	0.33	0.30	0.29
Government	0.52	0.68	0.60	0.36	0.33	0.32
Scenario 2						
Residential	0.44	0.57	0.53	0.36	0.39	0.43
Commercial	0.48	0.62	0.58	0.39	0.43	0.47
Government	0.52	0.68	0.62	0.42	0.46	0.51

[21] We assume tariff structure across customer segments is unchanged, and adjust current tariffs for each segment by a constant percentage to calculate the tariff requirements.

Scenario 3

Residential	0.44	0.57	0.57	0.49	0.54	0.57
Commercial	0.48	0.62	0.62	0.54	0.59	0.63
Government	0.52	0.68	0.68	0.58	0.64	0.68

We propose that Kosrae work with donors and lenders to develop a financing package that would allow the Master Plans to be implemented without an increase in tariffs. One option would be to bid out solar/storage investment through IPPs on the basis that the full charge by the IPP should not exceed the cost of avoided diesel. Such pricing by IPPs would allow KUA to access private financing without having to maintain a cushion of revenue to cover the debt service cover ratio itself. This may also allow KUA to avoid the operating cost contingency.

We recommend that Kosrae announces a commitment to a medium-term stable tariff path.

5.3 Implementation Plan

Here, we discuss the rollout of investments, and what additional capacity within KUA will be needed to implement and maintain these investments.

In the funding and financing plan, we have ensured KUA has all the resources it needs to successfully implement the investment plan. However, outsourcing is a possibility if it provides greater value for money. This is discussed in Appendix H.

5.3.1 Rollout of physical capital projects

We separate activities to be carried out over the 20-year period of the Master Plan into generation capital projects, and distribution improvements. The rollout plan outlines the sequencing of these activities (Table 5.7).

When sequencing the rollout plan we consider already committed/funded capital projects. These include:

- The new Japanese International Cooperation Agency-funded power plant (2x600kW diesel gensets), which we assume will be operational in 2018
- The new World Bank-funded 600kW genset located in the old power station building to provide backup capacity, which we assume will be operational by 2019
- The relocation of 6.2 miles (10km) of the main feeder to align with new road construction.

We include new connections in the rollout plan. On top of this, asset-based replacement and general network upgrades will be ongoing as peak demand increases.

Table 5.7: Rollout Plan for Kosrae

Year	2018	2019-2023	2024-2028	2029-2033	2034-2037
Main Grid[22]	**Generation capital projects** ▪ 1.8MW diesel ▪ 300kW solar PV **Additional connections** ▪ 13 new residential connections ▪ 2 new commercial connections	**Generation capital projects** ▪ 2MW solar PV ▪ 1.25MW (5MWh) storage **Additional connections** ▪ 13 new residential connections a year ▪ 2 new commercial connections a year ▪ Water bottling plant connection **Distribution** ▪ Relocation of distribution lines further inland	**Generation capital projects** ▪ 2MW solar PV ▪ 1.25MW (8MWh) storage **Additional connections** ▪ 14 new residential connections a year ▪ 2 new commercial connections a year	**Generation capital projects** ▪ 1MW solar PV ▪ 0.75MW (3MWh) storage **Additional connections** ▪ 15 new residential connections a year ▪ 2 new commercial connections a year	**Generation capital projects** ▪ 1MW solar PV ▪ 0.5MW (1MWh) storage **Additional connections** ▪ 16 new residential connections a year ▪ 2 new commercial connections a year
Mini-grid: Walung		**Mini-grid construction** ▪ 2x20kW diesel ▪ 40kW solar PV ▪ 120kWh storage ▪ 15kW converter ▪ LV underground network	**Replacement** ▪ Replace one diesel genset	**Replacement** ▪ Replace second diesel genset ▪ Replace batteries	**Replacement** ▪ Replace converter

[22] Generation capital projects for the main grid show new capacity but not replacements, overhauls, or retirements of existing capacity.

5.3.2 Implementation capacity

To implement the Master Plans, KUA will need additional staff

We have considered whether KUA has the capacity to implement the activities required in the plan. Table 5.8 highlights the additional capacity that will be needed.

The requirements in Table 5.8 relate to ongoing operational, managerial, and maintenance functions and do not include building the new infrastructure (for which we assume contractors will be engaged). The table shows when these staff would need to be engaged or trained, but once engaged they would continue their work throughout the whole Master Plan period (and beyond), unless otherwise stated.

Table 5.8: Capacity Requirements for KUA

	1–5 Years	5–10 Years
Main grid	2 new engineers hired and trained in RE and control systems	1 new engineer trained in RE and control systems 2 new electrical maintenance technicians
Walung mini-grid	4 operators hired and trained for the Walung mini-grid. At least 1 should be an electrical technician. Ideally 1 should be a mechanic, but if this is not possible a mechanic could be sent from town as needed An existing engineer or technician from KUA should be given responsibility for technical support to Walung 1 casual billing assistant in Walung (most of the administration would be done from KUA's head office) An existing KUA staff member should be given explicit responsibility for coordinating the electrification program for Walung (part-time role)	

KUA will take lead responsibility for implementing the Master Plan investments. Even if KUA chooses to outsource some project implementation tasks, it would still need to manage these contracts and oversee implementation.

The State Energy Workgroup (SEW) has an interest in providing strategic guidance and in monitoring progress and results to ensure that the desired state-level policy outcomes are met. SEW does not have the capacity to fulfil this role.

The Master Plan includes a budget for technical assistance to fulfil the various monitoring, coordinating and administrative functions (the National Energy Master Plan provides more details). We assume this will be covered by a grant and do not include it in the tariff calculation.

5.3.3 Implementation risks

We discuss the main risks specific to Kosrae. Appendix E then highlights various risks that are common to all states using the same technology and investments proposed in this Plan.

Managing the mini-grid in Walung will present a new challenge for KUA due to its limited experience with mini-grids

From a technical perspective, the main risk is inexperience with the battery and control system. One of KUA's engineers will need to be trained in how the system works and should be involved in the design, construction, and commissioning. A web-based monitoring system that can be accessed from KUA main office will also help with this.

To avoid any difficulties with collecting payments, the Master Plan provides all mini-grid customers in Walung with Cashpower meters. We also propose that a KUA staff member be given explicit responsibility for coordinating and monitoring the electrification of Walung.

Kosrae's small population might make it difficult to find and retain skilled staff

Knowledge sharing and support across the four states could help mitigate this risk.

Land

The additional 4.5MW of solar capacity on the main grid will need about 45,000m^2 (about 484,000 square feet) of land (or roof space). There is potential to use the government land at the center of Kosrae island (Figure 5.6). This land is not developed and would need to be cleared and levelled before it could be used. We understand that an area of government land outside the main town may be available. There may also be a possibility of installing floating PV capacity on the calm water between the airport and the mainland.

Some of the required PV capacity can be housed on government buildings. The government stated during consultations that it will work with KUA to put grid-integrated PV with storage on the roofs of government buildings. Previously the Government had intended to install stand-alone solar without storage.

A feasibility study currently being undertaken by Entura is checking the feasibility of specific sites for solar PV in Kosrae. Once these sites have been identified, a meeting among relevant stakeholders in Kosrae will be held to see what can be made available.

Figure 5.6: Government Land in Kosrae

Source: Kosrae Island Resource Management Authority

We assume that the Walung mini-grid generating units will be located on public land. The solar systems are small enough to be accommodated on public buildings such as the school and church. The community—as the only one in Kosrae State without electricity access—is likely to be engaged in the program and may be able to help facilitate land access for distribution lines.

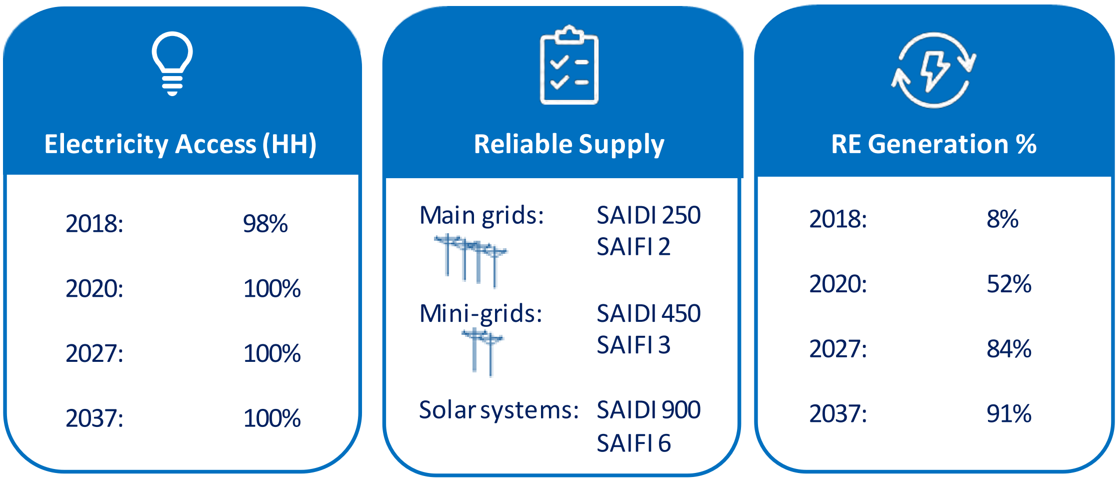
Coastal erosion

During consultations, stakeholders in Kosrae highlighted the risk of coastal erosion. KUA is already planning to relocate part of its road and electricity distribution network in response to this risk. If households very close to the shore request connection to the electricity network, KUA will need to assess the risk of coastal erosion before installing the new distribution infrastructure and house wiring.

5.4 Outcomes

If Kosrae implements the above plans it can expect to meet its main energy sector objectives. Figure 5.7 summarizes the outcomes the plans will help Kosrae achieve.

Figure 5.7: Summary of the Outcomes of the Kosrae State Energy Master Plan

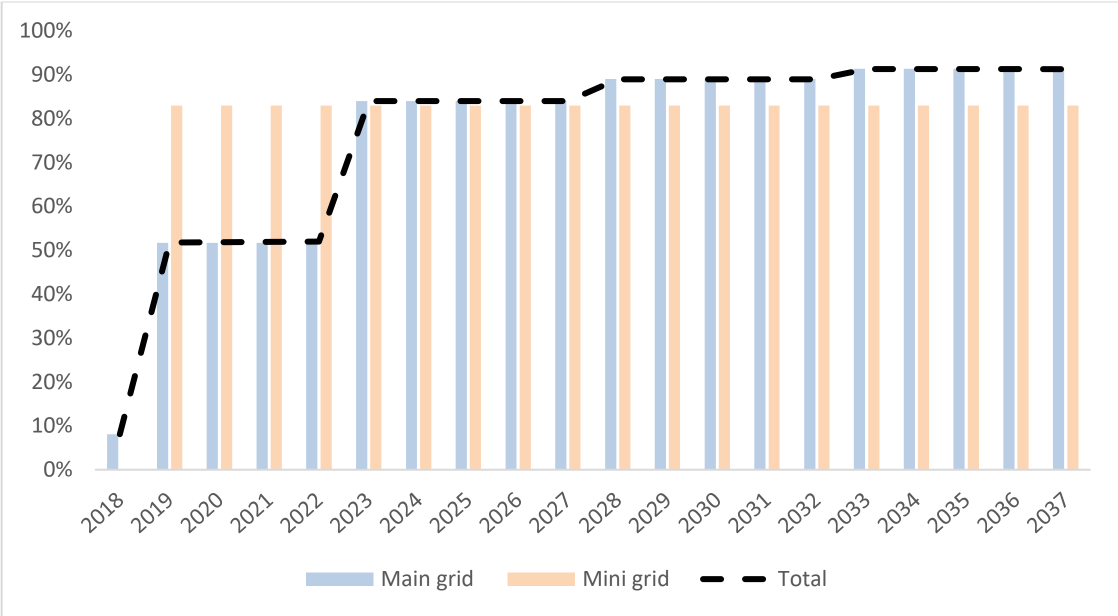


The main outcome of the Master Plan is that 100 percent of Kosrae will be electrified once the Walung mini-grid is built in 2019. In addition, during the 20 years of the Master Plan the percentage of electricity generated from renewable sources will increase, and carbon dioxide (CO_2) emissions and diesel use will fall.

Figure 5.8 shows RE as a percentage of total generation for the main grid and the Walung mini-grid. The total line shows the weighted average for the whole state.

The share of RE in Kosrae's electricity generation would increase from eight percent in 2018, to 84 percent in the first 5 years—exceeding the national target of 30 percent.

Figure 5.8: RE Percentage of Generation for Kosrae



CO_2 emissions and diesel use would decrease by 84 percent (Table 5.9).

Table 5.9: Kosrae Emissions and Diesel Use

	2018	2019–2023	2024–2028	2029–2033	2034–2037
CO_2 emissions (tonnes/year)	4,734	2,868	955	775	778
Diesel use (gallons/year)	458,107	277,498	92,406	74,971	75,251

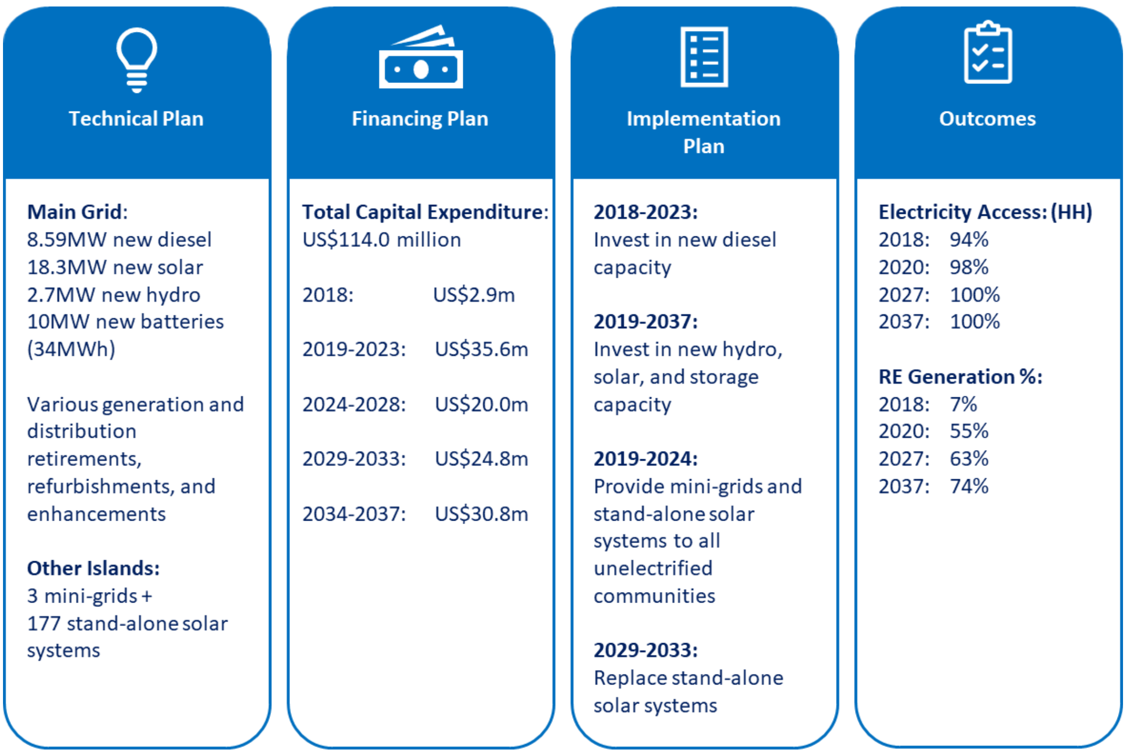
6 Pohnpei State Energy Master Plan

The Pohnpei State Energy Master Plan provides a least-cost strategy to achieve the state's energy goals. The state will achieve its goal of 100 percent electrification by 2025 and will achieve the national target of 30 percent RE by 2019. Total capital investment required over the 20 years of the Master Plan is US$114.0 million. The Master Plan has three core components:

- A **Technical Plan** that outlines the generation and distribution assets that need to be purchased for the state to be able to provide a reliable, sustainable electricity service to all residents at least-cost
- A **Financing Plan** that outlines how the Technical Plan can be feasibly financed and funded
- An **Implementation Plan** that discusses key considerations and risks for rolling out the Technical Plan.

Figure 6.1 summarizes the Master Plan's components and their outcomes.

Figure 6.1: Summary of the Pohnpei State Energy Master Plan

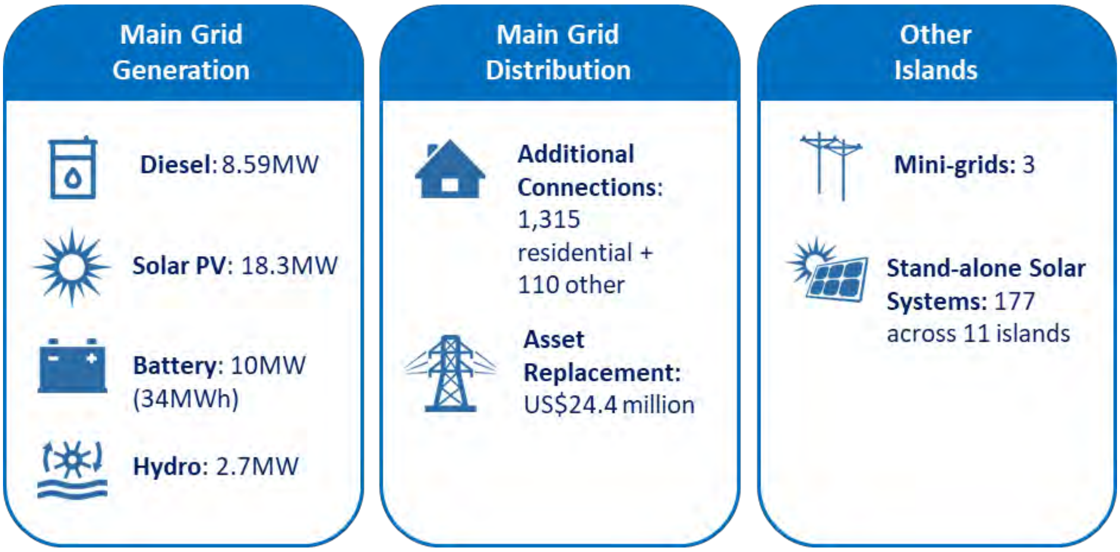


6.1 Technical Plan

The Technical Plan outlines required upgrades and improvements to the grid on Pohnpei Proper, and the least-cost options for achieving the desired level of service on all other islands in the State of Pohnpei. On Pohnpei Proper, the plan includes investment in new solar PV and hydro capacity to reduce the cost of electricity, as well as diesel to ensure security of supply. Distribution asset replacements and upgrades are needed to improve system reliability, while connections on the main grid are for households not currently connected, and the growth we have forecast for number of households and new businesses. Outside Pohnpei Proper, the plan includes the construction of three mini-grids and the provision of stand-alone solar systems on the remaining two outer island municipalities in Pohnpei.

Figure 6.2 summarizes the new infrastructure required in Pohnpei.

Figure 6.2: Summary of New Infrastructure in Pohnpei Technical Investment Plan



6.1.1 Pohnpei main grid

Over the 20-year Master Plan period the main-grid on Pohnpei Proper needs investment in: new generation capacity, refurbishment and replacement of existing generation assets, extension of the distribution network to connect new customers, and refurbishment and replacement of existing distribution assets.

We have labelled recommended generation capacity 'new' if the assets change the makeup of the generation system. All other capital is included as 'replacement', and includes totally replacing an asset, large asset refurbishment, and replacing major components of an asset. Diesel generators are categorized as 'new' if they add additional generation capacity or are purchased when a generator of different capacity comes offline. Capital investment in diesel generators is categorized as 'replacement' when a like for like replacement of a generator is made or when a major refurbishment of an existing generator is undertaken. Table 6.1 shows the new generation capacity our modeling suggests is required. In the text we explain the new generation investments, as well as discuss when replacements or refurbishments are required.

Diesel will continue to provide the backbone of the Pohnpei Utilities Corporation's generation system, helping ensure reliability

We assume that genset #3 comes back into service during 2018, and that 1.09MW of new diesel gensets (from the two new CAT C-18 Prime units that Pohnpei Utilities Corporation (PUC) has ordered) are operational in 2018. This is needed to meet the required service standards.

In addition, we assume that three new 2.5MW medium-speed diesel gensets are installed at the Pohnpei power station by 2020. This will allow the older, less fuel efficient, high-speed gensets to be progressively retired over the life of the Master Plan.

Investing in new RE generation capacity provides an opportunity to reduce overall costs

We assume that 300kW of solar PV capacity, from the New Zealand Ministry of Foreign Affairs and Trade (MFAT) project, is operational in 2018.

This new generation capacity (combined with the new medium-speed diesel engines to be installed by 2020, the existing diesel engines, and existing RE capacity) is sufficient to meet electricity demand on the main island over the 20-year period of the Master Plan with replacement at end-of-life. Installing new solar and hydropower generation capacity provides an opportunity to reduce the cost of energy, by reducing the use of diesel.

Over the 20 years of the Master Plan, we recommend that 2.7MW new hydropower capacity is installed, and 18.3MW of new solar PV generation is installed alongside 34MWh of battery storage and 10MW of Battery inverters. New solar PV and hydropower capacity will reduce the average cost of electricity by reducing PUC's diesel fuel use and therefore expenditure on diesel fuel. The upfront capital cost of solar PV and hydropower will be either paid for through grants or smoothed over time with cheap concessional financing so the cost per kWh will be lower than that provided by diesel generation. We recommend that new RE generation capacity is installed in the first 5 years of the Master Plan to reduce the cost of generation and free up capacity for other investment (Table 6.1).

Table 6.1: Pohnpei New[23] Generation and Storage Capacity for Main Grid

	2018	2019–2023	2024–2028	2029–2033	2034–2037
Diesel	1.09MW	7.5MW	-	-	-
Solar PV	0.3MW	3MW	5MW	4MW	6MW
Hydro	-	2.7MW	-	-	-
Battery storage	-	1MWh	5MWh	7MWh	21MWh
Battery inverter	-	1MW	0.5MW	3.5MW	5MW

In the period 2019–2023:

- Three 2.5MW medium-speed diesel gensets should be brought online. This will allow for the ageing CAT C-18 units to be retired and the Vital IPP to be retired or released by 2021. The new units will increase fuel efficiency and reduce O&M costs compared to the existing units
- 3MW of solar PV capacity should be developed at the Pohnlangas solar site
- The 2.7MW Lehnmesi hydropower scheme should be developed. This scheme incorporates storage to provide firmer capacity to the mix
- Energy storage should be deployed at the Pohnpei power station, providing 1MW of capacity and 1MWh of storage to manage integration of the PV plants
- The recommended investments in solar and storage will meet a large proportion of Pohnpei Proper's demand in 2023, reducing the use of diesel and therefore the cost of electricity. However, diesel-off is not allowed—that is, at least one genset must run at all times.

[23] New only includes new generation assets that change the generation mix. Like for like replacement of retired assets is not included.

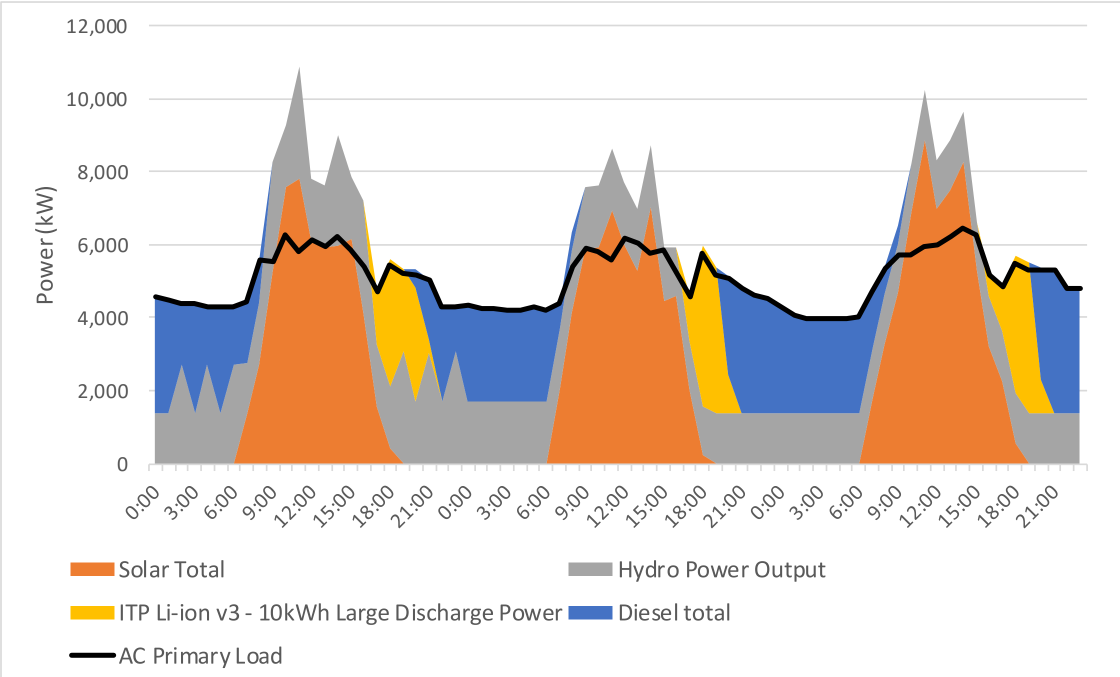
In the period 2024–2028:

- 5MW of solar PV capacity should be developed to offset increasing use of diesel generation as loads increase. This capacity could be part of the Pohnlangas solar site. It could also be deployed behind the meter on government or commercial buildings
- All gensets from 2023 should be retained. Diesel-off is still not allowed as the battery storage capacity is still too low at the start of this period and hydropower must not be grid-forming
- Energy storage should be deployed at the Pohnpei power station, providing 0.5MW of capacity and 5MWh of storage to manage integration of the PV plants.

In the period 2029–2033:

- 2 x 545kW gensets are retired and 3 x 2,500kW gensets have a major overhaul
- 4MW of solar PV capacity should be developed at a new site (assuming Pohnlangas is limited to about 10MW). Some of the capacity could be deployed behind the meter on government or commercial buildings
- New energy storage should be deployed, either at the Pohnpei power station, or at the Pohnlangas solar site, providing 3.5MW of capacity and 7MWh of storage
- Diesel-off is now allowed as battery and inverter sizes are much larger
- The new renewable capacity built up since 2018 makes a significant contribution to generation in 2033 (Figure 6.3).

Figure 6.3: Pohnpei Load Duration Curve and Contribution of Generation Sources, 2033



In the period 2034–2037:

- 2 x 1,650kW gensets should be replaced
- Diesel-off is still allowed
- 6MW of solar should be developed to offset increasing use of diesel generation as loads increase. It could be deployed behind the meter on government or commercial buildings, or at a new site
- New energy storage should be deployed, either at the Pohnpei power station or at the Pohnlangas solar site, providing 5MW of capacity and 21MWh of storage.

Replacement capital will also be needed to maintain existing generation capacity

The current solar PV plants will reach the end of their lives during the period of the Master Plans, and we assume they will be replaced. We assume energy storage capacity will achieve a 10-year life and will be replaced at least once during the Master Plan timeframe.

The spreadsheets that will be provided as part of data handover break down the replacement capital needed over the 20-year period.

New connections will be needed as the number of households increases

Pohnpei Proper has a 100 percent electrification rate. However, we forecast an increase in the number of households—which will require new connections. Our forecast is based on the increase in Pohnpei Proper between 1994 and 2010.

We assume five new commercial and government connections each year, except between 2019 and 2023, when we expect two extra from the new hotel/casino and the port expansion. Table 6.2 shows the new residential, commercial, and government connections. The costs of these connections are provided in the accompanying spreadsheets.

Table 6.2: Average Annual New Connections

	2018	2019-2023	2024-2028	2029-2033	2034-2037
New Residential Household Connections	83	83	89	94	100
New Commercial & Government Connections	5	7	5	5	5

The existing distribution network will need upgrades and maintenance

General network and demand growth includes minor feeder extensions and updating transformers as peak demand gradually increases and the expenditure cannot be tied to any specific large customer load project. Our analysis suggests that this will cost US$500,000 every 5 years.[24]

We used the asset register to make replacement estimates (see Table 6.3). Details of asset lifespans and replacement costs are in Appendix B.

[24] The network expansion requirement is likely to be quite limited due to network layout and because Pohnpei Proper is a small island. However, to be conservative we include a general allowance for some expansion/augmentation that is not specifically directed to one customer or project.

Table 6.3: Distribution Network Asset Replacement (average annual figures, US$)

	2018	2019–2023	2024–2028	2029–2033	2034–2037
Age-based Asset Replacement	967,750	1,012,180	1,090,405	1,174,676	1,255,970

6.1.2 Other islands

We propose mini-grids for Touhou and Ueru (Kapingamarangi), Pingelap, and Sapwuahfik.[25] We propose stand-alone solar systems for Mwoakilloa, Nukuoro, the four other islets of Kapingamarangi, and the five islets off Pohnpei Proper. We assume that all infrastructure is new. However, where schools already have solar, the panels could be reused.

Touhou and Ueru (Kapingamarangi)

The mini-grid in Touhou and Ueru needs a mixture of diesel and solar generation, as well as storage. The capacity for each of these asset types is shown in Table 6.4.

Table 6.4: Kapingamarangi Mini-grid Capacity 2018–2037

Asset Type	Capacity
Diesel	100kW
Solar	20kW
Storage	30kWh

We suggest an LV underground network for distribution. The initial costs are higher than an above ground network, but less maintenance is needed, and it is more weather resistant. The estimated cost is US$365,500.

Pingelap and Sapwuahfic

Pingelap and Sapwuahfic have a similar number of households and so the same generation solution is required. Table 6.5 presents the diesel, solar, and storage requirements for each island.

Table 6.5: Pingelap and Sapwuahfic Mini-grid Capacity 2018–2037

Asset Type	Capacity
Diesel	40kW
Solar	20kW
Converter	10kW
Storage	30kWh

Again, we suggest an LV underground network for distribution. The costs are about the same as Kapingamarangi at US$365,500 on each island.

[25] This recommendation is primarily based on the number and distribution of households on each island. Our analysis suggests that for some of these islands, solar systems may be slightly cheaper, but that mini-grids would be easier to maintain and manage. Following consultations, the Master Plan provides mini-grids for these islands.

Stand-alone solar systems (Mwoakilloa, Nukuoro, Kapingamarangi four islets, and Pohnpei Proper five islets)

For the remaining islands, stand-alone solar systems are the most efficient option due to the lower number of households.

The number of stand-alone solar systems required in each place is shown in Table 6.6. These numbers include residential, schools, dispensaries, and other facilities.[26] The sizes we assume are:

- 200W/1.2kWh for solar home systems (SHS)[27]
- 10kW systems for schools
- 2kW systems for other users such as dispensaries and shops.

Table 6.6: Number of Stand-alone Solar Systems by Customer Type

Location	Household	School	Dispensary	Other
Mwoakilloa	42	1	1	2
Nukuoro	53	1	1	2
5 islets off Pohnpei Proper[28]	59	0	0	0
4 islets in Kapingamarangi	15	0	0	0

The entire stand-alone solar systems will need to be replaced about every 8 years (provided they are well-maintained). We have factored in quarterly trips to each island for maintenance.

6.2 Financing Plan

The total amount needed to cover capital expenditure across the lifespan of the Master Plan is US$114.0 million.

Over 60 percent of the capital expenditure over the 20-year Master Plan period is on new generation capacity for the grid on Pohnpei Proper (Table 6.7). We recommend ongoing investment in solar PV with storage to lower the cost of generation and reduce reliance on diesel generation. Required expenditure for the main grid distribution network includes network upgrades currently being planned by PUC. The timing of capital requirements for the mini-grids and stand-alone solar systems is determined by when this infrastructure is rolled out. We recommend spreading the rollout over the first two 5-year blocks of the Master Plan to ensure PUC has sufficient capability to manage the rollout. Capital expenditure on mini-grids and stand-alone solar in later periods is for asset replacement.

[26] Other facilities may include commercial entities or community centers.

[27] For the purposes of the Master Plan we assume that all households use 200kW systems. However, we recognize that some households may want larger sizes. As an illustration, Appendix B outlines the additional cost for two larger sizes of SHS.

[28] The five islets are Parem, Lenger, Mwand Peidak, Mwahd Peidi, and Dehpehk.

Table 6.7: Capital Expenditure Requirements (US$ million 2016)

	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
New Main Grid Generation	1.78	26.38	12.73	11.82	19.89	72.59
Main Grid Generation Replacement	0.00	0.00	0.00	5.41	4.81	10.22
Main Grid Distribution	1.07	7.36	6.53	6.98	6.03	27.96
Mini-grids	0.00	1.37	0.72	0.02	0.08	2.19
Stand-alone Solar Systems	0.00	0.53	0.00	0.53	0.00	1.06
Total	2.85	35.63	19.97	24.76	30.80	114.02

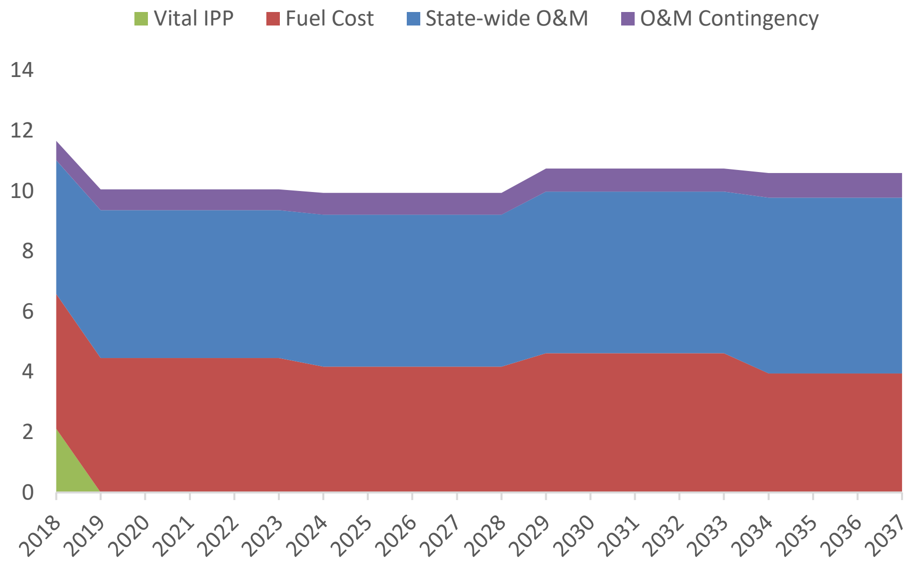
Operating expenses include:

- Pohnpei Proper generation O&M cost
- Pohnpei Proper distribution O&M cost
- Pohnpei Proper fuel cost
- Mini-grid generation O&M cost
- Mini-grid distribution O&M cost
- Mini-grid fuel cost
- Stand-alone solar O&M costs
- Administration and general fixed costs
- A 15 percent contingency on all technical O&M expenditure
- Project preparation costs (5 percent of total capital investment) for new capital projects (includes owner's engineer, procurement, and so on).

Operating expenses remain roughly level over the 20 years of the Master Plan despite growing consumption of electricity

Investment in new solar PV and hydropower capacity will reduce PUC's use of diesel fuel. The volume of diesel fuel used falls by around 25 percent over the 20 years, but expenditure on fuel will remain roughly level because of increasing diesel prices.

Figure 6.4: Estimated State-wide Operating Expenses, US$ million



The financial spreadsheet provided to PUC and the FSM Department of Resources and Development includes a more detailed breakdown.

We calculate debt service payments for three scenarios

The debt service payment made each year will include a repayment of the principal of the loan(s) (capital amortization) as well as an interest payment (cost of financing). We have calculated debt service payments for three scenarios:

- Scenario 1: All capital expenditure is paid for with grant funding
- Scenario 2: Capital expenditure on the mini-grids and stand-alone solar systems is paid for with grant funding. Capital expenditure on Pohnpei Proper is financed with concessional loans. Details of assumed loan terms offered by donor organizations are available in Appendix C
- Scenario 3: Capital expenditure on the mini-grids and stand-alone solar systems is paid for with grant funding. Capital expenditure on Pohnpei Proper is financed with commercial loans. (This scenario approximates the cost of getting IPPs for solar and storage as well as of PUC financing the replacement of the network on its own balance sheet.) Details of assumed loan terms offered by commercial banks are available in Appendix C.

In all three scenarios, the power sales revenue earned from keeping tariffs at their current level is sufficient to cover the cash requirements

Even in the high-financing-cost Scenario 3, where the revenue requirement grows over time, electricity consumption grows at a sufficient rate to enable tariffs to remain constant.

Figure 6.5: Cash Requirements in the Three Financing Scenarios, US$ million

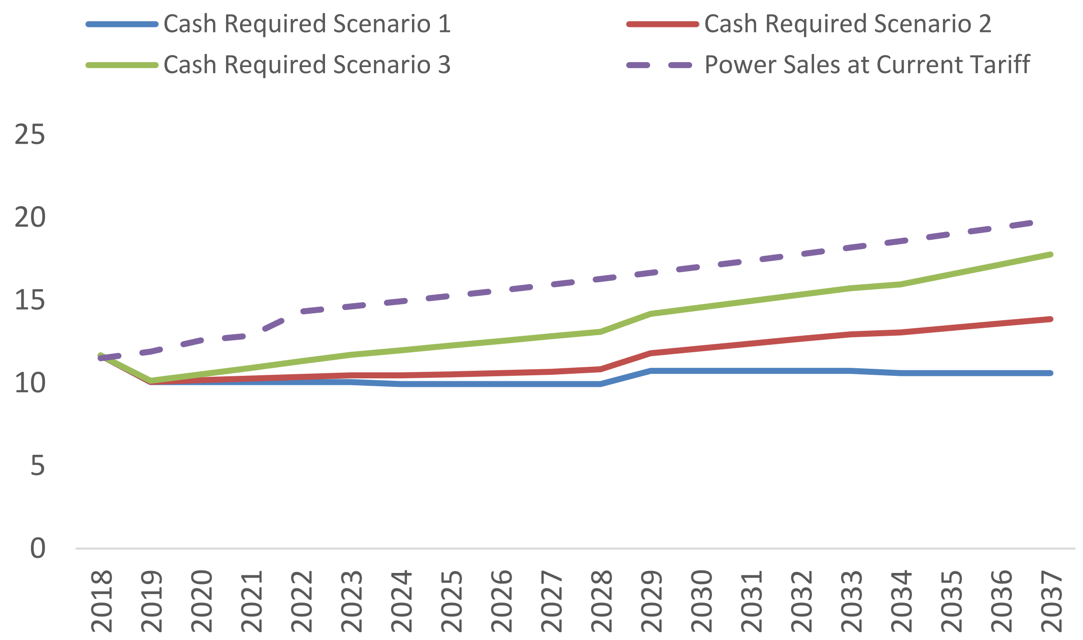


Table 6.8: Average Tariff Required to Cover Cashflows by 5-year Period and Customer Segment, US$ per kWh[29]

	Current	2018	2019–2023	2024–2028	2029–2033	2034–2037
Scenario 1						
Residential	0.39	0.40	0.30	0.25	0.24	0.22
Commercial	0.39	0.40	0.30	0.25	0.24	0.22
Government	0.39	0.40	0.30	0.25	0.24	0.22
Scenario 2						
Residential	0.39	0.40	0.30	0.27	0.28	0.27
Commercial	0.39	0.40	0.30	0.27	0.28	0.27
Government	0.39	0.40	0.30	0.27	0.28	0.27
Scenario 3						
Residential	0.39	0.40	0.32	0.31	0.34	0.34
Commercial	0.39	0.40	0.32	0.31	0.34	0.34
Government	0.39	0.40	0.32	0.31	0.33	0.34

We recommend that PUC consider a stable medium-term tariff path once the financing package is confirmed.

[29] We assume tariff structure across customer segments is unchanged, and adjust current tariffs for each segment by a constant percentage to calculate the tariff requirements.

PUC will take lead responsibility for implementing the Master Plan investments. Even if PUC chose to outsource some project implementation tasks, it would still need to manage these contracts and oversee implementation.

The State Energy Workgroup (SEW) has an interest in providing strategic guidance and in monitoring progress and results to ensure that the desired state-level policy outcomes are met. SEW does not have the capacity to fulfil this role.

The Master Plan includes a budget for technical assistance to fulfil the various monitoring, coordinating and administrative functions (the National Energy Master Plan provides more details). We assume this will be covered by a grant and do not include it in the tariff calculation.

6.3 Implementation Plan

Here, we discuss the rollout of investments, and what additional capacity within PUC will be needed to implement and maintain these investments. We also briefly discuss project risks.

In the funding and financing plan, we have ensured PUC has all the resources it needs to successfully implement the investment plan. However, outsourcing is a possibility if it provides greater value for money. This is discussed in Appendix H.

6.3.1 Rollout of physical capital projects

We separate activities to be carried out over the 20-year period of the Master Plan into generation capital projects and distribution improvements. The rollout plan outlines the sequencing of these activities (Table 6.9).

When sequencing the rollout plan we considered already committed/funded capital projects. These are:

- Two new 545kW diesel gensets for the diesel power plant
- Replacement of genset #3 engine and return to operation
- New 300kW solar PV capacity funded by MFAT.

We assume that all these projects are operational in 2018.

Hydropower capacity installed in the 2019–2023 period is at the site identified at Lehnmesi.

New connections are included in the rollout plan. On top of this, asset-based replacement and general network upgrades will be ongoing as peak demand increases.

We include a schedule for replacing or retiring existing diesel generators in the rollout plan. Existing solar panels are replaced in the Master Plan period as they are already 5–10 years old. New solar panels are expected to last the entire Master Plan period, but batteries and inverters will need require replacing within the Master Plan period.

The rollout plan will enable all consumers in unserved islands to be electrified within 10 years. We have sequenced the rollout to start with the most accessible communities to test out the technology, billing, logistics, and management approach before rolling out to less-accessible islands.

Table 6.9: Rollout Plan for Pohnpei

<table>
<tr><th>Year</th><th>2018</th><th>2019–2023</th><th>2024–2028</th><th>2029–2033</th><th>2034–2037</th></tr>
<tr><td>Main Grid</td><td>Generation capital projects
New 1.09MW diesel
Replacement and return of genset #3 to service
300kW solar funded by MFAT</td><td>Generation capital projects
New 7.5MW diesel
New 2.7MW Lehnmesi Hydropower Plant
New 3MW solar
New 1MW battery inverter
New 1MWh battery storage
Additional connections
84 new residential connections a year
5 new commercial connections a year
New hotel/casino connected</td><td>Generation capital projects
New 5MW solar
New 0.5MW battery inverter
New 5MWh battery storage
Additional connections
90 new residential connections a year
5 new commercial connections a year</td><td>Generation capital projects
2 x 545kW gensets retired
3 x 2500kW gensets have a major overhaul
New 4MW solar
New 3.5MW battery inverter
New 7MWh battery storage
Additional connections
95 new residential connections a year
5 new commercial connections a year</td><td>Generation capital projects
2 x 1,650kW gensets replaced
New 6MW solar
New 5MW battery inverter
New 21MWh battery storage
Additional connections
101 new residential connections a year
5 new commercial connections a year</td></tr>
<tr><td>Mini-grid: Kapingamarangi</td><td></td><td></td><td>Mini-grid construction
2 x 50kW diesel gensets
20MW solar
50kW of converters
30kWh of storage
LV underground network</td><td></td><td>Replacement
Replace gensets
Replace batteries</td></tr>
<tr><td>Mini-grid: Pingelap</td><td></td><td>Mini-grid construction
40kW diesel genset</td><td></td><td>Replacement
Replace gensets</td><td>Replacement
Replace converters</td></tr>
</table>

		▪ 20MW solar ▪ 10kW of converters ▪ 30kWh of storage ▪ LV underground network		▪ Replace batteries	
Mini-grid: Sapwuahfik		**Mini-grid construction** ▪ 40kW diesel genset ▪ 20MW solar ▪ 10kW of converters ▪ 30kWh of storage ▪ LV underground network		**Replacement** ▪ Replace gensets ▪ Replace batteries	**Replacement** ▪ Replace converters
Stand-alone solar systems		**Stand-alone solar system installation** ▪ Install 42 stand-alone solar systems in Mwokilloa (including a school, a dispensary, and 2 community centers) ▪ Install 57 stand-alone solar systems in Nukuoro (including a school, a dispensary, and 2 community centers) ▪ Install 59 stand-alone solar systems among 5 islets off Pohnpei Proper: Parem, Lenger, Mwand Peidak, Mwahd Peidi, and Dehpehk ▪ Install 15 stand-alone solar systems in Kapingamarangi 4 islets		**Capital replacement** ▪ Replace all stand-alone solar systems	

6.3.2 Implementation capacity

To implement the Master Plans, PUC will need additional staff

We considered whether PUC has the capacity to implement the activities required in the plan. Table 6.10 highlights the additional capacity that will be needed.

The requirements in Table 6.10 relate to ongoing operational, managerial, and maintenance functions and do not include building the new infrastructure (for which we assume contractors will be engaged). The table shows when these staff would need to be engaged or trained, but once engaged they would continue their work throughout the whole Master Plan period (and beyond), unless otherwise stated.

Table 6.10: Capacity Requirements for PUC

Year	2018	2019–2023
Main Grid	1 new employee based in Pohnpei to manage stand-alone solar systems in the 5 islets and assist the other stand-alone solar system employees	At least 1 new junior/intermediate engineer to help manage and support outer island staff 2 new engineers to be trained in RE and control systems for the main grid 2 new electrical technicians to be trained in battery and control systems
Mini-grid: Kapingamarangi		4 staff members employed and trained (1 with basic electrical training)
Mini-grid: Pingelap and Sapuahfik		3 staff members each, employed and trained (1 with basic electrical training)
Stand-alone solar systems	1 casual employee for each lagoon island, to do basic maintenance and assist with billing	1 casual employee in Mwokilloa and 1 employee in Nukuoro

6.3.3 Implementation risks

Here we discuss the main risks specific to Pohnpei. Appendix E highlights various risks associated with the types of technology and investments proposed in this Plan. Many of these are common to all states using the same technologies.

Land does not appear to be a constraint

We assume that all new diesel capacity on Pohnpei Proper will be accommodated at the site of the existing diesel power station, and that up to 18MW of new solar capacity will be in a single location at the Pohnlangas site. As these sites are already operational/prepared, we do not foresee any major land access, social, or environmental challenges. Another site(s) will be required for the remaining solar PV capacity. The forthcoming feasibility study on integrating additional solar PV capacity into Pohnpei's main grid will assess possible sites in more detail.

We assume that mini-grids will be located on public land, but a more detailed assessment would need to be made before building on each island.

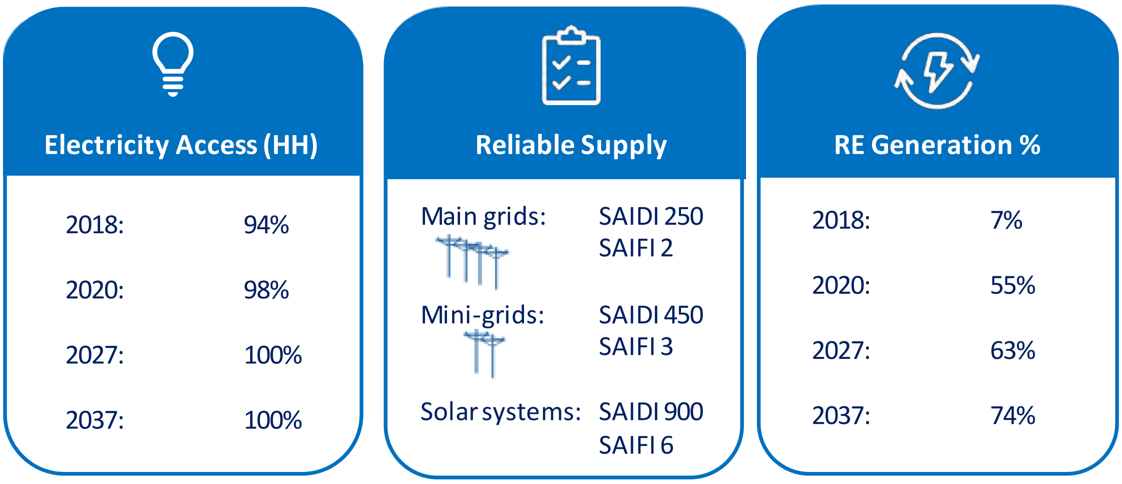
Risks of the proposed Lehnmesi hydropower plant will need to be assessed carefully

The investment plan for Pohnpei includes 2.7MW of hydropower capacity on the Lehnmesi River. Hydropower brings various environmental and social risks. Appendix G discusses some of the risks of the project. Before proceeding with such a development, PUC would need to do a comprehensive environmental and social impact assessment.

6.4 Outcomes

If Pohnpei implements the above plans it can expect to meet its main energy sector objectives. Figure 6.6 summarizes the outcomes the plans will help Pohnpei achieve.

Figure 6.6: Summary of Outcomes of the Pohnpei State Energy Master Plan

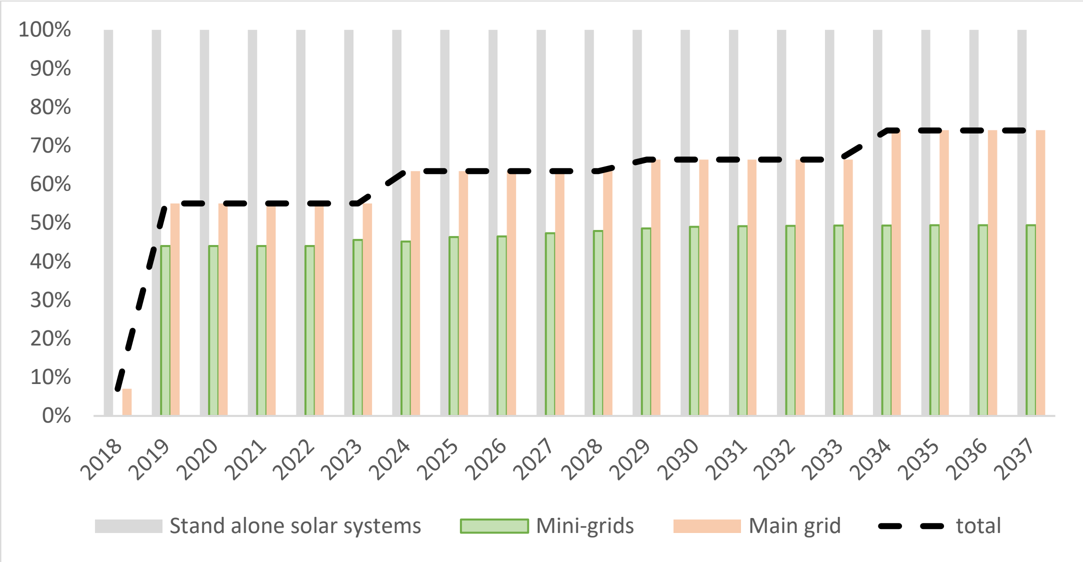


The main outcome of the Master Plan is that, by 2025, 100 percent of households, businesses, and public facilities in Pohnpei will have access to a reliable, affordable electricity service. In addition, during the 20 years of the Master Plan the percentage of electricity generated from renewable sources will increase, and carbon dioxide (CO_2) emissions and diesel use will fall.

The Master Plan achieves Pohnpei's RE, emissions, and diesel reduction targets

Figure 6.7 shows RE as a percentage of total generation for the stand-alone solar systems, mini-grids, and main grid. The total line shows the weighted average for the whole state.

Figure 6.7: RE Percentage of Generation for Pohnpei



Increased RE decreases exposure to fossil fuel volatility, which is a state and national target. Fuel use decreases significantly in the first 5 years and then decreases gradually across the rest of the period (see Table 6.11). At the end of the 20 years, fuel use (and emissions) will be nearly half of 2018 levels. This exceeds PUC's target of reducing petroleum products by 15 percent.

Table 6.11: Pohnpei Emissions and Diesel Use

	2018	2019–2023	2024–2028	2029–2033	2034–2037
CO_2 emissions (tonnes/year)	18,471	13,121	11,501	11,893	9,791
Diesel use (gallons/year)	1,787,333	1,269,637	1,112,939	1,150,808	947,475

7 Yap State Energy Master Plan

The Yap State Energy Master Plan provides a least-cost strategy to achieve the state's energy goals. The state will achieve its goal of 100 percent electrification by 2025, and will achieve the national target of 30 percent renewable energy (RE) by 2019. Total capital investment required over the 20 years of the Master Plan is US$58.9 million. The Master Plan has three core components:

- A **Technical Plan** that outlines the generation and distribution assets that need to be purchased for the state to be able to provide a reliable, sustainable electricity service to all residents at least-cost
- A **Financing Plan** that outlines how the Technical Plan can be feasibly financed and funded
- An **Implementation Plan** that discusses key considerations and risks for rolling out the Technical Plan.

Figure 7.1 summarizes the Master Plan's components and their outcomes.

Figure 7.1: Summary of Outcomes of the Yap State Energy Master Plan

Technical Plan	Financing Plan	Implementation Plan	Outcomes
Main Island: 2.48MW new diesel 8.3MW new solar 4MW new batteries (30MWh) Various generation and distribution retirements, refurbishments, and enhancements **Other Islands:** 2 new mini-grids, 7 enhanced mini-grids + 262 stand-alone solar systems	**Total Capital Expenditure:** US$58.9 million 2018: US$1.3m 2019-2023: US$15.1m 2024-2028: US$13.2m 2029-2033: US$15.8m 2034-2037: US$13.5m	**2019-2023:** Install 5 miles of new underground cable + 21 miles of overhead cable **2019-2027:** Provide mini-grids and stand-alone solar systems to all unelectrified communities **2024-2033:** Invest in new diesel capacity **2019-2037:** Invest in new solar and storage capacity **2019-2037:** Enhance and/or replace mini-grid components and stand-alone solar systems	**Electricity Access: (HH)** 2018: 85% 2020: 90% 2027: 100% 2037: 100% **RE Generation %:** 2018: 22% 2020: 43% 2027: 62% 2037: 86%

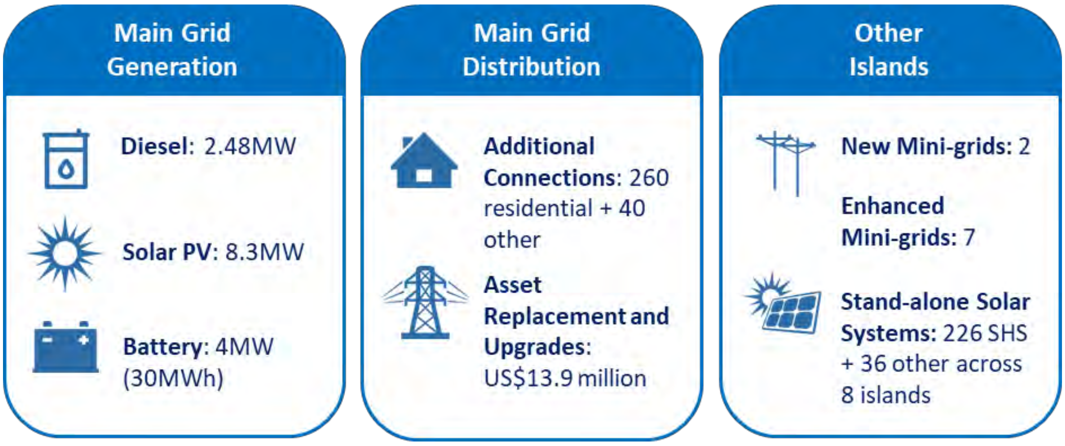
7.1 Technical Plan

The Technical Plan outlines required upgrades and improvements to the grid on Yap Proper, and the least-cost options for achieving the desired level of service on all other islands in the State of Yap.

On Yap Proper, the plan includes investment in new solar PV capacity to reduce the cost of electricity, as well as diesel to ensure security of supply. Distribution asset replacements and upgrades are already being planned by Yap State Public Service Corporation (YSPSC). The Plan also allows for additional connections on the main grid for households not currently connected, and the growth we have forecast for number of households and new businesses. Outside Yap Proper, the plan includes the upgrade of 7 existing mini-grids, construction of 2 new mini-grids and provision of stand-alone solar systems on the remaining 8 inhabited islands in Yap.

Figure 7.2 summarizes the new infrastructure required in Yap (not including replacements of existing generation infrastructure).

Figure 7.2: Summary of New Infrastructure in Yap Technical Investment Plan



7.1.1 Yap Proper main grid

Over the 20-year Master Plan period the main grid on Yap Proper needs investment in: new generation capacity, replacement or refurbishment of existing generation assets, extension of the distribution network to connect new customers, and replacement of existing distribution assets.

We have labelled recommended generation capacity 'new' if the assets change the makeup of the generation system. All other capital is included as 'replacement', and includes totally replacing an asset, large asset refurbishment, and replacing major components of an asset. Diesel generators are categorized as 'new' if they add additional generation capacity or are purchased when a generator of different capacity comes offline. Capital investment in diesel generators is categorized as 'replacement' when a like for like replacement of a generator is made or when a major refurbishment of an existing generator is undertaken. Table 7.1 shows the new generation capacity our modeling suggests is required. In the text we explain the new generation investments, as well as discuss when replacements or refurbishments are required.

Investing in new RE generation capacity provides an opportunity to reduce overall costs

Over the 20 years of the Master Plan, we recommend that 8.3MW of new solar PV generation is installed alongside 30MWh of battery storage. New solar PV capacity will reduce the average cost of electricity by reducing YSPSC diesel fuel use and therefore expenditure on diesel fuel. The upfront capital cost of solar PV will be either paid for through grants or smoothed over time with cheap concessional financing so the cost per kWh will be lower than that provided by diesel generation. Investment to optimize diesel capacity in the 2029–2033 period will help maintain service standards as energy consumption increases.

We assume the 875kW wind farm is operational by 2018. We do not identify expansion of the wind farm as one of the least-cost options, so this is not included in the investment plan.

Table 7.1: Yap New[30] Generation and Storage Capacity for Main Grid

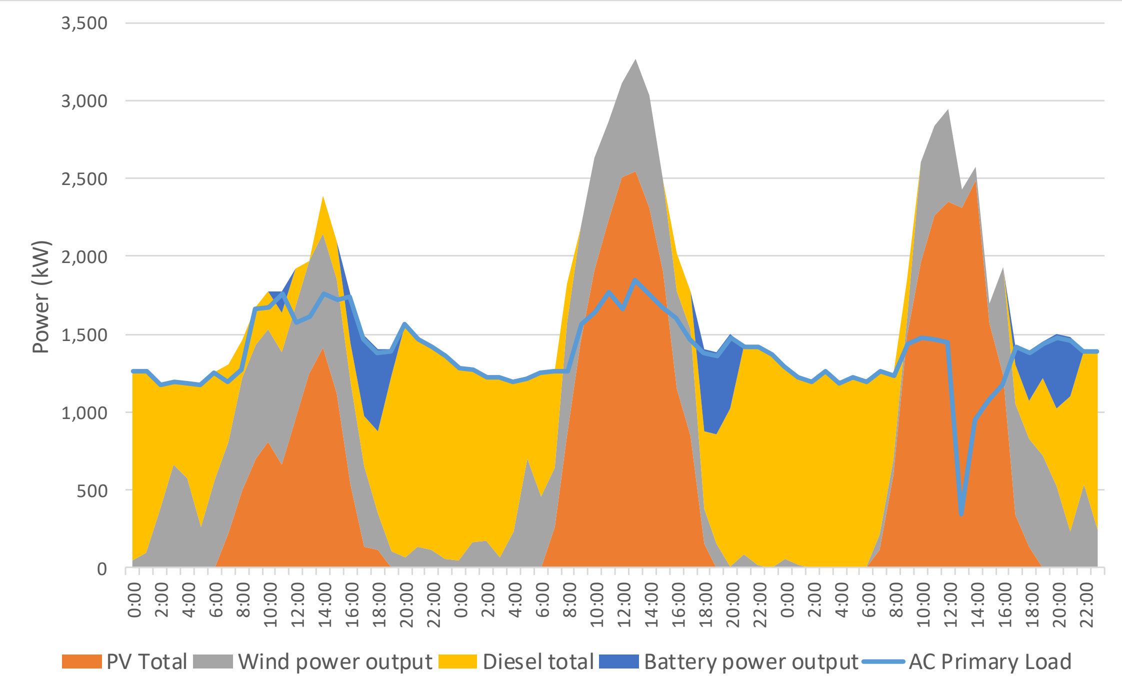
	2018	2019–2023	2024–2028	2029–2033	2034–2037
Diesel	-	0.83MW	-	1.65MW	-
Solar PV	-	2MW	2MW	2.5MW	1.8MW
Battery inverter	-	0.5MW	1.5MW	0.5MW	1.5MW
Battery storage	-	3MWh	7MWh	10MWh	10MWh

In the period 2019–2023:

- A second 830kW diesel generator should be added. This has been included at YSPSC's request, to allow the power station operators to manage the run hours on smaller generators better and extend their lives. YSPSC reported that the existing 830kW generator is currently being run hard in response to fluctuations in wind farm generation, and it is not expected to last more than 5 years. The second 830kW will allow YSPSC to reduce the run hours on the existing generator so that it will not require replacement for at least 10 years. This may defer the need for a new 830kW generator later in the Master Plan period
- 2MW of solar PV capacity should be developed at one or more sites. Some of the capacity could be deployed behind the meter on government or commercial buildings, but additional options such as ground-mounted and floating systems may also be needed
- Energy storage should be deployed at the Yap power station, providing 0.5MW of capacity and 3MWh of storage to manage integration of the wind turbines and PV plants and increased use of RE
- The recommended investments in solar and storage will meet a large proportion of Yap Proper's demand in 2023, reducing the use of diesel and therefore the cost of electricity (Figure 7.3).

[30] New only includes new generation assets that change the generation mix. Like for like replacement of retired assets is not included.

Figure 7.3: Yap Load Duration Curve and Contribution of Generation Sources, 2023



In the period 2024–2028:

- 2MW of solar PV capacity should be developed. This could be at one of the existing solar sites
- The battery inverter capacity should be increased by 1.5MW and storage capacity by 7MWh. This could be deployed at the Yap power station, at one of the solar sites, or at the wind farm.

In the period 2029–2033:

- A new CAT 1,650kW unit (to match the other two generators) should be added in this period. A 3.2MW Deutz generator is retired in this period and the new CAT will ensure N+2 is met. One of the existing 1,650kW CAT generators should be replaced in this period
- 2.5MW of solar PV capacity should be developed. This could be at one of the existing solar sites
- The battery inverter capacity should be increased by 0.5MW and storage capacity by 10MWh to address growth in the load.

In the period 2034–2037:

- 1.8MW of new solar PV capacity should be developed at one of the solar sites
- The battery inverter capacity should be increased by 1.5MW and storage capacity by 10MWh to address growth in the load and maintain reliability standards
- Two diesel gensets should be replaced in this period (1 x 1,650kW + 1 x 830kW). Both of these are required to maintain N-2 security criteria.

Replacement of new renewable generation assets will also be needed to maintain generation capacity

The current PV solar plants will reach their end of life during the period of the Master Plans and we assume they will be replaced. We assume energy storage will achieve a 10-year life and will be replaced at least once during the Master Plan timeframe. An estimate of the total cost of generation replacement capital including both diesel and renewables for each period of the Master Plan is included in Table 7.9.

The spreadsheets that will be provided as part of data handover break down the replacement capital needed over the 20-year period.

New connections will be needed as the number of households increases

New connections will be needed for the increase in number of households that we have forecast. We also estimate two new commercial or government entities being connected each year on average. Table 7.2 shows the new residential, commercial, and government connections. The costs of these connections are provided in the accompanying spreadsheets.

Table 7.2: Average Annual New Connections

	2018	2019-2023	2024-2028	2029-2033	2034-2037
New Residential Household Connections	13	13	13	13	13
New Commercial & Government Connections	2	2	2	2	2

We do not propose a way to provide electricity access in Rumung, reflecting the community's request not to be provided with electricity.

The existing distribution network will need upgrades and maintenance

General network and demand growth includes minor feeder extensions and updating transformers as peak demand gradually increases and the expenditure cannot be tied to any specific large customer load project. Our analysis suggests that this will cost US$200,000 every 5 years (or US$40,000 on average each year), with an additional US$100,000 in the 2033-2037 period.

In addition, it will cost US$3.5 million over 5 years to implement YSPSC's proposed distribution network enhancements. These enhancements include 21 miles of overhead medium-voltage (MV) cables (new cables and reinforcements), 5 miles of underground MV cables (from the power station to the airport and hospital), and reclosers.

We used the asset register to make replacement estimates. Details of asset lifespans and replacement costs are in Appendix B.

Table 7.3: Distribution Network Asset Replacement (average annual figures)

	2018	2019–2023	2024–2028	2029–2033	2034–2037
Age-based Asset Replacement	409,125	427,908	460,978	496,605	530,972

7.1.2 Other islands

Based on the numbers and distribution of households, and the existing infrastructure, our modeling suggests that solar/diesel hybrid mini-grids[31] are the least-cost option for: Fadrai, Asor, Fais, Satowal; Falalop, Ulithi; Falalop, Woleai; Mogmog; Ifalik; and Lamotrek.

We propose stand-alone solar systems for all other islands: Nugulu, Tahoilap, Sileap, Wottegai, Falalus, Eauripuk, Faraulep 1, Faraulep 2, and Elato.

Fadrai, Asor, Fais, Satowal

These islands already have mini-grids that are 100 percent solar. The existing systems are over-sized relative to current load to allow for vegetation (which is important for cyclone protection), which prevents the solar PV modules from performing to their maximum capacity. Even so, our analysis suggests that the existing systems have enough capacity to satisfy demand over the Master Plan period. No significant load growth is expected because consumers are already at an established level of consumption and the population is not expected to grow.

Batteries will need to be replaced about every 10 years. If additional PV capacity turns out to be needed then it can be added at low cost.

To meet the reliability standards, the investment plan includes a 20kW diesel generator on each island. To meet the standards without using diesel, the solar capacity would need to be supplemented with additional batteries—which would be more expensive. Appendix B sets out the extra cost of this option, compared to using diesel. However, there may be logistical and environmental benefits to doing this.

We understand that some islands have more than one mini-grid. YSPSC could consider interconnecting these as a way of meeting N+1 redundancy. This is not currently included in the Master Plan and would require more detailed analysis.

Falalop, Ulithi; Falalop, Woleai; and Mogmog

We have modeled these islands with their existing generators and networks to establish the least-cost generation mix.

As all have existing networks, we do not model any new network costs. The costs of maintaining the existing networks are in Appendix B.

For **Falalop**, **Ulithi**, the generation capacity needed is presented in Table 7.4. The existing system was modeled with 6kW of grid-connected PV and a 90kW generator.[32] We added a second diesel generator to provide the required redundancy.

The solar includes the 6kW of existing PV and would need another 80kW. This could include the 60kW currently being built if it is grid-connected rather than stand-alone.

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[31] In all cases we use hybrid systems, as our analysis suggests that diesel is the least-cost way to meet the required reliability standards. However, following discussions with YSPSC, we appreciate that there may be some practical, logistical, and environmental benefits to using 100 percent solar PV systems with battery storage. Therefore, we outline in Appendix B the additional cost of meeting these standards using batteries instead, in case YSPSC wishes to pursue this option for some islands.

[32] YSPSC asked us to consider, for islands with existing diesel mini-grids, whether solar PV could be added, to be used in the day, with the diesel being used at night. We modeled new solar PV and battery systems for the existing diesel mini-grids in Yap to identify the least-cost generation mix. In all cases, adding PV and storage reduces the cost of energy compared to diesel only.

Table 7.4: Falalop, Ulithi Mini-grid Capacity[33]

Asset Type	Capacity
Diesel	200kW
Solar	86kW
Storage	140kWh
Converter	80kW

Table 7.5 presents the capacity required in **Falalop, Woleai**. The diesel generation includes the existing 50kW genset as well as one new 50kW genset.

It may be possible to integrate the existing PV capacity into the new system, but this would require a more detailed assessment of the condition and set-up of the existing system.

Table 7.5: Falalop, Woleai Mini-grid Capacity

Asset Type	Capacity
Diesel	100kW
Solar	40kW
Storage	130kWh
Converter	30kW

The generation capacity required for Mogmog is in Table 7.6. Mogmog has an existing 24kW diesel genset. A second identical genset is required to provide redundancy.

The existing 47kW PV system will be integrated into the mini-grid and new solar PV capacity will not be needed until 2029–2033.

Table 7.6: Mogmog Mini-grid Capacity

Asset Type	Capacity
Diesel	24kW
Solar	10kW
Storage	30kWh
Converter	10kW

Ifalik and Lamotrek

We propose mini-grids for Ifalik and Lamotrek. The generation requirements needed for each are set out in Table 7.7. The requirements are the same because of similar numbers of households in these two municipalities.

[33] We understand that YSPSC is in the process of collecting more reliable load data that would help determine the optimal size for this system.

Table 7.7: Ifalik and Lamotrek Mini-grid Capacity

Asset Type	Capacity
Diesel	40kW
Solar	20kW
Storage	30kWh
Converter	10kW

To meet the reliability standards, the investment plan includes a small diesel generator on each island. To meet the standards without using diesel, the solar capacity would need to be supplemented with additional batteries—which would be more expensive (see Appendix B).

We suggest an LV underground network for distribution on both islands. Estimated costs are in Appendix B.

Stand-alone solar systems

For the remaining islands, stand-alone solar systems are the most efficient option due to the lower number of households.

There are 343 solar home systems (SHS) in Yap. However, the investment plan assumes starting from scratch as no information exists on what condition the existing SHS are in and when they would need to be replaced. If follow-up surveys are carried out and some SHS are still considered useable, the capital expenditure requirement can be adjusted.

Table 7.8 shows the number of stand-alone solar systems required in each place. These numbers include residential, schools, dispensaries, and other facilities.[34] The sizes assumed are:

- 200W/1.2kWh for home systems[35]
- 10kW systems for schools[36]
- 2kW systems for other users such as dispensaries and shops.

The proposed SHS are smaller than the existing ones in Yap (500W). Our analysis suggests smaller systems could satisfy expected demand, at lower cost than the larger systems.

[34] Other facilities may include commercial entities or community centers.

[35] For the purposes of the Master Plan we assume that all households use 200kW systems. However, we recognize that some households may want larger sizes. As an illustration, Appendix B outlines the additional cost for two larger sizes of SHS.

[36] Although the existing school systems are smaller than this, the 10kW is intended to allow the system to support wider community activities.

Table 7.8: Number of Stand-alone Solar Systems by Customer Type

Islands	Household	School	Dispensary	Other
Nugulu	18[37]	1	1	2
Tahoilap	21	1	1	2
Sileap	27	1	1	2
Wottegai	34	1	1	2
Falalus	23	1	1	2
Eauripuk	26	1	1	2
Faraulep 1	21	1	1	2
Faraulep 2	31	1	1	2
Elato	25	1	1	2
Total	226	9	9	18

The total number of SHS is lower than the number currently in Yap. This is because some places that currently have SHS will be provided with mini-grids instead.

The entire system will need to be replaced about every 8 years (provided it is well-maintained). We have factored in quarterly trips to each island for maintenance.

7.2 Financing Plan

The total amount needed to cover capital expenditure across the lifespan of the Master Plan is US$58.9 million

Half of the capital expenditure over the 20-year Master Plan period is on new generation capacity for the grid on Yap Proper (Table 7.9). We recommend ongoing investment in solar PV with storage to lower the cost of generation and reduce reliance on diesel generation. Required expenditure for the main grid distribution network includes network upgrades currently being planned by YSPSC. The timing of capital requirements for the mini-grids and stand-alone solar systems is determined by when this infrastructure is rolled out. We recommend spreading the rollout over the first two 5-year blocks of the Master Plan to ensure YSPSC has sufficient capability to manage the rollout.

[37] We have mixed information on the number of households in Nugulu. To ensure the Master Plan has sufficient budget to electrify the entire community, we take a conservative approach and assume 18 households (based on waypoint data). If there are fewer households the cost will be lower.

Table 7.9: Capital Expenditure Requirements (US$ million 2016)

	2018	2019–2023	2024–2028	2029–2033	2034–2037	Total
New Main Grid Generation	0.00	6.80	6.94	9.15	5.95	28.83
Main Grid Generation Replacement	0.70	0.00	1.69	1.65	4.17	8.20
Main Grid Distribution	0.45	6.31	2.74	2.93	2.63	15.06
Mini-grids	0.12	1.36	1.33	0.89	0.17	3.86
Stand-alone Solar	0.00	0.63	0.53	1.16	0.63	2.94
Total	1.27	15.09	13.22	15.77	13.55	58.90

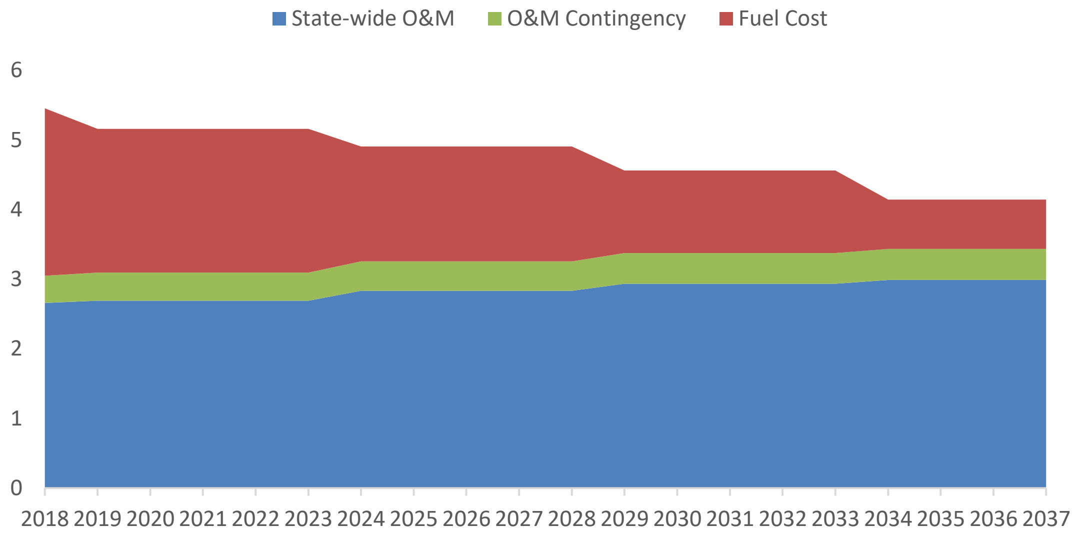
Operating expenses include:

- Yap Proper generation O&M cost
- Yap Proper distribution O&M cost
- Yap Proper fuel cost
- Mini-grid generation O&M cost
- Mini-grid distribution O&M cost
- Mini-grid fuel cost
- Stand-alone solar O&M costs
- Administration and general fixed costs
- A 15 percent contingency on all technical O&M expenditure
- Project preparation costs (5 percent of total capital investment) for new capital projects (includes owner's engineer, procurement, and so on).

Operating expenses fall by US$1.3 million a year between 2018 and 2037 because of a reduction in diesel use

Fuel cost makes up almost 50 percent of total operating expenses in 2018. As new RE capacity comes online, fuel consumption declines and fuel cost falls to less than 20 percent of operating expenses. The shift from diesel to renewables also leads to a fall in generation operating and maintenance costs on Yap Proper because of lower run hours for diesel generators. State-wide operating expenses—excluding the fuel cost—increase over the Master Plan period. This increase is because administration and general costs, and distribution costs on Yap Proper, grow with load growth; and operating expenses for new mini-grids and stand-alone solar systems are added. The net effect of lower fuel cost and growing operating and maintenance costs is a reduction in operating expenses each year of US$1.3 million from 2018 to 2037.

Figure 7.4: Estimated State-wide Operating Expenses, US$ million



The financial spreadsheet provided to YSPSC and the FSM Department of Resources and Development includes a more detailed breakdown.

We calculate debt service payments for three scenarios

The debt service payment made each year will include a repayment of the principal of the loan(s) (capital amortization) as well as an interest payment (cost of financing). We have calculated debt service payments for three scenarios:

- Scenario 1: All capital expenditure is paid for with grant funding
- Scenario 2: Capital expenditure on mini-grids and stand-alone solar systems is paid for with grant funding. Capital expenditure on Yap Proper is financed with concessional loans. Details of assumed loan terms offered by donor organizations are available in Appendix C
- Scenario 3: Capital expenditure on the mini-grids and stand-alone solar systems is paid for with grant funding. Capital expenditure on Yap Proper is financed with commercial loans. (This scenario approximates the cost of getting IPPs for solar and storage as well as of YSPSC financing the replacement of the network on its own balance sheet.) Details of assumed loan terms offered by commercial banks are available in Appendix C.

In all three scenarios, power sales revenue earned from keeping tariffs at their current level is sufficient to cover the cash requirements

Even in the higher-cost Scenario 3, where the revenue requirement grows over time, electricity consumption grows at a sufficient rate to enable tariffs to remain constant.

Figure 7.5: Cash Requirements in the Three Financing Scenarios, US$ million

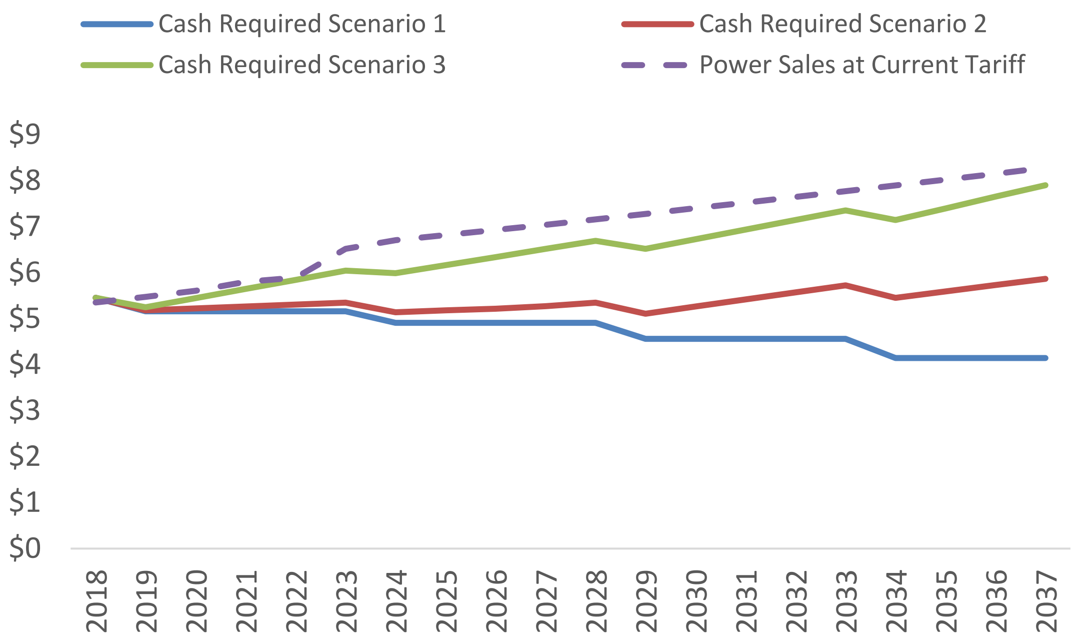


Table 7.10: Average Tariff Required to Cover Cashflows by 5-year Period and Customer Segment, US$ per kWh[38]

	Current	2018	2019–2023	2024–2028	2029–2033	2034–2037
Scenario 1						
Residential	0.41	0.42	0.36	0.29	0.25	0.21
Commercial	0.49	0.50	0.43	0.35	0.30	0.25
Government	0.77	0.78	0.68	0.55	0.47	0.39
Scenario 2						
Residential	0.41	0.42	0.37	0.31	0.30	0.29
Commercial	0.49	0.50	0.44	0.37	0.35	0.34
Government	0.77	0.78	0.69	0.58	0.55	0.54
Scenario 3						
Residential	0.41	0.42	0.40	0.38	0.38	0.38
Commercial	0.49	0.50	0.47	0.45	0.45	0.46
Government	0.77	0.78	0.74	0.70	0.71	0.72

We recommend that YSPSC develop a medium-term smoothed tariff path once the financing package is confirmed.

[38] We assume tariff structure across customer segments is unchanged, and adjust current tariffs for each segment by a constant percentage to calculate the tariff requirements.

7.3 Implementation Plan

Here, we discuss the rollout of investments, and what additional capacity within YSPSC will be needed to implement and maintain these investments.

In the funding and financing plan, we have ensured YSPSC has all the resources it needs to successfully implement the investment plan. However, outsourcing is a possibility if it provides greater value for money. This is discussed in Appendix H.

7.3.1 Rollout of physical capital projects

We separate activities to be carried out over the 20-year period of the Master Plan into generation capital projects and distribution improvements. The rollout plan outlines the sequencing of these activities (Table 7.11).

We include new connections in the rollout plan. On top of this, asset-based replacement of distribution assets and general network upgrades will be ongoing as peak demand increases.

We include a schedule for replacing or retiring existing diesel generators in the rollout plan. Existing solar panels are replaced in the Master Plan period as they are already 5–10 years old. New solar panels are expected to last the entire Master Plan period, but batteries and inverters will need require replacing within the Master Plan period.

We assume all consumers in unserved islands are electrified by 2025. We have sequenced the rollout to start with the most accessible communities to test out the technology, billing, logistics, and management approach before rolling out to less-accessible islands.

Table 7.11: Rollout Plan for Yap

Year	2018	2019–2023	2024–2028	2029–2033	2034–2037
Main Grid	**Additional connections** ▪ 13 new residential connections a year ▪ 2 new commercial connections a year	**Generation capital projects** ▪ New 0.83MW diesel ▪ New 2MW solar ▪ New 0.5MW (3MWh) storage **Additional connections and lines** ▪ Underground cable from airport to hospital—5 miles ▪ 21.4 miles of overhead cable plus poles ▪ 13 new residential connections a year ▪ 2 new commercial connections a year	**Generation capital projects** ▪ New 2MW solar ▪ New 1.5MW (7MWh) storage **Additional connections** ▪ 13 new residential connections a year ▪ 2 new commercial connections a year	**Generation capital projects** ▪ New 1.65MW diesel ▪ Replacement of 1.65MW CAT ▪ Retirement of one 3.2MW Deutz ▪ New 2.5MW solar ▪ New 0.5MW (10MWh) storage **Additional connections** ▪ 13 new residential connections a year ▪ 2 new commercial connections a year	**Generation capital projects** ▪ Replacement of 1.65MW CAT ▪ Replacement of 0.83MW CAT ▪ New 1.8MW solar ▪ New 1.5MW (10MWh) storage **Additional connections** ▪ 13 new residential connections a year ▪ 2 new commercial connections a year
Mini-grid: Fadrai, Asor, Fais, Satowal		**Replacement and generation capital projects** ▪ Battery replacement on existing mini-grids. Assess state of other components ▪ 20kW diesel		**Replacement** ▪ Genset replacement ▪ Battery replacement ▪ Solar panel replacement	
Mini-grid: Falalop, Ulithi		**Generation capital projects**		**Replacement**	**Replacement**

Year	2018	2019–2023	2024–2028	2029–2033	2034–2037
		▪ 200kW diesel ▪ 86kW solar ▪ 140kWh storage ▪ 80kW converter		▪ Genset replacement ▪ Battery replacement	▪ Converter replacement
Mini-grid: Falalop, Woleai		**Generation capital projects** ▪ 100kW diesel ▪ 40kW solar ▪ 130kWh storage ▪ 30kW converter		**Replacement** ▪ Genset replacement ▪ Battery replacement	**Replacement** ▪ Converter replacement
Mini-grid: Mogmog		**Generation capital projects** ▪ 24kW diesel ▪ 10kW solar ▪ 30kWh storage ▪ 10kW converter			**Replacement** ▪ Genset replacement ▪ Battery replacement
Mini-grid: Ifalik			**Generation capital projects** ▪ 40kW diesel ▪ 20kW solar ▪ 30kWh storage ▪ 10kW converter	**Replacement** ▪ Genset replacement ▪ Battery replacement	**Replacement** ▪ Converter replacement
Mini-grid: Lamotrek			**Generation capital projects** ▪ 40kW diesel ▪ 20kW solar		**Replacement** ▪ Genset replacement ▪ Battery replacement

Year	2018	2019–2023	2024–2028	2029–2033	2034–2037
			▪ 30kWh storage ▪ 10kW converter		
Stand-alone solar systems		**Stand-alone solar systems installation** ▪ Install about 116 stand-alone solar systems on 4 islands	**Stand-alone solar systems installation** ▪ Install about 146 stand-alone solar systems on 5 islands	**Capital replacement** ▪ Replace all 116 initial stand-alone solar systems	**Capital replacement** ▪ Replace the next 146 stand-alone solar systems

7.3.2 Implementation capacity

To implement the Master Plans, YSPSC will need additional staff

We have considered whether each utility has the capacity to implement the activities required in the plan. Table 7.12 highlights the additional capacity that would be needed.

The requirements in Table 7.12 relate to ongoing operational, managerial, and maintenance functions and do not include building the new infrastructure (for which we assume contractors will be engaged). The table shows when these staff would need to be engaged or trained, but once engaged they would continue their work throughout the whole Master Plan period (and beyond), unless otherwise stated.

Table 7.12: Capacity Requirements for YSPSC

	1–5 Years	5–10 Years
Main grid	1 new engineer trained in RE and control systems 1 existing engineer trained in RE and control systems 2 new technicians trained in RE and control systems Electrification manager/outer islands manager 1 new billing support staff to assist with billing for outer islands	1 new engineer trained in RE and control systems 2 new technicians trained in batteries, RE and control systems, to support outer islands
Mini-grids	1 new electrical technician trained in RE for each existing mini-grid	4 new staff per new mini-grid, including 1 electrical technician trained in RE and batteries and ideally 1 mechanic
Stand-alone solar systems	1 casual employee on each island, to do basic maintenance and assist with billing	1 casual employee on each lagoon island, to do basic maintenance and assist with billing

YSPSC will take lead responsibility for implementing the Master Plan investments. Even if YSPSC chooses to outsource some project implementation tasks, it would still need to manage these contracts and oversee implementation.

The State Energy Workgroup (SEW) has an interest in providing strategic guidance and in monitoring progress and results to ensure that the desired state-level policy outcomes are met. SEW does not have the capacity to fulfil this role.

The Master Plan includes a budget for technical assistance to fulfil the various monitoring, coordinating and administrative functions (the National Energy Master Plan provides more details). We assume this will be covered by a grant and do not include it in the tariff calculation.

7.3.3 Implementation risks

Here we highlight the main risks specific to Yap. Appendix E highlights various risks associated with the types of technology and investments proposed in this Plan. Many of these are common to all states using the same technology.

New investments in remote areas need to reflect previous experience

Many remote communities in Yap already have electricity access via mini-grids or stand-alone solar systems. It will be important, both technically and socially, to ensure that new investments implemented through the Master Plan are consistent with the existing infrastructure.

For cost reasons, investments should, as far as possible, complement—rather than duplicate—existing infrastructure. In terms of institutional arrangements, YSPSC already has experience it can learn from in relation to the payment collection, maintenance, and management of equipment on outer islands. For example, YSPSC advised that it has faced significant challenges in collecting fees for SHS on remote islands. The investment plan will address this concern by providing Cashpower meters to all stand-alone solar (and mini-grid) customers.[39]

From a social perspective, there are both benefits and challenges from starting from a point of partial electrification. Many remote communities in Yap are accustomed to electricity and already understand the benefits—and so may be more likely to buy-in to the electrification program and have high 'readiness' for such a program. They are already used to paying for electricity and have existing structures in place to manage them (even if some refinements may need to be made to these structures).

Sites for solar PV capacity will need to be identified

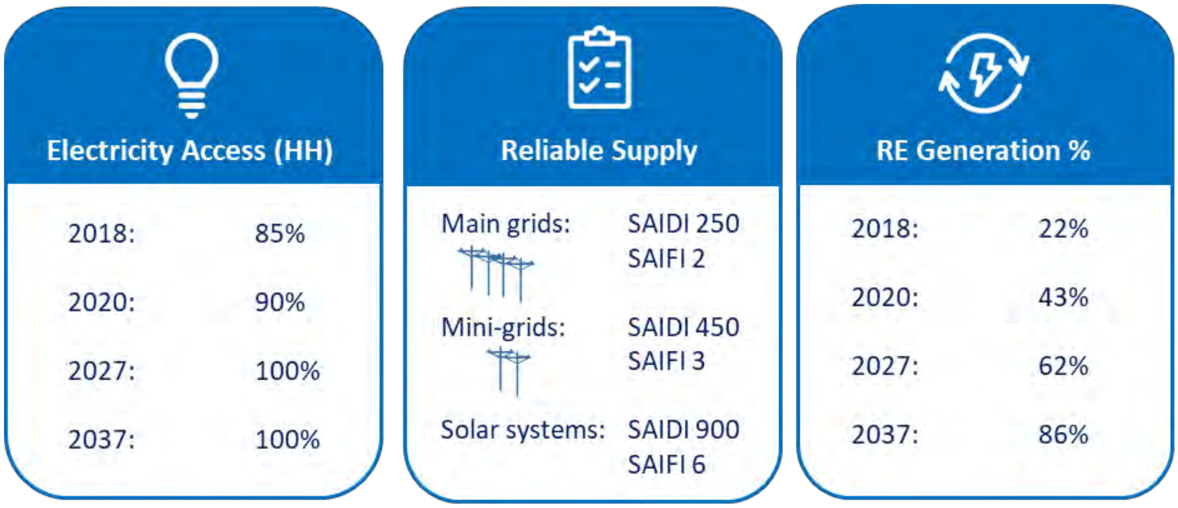
The Master Plan recommends 8.3MW of new solar PV capacity on Yap Proper. This would require an area of about 83,000m2 (about 893,000 square feet). Preliminary indications are that the roofs of government buildings may be able to accommodate only up to 1MW. A 1.2MW floating solar PV project is being considered for Global Climate Fund (GCF) funding. Private land could potentially be acquired for ground-mounted systems, and private roof sites could also be considered. The ongoing feasibility study on additional solar PV in Yap will provide further information.

7.4 Outcomes

If Yap implements the above plans it can expect to meet its main energy sector objectives. Figure 7.6 summarizes the outcomes the plans will help Yap achieve.

[39] For islands that do not have adequate telecommunications services, we recommend providing radios. They can be used to communicate Cashpower transactions, as well as to report faults on systems.

Figure 7.6: Summary of Outcomes of the Yap State Energy Master Plan



The main outcome of the Master Plan is that, by 2025, 100 percent of households, businesses, and public facilities in Yap will have access to a reliable, affordable electricity service. In addition, during the 20 years of the Master Plan the percentage of electricity generated from renewable sources will increase, and carbon dioxide (CO_2) emissions and diesel use will fall.

Yap State is aiming for 30 percent of electricity generation on Yap Proper to come from renewable sources by 2020, and 50 percent by 2030.[40] The plan sees Yap meet both these targets. Figure 7.7 shows the percentage of RE generation for the stand-alone solar systems, mini-grids, and main grid. It also shows the weighted average RE percentage for the whole state.

[40] Yap State Energy Action Plan, revised version of February 2017.

Figure 7.7: RE Percentage of Generation for Yap

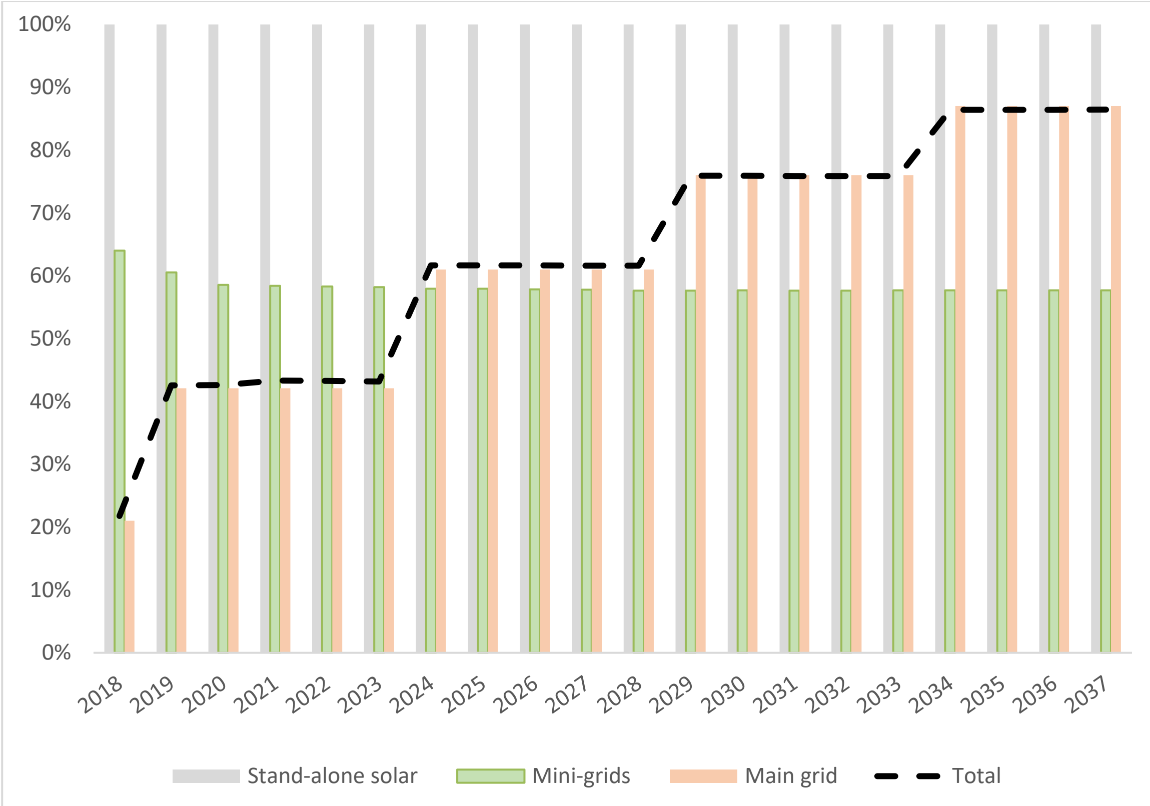


Table 7.13 shows the significant decline (78 percent) in CO_2 emissions and diesel use over the 20-year period. These numbers include the main grid and all mini-grids.

Table 7.13: Yap Emissions and Diesel Use

	2018	2019–2023	2024–2028	2029–2033	2034–2037
CO_2 emissions (tonnes/year)	7,376	5,496	4,091	2,792	1,616
Diesel used (gallons/year)	713,745	531,801	395,833	270,186	156,349

YSPSC also aims to supply 100 percent of the outer island population (14 islands with a total population of about 2,600) with 100 percent RE by 2020. The Master Plan supplies 100 percent of the outer island population with electricity. However, to meet the required service standards in the least-cost way, there would need to be a mixture of diesel and solar (even for mini-grids that are currently 100 percent solar). In Appendix B, we consider what the additional costs would be for the mini-grids to provide the same service standards without diesel.

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Energy Master Plans for the Federated States of Micronesia

Final Report (Appendices)

April
2018

Appendices

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Acronyms and Abbreviations

ADB	Asian Development Bank
ADF	Asian Development Fund
BESS	Battery Energy Storage Systems
CAIDI	Customer Average Interruption Duration Index
CNG	Compressed natural gas
COL	Concessional OCR loans
CPUC	Chuuk Public Utility Corporation
EE	Energy efficiency
EIA	Environmental Impact Assessment
EPA	Environmental Protection Agency
ESS	Energy storage systems
FSM	Federated States of Micronesia
GCF	Global Climate Fund
GHG	Greenhouse gas
IBRD	International Bank for Reconstruction and Development
IDA	International Development Association
IPP	Independent power producer
IRENA	International Renewable Energy Agency
JICA	Japanese International Cooperation Agency
KSORC	Korea South Pacific Ocean Research Center
KUA	Kosrae Utilities Authority
LDC	Load Duration Curve
LNG	Liquefied natural gas
LRMC	Long-run marginal cost
LV	Low-voltage
MD	Maximum Demand
MFAT	New Zealand Ministry of Foreign Affairs and Trade
MV	Medium-voltage

NEP	National Energy Policy
NEW	National Energy Workgroup
NGO	Non-government organisation
O&M	Operations and maintenance
ODA	Overseas Development Assistance
OCR	Ordinary Capital Resources
PPA	Power Purchase Agreement
PRIF	Pacific Region Infrastructure Facility
PSC	Public section comparator
PUC	Pohnpei Utilities Corporation
PV	Photovoltaics
R&D	Research & development
RE	Renewable energy
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCS	Solar community system
SEW	State Energy Workgroup
SHS	Solar home system
SPREP	Secretariat of the Pacific Regional Environment Programme
TOR	Terms of reference
US$	United States dollars
VfM	Value for money
YSPSC	Yap State Public Service Corporation

Appendix A: List of Stakeholders Consulted

This report is the result of our discussions with numerous utility, government, and other energy sector stakeholders across all four FSM states. Table A.1 lists the stakeholders we consulted directly and/or whom were invited to the formal consultation workshops.

We appreciate all the feedback and input provided, and apologize for any errors in or omissions from this list.

Table A.1: Stakeholders Consulted During Development of the State Energy Master Plans

Name	Designation	Organization
National		
Hubert Yamada	Assistant Secretary	Energy Division
Noel Comendador	Accountant	Energy Division
Ralph Karhammar	Energy Adviser	Energy Sector Development Program
Rob Solomon	Adviser to Secretary of Finance	Department of Finance
Jonathan Marmar		Dept. of Public Works and Transport
Arnold Canete		Dept. of Resources and Development (R&D)
Jienna	Director	FSM Chamber of Commerce
Sharon Pelep	Statistics Officer	FSM Statistics
James Lukan		R&D
Nick	Director	R&D
Chuuk		
Hon. Johnson Elimo	Governor	Chuuk State
Hon. Mark Mailo	President, Senate	Chuuk State
Hon. Singkoro Harper	Speaker, House of Representatives	Chuuk State
Mark Waite	CEO	CPUC
Paul Howell	Technical Manager	CPUC
Kelly Keller	CFO	CPUC
Eliseus Akapito		Member of State Energy Workgroup Chair of CPUC Board Director of Planning & Statistics for Chuuk State
Wilfred Robert	Chair	State Energy Workgroup
Larry Bruton	Owner	Bruton Enterprises (small business supplying solar home

Name	Designation	Organization
		and battery systems and components in Chuuk)
Sirene F. Killion		Chuuk Women's Council
Margary Wilsa		Chuuk Women's Council
Batsipa Saralin		Chuuk Women's Council
Shereen Killim		Chuuk Women's Council
Cindy Lippwe		Chuuk Women's Council
Tina M Berdin		Chuuk Women's Council
Carla Billy		Chuuk Women's Council
Peter Aten	Chief	Dept. of Commerce and Industry
Alvios William	Deputy Director	Dept. of Education
Julio Morar	Director	Dept. of Health Services
Kirisos Victus	Chief of Dispensary	Dept. of Health Services
Tos Nakayama	Director	Dept. of Transport and Public Works
Maria Tommy		Dou Fefen Association
Iromy K. Bruton	Director	Economic Commission
Various individuals		Udot community
Jaustence Francis		UFO Association
Darmy Atty		UNA
Marlin Karren		Volunteer
Kosrae		
Hon. Lyndon Jackson	Governor	Kosrae State
Fred Skilling	Director	KUA
Hairom Livae	Customer sales	KUA
Gerardo Protacio		KUA
Nena Tolanoa		KUA Board
Lipar George		State Energy Workgroup Chair Chair of KUA Board Representative of Kosrae Governor
Isao Mike	Board member	State Energy Workgroup
Bob	Board member	State Energy Workgroup
Livingston Taulung		DHS
Tulenssu Wagulu		DOE
Bob Skilling		DT&I / KPA

Name	Designation	Organization
Carsin Sigror		Governor's Office
Keitson Jones		KBA
Mary Livaie		Kosrae Women's Group
William Tosie		KPA
Maker Palsis		KSL
Julie Sigrah		KSL
Rolner Joe		KSL
Jeffry Tilfas		OAG
Jacob George		TMG
Pohnpei[1]		
Hon. Marcelo Peterson	Governor	Pohnpei State
Hon. Reed B. Oliver	Lieutenant Governor	Pohnpei State
	Attorney General	Pohnpei State
	Cabinet Members	Pohnpei State
	Speaker	Pohnpei State
	Vice Speaker	Pohnpei State
	Floor leader	Pohnpei State
	Members of Parliament	Pohnpei State
Nixon Anson	General Manager	PUC
Daisy Nanpei	Chief Financial Officer	PUC
Alex Nanpei		PUC
Sidney Kilmete		PUC
Robert		PUC
Nick Solomon	Chair	State Energy Workgroup
Representative		Dept. of Land
Mark Deorio	Assistant Secretary	Dept. of Transport, Communications and Infrastructure
Wilmer Kilmete	Project Manager	Dept. of Transport, Communications and Infrastructure
John Tiegmai	Safety and Inspection Manager	Dept. of Transport, Communications and Infrastructure
Alfred Aliven	Engineering Department	FSM Telecommunications Corporation
Caleb Gamule	Chief	Kapingamarangi

[1] Includes some people who were invited to the formal Master Plan consultations but whom were not able to attend.

Name	Designation	Organization
Itaia Fred	Chief	Nukuoro
Hirosi I. Boal	Chief	Pingelap
	Chief	Mokiloa
	Chiefs	Sapwafik (did not attend) Nukuro (did not attend) Kapiongamaringi (did not attend)
Governor's office staff		Pohnpei State
David Edwin	Chief	Sapwuahfik
Donna Scheuring		State Environmental Protection Agency
Alfred David		State Environmental Protection Agency
Representatives	Local government	Madolenihmw Kitti U Net Sokehs Kolonia
Representatives		Chamber of Commerce
Representatives		Women's Group
Representatives		Youths
Yap		
Hon. Tony Ganngiyan	Governor	Yap State
Victor Nabeyen	Deputy GM	Yap State Public Service Corporation
Virginia Hernandez	Accountant	Yap State Public Service Corporation
Faustino Yangmog	GM and Chairman	Yap State Public Service Corporation and State Energy Workgroup
Various representatives		Council of Chiefs
Juliana Garwan		Office of Administrative Services
Maria Laaw		Office of Planning and Budget
Christina Fillmed		State Environmental Protection Agency
Various representatives		Ulithi men's group
Various representatives		Ulithi women's group

Name	Designation	Organization
Other		
Leopold Sedogo	Senior Energy Specialist	World Bank
Mason Albert	Consultant	ADB
Jim Liston	Consultant	ADB
	Branch Manager	Bank of FSM
Asterio Takesy	VP Government Relation	Bank of Guam
Mary A Simmering	AVP, Branch Manager	Bank of Guam
Brendon Bateman	Consultant	Entura
Andy George	Consultant	Entura
Dean Haley	Consultant	Entura
Tim O'Meara	Consultant	Entura
Finley Perman	Consultant	Entura
Olivier Wortel	Consultant	Entura
Anna Mendiola	President and CEO	FSM Development Bank
Lara Studzinski	Director, Micronesian Regional Office	South Pacific Community (SPC)
Jared Morris	CEO	Vital Energy

Appendix B: Technical Plans – Inputs and Approach

The overall approach to developing the technical plans is to:

- Agree service standards (reliability targets and generation planning criteria) (Appendix B.1)
- Develop energy and peak demand forecasts for each sublocation (Appendix B.2)
- Assess feasible technologies and for each sublocation, and their costs (Appendix B.3)
- For main grids, prepare base-case with existing generation and loads
- For mini-grids, use geospatial data to assess appropriate type of distribution network for the location
- Model least-cost generation option in HOMER for the load using a range of feasible technologies at the location (Appendix B.4). Cost assumptions for each technology are built into the HOMER model, including estimated logistical costs for remote areas. For the main grids, modeling has been completed in 5-year blocks to show the investments required in each time period as loads change.

The least-cost scenarios that emerge from this analysis contain information on the technical composition of each scenario, and the capex and opex required.

As there are many unelectrified islands involved, we have not compared the cost of a mini-grid with that of stand-alone solar systems for each island. As agreed during consultations on the Inception Report, we initially use a threshold to allocate islands into the mini-grid or stand-alone solar system category. Based on stakeholders' feedback, we reduced this threshold (to 100 households). We also reviewed geospatial information on each mini-grid candidate to check whether a mini-grid is likely to be cost-effective given the distribution of households. Based on this, we calculated the costs of mini-grids for all relevant islands. For illustrative purposes we have, for some islands, compared the costs of both mini-grids and stand-alone systems.

B.1 Service Standards

The State Energy Master Plans set out how the states can meet two system standards: one for full grid-level service, and a remote service standard as an alternative for areas where full grid service is not appropriate or affordable.

In all cases, we assume that consumers would have continuous (24/7) access to electricity (at least, when the system is in service). On the main grids, we assume that customers will have effectively unlimited load access, whereas the outer islands will be limited to a lower consumption allowance per household. The allowances we have assumed are discussed in Appendix B, in the context of the load forecast.

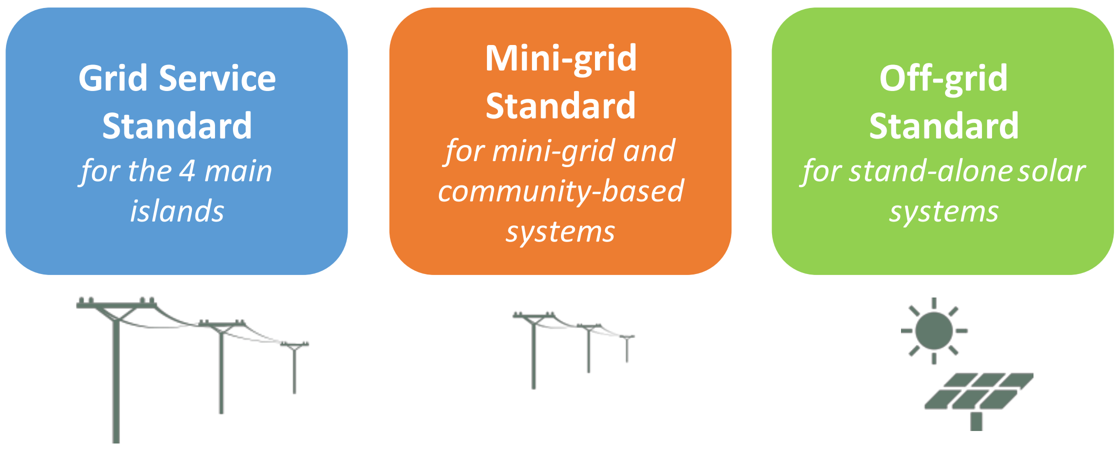
B.1.1 Reliability targets

We set reliability targets for three different areas of operation—reflecting the varying characteristics of the utilities' service territory.[2]

[2] Factors that contribute to the inherent reliability performance of electricity power generation systems and distribution networks (and which can vary across a utility's service territory) include: number of customers, customer density across the service territory, overall length of distribution lines, environment of the service territory, average age of network

Figure B.1 shows the three types of service standard:

Figure B.1: Service Standards



We use Total SAIDI, Total SAIFI, and Total CAIDI as the measures of system reliability in each area.

Reliable and sufficient location-based measures of SAIDI, SAIFI, and CAIDI do not currently exist in the FSM.[3] Therefore, the reliability indicators are the Total SAIDI, Total SAIFI, and Total CAIDI across areas of operation in each state.

Table B.1 provides the reliability targets that have been agreed with the utilities.

Table B.1: Total Reliability Targets

	SAIDI (minutes)	SAIFI (number)	CAIDI (minutes)
Grid Standard	250	2	125
Mini-grid Standard	450	3	150
Off-grid Standard	900	6	150

The indices are calculated for the whole system. For Grid Standard, this covers the whole grid distribution network. For the Mini-grid Standard and the Off-grid Standard, the indices will cover all systems of that type in a region or across the state.

The aggregate nature of the indices means that overall performance is monitored, and trouble spots may not be visible. Any trouble spots will need to be identified through other means.

The choice of standards was informed by the utilities' existing targets, an assessment of available and likely operational capability across each state, regional benchmarking, and the results of stakeholder consultations and previous social studies. Availability of actual SAIDI and SAIFI performance information for each utility in FSM is limited, but we have reviewed the available data and discussed with utilities their experiences with interruptions.

The service standards are intended to seek a reasonable balance between continuous service and cost for the majority of consumers. A small number of consumers—in

components, and availability of skilled utility personnel to manage and maintain the power facilities and the distribution network.

[3] Currently, the data collection on these measures is quite poor, but as part of the staged upgrades included in the plans, there will be a lot more automated data collection. However, the utilities will need to implement policies (and train staff) to record and use these data.

particular, hospitals—may want (and be willing to pay for) higher service standards. As it would not be cost-effective to apply these standards to entire islands or entire states, we assume that hospitals, and any other users that desire even greater reliability get their own backup generators. It is standard practice worldwide for hospitals and other critical facilities to have their own back-up power supply, regardless of grid reliability.

The indices are intended to monitor the utilities' performance in restoring normal faults and interruptions, rather than catastrophic failures or natural events.

Some areas with the Mini-grid Standard and Off-grid Standard are remote, and equipment needed to repair faults could take a long time to arrive. Some mitigation for this is provided in the proposed mini-grid plans, by providing two diesel generators in addition to the RE mini-grid infrastructure to reduce the risk of all generators being down at once. Despite this, longer outages may occur and are difficult to predict. Longer than typical interruptions of this nature could be excluded from calculations to not skew the results. Alternatively, including them in the targets would allow the utilities to assess whether long interruptions are typical or not, and determine whether they are caused by inadequate maintenance, or whether the target needs to be changed.

Index calculation relies on collection of information on the interruptions. The minimum details required are the length of the interruption, the number of customers affected, and the type of outage. Capacity building may be required to ensure that control room operators on the main grids learn which data to collect and how.

B.1.2 Generation planning criteria

For main grids, we assume that the generation planning standard is N+2, or the ability to operate at N-2 and still supply all customers. This standard allows for the loss of the two largest generators at the same time, and still supply the required load.

In addition to the N+2 generator planning standard, we have planned at least two sources of energy available for all loads, to cover both supply of load and supply of ancillary services (including spinning reserve for voltage and frequency stabilization).

In traditional times, this would likely mean two generators always running, even at times of minimum load. This would ensure that, if one generator failed, or a large load was turned on, the generators could pick up the load without loss of supply voltage or supply frequency. However, developments in new technology such as Battery Energy Storage Systems (BESS) have made it possible for the generator spinning reserve to be supplied by stored battery energy rather than traditional diesel generators, and our investment plans also factor in this option.

For mini-grids and stand-alone solar systems, the costs of providing N+2 may be prohibitive. Therefore, we have used less demanding generation planning criteria:

- For hybrid **mini-grids**, N+1 is provided by including two small diesel generators in addition to solar and battery systems. The inclusion of a second diesel generator is not capital intensive and greatly improves reliability in remote locations. This arrangement effectively provides N+2 most of the time, when any two of the battery and two generators are available. This arrangement effectively provides N+2 most of the time, when any two of the battery and two generators are available.
- For islands that will have **stand-alone solar systems**, it is cost-prohibitive to provide N+1 or N+2 redundancy. The aim for these islands is to provide a

system sized for 24-hr energy supply with N+0 redundancy. Reliability can be improved though technician training and a spare parts supply on each island.

B.2 Load Forecasts – Approach and Results

Here we discuss the methodology and assumptions underlying the load forecasts used in the State Energy Master Plans, as well as the consumption forecasts and assumed peak demand.

We break the consumption forecasts up into main islands and other islands as we have used a different methodology for each.

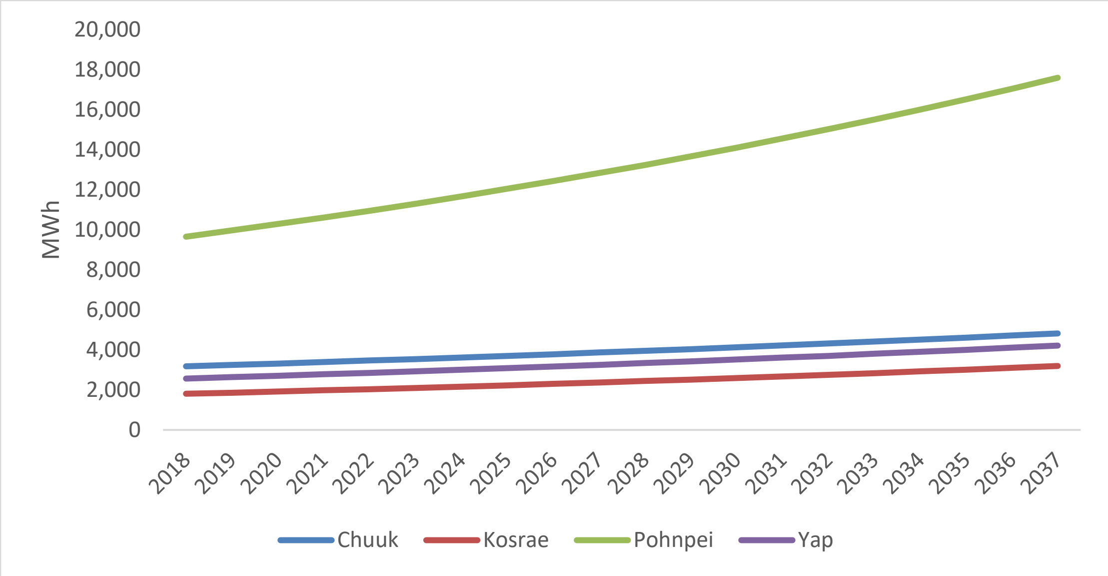
B.2.1 Electricity consumption - main grids

We present the consumption forecast and methodology by residential, government, and commercial customer groups.

Residential

The electricity consumption forecast for residential customers in presented in Figure B.2.

Figure B.2: Residential Consumption on Main Grids



We assume consumption will increase as the number of households and average income increase. To forecast changes to the number of households over the next 20 years, we took the geometric average growth rate between the 1994 Census and the 2000 Census. For Weno, the growth rate was 0.12 percent, for Kosrae it was 1.07 percent, for Pohnpei Proper it was 1.24 percent, and for Yap it was 1.66 percent. However, we revised this number down for Yap to an increase of 13 households per year based on our consultations.

We assume incomes will increase with GDP and that energy consumption will increase at the same rate as incomes. We forecast GDP to increase by 1.95 percent per year based on the geometric average over the last 20 years.

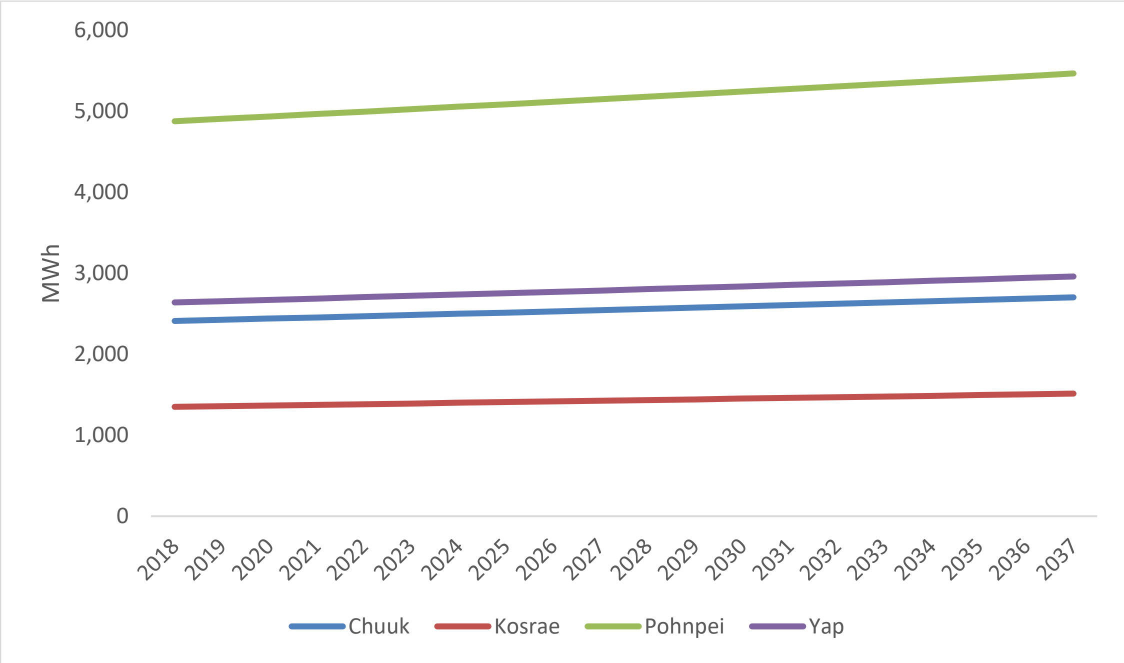
After discussions with the Government, we assumed that GDP will not be affected by the Compact Agreement ending in 2023. The current Compact Agreement funding covers three components: health, education, and infrastructure. The new trust fund would fully replace health and education funding. This leaves infrastructure. FSM receives US$25 million from the Compact Agreement for infrastructure, but has been spending less than half of this funding. By the end of the Compact Agreement, the FSM Government will have over US$100 million in the bank, to be spent over subsequent years. There is also likely to be an increase in funding from non-traditional donors. So, overall, we forecast infrastructure spending to continue at current levels.

We also factored unserved demand into our forecast. This was based on the number of people not connected and the number and duration of outages for people that are connected. For people that are not connected, we assume they will consume 650kWh/year when they are connected and that they will catch up to the state average over 20 years.

Government

We assume government consumption will increase with GDP but decrease with EE improvements. We assume that the FSM Government will be 30 percent more efficient with electricity consumption in the next 20 years. This is an average of 1.32 percent per year.

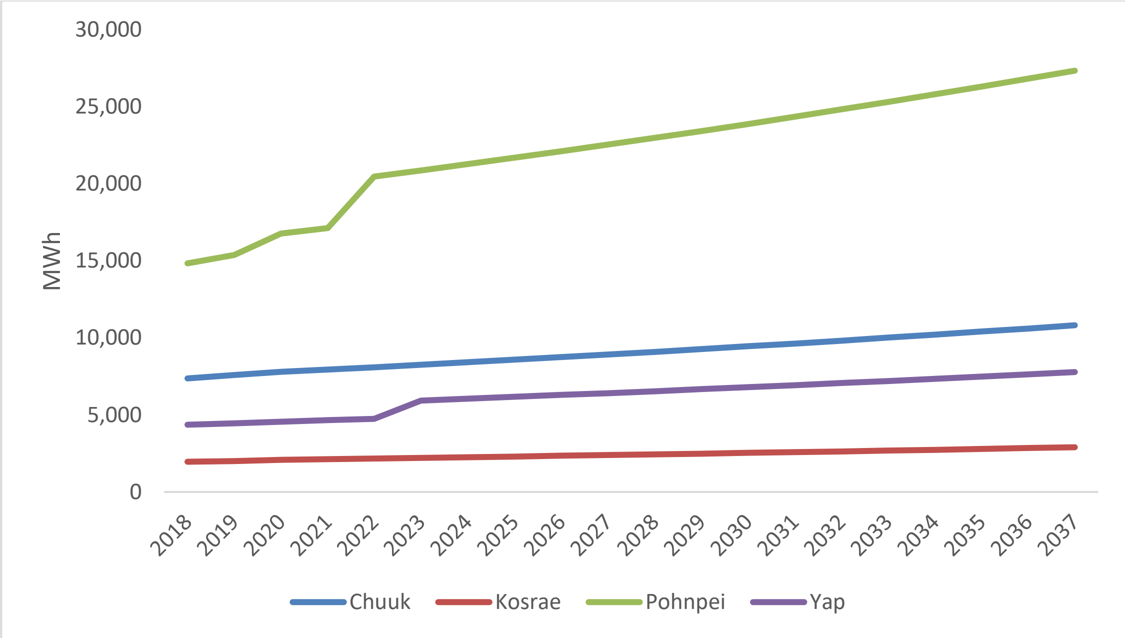
Figure B.3: Government Consumption on Main Grids



Commercial and industrial

We forecast commercial and industrial consumption to increase with GDP and with any new projects brought online.

Figure B.4: Commercial and Industrial Consumption on Main Grids



We factor in the load estimate for expected new projects that may become major energy users. The projects, load estimates, and expected start date are in Table B.2. The loads were estimated in consultation with stakeholders and based on project-specific information, and the loads of similar size and type facilities in other states and/or other Pacific Island countries.

There is considerable uncertainty around which projects will arise in the next 20 years, and their required load. For example, there is a possibility that the new hotel in Yap will have a much larger load than given in Table B.2. As the larger project is not committed, we assume a smaller load for the purposes of our analysis. This underscores the importance of states regularly reviewing and updating the State Energy Master Plans as circumstances change.

Table B.2: New Commercial and Government Projects by State

State	Project	Estimated Load (MWh/year)	Estimated Date
Chuuk	Blue Lagoon	569.4	2018
	KSORC Phase 1	87.6	2019
	KSORC Phase 2	43.8	2020
	Copra Processing Plant (Tonoas)	20	2020
Kosrae	Refurbishment of Water Bottling Plant	50	2020
Pohnpei	Sewer pumping station	150	2019
	Water Pumping and Treatment Facility	250	2019
	Hotel with Casino	1,100	2020
	Fish Processing Facility	30	2021
	Port Expansion	3,000	2022
Yap	Fish Processing Facility	30	2020
	New Hotel	1,100	2023

B.2.2 Electricity consumption – other islands

For the outer islands, we use data from Yap's outer islands as a guide for expected loads. We cross-referenced this with data from other countries in the region with remote islands including Tuvalu, Tonga, Marshall Islands, and Solomon Islands.

We assume that residential loads will dominate on outer islands. We analyzed data from Yap's mini-grids to ascertain "established" demand for outer island households. The data show significant variation across islands. There are also some outliers using significantly more energy than typical households.

Using the mean and median of the existing data, we selected the following figures for basic household energy consumption for the purposes of modeling:

- **Remote mini-grids**: 400kWh/household/year
- **Larger or more accessible mini-grids** such as Falalop, Ulithi and inner Chuuk lagoon: 650kWh/household/year
- **Fringe-of-grid/grid-connect** such as Walung, Kosrae or new connections on main grids: 980kWh/household/year
- **SHS**: 365kWh/household/year. This corresponds to approximately 1kWh/day, in-line with World Bank energy access Tier 3.[4]

  Demand forecasting for SHS is based on a bottom-up approach, using the World Bank Energy Access tiers as a guide. We also incorporated feedback from existing SHS and mini-grids in Yap—it appears that the 500W SHS previously provided may have been oversized for the needs of the recipients. SHS are sized

[4] World Bank: Energy Sector Management Assistance Program. June 2015. "Beyond Connections: Electricity Access Redefined, Executive Summary", www.worldbank.org/content/dam/Worldbank/Topics/Energy%20and%20Extract/Beyond_Connections_Energy_Access_Redefined_Exec_ESMAP_2015.pdf.

to provide 1kWh per day, or 365kWh per year. This is slightly lower than the 400kWh/year for outer island mini-grids and is consistent with the low to mid-range of households on the existing metered mini-grids in Yap. Following consultations, we have also sized a medium SHS and large SHS to cater for customers who wish to use more energy and can afford it (see Box B.1). We do not include the costs of these alternative sizes in the State Energy Master Plans.

For newly electrified islands, we model the load growth using an s-curve. Immediately after electrification the loads will be low, as many customers will not have many appliances and may not have sufficient infrastructure. Anecdotal evidence from other countries indicates that residents on unelectrified islands are often nervous about connecting to the grid initially but gain confidence after observing others in their community using the service.

Major infrastructure on unelectrified islands is designed to serve the "established" load—that is, the load that occurs after households have become accustomed to electrification.

In the first year, we assume only government loads (schools, dispensaries, and offices) are connected. Loads then increase quite sharply until Year 8 (2026) by which time the "established" load is reached.

Even though we assume that outer island loads will be predominantly residential, there will be some commercial development after electrification. This is most likely to be in the form of shops; services such as laundry, restaurants, or seamstresses; and trade services such as mechanics. We have also made an allowance in the load profile for street lighting on the mini-grids.

Box B.1: SHS Size Options

For the purposes of the financial modeling in the State Energy Master Plans, we assume that all residential solar home systems are 200W systems. These small systems do not have sufficient capacity to power some of the appliances that stakeholders stated as being important in our consultations (such as refrigerators). We have estimated the cost of a medium SHS and a large SHS that would cater for customers who wish to use more energy and can afford it. These larger systems also provide a higher peak power output that allows the customer to connect high-power appliances such as hot plates.

	Small System	Medium System	Large System
Size	0.2kW/1kWh	1kW / 2.1kWh	5kW / 8kWh
Peak Output	0.2kW	1kW	3.5kW
Cost (hardware)	$1,200	$3,500	$15,000
Appliances	LED lights (6) Phone chargers Small rice cooker Fan	LED lights (6) Phone chargers Rice cooker Fan Small fridge Microwave	LED lights (6) Phone chargers Rice cooker Fan Small fridge Microwave Washing machine Electric hotplate

Based on data from Yap's existing mini-grids, we estimate that up to 10 percent of households may choose a medium-sized system and a very small number—no more than one per island—may choose a large system.

To provide households with differentiated system sizes, the utilities would need to implement a system to match households with the optimal system size. To ensure equity between customers, consideration should be given to how the additional cost of the larger systems are funded. If the capital costs of SHS are financed and paid for through tariffs, then including the cost of the larger systems in the same pool of financing would imply a cross-subsidy from customers with smaller systems to larger systems. To avoid this cross-subsidy, the additional cost of the larger systems might be individually financed and built into the bills of customers with these systems.

We provide examples for Satowan (Chuuk), Walung (Kosrae), Kapingamarangi (Pohnpei), and Ifalik (Yap)

In these examples, only the school and dispensary are connected immediately after electrification. After a relatively slow start, loads grow rapidly over the first 8 years to 2026. This is caused by an increase in appliance acquisition in both the residential and commercial sectors. After this, load growth tapers off as we assume that a saturation point is reached—that is, most households already have the major appliances that they need in the long-term.

Figure B.5: Satowan (Chuuk) Consumption Forecast

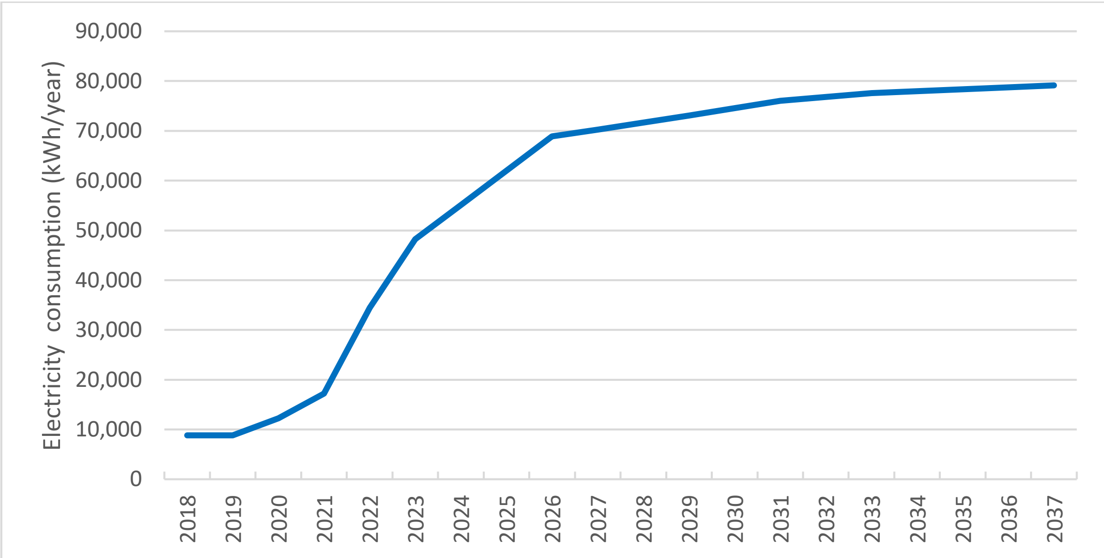


Figure B.6: Walung (Kosrae) Consumption Forecast

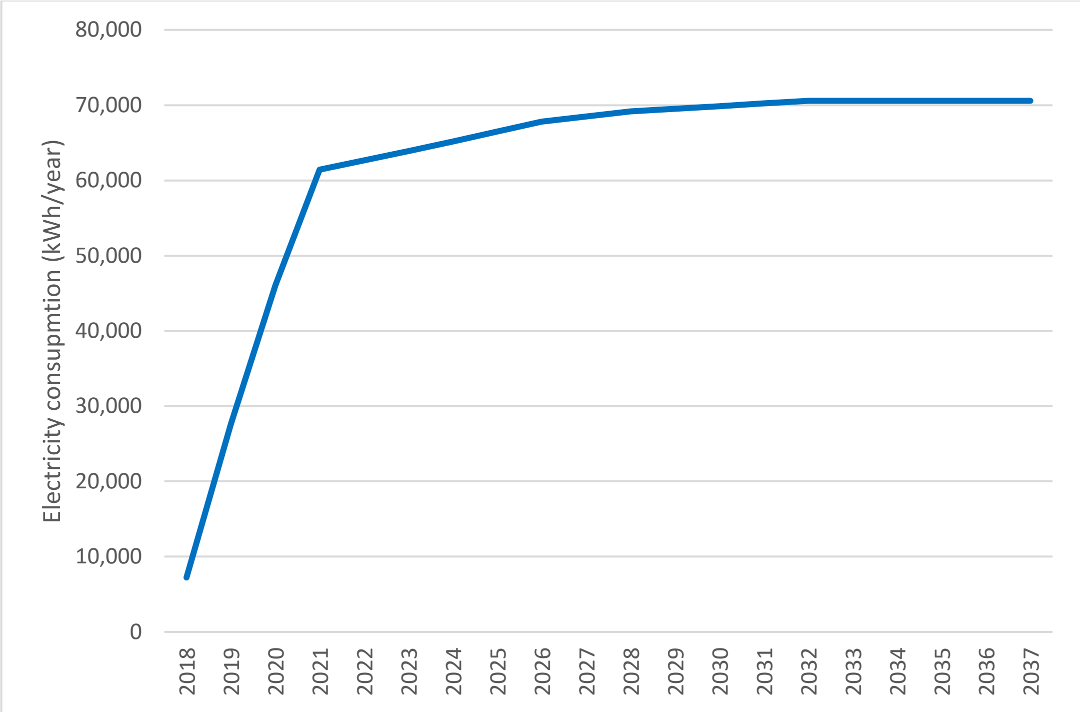


Figure B.7: Kapingamarangi (Pohnpei) Consumption Forecast

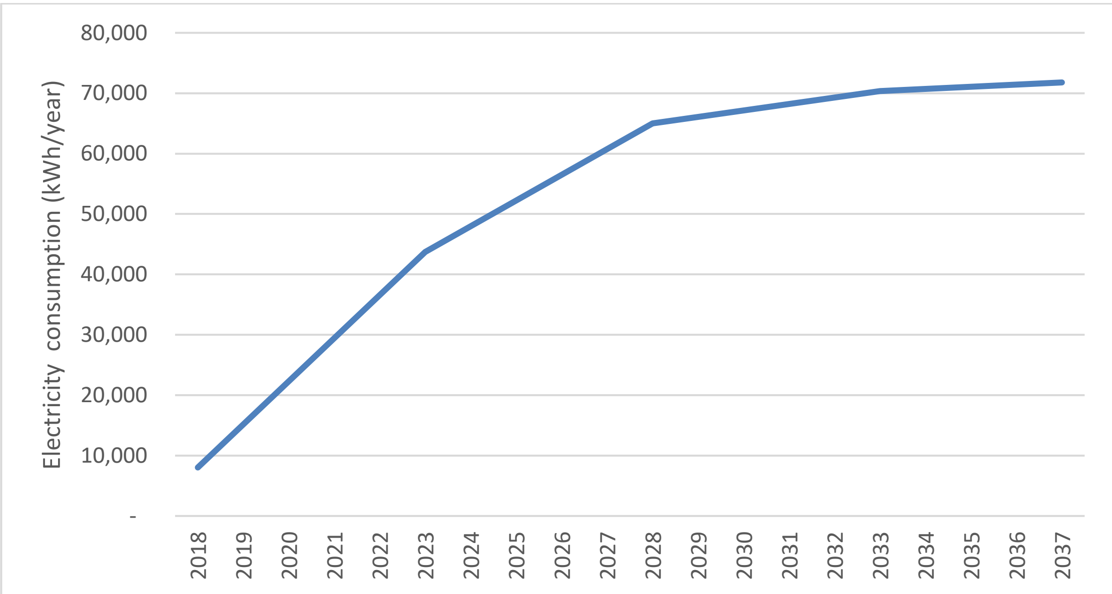
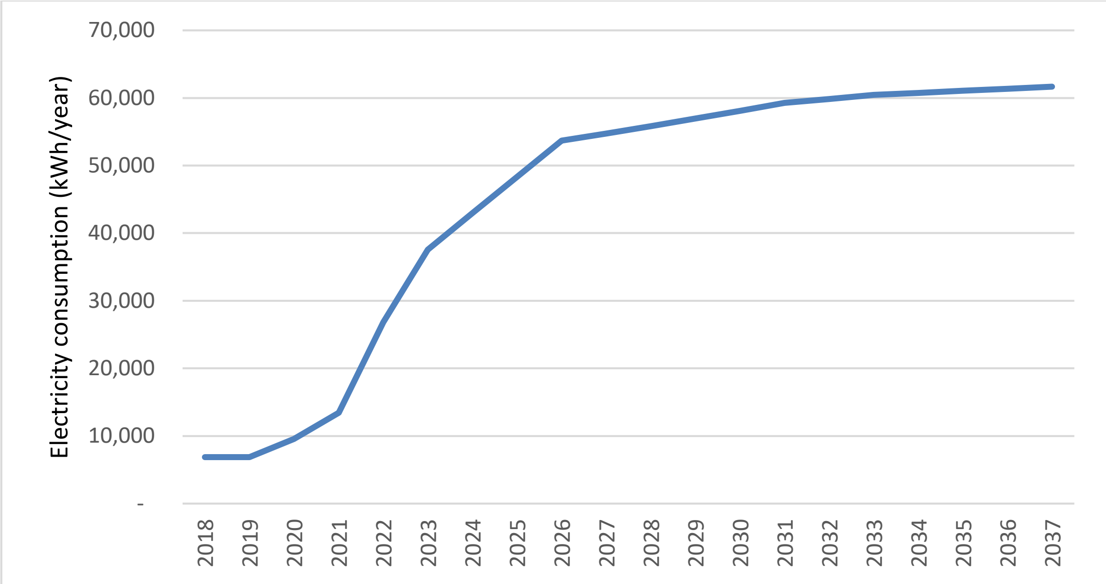


Figure B.8: Ifalik (Yap) Consumption Forecast



In the first year, we assume only government loads (schools, dispensaries, and offices) are connected. Loads then increase quite sharply until Year 8 (2026) by which time the "established" load is reached. Table B.3, Table B.4 and Table B.5 show the forecast consumption, in 5-year intervals, for the outer islands where mini-grids are the least-cost solution.

Table B.3: Chuuk Other Islands Electricity Consumption Forecast (kWh/year)

	2018	2023	2028	2033	2037
Faichuk	62,445	341,495	507,559	549,452	560,524
Udot mini	5,680	31,063	46,168	49,978	50,985
Romanum	11,402	62,353	92,674	100,323	102,344
Fanapanges	11,402	62,353	92,674	100,323	102,344
Lekinoch	8,816	48,213	71,658	77,572	79,135
Satowan	8,816	48,213	71,658	77,572	79,135
Houk	8,816	48,213	71,658	77,572	79,135
Nomwin	8,816	48,213	71,658	77,572	79,135
Tonoas	73,584	402,413	598,100	647,466	660,513
Uman	51,672	282,583	419,999	454,665	463,827
Etten	7,288	39,858	59,240	64,130	65,422
Parem	7,288	39,858	59,240	64,130	65,422
Fefen	73,584	402,413	598,100	647,466	660,513
Nama	7,178	39,253	58,340	63,156	64,428
Onoun	6,102	33,373	49,601	53,695	54,777

	2018	2023	2028	2033	2037
VITAL group	198,840	1,087,408	1,616,199	1,749,597	1,784,853

Notes: VITAL group includes Tonoas, Uman, and Parem

Table B.4: Pohnpei Other Islands Electricity Consumption Forecast (kWh/year)

	2018	2023	2028	2033	2037
Kapingamarangi	8,025	43,733	64,999	70,364	71,782
Sapuahfik	6,535	35,613	52,930	57,299	58,454
Pingelap	6,329	34,493	51,266	55,497	56,615

Table B.5: Yap Other Islands Electricity Consumption Forecast (kWh/year)

	2018	2023	2028	2033	2037
Ifalik	6,870	37,573	55,843	60,453	61,671
Lamotrek	4,874	26,653	39,613	42,883	43,747
Woleai	27,375	58,101	61,972	62,906	62,906
Falalop, Ulithi	118,625	251,772	268,544	272,593	272,593
Mogmog	10,950	23,240	24,789	25,162	25,162

B.2.3 Distribution and generation losses

To calculate the amount of energy required to be generated, we add to the energy consumption forecasts the estimated energy losses in the distribution system, and energy losses within the generation power stations.

Data on losses are limited and do not provide a true picture. It is not clear whether they reflect losses measured at the genset, the feeder, or elsewhere. Some reports have been developed for the FSM utilities that have tried to assess both technical losses such as inherent losses in overhead lines, underground cables, and transformers; and non-technical losses such as minor theft, utility and government installations that are not metered, and under-recovery of revenue.

Given the lack of data, we assume losses continue at current rates for Kosrae, Pohnpei, and Yap. For Chuuk, we assume they drop to 15 percent, based on discussions with CPUC:

- Chuuk: 15 percent
- Kosrae: 19 percent
- Pohnpei 19 percent
- Yap: 17 percent.

Losses within the generators are included in the generator models in HOMER, by generator type. The models also have derating over time built-in.

The State Energy Master Plans do not foresee radical steps that the FSM utilities can take to dramatically reduce generation and distribution losses in the life of the plan. Instead, we assume that incremental improvements will be made over time as more fuel-efficient generation assets are deployed, and lower loss distribution transformers replace older units.

B.2.4 Peak demand

We used two approaches to determine maximum demand (MD) for each state.

Approach 1

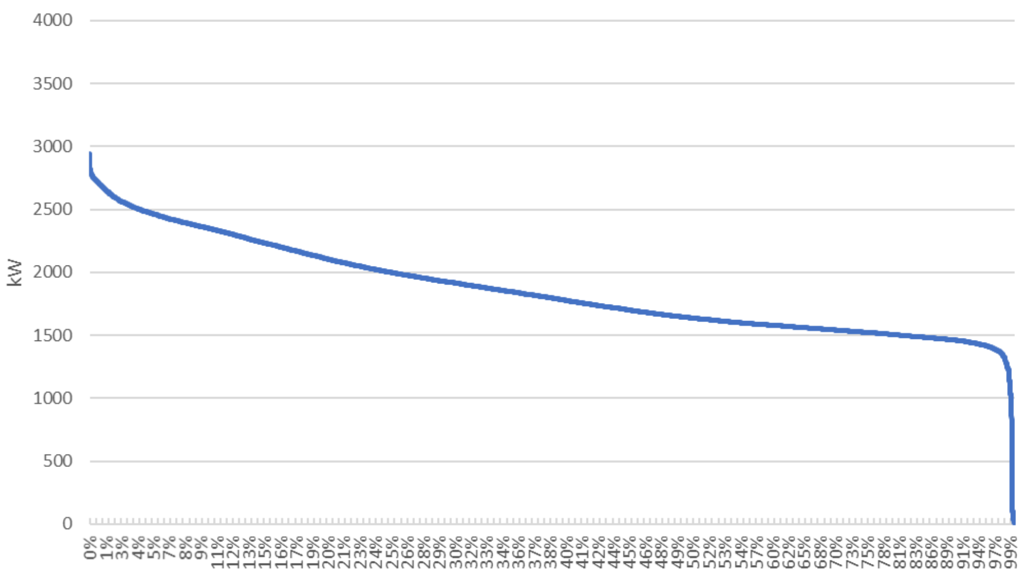
Each utility provided a data file consisting of 30-minute data listing the output of all generating units that were operating for each 30 minutes, including significant solar generators. All states had 12 months of such demand data, except for Pohnpei, which provided 4 months of data.

We analyzed the 30-minute data and prepared and a Load Duration Curve (LDC) for each dataset. We decided to select the 99th percentile demand as most typical of the genuine MD, which excludes very occasional peaks of short duration. The LDCs for each state are shown below.

Chuuk

We assessed Chuuk's actual MD in 2017 as 2862kW, at the 99th percentile of all data over the 12-month data analysis period (see Figure B.9).

Figure B.9: Chuuk Load Duration Curve, 12 months in 2016-2017

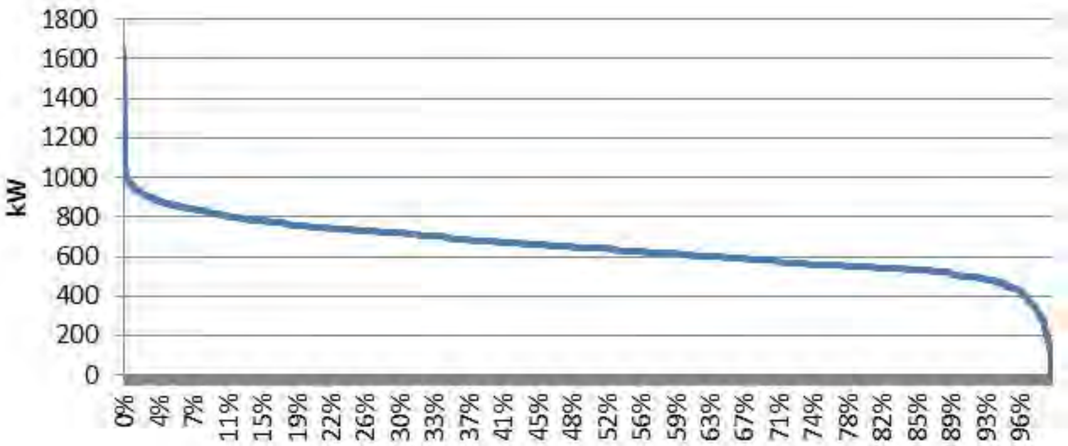


Source: Castalia/ITP based on data provided by CPUC

Kosrae

We assessed Kosrae's actual MD in 2017 as 960kW, at the 99th percentile of all data over the 12-month data analysis period (see Figure B.10).

Figure B.10: Kosrae Load Duration Curve, 12 months in 2017

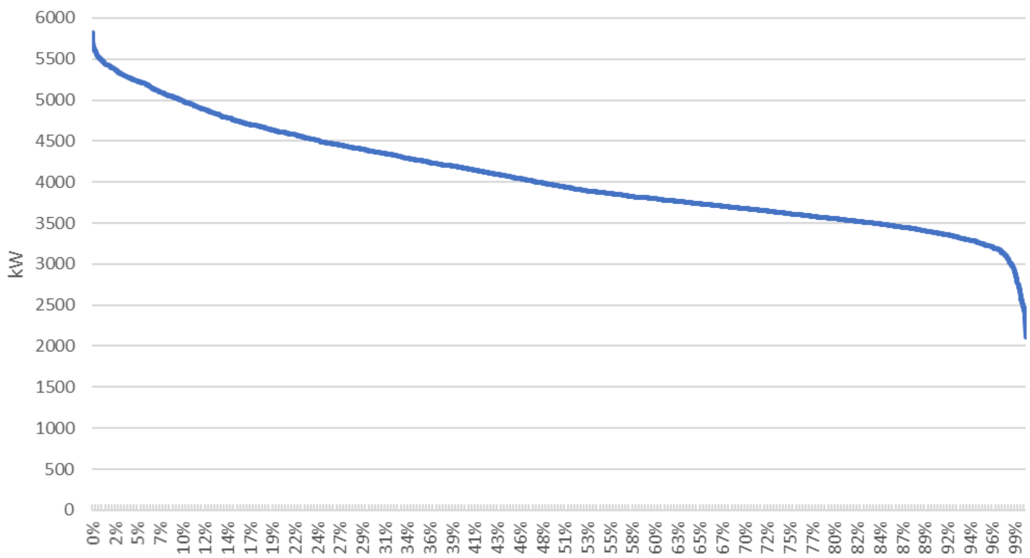


Source: Castalia/ITP based on data provided by KUA

Pohnpei

We assessed Pohnpei's actual MD in 2017 as 5,500kW, at the 99th percentile of all data over the 4-month data analysis period (see Figure B.11).

Figure B.11: Pohnpei Load Duration Curve, 4 months in 2017

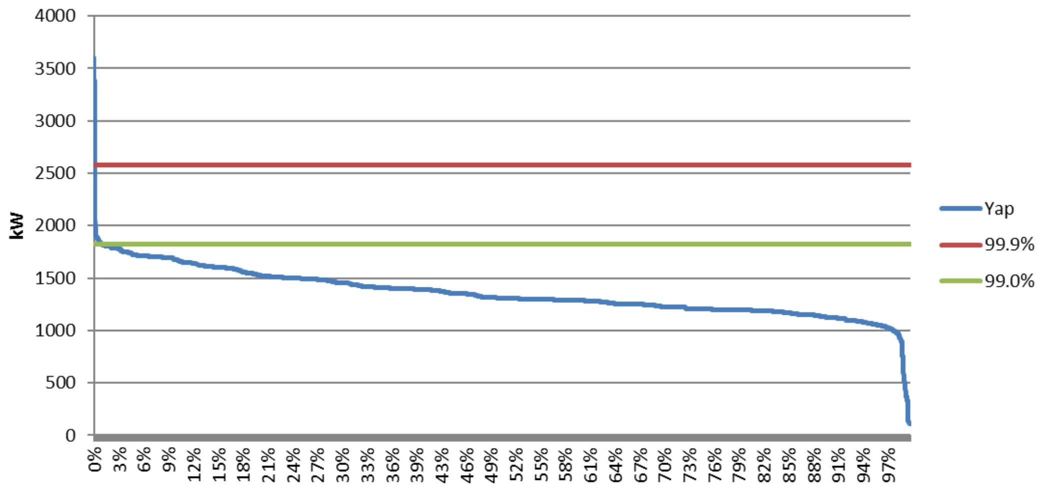


Source: Castalia/ITP based on data provided by PUC

Yap

We assessed Yap's actual MD in 2017 as 1,820kW, at the 99th percentile of all data over the 12-month data analysis period (see Figure B.12).

Figure B.12: Yap Load Duration Curve, 12 months in 2017



Source: Castalia/ITP based on data provided by YSPSC

Approach 2

We used the historical energy consumption for each state, for major customer segments (residential, commercial, and government) to develop forecasts of energy consumption, with escalators for household growth and GDP incorporated into the forecast.

We converted this energy consumption data into a kW MD forecast using some relatively straightforward algorithms for each customer segment. We used the same approach for all four states, but for illustrative purposes use the example of Chuuk.

Residential

We calculated the average annual energy per household by dividing the total residential energy consumption by the known data on the number of households (from the latest Census). This assumes that all households are uniform in nature, and does not segregate smaller from larger households, as no data are available to make the determination on the numbers of household types.

For Chuuk, this equates to 1,421kWh per household per year.

We converted the average annual energy consumption per household into an average MD per household. We assumed that an average household uses most of its energy for 6 days per week and for 50 weeks per year. We also assumed that most energy is used during 6 hours per day when residential activities are at their highest—likely during the morning and evening.

For Chuuk, this equates to a typical residential household MD of 0.68kW. Other states were similar.

We then multiplied the average MD per household by the number of households, and divided it by 3 to spread the demand across 3 phases. We assumed that all residential households are single-phase, and the total MD for a power system is usually represented as a 3-phase MD. We did not use any additional factors to provide greater diversity of demand across the typical 24-hour period per day, as no data are available to make any additional energy consumption diversity determinations.

For Chuuk, we calculated a total residential household MD of 477kW in 2018.

Commercial

The total annual energy consumption for the commercial segment was provided by each state. For Chuuk, this equates to 8,695,412 kWh per year.

We converted the annual energy consumption into an average MD, by assuming that the commercial business activity is generally undertaken for 6 days per week and for 52 weeks per year. We also assumed that most energy is used during 8 hours per day, when commercial activities are at their busiest.

We then divided commercial MD by 2.4 to spread the demand across 3-phases. We assume that 80 percent of commercial businesses are single-phase, 20 percent are 3-phase, and that the total MD for a power system is usually represented as a 3-phase MD. We did not use any additional factors to provide greater diversity of demand across the typical 24-hour period per day, as no data are available to make any additional energy consumption diversity determinations.

For Chuuk, this equates to a typical commercial MD of 1,421kW in 2018.

Government

The total annual energy consumption for the government segment was provided by each state. For Chuuk, this is 2,856,389 kWh per year.

We converted the annual government energy consumption into an average MD, by assuming that the government business activity is generally undertaken for 6 days per week and for 52 weeks per year. We also assume that most energy is used during 12 hours per day when government office activities are at their busiest.

We assume that the average government MD is 100 percent 3-phase loads, and that the total MD for a power system is usually represented as a 3-phase MD. We did not use any additional factors to provide greater diversity of demand across the typical 24-hour period per day, as no data are available to make any additional energy consumption diversity determinations.

For Chuuk this gives a typical government MD of 747kW in 2018.

The total system MD is then the sum of residential, commercial, and government MD figures, and for Chuuk this is 2,644kW in 2018.

This calculated figure correlates closely to the 99th percentile MD determined using Methodology 1 of 2,862kW for Chuuk in 2017 (within 6 percent, which is statistically a small variation).

B.3 Generation Options: Energy Resources, Technologies, and Costs

This section explores the energy resources and technologies that we considered as options for improving or complementing existing electricity infrastructure and to extend electricity access to unserved areas. We considered:

- Which energy resources are available in the FSM, where, and what their characteristics are
- Which technical options are available to complement or enhance the existing infrastructure, how much they cost, and which options are likely to be the most appropriate in different circumstances and locations.

When developing the least-cost electrification plans we also considered what electricity infrastructure already exists (including outside the main islands), and how that can best be used as part of an enhanced system.

B.3.1 Available energy resources

Fossil fuels (liquid petroleum fuels) will continue to play a key role in electricity generation for the foreseeable future. Nevertheless, there is technical potential to increase the use of RE (and hence reduce the use of fossil fuels), in-line with the National Energy Policy's (NEP's) objective.

Renewables are likely to be a more cost-effective and practical option than diesel in many remote communities. Table B.6 highlights the costs and characteristics of different RE sources.

The main indigenous resources available for electricity generation in FSM are solar (all states) and hydropower (Pohnpei and, to a lesser extent, Kosrae).

Table B.6: Costs and Characteristics of RE Options (US$)

	Solar	Wind	Hydropower run-of-river	Hydropower dam	Micro Hydro	Wave	Tidal	Biomass
Capital cost ($/W installed)	$2.30-$4.00	$3.76	$2.00-$3.50	Site-specific	$4.00-$7.00	$13.00	$3-$10	$3.00-$4.00
Generation cost ($/kWh)	$0.12-$0.30	$0.38-$0.44	$0.15-$0.30	$0.05-$0.30	$0.15-$0.30	Unknown	$0.20-$0.80	$0.40
Capacity factor	16%	25%	40%-80%	80%	40%-80%	20%	30%	70%
Dispatchability	No	No	No	Yes	No	No	No	Yes
Maturity	High	High	High	High	High	Low	Low-medium	High
Operating complexity	Low	High	Medium	Low	Low	High	High	High
Operating costs	Low	Medium	Low	Low	Low	High	Medium	High

Here we summarize the available RE resources in each state.

Solar

FSM receives average insolation of about 5.5kWh per m^2 per day on horizontal surfaces (a "good to very good solar resource", according to the International Renewable Energy Agency, IRENA[5]). This is considered sufficient for cost-effective PV and solar water-heating use.

Available energy varies regionally because of weather patterns and cloud levels. Local cloud formations associated with the mountains on the main islands of Pohnpei and Kosrae and the Lagoon Islands of Chuuk can be particularly influential on radiation levels.[6]

Land availability is a more important factor than solar radiation in solar PV site-selection in the Pacific Region. The solar resource across the Pacific Region is generally good even in non-ideal locations.

Table B.10 shows average insolation in the four states.

Hydropower

Feasible large-scale hydropower options are only available on Pohnpei.

All states have potential for numerous low-tech, fixed output, privately-owned and operated hydropower of less than 10kW that could be connected into the network via grid feed inverter (or other suitable control system). As generation at this scale is not generally something the utility would be involved in, these schemes may require suitable feed-in tariff and/or incentives to drive development. They have not been considered in the least-cost planning.

Pohnpei

Pohnpei is currently the only island that uses hydropower, in the form of the Nanpil hydropower plant. The Nanpil hydropower plant was installed in 1986 but fell into disrepair. However, it received a full refurbishment in 2014 and now operates on an ad-hoc basis, feeding into the Pohnpei grid when water is available. It is worth noting that the Nanpil headworks were not designed for hydropower; this has contributed to some of the operating issues this plant has experienced. We considered the possibility of upgrading the Nanpil hydropower scheme to provide a storage buffer and improve the capacity factor, but found that this would deliver energy at a higher cost than the Lehnmesi system.

The Lehnmesi river has an estimated 2.7MW of hydropower potential that could be developed with storage providing increased availability. This option provides the most cost-effective source of RE on Pohnpei.

The Nankawad river and the Seniphen river are not considered suitable for hydropower developments due to the local geography and the costs of construction relative to the size of the systems.

We do not consider Nankawad hydropower in our modeling because our review of the feasibility study and our site visit found that:

- The projected output was highly optimistic for the proposed scheme. The proposed machine would have a very narrow operating window—as such, it

[5] IRENA. 2013. "Pacific Lighthouses: Renewable energy opportunities and challenges in the Pacific Islands region – Federated States of Micronesia".

[6] Federated States of Micronesia Energy Policy 2012 Volume I. Department of Resources and Development. Division of Energy

would operate similarly to the Nanpil hydropower scheme with very poor capacity factor, high spill, and long periods of insufficient flow to operate

- There is not a good prospect of integrating storage cost effectively
- The required penstock is long compared with the available head and therefore relatively high capital cost.

Wind

NASA's meteorology database indicates that satellite average wind speed estimates are in the range of 4.6m/s to 5.7m/s at 50m above ground level. This is a low to moderate wind resource. Site-specific wind resources may provide suitable, cost-effective energy generation.

Yap

The 825kW Kabul Hill wind farm is being constructed. We included this in the modeling for Yap. Our modeling also considered the potential expansion of the wind farm to 5 turbines (1,375kW), but this was not the least-cost option for meeting the growth in demand. The overall costs of the wind farm were significantly higher than for solar PV.

We reviewed additional wind data provided by YSPSC, and although it suggests higher speeds than the satellite data, the speeds are still not high enough to change these modeling results.

Chuuk

Wind monitoring has been undertaken at Tonoas and Weno (Penia). The average wind speeds recorded are 5.3m/s (Tonoas) and 5.0m/s (Penia). Specific wind farm sites have not been identified as these wind speeds are considered too low for a sustainable wind farm. Wind data from the mast on Onoun Island was not available for inclusion in this report.

Liquid biofuels

The production and use of coconut oil for transport or electricity generation is unlikely due to the higher value of coconut products as an export commodity.

Small-scale use in outer islands may be possible where sufficient resource is available and access to export markets is cost-prohibitive.

Following consultations with stakeholders, our modeling does not include liquid biofuels as an option for electricity generation in any of the four states.

Biomass

The use of biomass from line clearance has been assessed as a sustainable method of dispatchable electricity generation for Pohnpei.[7]

Biogas

Small-scale use of biogas for cooking is currently very limited. Biogas production from waste water treatment plants or upgraded landfills has not been assessed.[8] FSM lacks the agricultural or food processing waste streams for electricity from biogas.

[7] Softbank Corp. 2014. Biomass Power in Pohnpei.

[8] IRENA Report. Pacific Lighthouses. Renewable energy opportunities and challenges in the Pacific Islands region. Federated States of Micronesia, 2013

Ocean energy

Ocean energy resources in FSM have not been measured in detail and the technology to convert the energy to electricity is not commercially available.

A 1.5MW wave energy project had been planned for Kosrae[9]. Ocean Energy Kosrae, the company delivering the project, closed operations in May 2017 due to a lack of guaranteed funding from the Kosrae Government.[10] Although Kosrae has an interest in ocean energy, we have not been able to include this as an option in our modeling. This is because we have insufficient information on the quality of the resource, the costs involved, or the technical feasibility (as the technology is largely unproven).

Wave energy technologies are not commercially available at present and are not likely to be available for at least 5 years. The technology is still in commercialization, with the most advanced technology, Carnegie's CETO, 5-10-years from commercial availability. The CETO technology, and others, require anchoring to the seabed, which limits the depth of water they can be deployed in.

Geothermal

There is no known geothermal resource in the FSM.

Energy storage

Energy storage will be an important element of the main grid to manage integration of variable renewable generation, store excess generation for later use, and provide a dispatchable energy source. Energy storage is a vital element of RE based mini-grids and stand-alone solar systems.

Hydropower offers the opportunity to integrate some storage into the scheme, and as such can provide dispatchable power and/or balancing generation from other renewable sources on main grids.

BESS can be used on grids of any size, and will likely be an important part of the FSM's future energy supply, both on main grids and on remote islands.

Our proposed investment plans include significant investments in storage capacity.

B.3.2 Technology options and costs

Our analysis suggests that the most appropriate option for electrifying FSM is a mix of small (on international scale) grids on the largest islands, mini-and micro-grids, and stand-alone solar systems for homes and public facilities. Table B.7 highlights the costs of these different supply options.

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[9] IRENA Report. Pacific Lighthouses. Renewable energy opportunities and challenges in the Pacific Islands region. Federated States of Micronesia

[10] http://oceanenergykosrae.com/en/

Table B.7: Costs of Supply Options (US$)

	SHS	Diesel Mini-grid	Hybrid Mini-grid	Micro-hydro
Capital cost ($/W installed)	$4.00	$3.00-$5.00	$7.00- $10.00	$6.00-$8.00
Generation cost ($/kWh)	$0.50	$0.75-$1.20	$0.50-$1.10	Site-specific
Maturity	High	High	High	High
Operating complexity	Low	Medium	Medium	Medium
Operating costs	Low	High	Low	Low

Source: Castalia/ITP analysis

Main grids

The main grids will continue to provide electricity for most of the population in FSM. To continue providing this service, the existing systems need maintenance and upgrade. The systems will adapt to a new portfolio of generation sources, and the choices of equipment and configuration need to enable the adaptation.

Diesel will continue to play a critical role over the long-term

Diesel generators will continue to provide core electricity production and grid-forming roles well beyond the 20-year State Energy Master Plans. This generation capacity will need to be able to adapt and support the introduction of RE sources. It is therefore imperative that the diesel generation capacity is capable of flexible, low-load operation and rapid response to fluctuations in supply and load. Specifications for new diesel generation should include these capabilities.

As RE capacity increases, energy storage systems (ESS) will become an integral part of the main grid systems

RE generation will be critical to reducing GHG emissions and meeting state and national objectives for RE use. Use of RE resources will differ between islands, leading to different integration challenges.

ESS will support the diesel generation by assisting with voltage and frequency control, controlling variable RE ramp rates, and providing energy to the grid to allow diesel units to come on-line. ESS will increase the utilization of RE by storing excess energy for use at other times. ESS will be most important on the main grids (and in other situations) where the most economic or only RE resource available is solar, because solar is restricted to daytime generation. RE generation will need to be treated as part of the generation portfolio, rather than as a negative load, to allow for active management and to ease integration issues. The RE will need to be visible to and controllable by the central grid controller. This will require robust and redundant communications systems. The central grid controller will need to be able to prioritize the dispatch of generation based on availability, quality, reliability, and marginal cost.

The main grids have the largest range of supply-side options available

Table B.8 indicates the options on the main island of each state. Distributed technologies are generally smaller scale and/or connected on the customer side of the meter. Central systems are generally larger-scale and connected to the distribution network. Both options may be privately-owned or utility-owned.

Table B.8: Supply-side Generation and Storage Options on the Main Grids

Technology	Chuuk	Kosrae	Pohnpei	Yap
Diesel	Yes	Yes	Yes	Yes
Solar – central	Yes	Yes	Yes	Yes
Solar – distributed	Yes	Yes	Yes	Yes
Hydropower – Storage	No	No	Yes	No
Hydropower – run-of river	No	No	Yes	No
Hydropower – mini, micro	No	Possible	Yes	No
Wind – central	No	No	No	Yes
Wind – distributed	Possible	Possible	Possible	Possible
Liquid biofuels	Possible	No	No	No
Biomass	Possible	Possible	Possible	Possible
Biogas	Possible	Possible	Possible	Possible
Ocean energy	Possible	Possible	Possible	Possible
Geothermal	No	No	No	No
Fossil Fuels	Yes	Yes	Yes	Yes
ESS – central	Yes	Yes	Yes	Yes
ESS – distributed	Yes	Yes	Yes	Yes

Mini-grids, off-grid options, and stand-alone solar systems

We considered various technical options to electrify communities outside the main islands. These options include mini-grids (hybrid, solar, or diesel), stand-alone solar systems for schools or homes, and the extension of the grid to some of Chuuk's lagoon islands.

For the most remote islands (without regular shipping access) small-scale solar systems are usually the most suitable option both technically and economically.

For larger population groups with better access, centralized mini-grids can be considered. Hybrid systems using diesel, solar PV, and battery storage currently provide lowest cost energy for remote mini-grids in the Pacific Region and elsewhere, with the optimal RE contribution being 40 percent to 90 percent depending on diesel delivery cost and ease of access. Mini-grids are also easier to manage than stand-alone solar systems—because they can use cash power pre-paid meters on the main grid, avoiding having to collect monthly fees for solar systems. CashPower may also be possible for SHS, but likely to be more difficult.

There is also a proposal to connect Weno to islands in the Chuuk lagoon (Faichuk). However, our preliminary assessment suggests this is unlikely to be a cost-effective way to provide electricity to these islands (Section B.7) and we have not included this option in the State Energy Master Plan.

Pico hydro battery charging units could theoretically form part of the supply mix for off-grid units on Pohnpei, Kosrae, and possibly Chuuk and Yap, where a suitable stream exists nearby. While it is generally unwise to rely solely on hydropower (depending on the available resource), hydropower does offer the benefit of reduced battery requirements (compared with solar). The hydropower would be augmented with solar PV or diesel generation for times of low stream flow. Several affordable off-the-shelf pico hydropower solutions are available. We do not include such systems in the State Energy Master Plans as we do not have sufficient information on hydropower resources on specific islands. In addition, we assume that—for implementation purposes—standardizing the use of SHS will be easier. This could, however, be considered for specific islands following site assessments.

Minimizing the risk of weather damage

The risks of damage to electricity infrastructure from typhoons and the tropical climate—and the costs of mitigating these—need to be considered. Where possible and cost-effective, infrastructure should be designed and sited to minimize the risk of damage from local weather patterns. These risks informed decisions on which technical solutions and investments the State Energy Master Plans should include.

The western states—Chuuk, Pohnpei, and Yap—are at risk of typhoons and storms. For example, Typhoon Sudal in Yap in April 2004 damaged or destroyed about 90 percent of structures, including power lines. Typhoon Maysak, which hit Chuuk and Yap in March 2015, caused more than US$8 million worth of damage to public infrastructure.[11] It brought down more than 70 percent of CPUC's distribution network. YSPSC's infrastructure, including small solar systems on outer islands, was also damaged.

This risk may affect the type of electricity infrastructure (for example, wind turbines, over-ground (versus underground) cables, solar panels), materials used, design configurations, and locations of facilities.

The storm season can make delivery to remote islands difficult and unreliable. This affects both regular deliveries such as diesel fuel and construction project logistics. Salty air reduces the durability of electrical system equipment, including air conditioners. Similarly, hot temperatures can affect the performance and lifetime of electrical equipment. Insuring solar systems and mini-grids in outer islands is difficult and the premium is high.

Recognizing these risks, the State Energy Master Plans provide for underground cables for all mini-grids. Our modeling factored in the restrictions on wind turbines during cyclones. Our cost estimates for solar PV factor in the structural requirements of meeting standards for cyclonic wind zones.

Underground versus overhead distribution

Underground distribution cables offer superior reliability, lower general maintenance and resilience to natural disasters, particularly typhoons. We considered the costs and benefits of providing underground cabling for new distribution networks, particularly in the outer islands, given that both Chuuk and Yap suffered major damage to their distribution networks in recent typhoons.

Underground networks are typically more capital-intensive than overhead networks. We compared the costs of building networks in remote island locations (Table B.9), and found that:

- For LV (110/220/480V) networks, there is minimal cost difference between overhead and underground construction. This is due to the low cost of local labor (digging shallow trenches is not expensive), cost of equipment for installing poles and poletop components on remote islands, and relatively

[11] USAID. 15 April 2015. "Micronesia – Typhoon Maysak: Fact Sheet #2 Fiscal Year (FY) 2015", https://scms.usaid.gov/sites/default/files/documents/1866/typhoon_maysak_fs02_04-15-2015.pdf.

straightforward technical requirements for underground networks at this voltage.[12]

- For MV (13.8kV) networks, the cost difference between overhead and underground construction is greater due to more complex technical requirements and economies of scale.

Most of the outer islands in FSM are small enough to be served by LV networks. Only one mini-grid (for the Tonoas group in Chuuk) is large enough to require a 13.8kV network. This island group is more accessible and has larger loads than most other islands.

We assume that all outer island LV networks will use underground cabling as the benefits outweigh the small capital cost difference.

For the Tonoas Group, we recommend that a 13.8kV overhead network be built as this is the lowest-cost option. However, there might be opportunities to install underground networks in a cost-effective way if projects are combined; for example, road-building projects can be combined with underground cable installation.

Compared to overhead MV networks, underground MV networks are more expensive, more challenging to trouble-shoot in the event of a fault, and more costly to repair. Also, the time taken to repair the underground MV networks is usually longer.

The cost assumptions in Table B.9 are based on values from recent projects in Kiritimati, Kiribati, and the Solomon Islands. Islands are classified as 'easy' or 'hard' based on topography and accessibility (for example, mountainous terrain, lack of roads, and heavy vegetation leads to a "hard" classification. This applies to most of the Chuuk lagoon islands).

Table B.9: Cost Assumptions for Cables

Type of cable	Cost per mile (US$)
LV underground	45,000
MV overhead – easy	90,000
MV overhead – hard	100,000
MV underground - easy[13]	135,000
MV underground – hard	180,000

We assume an average of 15 street lights per mini-grid, at an approximate cost of US$1,000 per mini-grid (including installation). For communities with stand-alone solar systems, we assume they will buy individual solar lights for street lighting, if desired.

B.4 HOMER Modeling

ITP used HOMER Energy's modeling software, HOMER Pro v3.9, originally developed by the United States National Renewable Energy Laboratory. It has over 100,000 users world-wide and is considered an industry standard assessment tool.

[12] We assume standard voltages across all islands so that standard equipment from the main islands can be used in other islands. Using 'special' voltages and systems in the remote islands risks long outages when a fault occurs.

[13] This is significantly more expensive than LV underground as the technical standards/requirements are much higher—resulting in higher labor costs as technical specialists are required.

The HOMER software can optimize across multiple component sizes for each part of the system. It is also capable of sensitivity analysis by varying component parameters. Variation of system component parameters has not been undertaken in this study.

To limit the number of scenarios considered to a reasonable number, the component sizing range was determined by modeling a selection of component sizes. This was then refined using a small range of component sizes. The optimization, based on the cost of energy, produces various scenarios with similar cost of energy and RE contribution. ITP selected the scenario with the lowest cost of energy for each of the scenarios considered.

B.4.1 Limitations of HOMER

As with any modeling tool, the quality of the results depends on the accuracy of the inputs and the algorithms used to determine the results. HOMER is a useful and powerful tool, but the analysis it performs is limited in several ways:

- The same load profile is used for each year
- The same solar resource profile is used for each year
- HOMER modeling does not account for system stability requirements
- HOMER does not necessarily dispatch diesel generators in a realistic way, when compared with how power stations operate.

These limitations on the analysis mean that the results predicted by HOMER would be unlikely to be achieved in any given year; rather, they represent an average outcome.

HOMER is limited to cycle-charging and load-following generator dispatch strategies. A mixed dispatch may improve the utilization of the back-up generators. This limitation means that the results are likely to be conservative and that any reduction in the cost of energy through use of a mixed strategy would be an improvement of the results.

The output from HOMER should be regarded as an indication of the likely optimum configuration, based on the information provided. The cost of energy, and the selection of optimal configurations based on the cost, can rapidly change with changes of the cost of components. We have not investigated the sensitivity of the optimization of the configuration to changes in these costs, or to changes in the load profile or the solar resource.

B.4.2 HOMER modeling inputs – main islands

This section details the inputs we used for HOMER modeling of the main islands.

Resources

We downloaded solar resource data from the NASA database using a representative location on the main island in each state. We have also derated solar output for additional local rain and shading, based on recorded data from existing PV systems and local terrain.

Table B.10: HOMER Insolation by State, kWh/m^2/day

State	Chuuk	Kosrae	Pohnpei	Yap
Average	5.47	5.39	5.40	5.63

Source: NASA from HOMER

We also obtained wind data for Yap from the the NASA database. The average wind speed for Yap was 5.7 m/s at 50 m above ground level.

Section B.3.1 provides more details, based on our assessment of energy resources.

Load profiles

We obtained the load profiles used for HOMER from hourly or sub-hourly records provided by the utilities. We prepared a representative year from the records. We scaled the base load profile by the energy consumption forecast for the modeled year in each of the time periods considered. HOMER uses the daily consumption as the input, so we converted the annual consumption to a daily value.

Table B.11: Daily Electricity Consumption by State and Year, kWh/day

	2018	2023	2028	2033	2037
Chuuk	35,647.59	39,289.29	42,921.23	46,933.48	50,446.80
Kosrae	14,086.44	15,693.66	17,358.80	19,240.45	20,922.15
Pohnpei	80,777.84	102,256.23	113,800.48	126,854.92	138,529.56
Yap	26,336.31	31,872.26	34,881.46	38,210.96	41,128.68

Diesel price

Diesel prices escalation was based on the projections described in Section B.4.3.

Table B.12: Diesel Price by State and Year, US$/Gallon

Utility	2018	2023	2028	2033	2037
CPUC	$3.33	$3.86	$4.09	$4.32	$4.47
KUA	$3.41	$3.94	$4.16	$4.43	$4.58
PUC	$2.99	$3.52	$3.75	$4.01	$4.16
YSPSC	$3.37	$3.90	$4.16	$4.39	$4.54

Source: Castalia based on EIA

Diesel generators

The diesel generators we used in the modeling were based on generator models provided with HOMER. These are provided by manufacturers and cover basic size and performance data including fuel consumption curves. Where a specific make and model was not available in HOMER, we selected an appropriate CAT generator model and adjusted it to suit the specific diesel engine size. Typically, a larger capacity generator was down-sized to the required capacity.

We used the generator fuel efficiency curves of the HOMER base model. The costs were based on the general costs in Table B.13.

Based on our experience, we assumed an average cost of US$1million/MW for high-speed diesel engines. However, costs may vary for individual projects. Medium-speed engines, such as those recently installed in Chuuk, and specified for Pohnpei, have a higher per unit capex, but lower lifecycle running costs.

Table B.13: Diesel Generator Costs

	Chuuk		Kosrae				Pohnpei		Chuuk, Pohnpei, Yap	Pohnpei		Yap[14]	
Generator	GE 1.8	CAT 3512	CAT 3606	CAT 3512	CAT 398	CAT 3512	Vital IPP Volvo	CAT 3512	CAT 3516	CAT C-18	CAT-C175-16	CAT 32	Deutz 3.2MW
Capacity, kW	1,800	1,360	1,100	800	450	600	355	600	1,650	545	2,500	830	3,200
Capex, US$	2.34m	1.36m	1.1m	800,000	450,000	600,000	355,000	600,000	1.65m	545,000	3.25m	830,000	4.16m
Fixed Opex, US$/year	20,430	31,688	25,6300	18,640	10,4850	13,980	NA	13,980	38,445	12,698.5	28,375	19,339	36,320
Variable Opex US$/hour	21.6	22.71	18.37	13.36	7.52	10.02	0.35	10.02	27.55	9.10	30	13.86	38.4

[14] We assume that the costs for the two new 1.6MW 3516 CAT generators in Yap are similar to those of similar generators in other states.

HOMER has an input for the variable opex, but not the fixed opex. Fixed opex was modeled as a calendar-based scheduled maintenance item.

We modeled high-speed diesel engines with a 30,000-hour lifetime. Due to the varying number of run-hours that accrue for each generator per year based on the number of generators in each power station, and the policy of cycling through each genset to share run-hours and maintenance requirements, these generators can last many years past the typical replacement time of 7-10 years.

We modeled medium-speed generators, such as the new generators recently installed in Chuuk, those being installed in Kosrae, and those planned for Pohnpei, with a 90,000 hour lifetime. The typical expected life for modern medium-speed engines is around 30 years. We assume that medium-speed generators are given a major mid-life overhaul that enables them to achieve this 90,000 hour life. In the later years of the modeling scenarios, generator run hours drop due to increased RE use, so the generator lifetime is extended.

Following consultations, we have revised the generator planning model and the types of generators used. Where possible, and where requested by the utilities, we have retained existing generators to achieve N+2 redundancy rather than adding new ones. This makes better use of existing investments in the diesel power plants and ensures that sufficient redundancy is always available.

Scheduled maintenance was included in the model for the diesel generators. This covered oil changes, a 5,000-hour tune up including valve sets and a 15,000-hour top overhaul. It is assumed that these service items will be carried out on-site by the utility staff with assistance from vendor technicians.

As a mature technology diesel gensets have a stable purchase cost. We assumed the replacement cost is the same as the initial capital cost.

Table B.14: Diesel Generator Typical Scheduled Maintenance Costs for High-Speed and Medium-Speed Engines

	High-Speed			Medium-Speed		
	Interval Hours	Downtime hours	Typical cost	Interval Hours	Downtime hours	Typical cost
Oil Change	250	8	US$2,000	N/A		
Tune up – valve set	5,000	48	US$16,000	10,000	72	US$24,000
Top End Overhaul	15,000	120	US$110,000	30,000	300	US$165,000
In-frame Mid-life Overhaul	N/A			45,000	600	US$500,000-US$600,000

Solar PV

Solar PV performance was modeled on a generic solar system including the inverter.

System lifetime was assumed to be 20 years for new installations, the life of existing system was set to 20 years minus their age with a minimum of 11 years to avoid being replaced twice in the project life. PV systems with a 20-year life were not replaced in the modeling period.

Assumed to be fixed arrays, south-facing with the slope of the array set to the latitude. Ground reflectance was modeled at 20 percent.

Output at the end of the model is 85 percent of the initial performance.

Thermal derating is set to -0.5 percent/DegC with the nominal operating cell temperature of 47DegC and efficiency at standard test conditions of 15.3 percent.

We assume the initial capital cost and replacement cost of solar PV is US$2,300/kW. This applies to relatively large (1MW or bigger) systems in the FSM. We assume an operational cost of US$10/kW/year.

We do not assume any cost reduction over time, as PV prices are unlikely to drop substantially from now.

We did not assume a cost reduction with scale.

Energy Storage

We modelled energy storage performance on a 10kW block of Li-ion batteries using an idealized battery model with round trip efficiency of 92 percent. Cycle life is based on 3,000 cycles to 80 percent depth of discharge. We assume a lifetime of 10 years with a total throughput of 30,000kWh.

Maximum charge current is 5A/Ah with maximum charge current of 100A and maximum discharge current of 100A.

Capital cost per unit is US$750/kWh and replacement cost is 75 percent of the capital cost. A cost reduction exponent of 0.93 is applied with increasing scale.

The cost of Li-ion batteries is projected to drop substantially over the next 20 years. We have incorporated this into the models over the State Energy Master Plan period, with battery costs dropping from US$750/kWh in 2017 to US$213/kWh in 2028, and flatlining from there on.

We use an operating cost of US$10/kW/year.

The HOMER modeling enabled us to determine the storage capacity needed as part of the least-cost mix of generation and storage to meet the required service standards.

Battery Inverter

The battery inverter is a generic model. It has a 95 percent efficiency for charge and discharge. Lifetime for the inverter is 10 years.

Capital cost per unit is US$1,000/kW and replacement cost is 75 percent of the capital cost. We apply a cost reduction exponent of 0.93 with increasing scale.

We use an operation cost of US$5/kW/year. This includes general electrical checks and minor parts replacement (typically fans, small fuses, or comms boards).

We assume the battery inverter provides micro-grid controller and integration functions.

Hydropower

River flow monitoring has been carried out in the past by the United States Geological Survey (USGS) for various sites on Pohnpei (and FSM generally). However, this monitoring has been discontinued for some years. We downloaded stream flow data from the USGS database for the sites of interest. The available data was daily mean discharge in cubic feet per second; before use we converted the data to liters/second by multiplying by 28.3.

Unfortunately, hourly data were not available. Pohnpei is characterized by very high rainfall, high runoff, and small catchments; as such the stream flow is highly variable within the day (that is, streams rise quickly immediately following rain, and subside soon after the rain has stopped). We assume that most rain events largely occur within a window of several hours. As such, daily mean data is not suitable for predicting output of run-of-river hydropower plants in these conditions *unless* the turbine has a very wide operating range, or significant water storage is implemented into the scheme. This has proved to be the case with the existing Nanpil hydropower plant, which experiences long periods with insufficient flow to operate, short periods of operation, and significant spill while operating.

Gross head was taken from topographical map and pipe friction losses assumed as 10 percent for Net Head calculation.

HOMER's hydropower module cannot import a daily data file, and if monthly hydro resource data is entered HOMER assumes the same value for each hour of the month. This results in an extremely optimistic generation prediction for FSM conditions. Therefore, for each scenario we modelled, we created a synthesized hourly data file in Microsoft Excel. As the different schemes have different characteristics, we modelled actual power output in Microsoft Excel for each scheme, and then converted the hourly kW data to streamflow (liters per second) at a nominal head of 100m (32.8ft), efficiency 100 percent, and zero pipe friction losses.

HOMER can only model one hydro turbine, so for multiple hydro scenarios the synthesized streamflow data was aggregated into one file.

Nanpil existing scenario

Daily mean USGS streamflow data for the Nanpil river was available from 1970 to 1990, with the gauging station located just upstream of the existing weir.

Actual hourly generation data for the months of September 2016, December 2016, March 2017, and June 2017 was available. In lieu of actual streamflow data for the period, we used this synthesize a year of hourly generation data. The full year was populated by copying March for February and April, June for May and July, and so on. The dataset correlates with the last 10 years of generation data (which average 577,000kWh per year including two very low years of around 200,000kWh) vis-à-vis 706,000kWh for the synthesized data set. We then converted the kW hourly data to streamflow (liters per second) for input into HOMER.

Lehnmesi

It is suggested that the previously proposed three Lehnmesi schemes be combined into one scheme, with the intake located at the site of the upper Lehnmesi intake (Lehnmesi 2), and turbine discharge close to sea level. This approach provides several benefits over the previous proposed designs. As the intake site appears suitable for significant storage and there are significant energy capture and operational benefits associated with storage, we assumed that this scheme incorporated a dam 20m high. Due to the assumed storage, which has the effect of averaging out streamflows, the available daily mean data is suitable for modeling the hydro generation.

USGS streamflow data was available for the period 1981 through 1990 near the site of the previously proposed Lehnmesi 1 intake. 1985 was selected as the most average year, including the drought year 1982/1983 (which was excluded from the previous 1994 study by Knight Piesold). As the proposed scheme has the intake upstream of the previous gauging station, there is a loss of catchment of approximately 12 percent, so we adjusted the data to reflect this loss of catchment.

The 1985 daily data was moderated so that the 1985 monthly means are equal to the monthly mean of all data. To create an hourly data set, we assumed the mean daily flow applied to all hours of the day. The flow is actually much peakier than this, but including significant storage makes this assumption relevant. An assumed environmental release of 100 liters per second was subtracted from the streamflow data to arrive at the flow available for the hydro scheme.

The approximate storage volume of 230,500m^3 was calculated based on the USGS topographical map with the dam crest at 150m above sea level. This storage equates to about 52MWh at zero inflow.

We modeled generation in Microsoft Excel based on a maximum drawdown of 90 percent, 142m gross head, maximum flow of 3m^3 per second (2.7MW installed capacity) and Turgo Impulse or similar turbines with a flat efficiency curve and wide operating range. In the model, turbine discharge was reduced to 50 percent of full load when the storage dropped to 50 percent.

We then converted the kW hourly data to streamflow (liters per second) for input into HOMER.

Nanpil Enhancement 1

This enhancement to the existing scheme involves a proposed 10m (32.8ft) high buffer storage located several hundred meters upstream of the existing weir where the gorge begins to narrow. It is assumed that storage is released to the existing weir as required.

Future enhancement (not modeled) would include:

- Extending the penstock to make use of the additional head; it is likely a machine upgrade would be required due to the additional head
- Increasing the generation capacity by the addition of an additional turbine or upgrade to the existing machine.

As a significant storage is incorporated in this scenario, we assumed that the USGS daily mean data would be suitable for predicting turbine output.

Using the USGS streamflow data, we selected 1985 to coincide with the Lehnmesi dataset. We moderated the 1985 daily data so that the 1985 monthly means equalled the monthly mean of all data. To create an hourly data set, we assumed the mean daily flow for all hours of the day. We subtracted an assumed combined water supply and environmental release of 254 liters per second[15] from the streamflow data to arrive at the flow available for the hydro scheme.

The approximate storage volume of 78,500m^3 was calculated based on the USGS topographical map with the dam crest at 130m above sea level. This storage equates to approximately 9MWh at zero inflow, and generation increases from the current average of 79kW (0.69GWh per year) to 337kW (3GWh per year).

We modeled generation in Excel based on a maximum drawdown of 90 percent, 68m gross head, maximum flow of 1.26m^3 per second (based on the existing machine nameplate) and minimum flow of 50 percent (that is, the current machine). In the model, turbine discharge was reduced to 50 percent when the storage dropped to 50 percent.

[15] 6 cubic feet per second plus 3 cubic feet per second, from US Army. 1993. "Nanpil Expansion Feasibility Report".

We then converted the kW hourly data to streamflow (liters per second) for input into HOMER.

Nanpil Enhancement 2

Nanpil Enhancement 2 assumes that storage is not implemented, but that a second smaller Turgo Impulse or similar machine is installed to operate either in parallel with the existing machine to increase peak output, or to operate at times when there was insufficient flow for the existing machine. Improved power station control/automation is assumed.

As this scenario incorporates no storage, we needed to model real-world stream flow variability. To do this we used the same 1985 dataset that we used for Nanpil Enhancement 1 and modified it by introducing a random variable which was adjusted to achieve a similar peak flow as recorded in the 1985 data year.

With the randomized flow, the model resulted in existing generation of 144kW on average. This is similar to 2015, but more than twice the average. It is not possible to correlate flow conditions between the 2 years, and it is likely that the current manual operation spills some energy that could be captured by automated control. We scaled down generation to 70 percent to better reflect actual average year generation. With the addition of a second turbine, average generation increased by 68kW, or about double the existing scenario.

We then converted the kW hourly data to streamflow (liters per second) for input into HOMER.

Wind turbines

For Yap the wind farm was modeled using the native Vergnet 275-C model in HOMER. This model includes the performance specifications such as the power curve. A 5 percent efficiency loss factor was applied to the performance to represent soiling, network availability and other losses.

The turbines capital cost and replacement cost were assumed to be the same at US$2,980,000 for the wind farm. Opex of US$89,400 per year.

Controller

The controller used for modeling used HOMER's load following algorithm. Generators are not used to charge energy storage. Energy storage charging is only carried out by renewable resources.

No capital cost was assumed for the controller to represent the current control system. Additional integration costs are assumed to be incorporated into the battery inverter costs. The opex cost of US$50,000/year covers the cost of the system operators. The controller was assumed to not be replaced during the analysis period.

The model run by HOMER is constrained to maintain operating reserve based on the set points in Table B.15.

Table B.15: HOMER Modeling Constraints

Maximum annual capacity shortage	0
Minimum renewable fraction	0
Operating reserve as percentage of hourly load	10
Operating reserve as percentage of peak load	0
Operating reserve as percentage of solar power output	25
Operating reserve as percentage of wind power output	50

Mini-grids

Two diesel generators are included in each mini-grid to provide N+1.5 redundancy.

For new mini-grids, the costs of building the new underground distribution network are factored into the total cost of the mini-grid. Our cost assumptions are shown in Table B.9.

We factor in the cost of shipping equipment to the island. We estimate that this costs between US$20,000 and US$100,000 depending on remoteness.

We calculate non-fuel opex based on data from Yap mini-grids. Non-fuel opex includes network maintenance, staff costs, vehicle costs, spare parts, travel, and administration, including billing. This ranges from approximately US$25,000 for smaller diesel mini-grids to US$100,000 for larger grids such as Falalop, Ulithi. The non-fuel opex costs have a fairly large impact on the total cost of energy, especially for very small grids.

We assume existing 100 percent RE mini-grids have lower opex of US$10,000/year. We would like to check this with YSPSC as it is based on its RE mini-grids.

We recommend that islands that do not have adequate telecommunications when the mini-grids and stand-alone solar systems are built receive a radio base station and system at a cost of about US$10,000 per island. Radios can be used both to communicate CashPower transactions and to report faults on systems.

The economic life for equipment, which was used in HOMER for mini-grid modeling, is presented in Table B.16.

Table B.16: Economic Life of Equipment Used in HOMER Modeling for Mini-Grids

	Lifetime (years)
PV	20
Batteries	15
Network	40
Generators	7.5

As generator life depends on run-hours more than years, generators on high-penetration PV mini-grids will typically last longer than those on diesel-only grids.

Other mini-grid modeling inputs include:

- Discount rate: 6 percent
- Inflation: 1.5 percent
- Fuel: see Table B.12 and the text below.

B.4.3 Diesel price projections

The FSM utilities pay FSM Petrocorp a contract price based on Singapore MOPS[16] + Fixed Add On + Taxes. The fixed add on is determined by a Fuel Supply Agreement. We did not have access to MOPS forecasts, so our diesel price projections are based on a structure of EIA US Diesel price projection + Estimated Fixed Add On + Taxes. The fixed add on in the projections will not be the same as the fixed add on in the pricing formula because the Singapore MOPS and the EIA numbers are not the same. However, the global diesel prices to 2037 should track the US$ prices. Our methodology assumes each utility pays a fixed margin above the global diesel price.

Average yearly diesel fuel price data for the period 2015 through 2017 has been provided by the four utilities.[17]

Table B.17: FSM Utility Diesel Prices (Nominal US$ per Gallon)

Utility	2011	2012	2013	2014	2015	2016	2017
CPUC	$4.25	$4.48	$4.44	$4.40	$3.37	$2.69	$2.88
KUA				$4.48	$3.44	$2.76	$3.00
PUC		$4.36	$4.29	$3.96	$2.85	$2.34	$2.59
YSPSC	$4.66	$4.79	$4.70	$4.44	$3.23	$2.81	$3.09

Source: CPUC, KUA, PUC, YSPSC

Diesel fuel is taxed a flat amount per gallon, including a national component and in some cases a state component.[18]

Table B.18: FSM Diesel Fuel Taxes, US$ per Gallon[19] (2013)

National	$0.05
Chuuk	.
Kosrae	.
Pohnpei	.
Yap	$0.05

Source: Deloitte. Thinking of doing business in Micronesia? Tax and Investment Profile for Micronesia. 31 January 2013

Our projections are based on US EIA real price projections[20] in 2016 US$. The US EIA prices include a Federal tax and an average state tax. The Federal tax on diesel is fixed at US$0.244 per gallon. The average state tax was US$0.286 in 2016, and state taxes increase at the rate of inflation. We remove the state and federal tax from the EIA projections used as the basis for FSM price projections.

We remove the fuel taxes component of the nominal FSM diesel prices and deflate the prices to real 2016 US$ values. For the years 2015, 2016, and 2017 we subtracted the EIA

[16] Mean of Platts Singapore

[17] We calculate average diesel prices for KUA and PUC as the average of monthly fuel cost / monthly fuel consumption for each calendar year. January 2013.

[18] Deloitte. Thinking of doing business in Micronesia? Tax and Investment Profile for Micronesia.

[19] To check and update if required

[20] United States Energy Information Administration. Petroleum and Other Liquids Prices. Accessed: 13 October 2017.

real prices from the FSM real diesel prices to get a price margin for each utility exclusive of taxes. We take the average margin in the three periods as an estimate of the margin paid by the utilities over US prices in perpetuity.

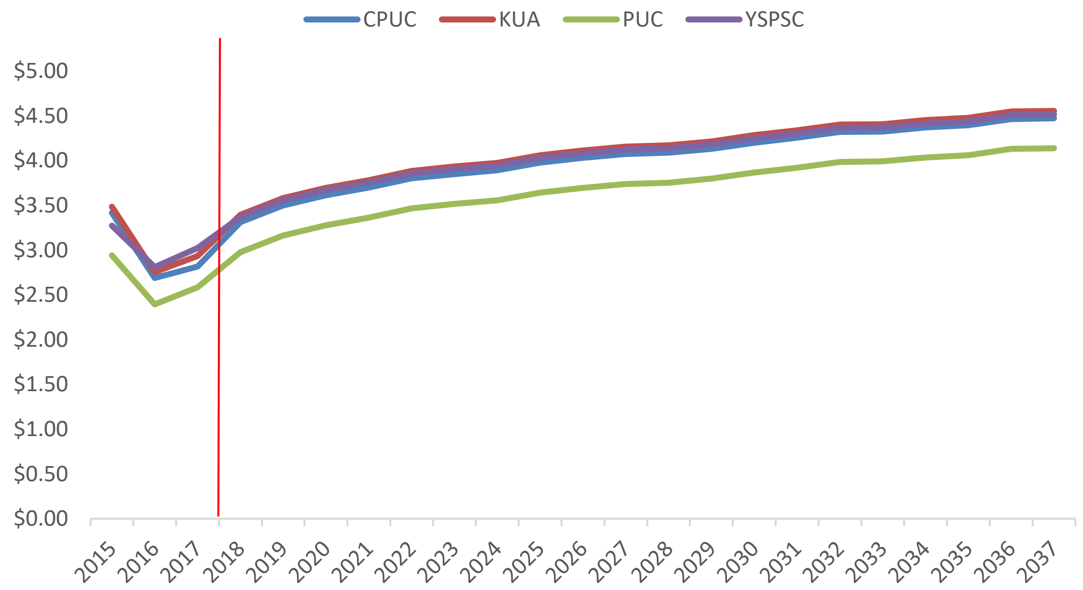
Table B.19: Margins Paid by FSM Utilities (Real 2016 US$ per Gallon)

Utility	2015	2016	2017	Average
CPUC	$1.14	$0.86	$0.67	$0.89
KUA	$1.21	$0.93	$0.78	$0.97
PUC	$0.67	$0.56	$0.43	$0.55
YSPSC	$0.95	$0.93	$0.82	$0.90

Source: Castalia based on data from EIA, CPUC, KUA, PUC, and YSPSC

We add the average price margins and taxes to the US EIA price projections to get price projections for the FSM utilities in real 2016 US$.

Figure B.13: FSM Utility Diesel Price Projections (Real 2016 US$ per Gallon)

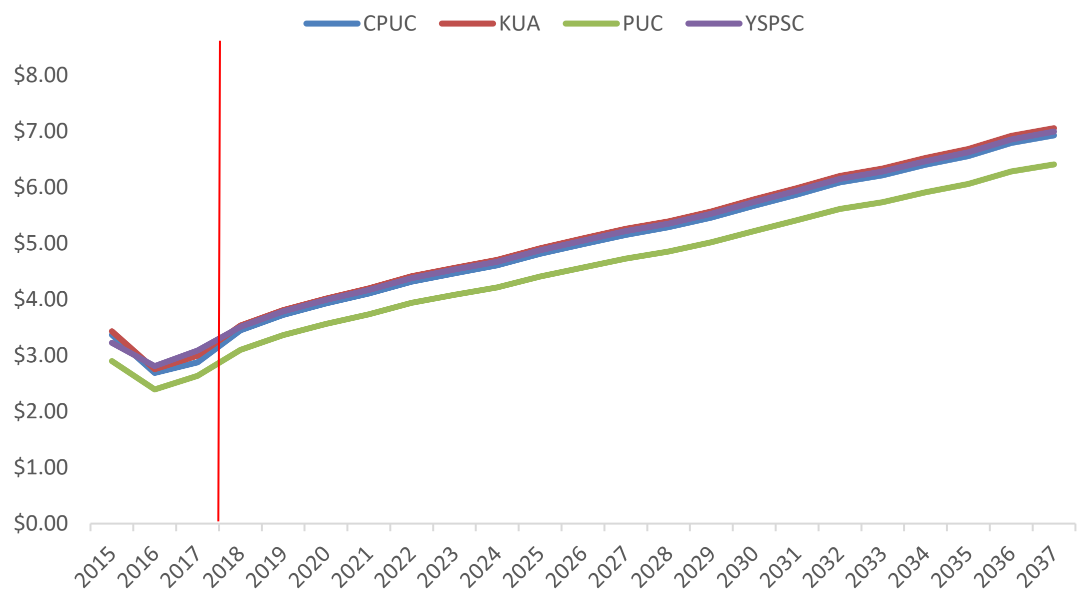


Note: Actual data to 2017. Projections from 2018 to 2037

Source: Castalia based on data from EIA, CPUC, KUA, PUC, and YSPSC

We inflate the real price projections (using the same inflation assumption used by EIA) to get projections in nominal US$.

Figure B.14: FSM Utility Diesel Price Projections (Nominal US$ per Gallon)

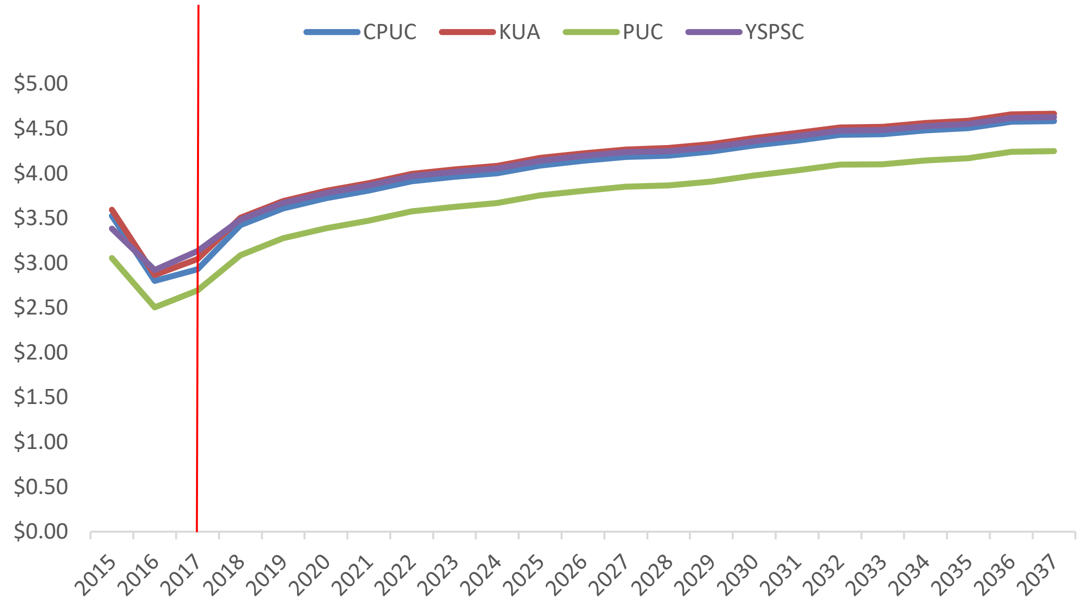


Note: Actual data to 2017. Projections from 2018 to 2037

Source: Castalia based on data from EIA, CPUC, KUA, PUC, and YSPSC

We calculate the additional cost of diesel on outer islands based on the general commodity rate for intra-island freight transported on the national ship. Intra-state freight is charged at US$35.00 per revenue ton. This equates to a US$0.11 charge per gallon of diesel. Diesel is transported in the ship's fuel tank and pumped into drums at each island, so we assume zero charges for the weight of drums containing fuel and for transporting empty drums. We assume transport charges are adjusted for inflation over time. To calculate price projections for outer islands diesel in real 2016 US$, we add US$0.11 per gallon to all current and future prices.

Figure B.15: FSM Utility Diesel Price Projections for Other Islands (Real 2016 US$ per Gallon)



Note: Actual data to 2017. Projections from 2018 to 2037

Source: Castalia based on data from EIA, CPUC, KUA, PUC, and YSPSC

We adjust the transport charge annually to account for inflation to calculate outer island fuel cost projections in nominal US$.

B.5 Generation Planning Models

We have produced a generation planning model for each main island power station, to forecast the correct mix of scheduled and variable generation sources that will be required to achieve N-2 generator redundancy[21] over the life of the State Energy Master Plans. The planning models take into account the current allocation of diesel gensets and existing renewables, and forecast the likely need for augmentation, replacement, or retirement of diesel gensets, as new RE generation sources come on-line in future years.

In assessing the credibility of scheduled generation sources, we have taken the view that modern BESS will be capable of being dispatchable and have sufficient capacity and response time to be considered for Spinning Reserve duty, and for managing short-term fluctuations in voltage and frequency, similar to the capability of rotating synchronous diesel gensets. We have assumed that the BESS systems will be installed in blocks, with inverters of 1MW capacity. This has the effect of allowing the retirement of several diesel engine gensets over the course of the State Energy Master Plans, which provides future savings in operating and fuel costs.

The models for each state for the first 5 years of the Master Plan are presented below. We will provide the spreadsheets as part of data handover.

[21] N-2 redundancy is defined as having one of the 2 largest gensets off-line for maintenance, and losing the next largest genset on Fault, and still supplying the Maximum Demand.

Figure B.16: Chuuk Generation Planning Model

Chuuk Power Station - Capacity Planning Model

Assumptions

Maximum Demand (MD)

Maximim Safe Capacity (SC) inclusive of 10% spinning reserve

	MD 2.7MW			MD 2.7MW			MD 2.75MW		
	SC 2.45MW			SC 2.45MW			SC 2.5MW		
	Base Case - Jan 2018			2019			2020		
	With 2 * new GE Engines			No Change from 2018			No change from 2018/2019		
	Description	**Diesel**	**Solar**	**Description**	**Diesel**	**Solar**	**Description**	**Diesel**	**Solar**
	GE Set #1	1850		GE Set #1	1850	0	GE Set #1	1850	
	GE Set #2	1850		GE Set #2	1850	0	GE Set #2	1850	
	OLD Cat Set #3	1600		OLD Cat Set #3	1600	0	OLD Cat Set #3	1600	
	OLD Cat Set #4	1300		OLD Cat Set #4	1300	0	OLD Cat Set #4	1300	
	OLD Cat Set #5	1300		OLD Cat Set #5	1300	0	OLD Cat Set #5	1300	
						0			
	Airport Solar		60	Airport Solar		60	Airport Solar		165
	CSHS Solar		200	CSHS Solar		200	CSHS Solar		200
	Other Commercial Solar		0	Other Commercial Solar		0	Other Commercial Solar		0
	Other Customer Solar		0	Other Customer Solar		0	Other Customer Solar		0
	New PV			New PV			New PV		
	New Battery Storage			New Battery Storage			New Battery Storage		
Capacity of Each Generation Type		7900	260		7900	260		7900	365
Total Power Station/System Installed Capacity			8160			8160			8265
N-2 capacity with renewables			4460			4460			4565
N-2 Capacity without renewables			4200			4200			4200
N-2 capacity with renewables and 10% spinning reserve			4014			4014			4109
N-2 Capacity without renewables and 10% spinning reserve			3780			3780			3780

	MD 2.8MW				MD 2.85MW				MD 2.9MW			
	SC 2.55MW				SC 2.6MW				SC 2.65MW			
	2021				2022				2023			
	1MW/1MWH BESS Installed				BESS Increased to 2MWh, new PV 1.25MW				BESS Increased to 3MWh, new PV 1.25MW			
	Description	**Diesel**	**Solar**	**Battery**	**Description**	**Diesel**	**Solar**	**Battery**	**Description**	**Diesel**	**Solar**	**Battery**
	GE Set #1	1850			GE Set #1	1850			GE Set #1	1850		
	GE Set #2	1850			GE Set #2	1850			GE Set #2	1850		
	OLD Cat Set #3	1600			OLD Cat Set #3	1600			OLD Cat Set #3	1600		
	OLD Cat Set #4	1300			OLD Cat Set #4	1300			OLD Cat Set #4	1300		
	OLD Cat Set #5	1300			OLD Cat Set #5	1300			OLD Cat Set #5	1300		
	Airport Solar		165		Airport Solar		165		Airport Solar		165	
	CSHS Solar		200		CSHS Solar		200		CSHS Solar		200	
	Other Commercial Solar		0		Other Commercial Solar		0		Other Commercial Solar		0	
	Other Customer Solar		0		Other Customer Solar		0		Other Customer Solar		0	
	New PV				New PV		2000		New PV		4000	
	New Battery Storage				New Battery Storage (3.5MWh)			500	New Battery Storage (7MWh)			1000
Capacity of Each Generation Type		7900	365	0		7900	2365	500		7900	4365	1000
Total Power Station/System Installed Capacity				8265				10765				13265
N-2 capacity with renewables				4565				7065				9565
N-2 Capacity without renewables				4200				4700				5200
N-2 capacity with renewables and 10% spinning reserve				4109				6359				8609
N-2 Capacity without renewables and 10% spinning reserve				3780				4230				4680

BESS Treated as Dispatchable

Need to consider BESS Separable PCS units/blocks for redundancy purposes - Assume 1MW PCS Blocks

Figure B.17: Kosrae Generation Planning Model

Kosrae Power Station - Capacity Planning Model

Assumptions

Maximum Demand (MD)

Maximim Safe Capacity (SC) inclusive of 10% spinning reserve

	MD 1.1MW			MD 1.1MW			MD 1.1MW		
	SC 1.0MW			SC 1.0MW			SC 1.0MW		
	Base Case - Jan 2018			2019			2020		
	With 3 * new Engines			No Change from 2018			Old Genset #4 Retired		
	Description	**Diesel**	**Solar**	**Description**	**Diesel**	**Solar**	**Description**	**Diesel**	**Solar**
	CAT Genset #4	560		CAT Genset #4	560	0	CAT Genset #4	0	
	CAT Genset #6	1100		CAT Genset #6	1100	0	CAT Genset #6	1100	
	CAT Genset #8	800		CAT Genset #8	800	0	CAT Genset #8	800	
	New Diahatsu Genset #9	600		New Diahatsu Genset #9	600	0	New Diahatsu Genset #9	600	
	New Diahatsu Genset #10	600		New Diahatsu Genset #10	600	0	New Diahatsu Genset #10	600	
	New WB Genset #11			New WB Genset #11	600		New WB Genset #11	600	
						0			
	Powerstation Solar PV		200	Powerstation Solar PV		200	Powerstation Solar PV		200
	Governor Solar PV		100	Governor Solar PV		100	Governor Solar PV		100
	Other Commercial Solar		0	Other Commercial Solar		0	Other Commercial Solar		0
	Other Customer Solar		0	Other Customer Solar		0	Other Customer Solar		0
	New PV			New PV			New PV		
	New Battery Storage			New Battery Storage			New Battery Storage		
Capacity of Each Generation Type		3660	300		4260	300		3700	300
Total Power Station/System Installed Capacity			3960			4560			4000
N-2 capacity with renewables			2060			2660			2100
N-2 Capacity without renewables			1760			2360			1800
N-2 capacity with renewables and 10% spinning reserve			1854			2394			1890
N-2 Capacity without renewables and 10% spinning reserve			1584			2124			1620

	MD 1.15MW				MD 1.15MW				MD 1.2MW			
	SC 1.05MW				SC 1.05MW				SC 1.1MW			
	2021				2022				2023			
	Description	**Diesel**	**Solar**	**Battery**	**Description**	**Diesel**	**Solar**	**Battery**	**Description**	**Diesel**	**Solar**	**Battery**
	CAT Genset #4	0			CAT Genset #4	0			CAT Genset #4	0		
	CAT Genset #6	1100			CAT Genset #6	1100			CAT Genset #6	1100		
	CAT Genset #8	800			CAT Genset #8	800			CAT Genset #8	800		
	New Diahatsu Genset #9	600			New Diahatsu Genset #9	600			New Diahatsu Genset #9	600		
	New Diahatsu Genset #10	600			New Diahatsu Genset #10	600			New Diahatsu Genset #10	600		
	New WB Genset #11	600			New WB Genset #11	600			New WB Genset #11	600		
	Powerstation Solar PV		200		Powerstation Solar PV		200		Powerstation Solar PV		200	
	Governor Solar PV		100		Governor Solar PV		100		Governor Solar PV		100	
	Other Commercial Solar		0		Other Commercial Solar		0		Other Commercial Solar		0	
	Other Customer Solar		0		Other Customer Solar		0		Other Customer Solar		0	
	New PV				New PV		1000		New PV		2000	
	New Battery Storage			0	New Battery Storage (2.5MWh)			500	New Battery Storage (5MWh)			1250
Capacity of Each Generation Type		3700	300	0		3700	1300	500		3700	2300	1250
Total Power Station/System Installed Capacity				4000				5500				7250
N-2 capacity with renewables				2100				3600				4900
N-2 Capacity without renewables				1800				2300				2600
N-2 capacity with renewables and 10% spinning reserve				1890				3240				4410
N-2 Capacity without renewables and 10% spinning reserve				1620				2070				2340

BESS Treated as Dispatchable

BESS Becomes largest dispatchable unit - removed for N-2 Calculation

Need to consider BESS Separable PCS units/blocks for redundancy purposes - Assume 1MW PCS Blocks

Figure B.18: Pohnpei Generation Planning Model

Pohnpei - Capacity Planning Model

Assumptions

Maximum Demand (MD)

Maximim Safe Capacity (SC) inclusive of 10% spinning reserve

MD 6.05MW
SC 5.5MW

	Base Case Jan 2018 — With 2 * New Cat 545kW Engines			
	Description	Diesel	Solar	Hydro
	New Set #1	0		
	New Set #2	0		
	New Set #3	0		
	New Set #4	0		
	CAT Set #1	1650		
	CAT Set #2	1650		
	CAT Set #4	1650		
	CAT Set #5	1650		
	Cat Set #6	600		
	Cat Set #7 peaker	0		
	Cat Set #8 peaker	0		
	IPP Set #1	350		
	IPP Set #2	350		
	IPP Set #3	350		
	IPP Set #4	350		
	Existing Hydro			700
	New Hydro			
	Existing Solar PV Pohnlagas		600	
	Existing Solar PV Other		220	
	New PV Pohnlagas			
	New PV			
	New BESS			
Capacity of Each Generation Type		8600	820	700
Total Power Station/System Installed Capacity				10120
N-2 capacity with renewables				6820
N-2 Capacity without renewables				5300
N-2 capacity with renewables and 10% spinning reserve				6138
N-2 Capacity without renewables and 10% spinning reserve				4770

MD 6.2MW
SC 5.6MW

	2019 — With Set # 3 repaired, & New 300kW Solar PV			
	Description	Diesel	Solar	Hydro
	New Set #1	0		
	New Set #2	0		
	New Set #3	0		
	New Set #4	0		
	CAT Set #1	1650		
	CAT Set #2	1650		
	CAT Set #3	1650		
	CAT Set #4	1650		
	CAT Set #5	1650		
	Cat Set #6	600		
	Cat Set #7 peaker	545		
	Cat Set #8 peaker	545		
	IPP Set #1	350		
	IPP Set #2	350		
	IPP Set #3	350		
	IPP Set #4	350		
	Existing Hydro			700
	New Hydro			
	Existing Solar PV Pohnlagas		600	
	Existing Solar PV Pohnlagas		220	
	New PV Pohnlagas		300	
	New PV			
	New BESS			
Capacity of Each Generation Type		11340	1120	700
Total Power Station/System Installed Capacity				13160
N-2 capacity with renewables				9860
N-2 Capacity without renewables				8040
N-2 capacity with renewables and 10% spinning reserve				8874
N-2 Capacity without renewables and 10% spinning reserve				7236

MD 6.3MW
SC 5.7MW

	2020 — Old Set#6 Retired			
	Description	Diesel	Solar	Hydro
	New Set #1	0		
	New Set #2	0		
	New Set #3	0		
	New Set #4	0		
	CAT Set #1	1650		
	CAT Set #2	1650		
	CAT Set #3	1650		
	CAT Set #4	1650		
	CAT Set #5	1650		
	Cat Set #6	0		
	Cat Set #7 peaker	545		
	Cat Set #8 peaker	545		
	IPP Set #1	350		
	IPP Set #2	350		
	IPP Set #3	350		
	IPP Set #4	350		
	Existing Hydro			700
	New Hydro			
	Existing Solar PV Pohnlagas		600	
	Existing Solar PV Pohnlagas		220	
	New PV Pohnlagas		300	
	New PV			
	New BESS			
Capacity of Each Generation Type		10740	1120	700
Total Power Station/System Installed Capacity				12560
N-2 capacity with renewables				9260
N-2 Capacity without renewables				7440
N-2 capacity with renewables and 10% spinning reserve				8334
N-2 Capacity without renewables and 10% spinning reserve				6696

MD 6.5MW
SC 5.9MW

	2021 — New Medium Speed gensets installed, Retire High Speed Gensets #1 & #2, IPP Discontinued			
	Description	Diesel	Solar	Hydro
	New Set #1	2500		
	New Set #2	2500		
	New Set #3	2500		
	New Set #4	0		
	CAT Set #1	0		
	CAT Set #2	0		
	CAT Set #3	1650		
	CAT Set #4	1650		
	CAT Set #5	1650		
	Cat Set #6	0		
	Cat Set #7 peaker	545		
	Cat Set #8 peaker	545		
	IPP Set #1	0		
	IPP Set #2	0		
	IPP Set #3	0		
	IPP Set #4	0		
	Existing Hydro			700
	New Hydro			
	Existing Solar PV Pohnlagas		600	
	Existing Solar PV Pohnlagas		220	
	New PV Pohnlagas		300	
	New PV			
	New BESS			
Capacity of Each Generation Type		13540	1120	700
Total Power Station/System Installed Capacity				15360
N-2 capacity with renewables				10360
N-2 Capacity without renewables				8540
N-2 capacity with renewables and 10% spinning reserve				9324
N-2 Capacity without renewables and 10% spinning reserve				7686

MD 7.2MW
SC 6.5MW

	2022 — New PV			
	Description	Diesel	Solar	Hydro
	New Set #1	2500		
	New Set #2	2500		
	New Set #3	2500		
	New Set #4	0		
	CAT Set #1	0		
	CAT Set #2	0		
	CAT Set #3	1650		
	CAT Set #4	1650		
	CAT Set #5	1650		
	Cat Set #6	0		
	Cat Set #7 peaker	545		
	Cat Set #8 peaker	545		
	IPP Set #1	0		
	IPP Set #2	0		
	IPP Set #3	0		
	IPP Set #4	0		
	Existing Hydro			700
	New Hydro			
	Existing Solar PV Pohnlagas		600	
	Existing Solar PV Pohnlagas		220	
	New PV Pohnlagas		300	
	New PV		1500	
	New BESS			
Capacity of Each Generation Type		13540	2620	700
Total Power Station/System Installed Capacity				16860
N-2 capacity with renewables				11860
N-2 Capacity without renewables				8540
N-2 capacity with renewables and 10% spinning reserve				10674
N-2 Capacity without renewables and 10% spinning reserve				7686

MD 7.35MW
SC 6.7MW

	2023 — New Hydro, PV & battery storage				
	Description	Diesel	Solar	Battery	Hydro
	New Set #1	2500			
	New Set #2	2500			
	New Set #3	2500			
	New Set #4	0			
	CAT Set #1	0			
	CAT Set #2	0			
	CAT Set #3	1650			
	CAT Set #4	1650			
	CAT Set #5	1650			
	Cat Set #6	0			
	Cat Set #7 peaker	545			
	Cat Set #8 peaker	545			
	IPP Set #1	0			
	IPP Set #2	0			
	IPP Set #3	0			
	IPP Set #4	0			
	Existing Hydro				700
	New Hydro				2700
	Existing Solar PV Pohnlagas		600		
	Existing Solar PV Pohnlagas		220		
	New PV Pohnlagas		300		
	New PV		3000		
	New BESS (1MWh)			1000	
Capacity of Each Generation Type		13540	4120	1000	3400
Total Power Station/System Installed Capacity					22060
N-2 capacity with renewables					17060
N-2 Capacity without renewables					9540
N-2 capacity with renewables and 10% spinning reserve					15354
N-2 Capacity without renewables and 10% spinning reserve					8586

BESS Treated as Dispatchable

Need to consider BESS Separable PCS units/blocks for redundancy purposes - Assume 1MW PCS Blocks

Figure B.19: Yap Generation Planning Model

YAP Power Station - Capacity Planning Model

Assumptions

Maximum Demand (MD)

Maximim Safe Capacity (SC) inclusive of 10% spinning reserve

	MD 2.0MW SC 1.8MW				MD 2.1MW SC 1.9MW			
	Base Case - Jan 2018 With 3 * new cat Engines				2019 New 830kW Genset			
	Description	**Diesel**	**Wind**	**Solar**	**Description**	**Diesel**	**Wind**	**Solar**
	Cat Set #1	1650			Cat Set #1	1650		0
	Cat Set #2	1650			Cat Set #2	1650		0
	Cat Set #3	830			Cat Set #3	830		0
					Cat Set #4	830		0
	Deutz 1	3295			Deutz 1	3295		0
	Deutz 2 (Not In Service)	0			Deutz 2	0		0
	Vergnet Wind #1		275		Vergnet Wind #1		275	
	Vergnet Wind #2		275		Vergnet Wind #2		275	
	Vergnet Wind #3		275		Vergnet Wind #3		275	
	PEC Solar Pv			200	PEC Solar Pv			200
	Sports Complex Solar PV			263	Sports Complex Solar PV			263
	Other Commercial Solar			114	Other Commercial Solar			114
	Other Customer Solar			143	Other Customer Solar			143
	New PV				New PV			
	New Battery Storage				New Battery Storage			
Capacity of Each Generation Type		7425	825	720		8255	825	720
Total Power Station/System Installed Capacity				8970				9800
N-2 capacity with renewables				4025				4855
N-2 Capacity without renewables				2480				3310
N-2 capacity with renewables and 10% spinning reserve				3622.5				4369.5
N-2 Capacity without renewables and 10% spinning reserve				2232				2979

	MD 2.15MW SC 1.95MW					MD 2.2MW SC 2.0MW				
	2020 No change from 2019					2021 No change from 2020				
	Description	**Diesel**	**Wind**	**Solar**	**Battery**	**Description**	**Diesel**	**Wind**	**Solar**	**Battery**
	Cat Set #1	1650				Cat Set #1	1650			
	Cat Set #2	1650				Cat Set #2	1650			
	Cat Set #3	830				Cat Set #3	830			
	Cat Set #4	830				Cat Set #4	830			
	Deutz 1	3295				Deutz 1	3295			
	Deutz 2	0				Deutz 2	0			
	Vergnet Wind #1		275			Vergnet Wind #1		275		
	Vergnet Wind #2		275			Vergnet Wind #2		275		
	Vergnet Wind #3		275			Vergnet Wind #3		275		
	PEC Solar Pv			200		PEC Solar Pv			200	
	Sports Complex Solar PV			263		Sports Complex Solar PV			263	
	Other Commercial Solar			114		Other Commercial Solar			114	
	Other Customer Solar			143		Other Customer Solar			143	
	New PV					New PV				
	New Battery Storage					New Battery Storage				
Capacity of Each Generation Type		8255	825	720	0		8255	825	720	0
Total Power Station/System Installed Capacity					9800					9800
N-2 capacity with renewables					4855					4855
N-2 Capacity without renewables					3310					3310
N-2 capacity with renewables and 10% spinning reserve					4370					4370
N-2 Capacity without renewables and 10% spinning reserve					2979					2979

	MD 2.25MW SC 2.05MW					MD 2.5MW SC 2.25MW				
	2022 1MW PV + 500kW/1.5MWh BESS Installed					2023 PV Increased to 2MW, BESS Increased to 3MWh				
	Description	**Diesel**	**Wind**	**Solar**	**Battery**	**Description**	**Diesel**	**Wind**	**Solar**	**Battery**
	Cat Set #1	1650				Cat Set #1	1650			
	Cat Set #2	1650				Cat Set #2	1650			
	Cat Set #3	830				Cat Set #3	830			
	Cat Set #4	830				Cat Set #4	830			
	Deutz 1	3295				Deutz 1	3295			
	Deutz 2	0				Deutz 2	0			
	Vergnet Wind #1		275			Vergnet Wind #1		275		
	Vergnet Wind #2		275			Vergnet Wind #2		275		
	Vergnet Wind #3		275			Vergnet Wind #3		275		
	PEC Solar Pv			200		PEC Solar Pv			200	
	Sports Complex Solar PV			263		Sports Complex Solar PV			263	
	Other Commercial Solar			114		Other Commercial Solar			114	
	Other Customer Solar			143		Other Customer Solar			143	
	New PV (1MW)			1000		New PV (1MW)			2000	
	New Battery Storage (1.5MWh)				500	New Battery Storage (1.5MWh)				500
Capacity of Each Generation Type		8255	825	1720	500		8255	825	2720	500
Total Power Station/System Installed Capacity					11300					12300
N-2 capacity with renewables					6355					7355
N-2 Capacity without renewables					3810					3810
N-2 capacity with renewables and 10% spinning reserve					5720					6620
N-2 Capacity without renewables and 10% spinning reserve					3429					3429
	BESS Treated as Dispatchable					BESS Treated as Dispatchable				
						Need to consider BESS Separable PCS units/blocks for redundancy purposes - Assume 1MW PCS Blocks				

N-2 Capacity is defined as having one of the 2 largest Gensets off-line for maintenance, and losing the next largest Genset on Fault, and still supplying the Maximum Demand

B.6 Distribution Requirements

We have developed forecasts for capital expenditure on the main island networks for each state. These are made up of estimates for capex required for new customers and general load growth, capex required for replacement of network assets over time, and capex required for specific large projects that have been identified for some networks.

For customer load growth capex expenditure, we have based the estimates on the same residential household growth, and commercial/government energy growth used in the base forecast models. We have made an allowance for the unit cost of assets required to connect both residential and commercial/government customers as the number grows over the life of the forecast period. We have made an additional allowance for capex for specific large customer projects, such as future hotel development in some states, or other large infrastructure, in the year that each state has advised us that it expects the development to proceed.

We have calculated future network asset replacement costs by estimating the number and typical life of each asset type for each island. Where these data are not available in asset registers, we have made assumptions based on visual observation, distance estimates for feeders, and industry experience.

The asset replacement costs assume a regular replacement schedule of parts as they near end-of-life, to prevent sudden failure of large sections of the network. The tables below show the assumed quantities and costs for each main island network.

Table B.20: Distribution Asset Replacement Costs for Chuuk

Asset Type	Quantity	Life	Replacement units per year	Unit replacement cost (US$)	Cost per year
3 Phase Overhead MV (13.8kV) Conductors	38	40	0.95	$30,000	$28,500
1 Phase Overhead MV (13.8kV) Conductors	0	40	0	$10,000	$-
3 Phase Overhead LV Conductors	0	40	0	$15,000	$-
Crossarms	1000	40	25	$500	$12,500
3 Phase Underground MV Cable	0	40	0	$200,000	$-
3 Phase Undergound LV Cable	0	40	0	$50,000	$-
Concrete Poles	800	40	20	$1,000	$20,000
Timber Poles	0	40	0	$1,000	$-
Pole Transformers	300	40	7.5	$25,000	$187,500
Pad Transformers	0	40	0	$25,000	$-
MV Overhead line Switches	19	40	0.475	$30,000	$14,250
Customer Meters	2100	20	105	$100	$10,500
TOTAL					**$273,250**

Table B.21: Distribution Asset Replacement Costs for Kosrae

Asset Type	Quantity	Life	Replacement units per year	Unit replacement cost (US$)	Cost per year (US$)
3 Phase Overhead MV (13.8kV) Conductors	25	40	0.625	$30,000	$18,750
1 Phase Overhead MV (13.8kV) Conductors	3	40	0.075	$10,000	$750
3 Phase Overhead LV Conductors	15	40	0.375	$15,000	$5,625
Crossarms	1000	40	25	$500	$12,500
3 Phase Underground MV Cable	0	40	0	$200,000	$-
3 Phase Undergound LV Cable	0	40	0	$50,000	$-
Fibreglass Poles	390	40	9.75	$1,000	$9,750
Timber Poles	570	40	14.25	$1,000	$14,250
Pole Transformers	283	40	7.075	$25,000	$176,875
Pad Transformers	0	40	0	$25,000	$-
MV Overhead line Switches	10	40	0.25	$30,000	$7,500
Customer Meters	1200	20	60	$100	$6,000
TOTAL					**$252,000**

Table B.22: Distribution Asset Replacement Costs for Pohnpei

Asset Type	Quantity	Life	Replacement units per year	Unit replacement cost (US$)	Cost per year
3 Phase Overhead MV (13.8kV) Conductors	68	40	1.7	$30,000	$51,000
1 Phase Overhead MV (13.8kV) Conductors	87	40	2.175	$10,000	$21,750
3 Phase Overhead LV Conductors	0	40	0	$15,000	$-
Crossarms	4000	40	100	$500	$50,000
3 Phase Underground MV Cable	0	40	0	$200,000	$-
3 Phase Undergound LV Cable	0	40	0	$50,000	$-
Concrete Poles	2500	40	62.5	$1,000	$62,500
Timber Poles	1500	40	37.5	$1,000	$37,500
Pole Transformers	1000	40	25	$25,000	$625,000

Asset Type	Quantity	Life	Replacement units per year	Unit replacement cost (US$)	Cost per year
Pad Transformers	20	40	0.5	$25,000	$12,500
MV Overhead line Switches	50	40	1.25	$30,000	$37,500
MV Overhead line Switches	50	40	1.25	$30,000	$37,500
Customer Meters	6500	20	325	$100	$32,500
TOTAL					**$967,750**

Table B.23: Distribution Asset Replacement Costs for Yap

Asset Type	Quantity	Life	Replacement units per year	Unit replacement cost (US$)	Cost per year
3 Phase Overhead MV (13.8kV) Conductors	62	40	1.55	$30,000	$46,500
1 Phase Overhead MV (13.8kV) Conductors	18	40	0.45	$10,000	$4,500
3 Phase Overhead LV Conductors	0	40	0	$15,000	$-
Crossarms	3000	40	75	$500	$37,500
3 Phase Underground MV Cable	1	40	0.025	$200,000	$5,000
3 Phase Undergound LV Cable	0	40	0	$50,000	$-
Concrete Poles	2875	40	71.875	$1,000	$71,875
Timber Poles	0	40	0	$1,000	$-
Pole Transformers	374	40	9.35	$25,000	$233,750
Pad Transformers	0	40	0	$25,000	$-
MV Overhead line Switches	0	40	0	$30,000	$-
Customer Meters	2000	20	100	$100	$10,000
TOTAL					**$409,125**

The capex estimates also include capex for specific projects that the utilities are planning. As highlighted in the State Energy Master Plans, we have incorporated the following specific projects:

- In Kosrae, relocation of 6.2 miles (10km) of line away from the coast (US$3 million)
- In Yap, YSPSC's planned network enhancements that include 21 miles of overhead MV cables (new cables and reinforcements), 5 miles of underground MV cables (from the power station to the airport and hospital), and reclosers (US$3.5 million).

B.7 Other Options Considered

CPUC and YSPSC requested that we consider specific generation and distribution options to see how they compare to the least-cost plan. These options were either unlikely to be technically feasible or were more expensive than the least-cost approach.

B.7.1 Chuuk

When assessing what would be the most appropriate investments for Chuuk, we also considered:

- Using other types of electricity generation—gas, wind (in the northern islands), and waste-to-energy
- Connecting some islands to Weno by undersea cable

Using other types of electricity generation

We considered the potential to use gas, wind, and waste-to-energy for electricity generation in Chuuk. The State Energy Master Plans do not include any of these options as our analysis suggests these are unlikely to be cost-effective and/or technically feasible at present, or because we had insufficient information to make a full assessment.

Gas

CPUC requested that we analyze this option, especially given that gas turbines have a much lower maintenance requirement than diesel turbines. However, CPUC was concerned that security of gas supply may be an issue.

ITP has previously assessed the option of using gas for electricity generation in Tonga.[22] We reviewed the key findings of that study in the context of Chuuk and the FSM. We found that:

- Small, high-speed generators are too small to warrant conversion. CPUC would need to source new dedicated gas engines or turbines, as replacements or as new capacity
- Hydrogen and biogas are not practical fuels for Chuuk at present
- In Tonga, liquefied natural gas (LPG), bottled gas, was butane, not a butane–propane mix. Butane is not a suitable fuel for engines. We have not been able to confirm the nature of LPG supplied in FSM
- There is insufficient demand from Chuuk and FSM to establish a regional bulk transport of compressed natural gas (CNG) or LNG. FSM could be a sub-

[22] Diesel to Gas – Fuel Substitution Feasibility Report, A component of the Tonga Energy Roadmap Institutional & Regulatory Framework Strengthening Project, January 2016

regional destination if bulk supply was established to larger markets in the region

- Shipment in ISO containers is technically feasible. We consider shipment of LNG in ISO containers to be the only possible commercially feasible option
- For Tonga, the use of LNG for electricity generation, with supply in ISO containers, may be viable. However, a detailed feasibility study would be required for Chuuk and the FSM.

These findings are consistent with the Pacific Region Infrastructure Facility (PRIF) report that concludes:

> "For many small Pacific countries where LNG and/or LPG are generally expensive compared to diesel, pursuing an aggressive strategy of using renewables, energy storage, and EE (both supply-side and demand-side) is possibly the most viable approach to reduce overall fuel costs."[23]

Wind

Wind monitoring results for Tonoas and Penia show 5.3m/s and 5.0m/s wind speed at 35m above ground level, respectively. We consider these speeds too low for cost-effective wind generation.

A wind turbine is proposed for Onoun, but as we do not yet have any wind data for Onoun we could not assess the feasibility of this specifically. However, we modeled a generic small turbine with an estimated resource and found it to be less cost-effective than solar on Onoun.

Waste-to-energy

There is insufficient resource for municipal waste for a sustainable project. A recent feasibility study for a biomass waste-to-energy project in Pohnpei concluded that that the tree trimmings from line clearance could support a 250kWe biomass gasification plant.[24] A similar study would be needed to determine the potential in Chuuk. However, we have been advised that landowners typically they want the timber from their own trees (although the leaves are sent to landfill this is not a large volume). In addition, the length of the network in Chuuk is smaller than that in Pohnpei and so the volume of tree trimmings will be smaller.

We did not have enough resource information to model the technology in HOMER. In addition, the feasibility assessment estimated costs of US$0.37 to US$0.40 per kWh, which is higher than the cost of energy in Chuuk and Pohnpei.

Connecting some islands to Weno by undersea cable

CPUC has received a proposal to connect the following islands to Weno by an undersea Direct Current (DC) cable:[25]

- Tol, Polle, Wonei, Patta,
- Tonoas
- Fefen

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[23] Pacific Region Infrastructure Facility, LPG and Natural Gas as Alternative Energy Sources for the Pacific, April 2016, Page 57

[24] Softbank Corp, Biomass Power in Pohnpei, 13 October 2014

[25] There is an alternative version of the proposal that envisages a cable from Weno just to the Faichuk region.

- Uman
- Udot
- Romanum
- Fanapanges
- Siis.

CPUC believes this undersea DC cable proposal, which would require connection to substations on Weno, and an expansion of the Weno power station, offers significant operational advantages over individual mini-grid generation on each island (for example, less need to travel to do maintenance).

We were unable to validate the accuracy of the DC cable and converter station cost estimates included in the DC cable proposal, so we proceeded with an assessment of this option using the costs of an AC cable solution, which was more readily verified using estimates from other projects. We compared the costs of an AC undersea cable to the scenario assumed in the State Energy Master Plan (in which, Siis has stand-alone solar systems and the other islands have mini-grids). We found that the 'no cable' scenario would be a much more cost-effective option on a life-cycle basis.

We estimate that the costs of the AC undersea cable network are approximately US$29 million including installation, age-based replacement, and opex over the 20-year period. The network will last 40 years so we added a terminal value at the end of the 20-year period.

These costs far outweigh any potential savings if all the power generation was based in Weno. These cost savings will be for generation only, as a distribution network will still be needed on each island for the undersea cable to connect to.

The DC undersea cable solution may be a valid future alternative. This is likely to be significantly cheaper than the AC cable solution but is not a proven technology at this time. It is not possible to accurately validate the material and deployment costs, as there are currently no cases where this type of cable has been deployed at this voltage in a distributed island environment. By the time this is a tested technology and ready for installation in FSM, the islands will already have mini-grids (as they do not want to wait that long to get electricity access).

CPUC may wish to revisit the cable option in the future. However, sunk costs will need to be considered when deciding if a DC cable is the most appropriate solution (although the individual island distribution networks would be needed in both scenarios – it is just the mini-grid generators that would become redundant with the cable).

As a result, the Chuuk State Energy Master Plan does not include an option to supply these islands via either an AC undersea cable or a DC undersea cable from Weno.

B.7.2 Yap

When assessing what would be the most appropriate investments for Yap, we also considered:

- Increasing mini-grid RE
- Using flywheels as spinning reserve—This did not help reduce the cost of energy in our modeling because the storage duration was too short. The flywheel is used more for grid stability than for energy storage.

Increasing mini-grid RE

YSPSC has an objective to supply 100 percent of the outer island population with 100 percent RE by 2020. The State Energy Master Plan supplies 100 percent of the outer island population with electricity, but includes some diesel to meet the required service standards in the least-cost way.

Providing all outer islands with 100 percent RE (solar PV and batteries) that meets the State Energy Master Plan service standards without using diesel would involve significant additional capital cost. Our analysis suggests that, for all islands except Falalop, Ulithi, the cost of a 100 percent RE system would be about 40 percent higher than that of the solar with diesel back-up (the solution included in the State Energy Master Plan). For example, for Ifalik and Lamotrek, the cost of each system would increase from about US$0.75 million to US$1.04 million. For Falalop, Ulithi, the generation capex would increase from about US$435,000 to about US$2.5 million, and the cost of energy would increase from about US$0.88 to about US$1.52/kWh.

Although, under the State Energy Master Plan, the islands that are currently 100 percent solar would receive a diesel generator (to ensure the State Energy Master Plan service standards can be met), this would only be used infrequently, for back-up. We estimate that diesel use will be very low, perhaps three drums per year. We understand that the other mini-grids in Yap use about six drums of fuel a year (apart from Ulithi which is higher). Therefore, the environmental and logistical challenges involved in using diesel in the outer islands are likely to be minor.

B.8 Role of Specific Projects

Table B.24 maps projects identified in the State Energy Action Plans, the GCF applications, and the ADB list of feasibility studies to the investments in the State Energy Master Plans.

We focus on the relevant generation and distribution capital investment projects. We have excluded some actions we know are already completed.

Table B.24: Relationship Between State Energy Master Plan Investments and Existing Project Concepts

Chuuk

Project type	Proposed project/investment	Source	Role of project in State Energy Master Plan
Generation (Weno): Solar PV	PV solar grid-tied systems on government and administrative buildings up to 450kWp: ▪ CPUC power plant (50kWp) ▪ CPUC Waste Water Treatment Plant (50kWp) ▪ Airport car park (135kWp)	State Energy Action Plan (May 2016 version), action 3.A.1.1	State Energy Master Plan involves 12MW of additional grid-tied solar on Weno. CPUC's proposed sites could be considered for part of this.
Generation (Tonoas, Penia): Wind	Grid-connected wind farm, plus storage	State Energy Action Plan (May 2016 version), action 3.B.4	Not included in the State Energy Master Plan because the data on the wind resource in Chuuk shows insufficient wind speed for a sustainable wind energy project. This is based on the measurements at Tonoas and Penia.
Generation: Ocean energy	Wave power plant connected to a PV hybrid system, plus storage	State Energy Action Plan (May 2016 version), action 3.C.4	Not included in the State Energy Master Plan because we have insufficient data on the wave energy resource in Chuuk and the costs of the technology. The technology is still in commercialization with the most advanced technology, Carnegie's CETO, 5-10 years from commercial availability. The CETO technology, and others, require anchoring to the seabed, which limits the depth of water they can be deployed in. The seabed surrounding the Chuuk islands tends to be unsuitable. Locations within the lagoons will not have sufficient wave resource for a viable project.
Generation: Waste to energy/biomass	Waste to energy/biomass plant connected to an island grid system	State Energy Action Plan (May 2016 version), action 3.D.4	Not included in the State Energy Master Plan as resource is not known. May be considered in future following a resource assessment.
Generation: Gas/coconut oil	LNG, LPG or coconut oil generation unit plus fuel storage	State Energy Action Plan (May 2016 version), action 3.E.3	Gas not included in the State Energy Master Plan (see previous explanation).

Project type	Proposed project/investment	Source	Role of project in State Energy Master Plan
			Coconut oil not included in the State Energy Master Plan as stakeholders advised that Chuuk is no longer considering this option due to the value of coconut oil for other purposes.
Generation (other islands): Diesel/solar PV hybrid	Power generation IPP between VITAL & CPUC for Tonoas, Fefan, and Uman	State Energy Action Plan (May 2016 version), action 1.4	We understand that CPUC has signed an IPP agreement with Vital. The ground-breaking ceremony for this plant was held in October 2017.
Generation (other islands): RE/storage/diesel hybrid mini-grids	(First priority) Mini-grids for: Mortlocks Region: Satowan North West Region: Onoun Faichuk Region: Romanum (Second priority) Mini-grids for all other municipalities not scheduled for SHS	State Energy Action Plan (May 2016 version), action 3.A.2.1	State Energy Master Plan includes mini-grids in Satowan, Onoun, and Romanum (as well as in Tonoas/Fefen/Uman, Tol/Polle, Wonei/Patta, Udot (partial), Fanapanges, Lekinoch, Nema, Nomwin, and Houk). We are carrying out a feasibility study for the Udot mini-grid. ADB is currently funding feasibility studies for 9 mini-grids. We understand that CPUC has requested support for these from the GCF.
Generation (other islands): Stand-alone solar systems on schools	7 schools in North West and Faichuk Regions	State Energy Action Plan (May 2016 version), action 3.A.2.2	State Energy Master Plan includes stand-alone solar systems for schools on all islands without mini-grids.
Generation (other islands): Solar home systems	North West Region: Ruo, Tamatam, Pollap, Makur, Onou, Unanu, Piherech Mortlocks Region: Piis-Emwar, Ta Faichuk Region: Eoit S. Namoneas Region: Parem N. Namoneas Region: Piis-Paneu, Fonoton Total: 493 SHS	State Energy Action Plan (May 2016 version), action 3.A.2.3	State Energy Master Plan provides SHS to all these islands. ADB currently funding feasibility studies for these SHS.
Distribution	Undersea DC cable from Weno to Faichuk	CPUC, IS Systems, and McMahon Report	Not included in the State Energy Master Plan as our analysis suggested it was more expensive than the alternatives.

Kosrae

Project Type	Proposed Project/Investment	Source	Role of project in State Energy Master Plan
Generation: Diesel	Replace one inoperative back up unit with new generator of higher efficiency	State Energy Action Plan 2012, action 1.5	KUA has ordered three new diesel units that we assume will be operational in 2018 (or 2019). We therefore do not include these in the State Energy Master Plan.
Generation: Solar	Expand the use of solar energy by doubling the capacity of the grid connected PV system (Gradual increase in usage of Solar PV system @ 5,000kWh annually).	State Energy Action Plan 2012, action 3.1	State Energy Master Plan includes an additional 6.3MW of solar PV capacity.
Generation: Solar	500kWp solar PV capacity and associated integration/control system	ADB feasibility study list/GCF list	Delivered by the PV and energy storage included in the State Energy Master Plan.
Generation: Ocean energy	Phase 1 (200kW wave power pilot plant) Phase 2 (4MW wave power plant)	State Energy Action Plan 2012, actions 3.6 and 3.7	Not included in the State Energy Master Plan because we have insufficient data on the wave energy resource in Kosrae or the costs of the technology. The technology is not proven. Ocean Energy Industries does not appear to be an active company as at 2017.
Generation: Waste to energy/biomass	Waste to energy/biomass generation facility	State Energy Action Plan 2012, action 3.9	Not included in the State Energy Master Plan because we have insufficient data on the resource.
Generation: Hydro	250kW hydropower plant	State Energy Action Plan 2012, action 3.11	Not included in the State Energy Master Plan because previous studies suggested the resource was limited, and a plant of this size is unlikely to be cost-effective if feasible at all.
Generation: Wind	200-500kW wind farm	State Energy Action Plan 2012, action 3.13	Not included in the State Energy Master Plan because wind resource data does not seem to be available in Kosrae. Wind monitoring would need to be undertaken prior to installation. Wind turbines at this scale are typically more expensive than solar PV.

Project Type	Proposed Project/Investment	Source	Role of project in State Energy Master Plan
Distribution	43km of 13.8kW greenfield distribution network rerouting (including poles, conductors and transformers etc.)—to relocate inland and reduce risk of impact from coastal erosion	ADB feasibility study list/GCF list	The State Energy Master Plan includes relocation of 10km of the network.

Pohnpei

Project Type	Proposed Project/Investment	Source	Role of project in State Energy Master Plan
Generation: Diesel	Major overhaul of gensets #1 and #2 (total 4MW) and top-end overhaul of #4 and #5 (total 4MW)	State Energy Action Plan (February 2017 version), action 1.1	These proposed overhauls are reasonable. Gensets #1 and #2 will need overhauling soon after #3 returns to service in 2018, as they were already second-hand when they were purchased. Gensets #4 and #5 are relatively new, but will need a top-end overhaul at mid-life. The timing will depend on the run hours accruing each year, but the overhaul will probably be needed within 1 or 2 years (probably before the new 3 x 2.5MW sets are installed in 2021).
Generation: Diesel	Repair or replacement of genset #3	Pohnpei Energy Assessment/State Energy Action Plan (February 2017 version), action 1.1	Included in the State Energy Master Plan – assumed to be in service in 2018.
Generation: Diesel	Permanent 10MW power plant	State Energy Action Plan (February 2017 version), action 1.3	State Energy Master Plan assumes 7.5MW of additional diesel capacity by 2020 to replace existing temporary units when they retire, and an allowance for addition of another 2.5MW if needed. The State Energy Master Plan forecasts do not require this within 20 years.
Generation: Solar	Rehabilitate the existing SHS	State Energy Action Plan (February 2017 version), action 3.3	Recent PUC survey of outer island equipment found that most SHS were in poor condition or lacking components.

Project Type	Proposed Project/Investment	Source	Role of project in State Energy Master Plan
			The State Energy Master Plan assumes that all consumers will receive new SHS or mini-grids.
Generation: Solar	Electrify currently unserved areas using solar PV	State Energy Action Plan (February 2017 version), action 3.6	State Energy Master Plan will electrify all unserved areas using solar PV (sometimes in combination with diesel and storage).
Generation: Solar	Electrify the public facilities in Pakin, Salapuk and others that are currently unserved (using solar PV)	State Energy Action Plan (February 2017 version), action 3.7	State Energy Master Plan will electrify all unserved public facilities using stand-alone solar systems or solar/diesel hybrid mini-grids.
Generation: Solar	Implement grid-connected solar PV systems	State Energy Action Plan (February 2017 version), action 3.11	State Energy Master Plan assumes that the 300kW MFAT-funded solar farm at the Pohnlangas site is operational in 2018. This is not included in the State Energy Master Plan budget. State Energy Master Plan includes an additional 18.3MW of PV capacity. Much of this could be developed at the Pohnlangas solar site.
Generation: Solar	9MWp ground-mount solar PV at Pohnlangas site	ADB feasibility study/GCF lists, State Energy Action Plan (February 2017 version), action 3.11	
Generation: Hydropower	Upgrade Nanpil hydropower	State Energy Action Plan (February 2017 version), action 3.1	We considered the possibility of upgrading the Nanpil hydropower scheme to provide a storage buffer and improve the capacity factor, but found that this would deliver energy at a higher cost than the Lehnmesi system.
Generation: Hydropower	Develop mini and micro hydropower plant schemes including on Lehnmesi and Senpehn rivers	State Energy Action Plan (February 2017 version), action 3.2	State Energy Master Plan includes 2.7MW of additional hydropower capacity at the Lehnmesi site. This is similar to the project the ADB is assessing, although the capacity is lower and incorporates a storage dam to increase availability. The State Energy Master Plan does not include hydropower at Nankawad as there are lower-cost ways to meet demand.
Generation: Hydropower	4.5MW run of river hydropower capacity at Lehnmesi	ADB feasibility study/GCF lists	
Generation: Hydropower	1MW run of river hydropower capacity at Nankawad	ADB feasibility study/GCF lists	

Project Type	Proposed Project/Investment	Source	Role of project in State Energy Master Plan
Storage	Introduce storage capacity for grid stability to maximize penetration of PV	State Energy Action Plan (February 2017 version), action 3.12	State Energy Master Plan includes 10MW of capacity and 34MWh.
Storage	5MW of containerized battery storage/system integration	ADB feasibility study/GCF lists	

Yap

Project Type	Proposed Project/Investment	Source	Role of project in proposed Master Plan
Generation: Diesel	2 x 1.6MW and 1 x 800kW (continuous rating) high-speed generators	State Energy Action Plan (February 2017 version), action 1.5	State Energy Master Plan assumes this is already operational by 2018.
Generation: Diesel	New 830kW high-speed diesel generator	State Energy Action Plan (February 2017 version), action 1.5	Included in the State Energy Master Plan
Generation: Solar	Yap Island Proper grid-tied solar PV systems to be installed up to 200kWp	State Energy Action Plan (February 2017 version), action 3.3	State Energy Master Plan includes an additional 8.3MW of solar PV capacity on Yap Proper.
Generation: Solar	300kWp grid-tied solar PV systems to be installed on Yap Island Proper	State Energy Action Plan (February 2017 version), action 3.4	
Generation: Solar	500kWp grid-tied PV systems to be installed on Yap Island Proper	State Energy Action Plan (February 2017 version), action 3.5	
Generation: Solar	1MW grid-tied solar PV for Yap Island Proper	State Energy Action Plan (February 2017 version), action 3.8	

Project Type	Proposed Project/Investment	Source	Role of project in proposed Master Plan
Generation: Solar	1.2MW floating solar PV capacity	ADB feasibility studies list	This project could be delivered as part of the 2MW of solar PV capacity included in the 2019-2023 period of the State Energy Master Plan. We understand that YSPSC has requested GCF support for a 1.5MW floating solar facility, which we assume is the same project.
Generation: Wind	500-600kW wind turbines for Yap Island Proper	State Energy Action Plan (February 2017 version), action 3.7	Bid awarded to Vergnet for 3 x 275kW wind turbines (action 4.0), and wind farm under construction. State Energy Master Plan assumes this wind farm is operational in 2018.
Generation: Wind	2 x 275kW wind turbine generators	ADB feasibility studies list	Not included in the State Energy Master Plan as the modeling identified lower-cost ways to meet demand.
Generation: Other islands	Electrify 4 of the non-electrified outer islands – 6 projects with solar PV stand-alone systems (SHS/SCS/micro-grids). Priority order as follows: ▪ Ulithi Mogmog; Woleai Falalop; Satawal – PV micro- and mini-grids ▪ Ulithi Falalop – AC-bus system for high school PV solar hybrid, or AC- bus systems in the outer-islands already electrified: ▪ Ulithi-Mogmog hybrid solar-diesel ▪ Ulithi-Falalop AC-bus solar-diesel ▪ Woleai-Falalop hybrid solar-diesel SHS and SCS for remaining outer islands:	State Energy Action Plan (February 2017 version), action 3.1	The first four have been completed. Our modeling treats these as existing networks, but we model the new generation options. The State Energy Master Plan will electrify the other non-electrified outer islands.

Project Type	Proposed Project/Investment	Source	Role of project in proposed Master Plan
	▪ Ulithi Falalop – grid connected PV system/hybrid with battery and diesel generator as back-up (up to 100kWp) ▪ 100kWp solar PV micro-grid for Falalop, Ulithi ▪ 62kWp solar PV micro-grid for Ifalik		
Storage	1MW of battery storage to enable employment of additional wind and solar PV and support actions 3.7 and 3.8	State Energy Action Plan (February 2017 version), action 3.9	State Energy Master Plan introduces 2MW/10MWh of battery storage in the 2019-2023 and 2024-2028 periods. The 1.5MW/0.125MWh storage and integration system could be delivered as part of this.
Storage	1.5MW (0.125MWh) battery storage and integration/control systems	ADB feasibility studies list	
Storage	1MW flywheel storage for power regulation on Yap Island Proper network	State Energy Action Plan (February 2017 version), action 3.6	Not included in the State Energy Master Plan as it did not help reduce the cost of energy. The storage duration is too short.

Source: Castalia based on State Energy Action Plans (latest available versions), Pohnpei Energy Assessment Draft Report, Terms of Reference for ADB Feasibility Studies, and GCF project application/lists.

Appendix C: Financing Plans – Inputs and Approach

We developed a financial model to estimate the financing, funding, and tariff requirements to implement the State Energy Master Plans. The model is a cash needs model that calculates the annual need for cash to cover all operating costs as well as the cost of servicing any financing. The required tariff is then calculated from the annual cash flow need by dividing the required revenue by the forecast demand. In this respect, the model mirrors the policy of the State Governments that the utilities are not profit maximizing entities but rather public service organizations. The cash needs approach is frequently used to set annual permitted revenue requirements for non-profit utilities, such as consumer cooperatives. For example, both in the Philippines and in the United States, the cash needs approach is explicitly adopted by the regulators for setting the tariffs of non-profit utilities.

A key feature of the cash needs approach is that it does not include depreciation since depreciation is a non-cash expense. Rather, this approach includes replacement investment when it is required and when it creates a call on cash. Over the medium-term, the replacement investment need and a hypothetical depreciation charge will have the same present value.

Cashflow inputs

Capital and operational expenditure estimates come from modelling in HOMER, analysis of existing operational expenses, and analysis of distribution network requirements. To account for FSM conditions, we have added a 15 percent contingency to the operating expenses that HOMER estimates.

When calculating cash needs we have also added a ten percent debt service coverage ratio on top of cash requirements to provide a cashflow security buffer. The tariffs estimated in the model will therefore provide sufficient cash each year with a small margin. Since FSM utilities are not intended to be profit maximising

Financing assumptions

We assume three possible sources of finance:

- Grants
- Concessional loans from multilateral and bilateral lenders
- Commercial loans, such as loans from banks in the FSM.

For the purposes of analysing the financial feasibility of the Master Plans, we consider three broad scenarios:

- In Scenario 1, all capital expenditure is financed by grants (in effect, it is fully funded so no financing is required)
- In Scenario 2, capital expenditure on mini-grids, stand-alone solar systems, and the Pohnpei power station are covered by grant funding. All other capital expenses are financed by concessional loans. For illustration we assume that loans are made up of equal shares of World Bank IBRD, World Bank IDA, ADB concessional OCR (COL) loans, and JICA OCA for lower middle-income countries. This combination of loans provides a benchmark for discussion and was selected for the following reasons:
  - We have included both IDA and IBRD loans because although FSM is eligible for cheaper IDA loans, IBRD borrowing is unlimited and is the most expensive donor organization financing the FSM utilities would pay

  - In 2017, FSM was designated to only receive Asian Development Fund (ADF) grants rather than COL loans from the ADB. However, for the purposes of this scenario, all capital expenditure is financed. We therefore include COL financing because if the ADB were to provide the FSM with financing it would be at COL terms.

- In Scenario 3, capital expenditure on mini-grids, stand-alone solar systems, and the Pohnpei power station are covered by grant funding. All other capital expenses are financed at commercial terms, for which we use the terms offered by the FSM Development Bank. The purpose of this scenario is to provide an indication of how much the capital requirements in the State Energy Master Plans would cost if they were financed without access to concessional terms. This scenario is illustrative, and the amounts the utilities would need to borrow are an order of magnitude larger than the US$3 million maximum exposure the FSM Development Bank is permitted by law per customer.

  Scenario 3 can also be treated as a proxy for the financial effects of procuring solar/battery storage output from private IPPs. Such IPPs would be expected to be financed on commercial terms.

These three scenarios are intended to provide the basis for analysis and to identify how much grant funding will be required to implement the State Energy Master Plans.

Table C.1: Terms of Loans Included in the Financial Model

Loan	Rate	Maturity	Grace period
World Bank IBRD	2.4%	20	-
World Bank IDA	1.95%	40	10
ADB Concessional OCR	1.5%	32	8
JICA ODA	1.2%	40	10
FSM Development Bank	5%	25	-

Tariff calculations

We have calculated the tariffs required to cover cash needs in the three financing scenarios. Tariffs are calculated assuming consumption is at the level estimated in the load forecast (see Appendix B). The calculated tariff structure across customer segments is based on the current tariff structure for each utility. The tariff for each customer group is changed by the percentage required to make revenue equal cash required. We have assumed that tariffs within a state will be equal for all customers across service areas (main grid and off-grid areas).

Costs of connecting and wiring houses

Households in the mini-grid and stand-alone solar system service areas that are not currently connected to power will require their households to be connected and internal wiring. Connection includes running a connecting wire from the feeder to a fibreglass pole at the boundary of a customer's property. Internal wiring will provide for one power point and two light bulbs. Based on information gathered in consultations we have priced the cost of connection at US$150 per household and the cost of internal wiring at $350 per household. We recommend that these costs are financed and added as a monthly payment to customers' bills. We assume that the financing terms are a 5-year loan period at four percent (the lower bound of interest rates offered by the FSM Development Bank).

Based on our analysis, it will cost US$2.81 per month over five years for households in the mini-grid areas to be connected to the grid, and US$6.55 per month over 5 years for households in mini-grid and stand-alone solar system areas to install internal wiring.

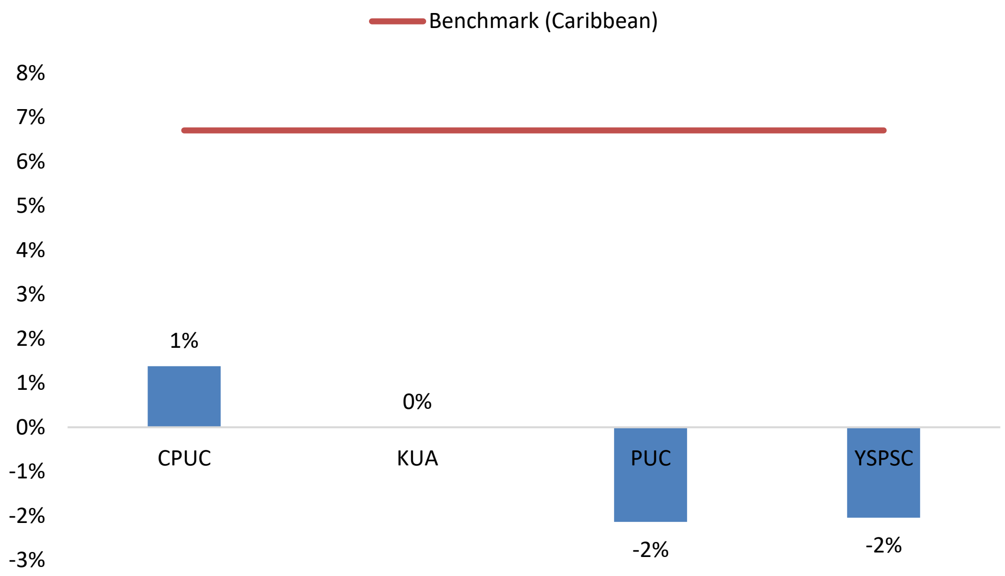
Appendix D: Financing Plans – Historical Performance of FSM's Utilities

Historical performance of FSM utilities provides an indication of the challenges and the risks for the implementation of the State Energy Master Plans. This Appendix sets out the historical context for the financial performance of utilities and the current approach to tariff setting.

D.1 Financial Performance

The return on assets (ROA) and return on equity (ROE) are well below international benchmarks[26] for all four utilities (Figure D.1 and Figure D.2)—and in some cases negative. We calculate ROA and ROE excluding grant funding from income. When grant funding is excluded, three of the utilities are losing money or just breaking even. While CPUC's power business is making a stable positive return, its profitability is significantly below average and is not enough to finance large new capital expenditure.

Figure D.1: Return on Assets for Power Business of FSM State Utilities[27] (2016)

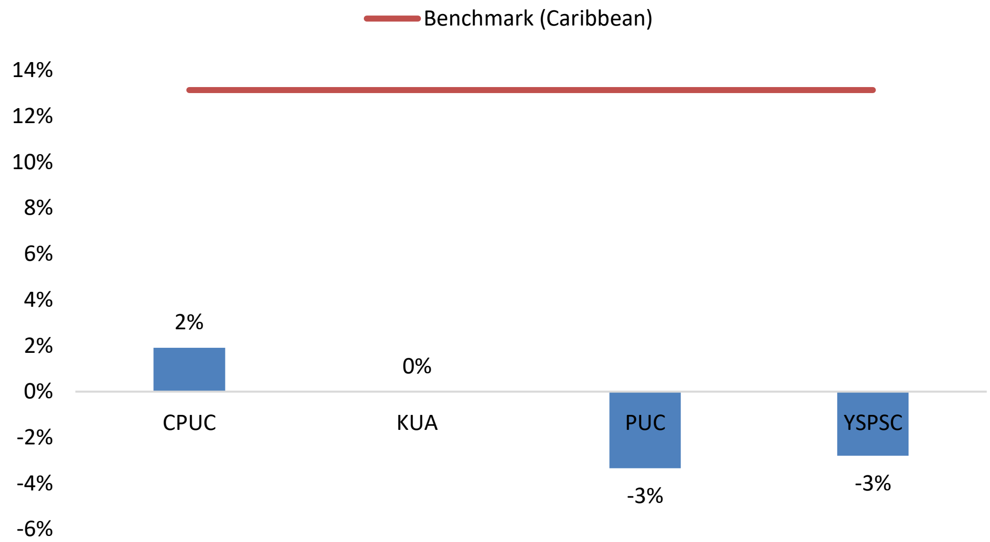


Source: Castalia with publicly available data from (AES DPP, AES Itabo, AES Andres, Barbados Light and Power CO. Ltd., and Consorcio Energetico Punta Cana-Macao); CPUC; KUA; PUC; YSPSC

[26] The international benchmarks for ROA and ROE are from a sample of five Caribbean island utilities (AES DPP, AES Itabo, AES Andres, Barbados Light and Power CO. Ltd., and Consorcio Energetico Punta Cana-Macao). Caribbean utilities were used as comparators to Pacific utilities in the 2012 PPA Pacific Power Utilities Benchmarking Report. We chose the utilities included in the benchmark based on their size and their being on island nations. The utilities we selected had energy revenue of less than US$400 million. We calculated benchmarks as the mean of ROA and ROE across the sample and over an 11-year period from 2004 to 2015. ROA and ROE in the most recent PPA report were calculated using a different methodology to that used here, and are therefore not used. If the source data for the PPA benchmarking becomes available, we will be able to benchmark FSM's utilities against their Pacific counterparts.

[27] Return on assets (ROA) is a financial ratio that calculates the profit a company earns as a percentage of overall resources.

Figure D.2: Return on Equity for Power Business of FSM State Utilities[28] (2016)



Source: Castalia with publicly available data from (AES DPP, AES Itabo, AES Andres, Barbados Light and Power CO. Ltd., and Consorcio Energetico Punta Cana-Macao); CPUC; KUA; PUC; YSPSC

D.2 Causes of Poor Financial Performance

In general, the utilities in the FSM are not profitable because tariffs do not reflect full costs. Even though tariffs are relatively high when compared with international standards, they do not allow the state utilities to recover their operating and maintenance costs, and/or finance new investments.

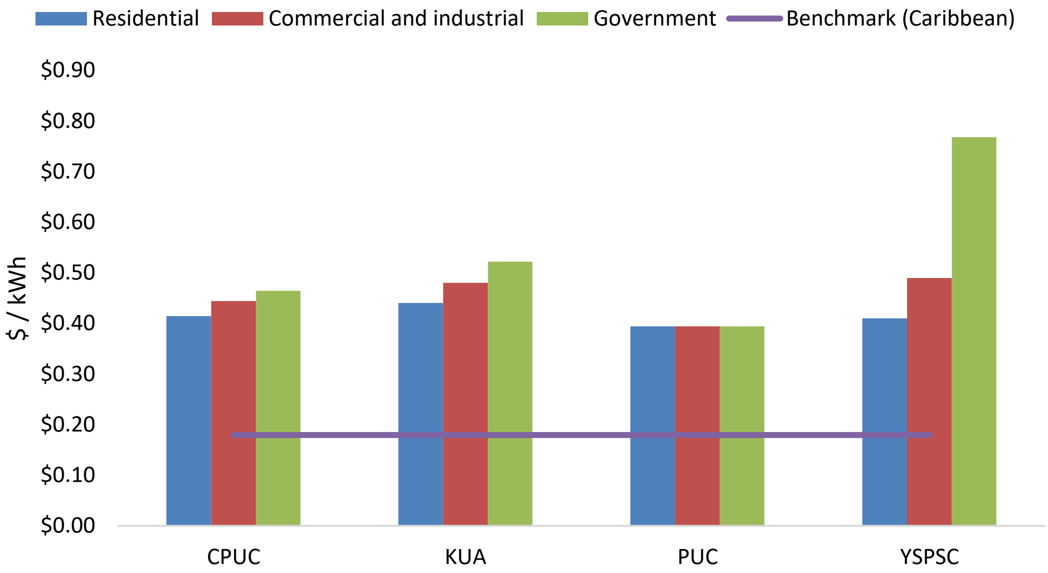
D.2.1 Misaligned tariffs reduce efficiency and revenue

All of PUC's customers currently pay the same tariff. However, PUC could increase revenue by moving to a targeted structure.

The current tariff structure in Yap is inefficient and burdens the utility with unnecessary risk. For example, YSPSC carries large fuel cost risk because it is not allowed to pass fuel cost movements through to tariffs. The other three utilities include a fuel cost correction mechanism in their tariffs. Simultaneously, the Yap State Public Service Corporation (YSPSC) tariff for government customers is significantly higher than its tariff for residential and commercial customers—effectively, the government is subsidizing the others. However, YSPSC does charge higher tariffs to outer island customers, recognizing the higher costs of service in these areas.

[28] Return on equity (ROE) is a financial ratio that calculates how many dollars of profit a company generates with each dollar of shareholders' equity.

Figure D.3: Average Tariff by Customer Segment



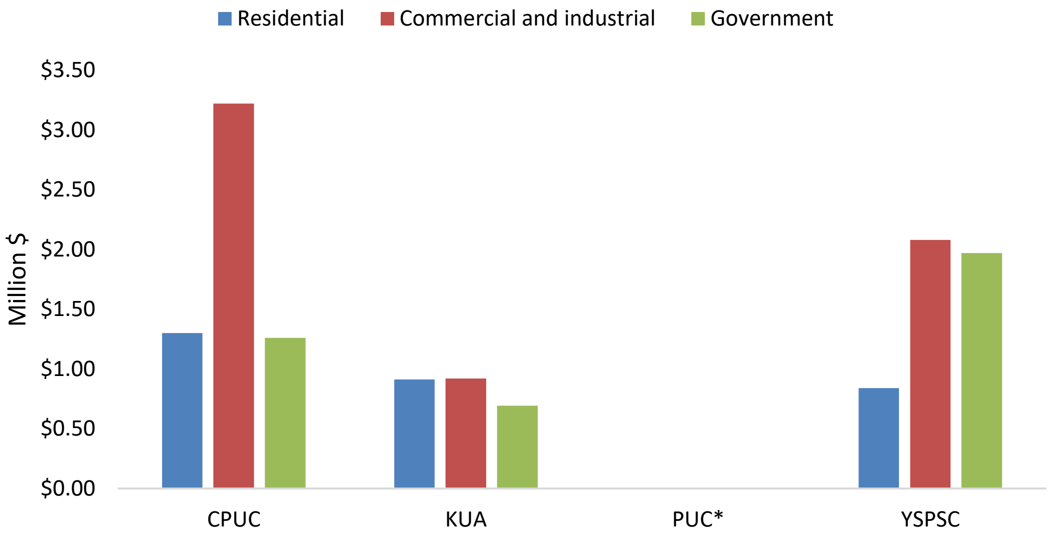
Source: Castalia with publicly available data from Bahamas Electricity Corporation, Barbados Light and Power Co. Ltd., AES Andres, AES Itabo, Consorcio Energetico Punta Cana-Macao, Empresa Distribuidora de Electricidad del Este, Energia que Potencia del Desarollo, Empressa de Generacion Hidroelectrica Dominicana, Empresa de Transmision Electrica Dominicana, Jamaica Public Service Company Ltd., Energie Bedrijven Suriname, and Trinidad and Tobago Electricity Comission; CPUC; KUA; Kosrae Utilities Authority. Financial Statements and Independent Auditors' Report. Years Ended September 30, 2016 and 2015; PUC; Pohnpei Utilities Corporation. Financial Statements, Additional Information and Independent Auditors' Report. Years ended September 30, 2016 and 2015; YSPSC

For CPUC and YSPSC, a marginal increase in the tariff charged to commercial and industrial customers will increase revenue more than increases for other customer segments

Commercial and industrial customers contribute the largest share of revenue for CPUC, KUA, and YSPSC (Figure D.4).[29] For CPUC and YSPSC this is because commercial and residential customers consume by far the most power. KUA is much more marginal and its tariff structure plays a role in commercial revenue being the highest.

[29] A breakdown by customer segment is not available for PUC because cash power revenue is not separated into residential and commercial customers.

Figure D.4: Utility Revenue by Customer Segment



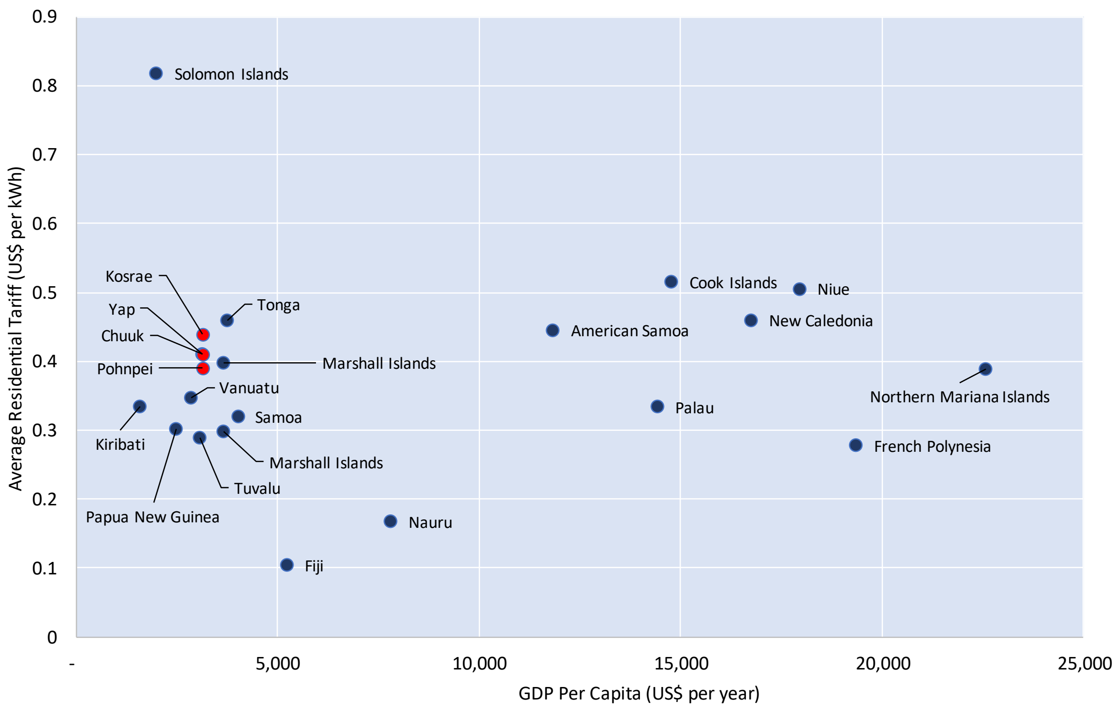
*PUC breakdown not available

Source: CPUC, KUA, PUC, YSPSC

Current tariffs in FSM compare favourably to those in other Pacific Islands

Figure D.5 shows that, compared to their peers in the Pacific, the utilities in FSM have low tariffs for residential customers.

Figure D.5: Comparison of Residential Tariffs for Pacific Island Nations



Source: Castalia based on data from the Pacific Power Association (June 2017. "Benchmarking Report: 2015 Fiscal Year"), World Bank, and FSM utilities.

Collection rates are generally high in the four states of the FSM and are not contributing to poor financial performance

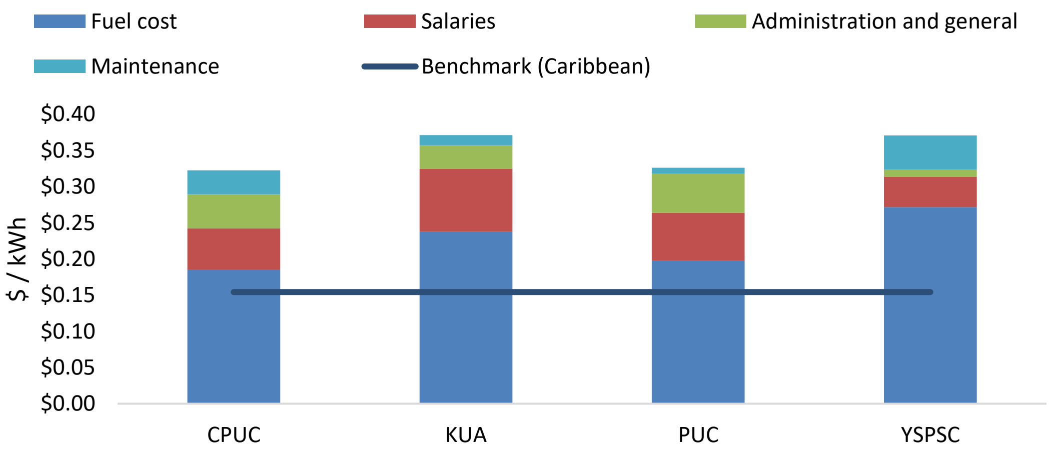
Cashpower is used as a tool to ensure payment rates are high. In Chuuk and Kosrae, 100 percent of residential customers are on cash power, and most residential customers in Pohnpei are also on cash power. In Yap, delinquent post-paid customers are transferred to cash power. In the period FY2012 to FY2016, Yap has averaged a collection rate of 87 percent on the main island and 71 percent on outer islands.

D.2.2 Reliance on imported fuel leads to a high cost of generation in the FSM

The cost of generation is high in the FSM relative to an international benchmark for island utilities. Reducing reliance on imported diesel will reduce the cost of electricity generation in all states of the FSM. For all four utilities, fuel cost is the largest component of cost per unit of electricity sold.

YSPSC is particularly vulnerable to fuel cost compared to the other utilities. Fuel cost per MWh sold is the highest for YSPSC, and a fuel cost correction is not built into tariffs.

Figure D.6: Cost per kWh of Electricity Sold



Note: Salaries, and Administration and general are for the entire utility rather than the power business only. YSPSC includes costs for mini-grids as well as the main grid

Depreciation and asset impairment excluded

Source: CPUC with publicly available data from Bahamas Electricity Corporation, Barbados Light and Power Co. Ltd., AES Andres, AES Itabo, Consorcio Energetico Punta Cana-Macao, Empresa Distribuidora de Electricidad del Este, Energia que Potencia del Desarollo, Empressa de Generacion Hidroelectrica Dominicana, Empresa de Transmision Electrica Dominicana, Jamaica Public Service Company Ltd., Energie Bedrijven Suriname, and Trinidad and Tobago Electricity Comission; Kosrae Utilities Authority. Financial Statements, and Independent Auditors' Report. Years ended September 30, 2016 and 2015; Pohnpei Utilities Corporation. Financial Statements, Additional Information and Independent Auditors' Report. Years ended September 30, 2016 and 2015; YSPSC; Yap State Public Service Corporation. Financial Statements and Independent Auditors' Report. September 30, 2016 and 2015.

Appendix E: Implementation Plans – Risk Assessment

As all states will use similar technologies, infrastructure, and institutional arrangements, many risks of the State Energy Master Plan investments are common to all states. The State Energy Master Plans highlight state-specific risks that exist because of the use of specific technologies or the geographic or social context in one state.

Here we highlight the broader technical, environmental, social, and institutional risks associated with the State Energy Master Plans, and suggest measures to prevent, mitigate, or compensate for, the impacts. Appendix F discusses the social context and risks in more detail, and Appendix G the environmental risks.

The proposed State Energy Master Plans include the costs of measures to mitigate some of the main risks (see Appendix B for more details of our assumptions). In particular:

- **Technical risks**—for example, we include storage capacity to reduce the risks associated with intermittency of solar generation, and assume limited use of diesel for generation in remote islands to make it easier to arrange logistics
- **Institutional risks**—for example, the investment plan provides for Cashpower for all mini-grids and stand-alone solar systems, to reduce the risk of collecting payments
- **Environmental risks**—For example, the plan provides for batteries from stand-alone systems in outer islands to be taken to the main island for proper disposal; the quantity of waste oil will fall significantly as the use of diesel decreases
- **Social risks**—For example, we assume that infrastructure will be placed on existing utility or public land if possible. We also do not include Rumung in the Yap State Energy Master Plan, as this community does not wish to use electricity.

Table E.1 highlights the main risks involved with different technologies and investment types, as well as more general risks associated with implementing the State Energy Master Plans. It also identifies possible mitigation measures.

This preliminary assessment does not replace the wider feasibility studies that are being carried out for selected projects, or the standard EPA process that would need to be followed as projects advanced towards implementation.

Table E.1: Technical, Institutional, Environmental, Social, and Other Risks

Technology / Investment type	Activities	Potential Impacts	Measures to prevent, minimize, mitigate or compensate for impacts
Solar PV	▪ Installing and maintaining panels	▪ Removal of neighboring assets (trees etc.) to avoid shading.	▪ Try to minimize removal ▪ Confirm no sensitive species affected
	▪ Installing panels	▪ Land acquisition.	▪ Use existing utility or public land and rooftops where possible (or potentially install panels over water—although this would increase the cost) ▪ If land needs to be purchased/leased, making sure the owners get a fair deal ▪ If land is donated, following World Bank guidelines (for example, must be less than 10 percent of the owner's land)
	▪ Use of batteries (especially in remote islands)	▪ Contamination from inappropriate disposal of used batteries. ▪ Costs of shipping out old batteries.	▪ The State Energy Master Plans provide for the costs of shipping used batteries to the main islands for appropriate disposal
Hydropower	▪ Changes to water use and river flow patterns. ▪ Inundation of land ▪ Dam construction	▪ Changes to river habitats, affecting migration, breeding, and feeding of in-river species. ▪ Changes to water quality and availability for other water users.	▪ A specific assessment would need to be done for the proposed Lehnmesi site, to identify risks and mitigation measures
Wind Farms	▪ Turbine construction and operation ▪ Road access	▪ Land acquisition ▪ Land clearance ▪ Bird strike	▪ The State Energy Master Plans do not include any additional wind capacity ▪ YSPSC will need to meet environmental requirements and mitigation measures as already agreed with the Yap State EPA for the existing wind farm

Technology / Investment type	Activities	Potential Impacts	Measures to prevent, minimize, mitigate or compensate for impacts
Diesel	▪ Discharges to air	▪ Discharges of emissions to air affecting ambient air quality.	▪ State Energy Master Plan does not propose any specific measures for minimizing particulates with the future purchase of standard diesel engines
	▪ Construction of energy facility	▪ Land acquisition.	▪ On the main islands, the State Energy Master Plans assume all new diesel capacity occurs at existing power station sites ▪ For mini-grids, the State Energy Master Plans assume the generators will be placed on public land, where possible. The issue of land acquisition will need to be assessed on a case-by-case basis
	▪ Fuel transport and storage	▪ Contamination from spillages, and leaks during handling. ▪ Logistics, security of supply risk, and reliance on imports for diesel-hybrid mini-grids in outer islands	▪ For mini-grids, the State Energy Master Plans assume very limited use of diesel on outer islands to reflect logistical and environmental risks of transporting and storing diesel in remote locations
	▪ Waste oil	▪ Environmental contamination	▪ The State Energy Master Plans result in a large reduction in diesel generation, and hence the quantity of waste oil. ▪ Chuuk already has a procedure in place ▪ Other utilities will need to identify an appropriate procedure, such as shipping out drums of waste oil on the regular supply boat and then to Guam (which is expensive), or incineration (which could perhaps be coupled with waste heat recovery)

Technology / Investment type	Activities	Potential Impacts	Measures to prevent, minimize, mitigate or compensate for impacts
	▪ Noise pollution		▪ Construct enclosures around the machines (however, in tropical environments this makes them very hot and so is not recommended) ▪ Careful site selection away from houses, and keeping residential development well away from the power station ▪ All staff should wear ear protection
Distribution lines	▪ Installing and maintaining lines	▪ Weather risks (for example, storms, erosion, corrosion, and typhoons) ▪ Safety	▪ All mini-grid distribution networks in the State Energy Master Plans are underground LV networks, except for a 13.8kV overhead network for the Tonoas Group ▪ Provide ongoing safety training for workers
General Risks		▪ Equitable access to services or facilities	▪ Use a clear, transparent, and fair method for sequencing project rollout sequencing ▪ Prioritize public facilities ▪ Obtain stakeholder buy-in before rolling out infrastructure
		▪ Social conflict	▪ Ensure transparency, consultation, and participation so that no project proceeds without broad community consensus ▪ The State Energy Master Plan for Yap does not cover Rumung, as this community prefers not to use electricity ▪ The proposed solution for Walung balances cost and equity considerations

Technology / Investment type	Activities	Potential Impacts	Measures to prevent, minimize, mitigate or compensate for impacts
		▪ Less reliability from intermittency of RE, particularly solar and wind, and the associated extreme weather and climate risks	▪ The State Energy Master Plans provide backup generators and battery storage that will help meet the agreed reliability standards
		▪ Scale/reliability of supporting infrastructure required to achieve least-cost plans, particularly telecoms, roads, shipping and port services and difficulties associated with shipping all raw materials for civils works to remote atolls.	▪ Plan combined rollout of infrastructure (for example, telecommunications) ▪ The State Energy Master Plan identifies an interim solution (radio) to facilitate Cashpower transactions and fault-reporting from remote islands without telecoms
		▪ Finding staff with the required skills	The State Energy Master Plans: ▪ Include training budgets ▪ Involve stand-alone solar systems for very remote locations where there are no skilled staff, since SHS use very low voltage and are safer for unskilled workers ▪ Use a 13.8kV network on only one, larger, island group where skilled staff can be placed
		▪ Low collection rates	▪ The State Energy Master Plans factor in prepay systems for all connections (including stand-alone solar systems)
		▪ Resource requirements for civil works	▪ The State Energy Master Plans factor in the cost of shipping all raw materials for civil works (such as concrete and wood) to remote atolls to avoid adverse environmental effects

Source: Castalia and ITP based on World Bank Environmental and Social Management Framework for the Energy Sector Development Project for FSM, research, and stakeholder consultations

Appendix F: Implementation Plan – Social Assessment

Confidential

Energy Master Plans for the Federated States of Micronesia

State Social Assessments Report to the Department of Resources and Development

April 2018

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Appendices

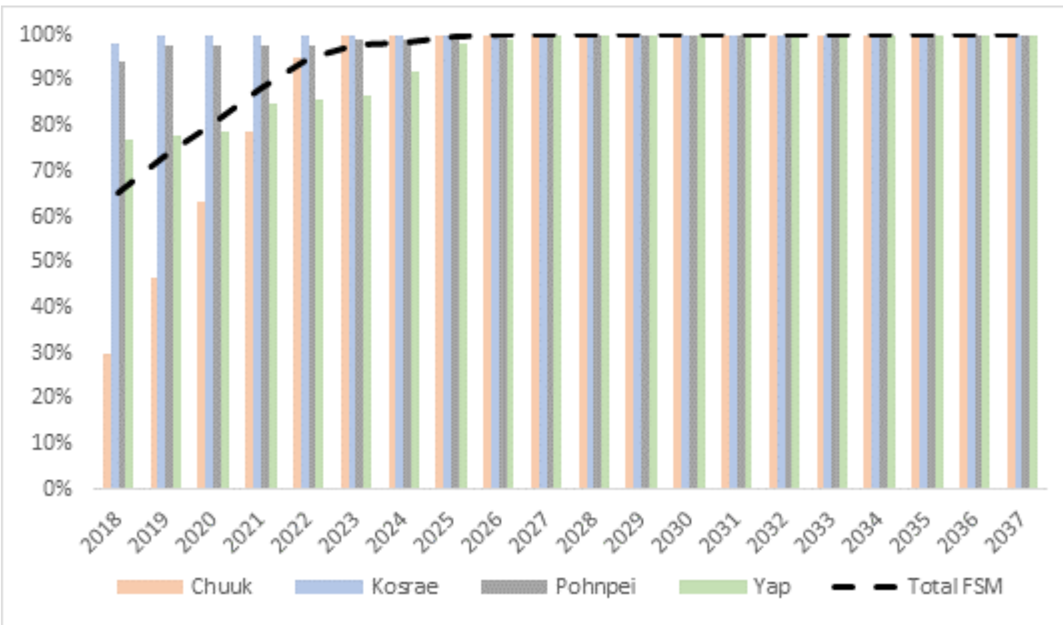
Tables

Figures

1 Introduction

The State Energy Master Plans (the Master Plans) directly contribute to a key social objective for the Federated States of Micronesia (FSM): to 'improve the life and livelihood of all FSM residents with affordable, reliable and environmentally sound energy'. The Master Plans have been designed to achieve near 100 percent electrification within 5 years as shown in Figure 1.1. The Master Plans also provide for a financing and funding framework that would enable currently unelectrified households to access electricity at the same price per kWh as all other households within their State. Since the cost of serving households on the outer islands will be significantly higher than the cost of serving households on the main islands, this financing framework provides for a degree of cross-subsidization between consumers on the main islands and consumers on the outer islands.

Figure 1.1: Electricity Access in FSM



Source: FSM Energy Master Plans

This report evaluates the social impact of the proposed Master Plans. This evaluation consists of three components:

- We assess the social impact of the current level and pattern of electricity access across the FSM, including the effects on health, gender and poverty. This assessment starts with a review of national level issues (National Social Assessment) and then focuses on the impacts in each State (State Social Assessments)
- We review the affordability of the expected tariffs required to implement the Master Plans
- We compare the proposed outcomes under the Master Plans with the business as usual situation.

We conclude with recommendations on issues requiring mitigation or management as part of master-planning.

We used information from our community consultations, the 2010 Census, Household Income and Expenditure Survey and information from previous studies to inform this assessment. A summary of our consultations is in Appendix A.

2 National Social Assessment

We discuss common social themes across states in the national section to avoid repetition. Common themes include:

- Health and gender aspects of energy planning
- Poverty in FSM
- Consumer awareness raising requirements.

Information from the National Social Assessment informed different sections of the Master Plans—in particular, the load forecast, the implementation plan, and the affordability sections.

2.1 Health and Gender Issues Related to Electricity in FSM

Our research and consultations highlighted empowerment of women as a social objective for the FSM. During stakeholder consultations, we made particular efforts to invite and meet with women's groups.

Electricity may be less affordable for female-led households relative to male-led households in Chuuk, Pohnpei, and Yap

Across the FSM, female-led households have a lower annual average income than male-led households. Total income[1] for female-led households in FSM in 2013 (latest available data) was 9 percent lower than for male-led households (Figure 2.1). Approximately 20 percent of households in FSM are led by females.[2]

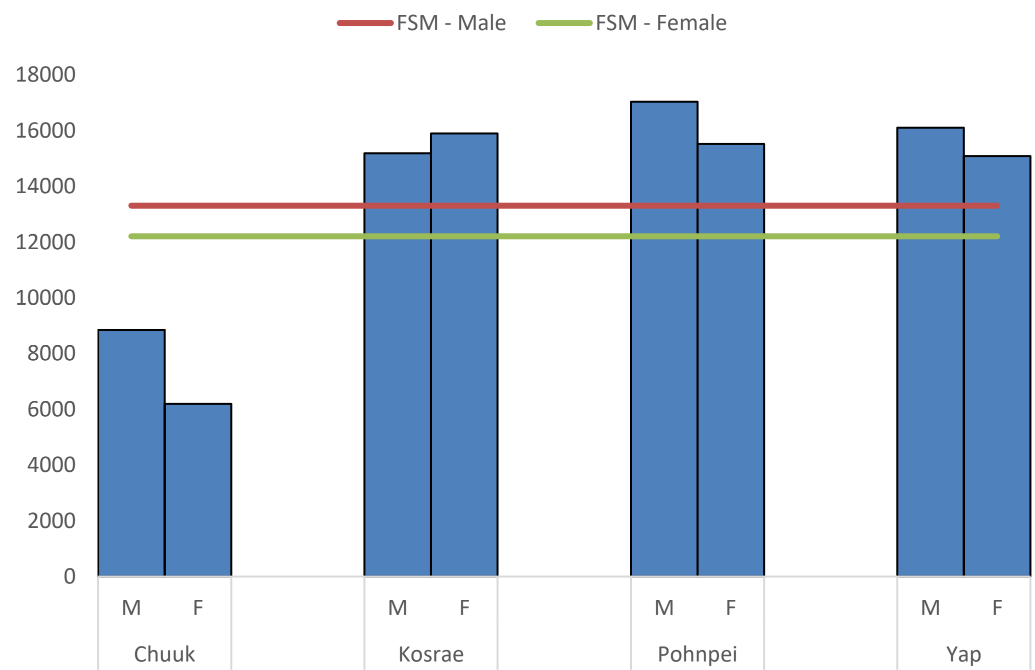
The income gap is particularly significant in Chuuk (40 percent lower for female-led than for male-led households). This is in the context of Chuuk already having significantly lower income per households than other States. In Pohnpei and Yap the income gap is 7 percent and 10 percent respectively.

In Kosrae, the total income of female-led households is higher than for male-led households, but by only two percent. This may reflect a higher proportion of households with male members working outside FSM.

1 Total income excluding imputed rents

2 FSM 2013 HIES

Figure 2.1: Average Annual Household Income by Gender-led Households



Source:2013/2014 FSM HIES

Men and women may have different priorities when it comes to electricity needs

In consultation with teachers in Udot, the men prioritized refrigerators and freezers over streetlights, whereas the women valued street lights due to the safety benefits.

On both Udot (Chuuk) and Falalop, Ulithi (Yap), women expressed a desire for washing machines to save time. This could encourage launderette businesses and the time saved might give women time to participate in other domestic enterprises, such as weaving or making handcrafts.

Both men and women expressed the need for lighting and power sockets to charge cellphones. Lighting can increase productivity in the home, as chores can be done later in the evening, creating time in the day for other activities.

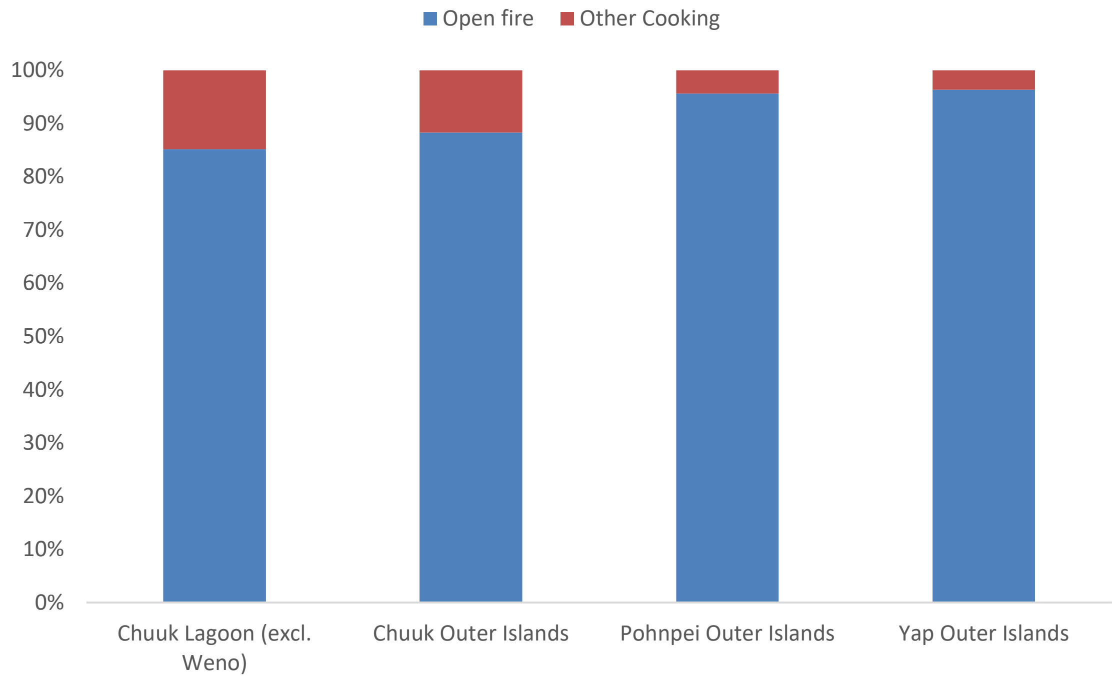
The information gathered on electricity needs helped inform the demand forecast—especially in places with no access to electricity, where estimating demand is more difficult.

Women will experience greater health benefits from using electricity to cook

Exposure to smoke from cooking over an open fire can have negative health impacts, particularly if the fire is in an enclosed space and not well ventilated. Cooking in the outer islands of FSM is usually done over an open fire (see Figure 2.2).

We learned in our consultations that cooking on the outer islands is mostly done by women. As a result, women are more vulnerable than men to adverse health impacts from cooking over an open fire.

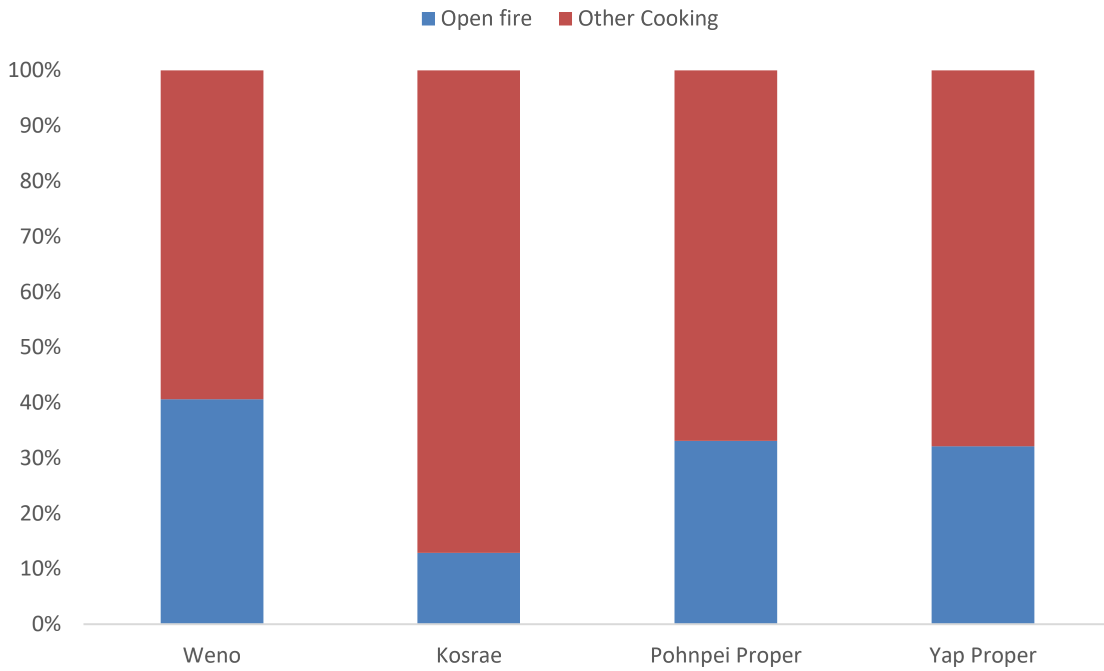
Figure 2.2: Cooking Facilities in Off-Grid Areas



Providing access to electricity will not lead to all households immediately adopting electric cookers. There will be a time lag for people to adopt the new technology and for households to be able to afford the new appliances.

Some households may not adopt electric cooking options even when access has been available for a sustained period. On Weno, Pohnpei Proper, and Yap Proper—where there is grid electricity—between 30 percent and 40 percent of households still use open fires.

Figure 2.3: Cooking Facilities in Grid Areas



Source: FSM 2010 Census

2.2 Poverty in FSM

Households in poverty are disproportionally likely to be without access to electricity. Residents of remote areas that are less likely to have electricity access have on average lower incomes and expenditures,[3] and are more likely to be below the national poverty line. Households below the national poverty line are also less likely to be able to afford upfront costs of electricity connection (connection charges and purchase of appliances).

The poorest quarter of households in the FSM are below the national poverty line as defined by the FSM Division of Statistics (Figure 2.4).[4] The official poverty line expressed in annual expenditure per household equivalent is US$9,662.[5] The fourth decile of households has a total average household expenditure of US$9,591[6].

The total average expenditure per household for all ten deciles is above the official annual food poverty line of US$4,091. On average, expenditure on food and non-alcoholic beverages makes up 34 percent of household expenditure across the FSM. This implies that on average,

[3] Expenditure statistics are considerably more up-to-date and detailed than income statistics. Given the low level of savings, expenditure data is used to proxy incomes.

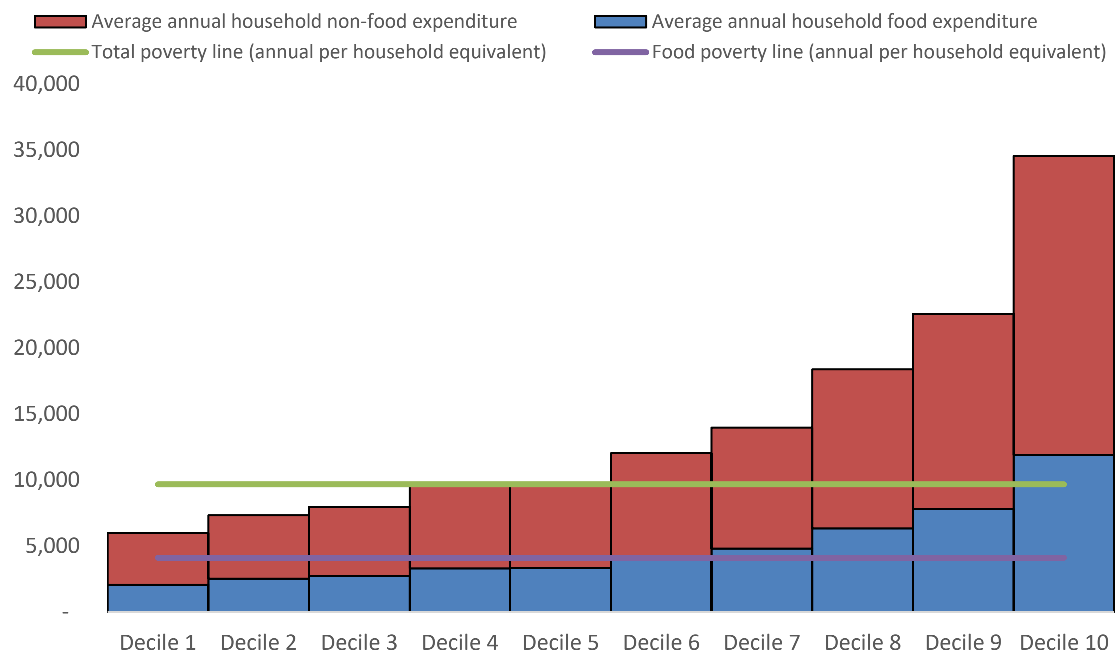
[4] FSM Stats. URL: www.fsmstats.fm/?page_id=276

[5] We calculate the total poverty line per household equivalent using the total poverty line per adult equivalent and the average number of people per household.

[6] Office of Statistics, Budget & Economic Management, Overseas Development Assistance and Compact Management, Government of the Federated States of Micronesia. 2014. Federated States of Micronesia. Household Income and Expenditure Survey 2013/14. Main Analysis Report

households have resources available to purchase energy. However, the poorest two deciles of households have less than $1,000 per annum available after the food budget to meet other expenditure commitments.

Figure 2.4: FSM Average Annual Household Expenditure by Decile (US$)



Source: 2013/2014 FSM HIES, and FSM Stats

2.3 Effect of FSM's Social Context on Master Plan Implementation

Implementation of the Master Plans relies on the availability of energy-project critical inputs. Insufficient availability of these inputs will constrain the implementation of the Master Plans and the achievement of wider development aspirations associated with the Master Plans. The critical inputs we have identified are:

- Ability to acquire land
- Access to staff with required skills
- Ability to collect payment for electricity.

Ability to acquire land

For main grids, we have identified that land availability for the location of photovoltaic projects will require considerable coordination between different levels of government and careful engagement with the land owners. We assume all new diesel capacity, and all storage capacity, will be accommodated at the existing diesel power stations.

In Pohnpei and Chuuk, some of the additional solar capacity could be installed at sites that the utilities have already identified and for which there are unlikely to be concerns around land ownership or land access. In Yap and Kosrae, there are also opportunities to use national and state government-owned land for solar sites. We have also identified opportunity to locate solar panels on the rooftops of government buildings. However, some acquisition of private land will also be required. Our review of the legislation and practice in the FSM confirms that there are no concerns about the risk of forced expropriation of land. Private property rights are well defined and enforced.

We have also identified opportunities for non-land-based location for solar panels, including on floating pontoons in the lagoons. Such opportunities will provide effective solutions to any land constraints.

For mini grids, our initial review of GIS data indicates that generation units can be fully located on public land, but this would need to be confirmed through more detailed assessment before building on each island. The requirements for land access for mini-grid distribution lines would need to be considered carefully in the local context, with consultations for the specific route involved. Again, our review of legislation and practice confirms that private and community property rights are secure, and there is no risk of expropriation. In fact, there is risk of projects being delayed or costs increasing due to demands of land owners.

If mini-grids cannot be built on public land, our research and consultations suggest it may be problematic in some locations to acquire land. Leasing is an option as the owner then gets to retain title. However, people can be wary of leases due to past arrangements where they have only received the first payment. In practice, land owners may demand up-front payment of long-term lease fees.

The level of difficulty varies by State (as well as between main islands and outer islands). More detailed assessment of land issues will be required when feasibility studies are conducted for each project.

Appendix B provides further information on the process for acquiring land in each State.

Finding staff with the required skills

One barrier could be identifying capable staff to manage the mini-grids and stand-alone solar systems. We recommend local staff members be hired to manage mini grids and stand-alone solar systems. People on outer islands are unlikely to have the required skills. Therefore, they would need training from the utilities.

Bringing staff from outer islands to the main islands for training is likely to be more efficient than training on each individual island. We have included training budgets in the Master Plans for this purpose.

As well as training budgets, the Master Plans propose using stand-alone solar systems for very remote locations where there are no skilled staff. Since stand-alone solar systems use very low voltage, they are safer for unskilled workers.

The Master Plans also minimize the use of 13.8kV networks (which require a higher level of skill among staff). For all but one of the mini-grids, the Master Plans propose low-voltage, underground networks as they require less maintenance. Above-ground, we only propose 13.8kV networks for one larger island where skilled staff can be placed.

Collection rates

In the Master Plans we recommend using prepay meters for all stand-alone solar systems and mini-grids (main grids already use them). This increases the cost, but not having prepay meters could result in a low collection rate.

In particular, people with solar home systems may be unwilling to pay a monthly fee. In our consultations, we found that people struggled to understand why they are paying an ongoing fee when they already have the system and the sun is free.

An example of refusal to pay is in Walung in Kosrae. Solar kits were given to households from a donor organization. Households were then meant to pay a small monthly fee to Kosrae Utilities Authority (KUA) for maintenance and for replacement at the end of the solar kit's life span. However, once the kits were given out, no one was willing to pay the tariff to KUA.

As well as prepay meters, there are alternative ways to ensure willingness to pay, including:

- Increasing awareness about operating and maintenance costs. If people understand what they are paying for, they may be more willing to pay. However, this does not work if donors give out new solar systems whenever they break
- The person responsible for collecting payments is a senior person in the community. In our experience from Tuvalu, we found that collection rates tend to be better if the person responsible for collecting payments is an older person and preferably an authority figure
- Making the island council responsible for making a monthly payment for all the systems on its island. The council can then recoup the payment from the families using whatever method it chooses. This method is used in some Tongan island groups.

Our consultations suggest that there is a significant sense of social solidarity, which would encourage people to pay if they are treated like everyone else. For this reason, we recommend that all consumers within each State pay the same per kWh rate through a pre-paid meter regardless of the type of connection available to them (that is, pre-paid meters would be installed for household systems as well as on the mini-grids). While it may be relatively easy for a user of a household system to by-pass the meter, there were strong indications that social solidarity would encourage people not to do so.

2.4 Consumer Awareness-Raising Needs

Consumers need to be aware of how to use electricity efficiently and safely. This will require changes in energy users' appliance purchases and use. Here we describe what we see as the main areas of potential energy efficiency. The Master Plans set out the key messages and approaches for an energy efficiency campaign.

Below, we set out an assessment of the opportunities to improve efficiency of energy use. We recommend promotional campaigns to encourage respective users to change their behavior.

Air conditioning in government buildings

The government sector accounts for 18 percent to 28 percent[7] of electricity consumption in FSM, and air conditioning is the main cause of this. Improving air conditioning design and efficiency—both in terms of the equipment used, and user behaviours—can offer savings of 15 percent to 40 percent of building energy consumption.

An audit of the National Government complex in Palikir was conducted in 2016 and that one of its main recommendations was using more efficient air conditioners. Based on the

[7] Castalia calculations based on data from CPUC, KUA, and YSPSC. Does not include PUC because of insufficient data.

recommendations of the audit report, SPC has recently advertised for a supplier of high-efficiency inverter-type air conditioning units for the complex.

The Yap State Government has also completed an audit of government buildings, which provides recommendations.

Commercial refrigeration

During our research mission, we observed many refrigerated containers ("reefers") outside restaurants, shops, and hotels. These are being used for bulk food refrigeration. Reefers are very inefficient compared to purpose-built cool rooms, and many are also sitting in the sun. Previous studies[8] have found that replacing reefers with cool rooms can reduce energy consumption by 50 percent to 60 percent. Further studies would be needed to quantify reefer energy consumption in FSM and develop a program for replacement.

Many of the reefers are owned by commercial operators (shops and restaurants) and are used for bulk storage of chilled food at both refrigeration and freezer temperatures. We do not know exactly how many reefers are used at each premise, but small shops and hotels typically use one reefer to five reefers per site. The reefers offer a flexible means of storing food but are very energy inefficient.

Research from Tuvalu shows that reefers typically use about 800kWh per reefer per month when operated outdoors in the sun.

Commercial premises can achieve large cost savings by installing purpose-built cool rooms to replace reefers. This is dependent on shops having sufficient space for a cool room, and a willingness to alter their operations to use a cool room rather than reefers.

Cool rooms are likely to cost US$15,000 to US$30,000 per site. They operate much more efficiently than reefers at the wharf, offering large electricity cost savings. Reefers, by contrast, have no upfront costs as they are typically rented on a weekly or monthly basis. Simple payback periods for cool rooms as reefer replacements are typically less than 3 years.

Assuming refrigeration accounts for 30 percent to 40 percent of commercial energy consumption, savings of about 12 million kWh per year are theoretically possible in FSM. The cost of this would be in the order of US$15 million across all states.

On Kosrae, there are 20 x 40ft reefers used for fish storage near the wharf. On Pohnpei, the number is unknown, but we estimate 100 reefers. In Chuuk, we estimate 60 reefers. In Yap, we estimate 30 reefers to 40 reefers plus wharf reefers.

Buildings

Building design standards can have a major impact on energy consumption. Standards that mandate sealed buildings and use of concrete led to very high energy consumption compared with more traditional styles that rely on natural ventilation and low thermal mass. A review of building standards would help to identify locally appropriate designs that can help reduce air conditioning use in the long-term.

Some of the State Energy Action Plans already include actions in this area. For example, Chuuk's State Energy Action Plan proposes to: "Formulate and establish legislation for an

[8] ITP completed reefer replacement studies for Tuvalu and Tonga in 2012 and 2014.

Energy Efficient Building Code to improve living standards, health and education by 2017”. We understand that this has not yet been done.

Other areas

Lighting replacement programs for government and commercial customers are already underway, so it is unlikely that further savings can be achieved by additional government initiatives in this area. The 2016 audit of the National Government complex in Palikir identified using energy efficient lights as a priority, and SPC has recently advertised for a supplier of LED T8 19W lights to replace the existing T12 linear fluorescent lights in the complex.

3 Chuuk State Social Assessment

The Chuuk State Social Assessment includes state aspirations, socioeconomic context, energy consumption, and willingness to pay. This information was used to inform different areas of the Master Plans, including the load forecast, affordability, and implementation. Social themes that were common for all states are discussed in the National Social Assessment to avoid repetition.

We used information from our community consultations, the 2010 Census, HIES, and other documents to inform this assessment. Information from the HIES groups people into three strata:

- Urban: Easy access to essential services and facilities. For Chuuk, this just includes Weno
- Rural: Medium access to essential services and facilities. This includes the rest of the lagoon islands
- Remote: Rare access to essential services and facilities. This includes all the outer islands.

3.1 State Development Aspirations

The most recent FSM-wide development aspirations were determined in an economic and strategic planning meeting in 2012.[9] In this meeting FSM sought development partner support across four broad development areas:[10]

- Growing the local economy through enhancing agriculture production and the production of value added agriculture products, maximizing benefits of FSM's fisheries resources, promoting tourism, and developing clean, renewable energy sources
- Developing economic infrastructure, including transport, communications, and power
- Improving health and education services
- Mainstreaming responses to climate change and mitigating threats to the environment.

Based on these nation-wide aspirations, Chuuk has laid out state specific development aspirations in the Chuuk State Development Plan. The Chuuk State Development Plan identifies ten sectors for development covering social, economic, and environmental development. The ten sectors are: health, education, tourism, marine resources, environment, social, agriculture, private sector, energy, and infrastructure. The Chuuk State Energy Master Plan will contribute to all these sectors either directly or indirectly by providing improved electricity service reliability and increasing access. We have assessed how the Master Plan will contribute to each sector in Table 3.2.

[9] The purpose of this meeting was to update and accelerate national development aspirations from the FSM Strategic Development Plan (2004-2023)

[10] Federated States of Micronesia Infrastructure Development Plan FY2016-FY2025 Volume 1

Table 3.1: Chuuk State Strategic Development Sectors

Development Sector	Sector detail	How can the Energy Master Plan contribute?
Health	Maintenance or improvement of health by the diagnosis, treatment, and prevention of disease, illness, injury, and other physical and mental deficiencies	▪ Hospitals and dispensaries need reliable electricity for medical equipment, lighting, and refrigeration of medicines and vaccines ▪ Electricity access will improve access to IT, which in turn provides access to information that will raise awareness about physical and mental issues ▪ Electricity access will improve access to information that will raise awareness about good practice for prevention of disease and illness
Education	Improving literacy, numeracy, and skill of labor force	▪ In our consultations on Udot, participants agreed that education is a priority for electricity ▪ Electricity access will provide lighting at schools to allow students to study when natural light is insufficient. Schools are also often used for community meetings in the evenings ▪ Electricity access will improve access to educational resources through IT and the internet
Tourism	Deals with visitors coming into Chuuk for recreational purposes and the needed products (goods and services) and infrastructures	▪ Reliable access to electricity will make Chuuk a more attractive tourist destination by improving the service provided by hotels, restaurants, and other tourism operators
Marine Resources	Protecting Chuuk's marine biodiversity while providing necessary steps that create social and economic benefits through marine resources	▪ Improved access and reliability of electricity will support the adoption of technologies to improve monitoring of fisheries and other marine resources
Environmental Sector	Deals with Chuuk's natural surroundings, human environment and the impending environmental threats and disasters	▪ The Master Plan will ensure electricity supply meets required environmental standards and has minimal adverse impacts on the environment ▪ Key environmental considerations are: – Disposal of batteries – Fuel storage – Achieving renewable energy targets – Contributing to national emissions reduction targets

Development Sector	Sector detail	How can the Energy Master Plan contribute?
Social	Focuses on gender equality, youth development, disabled rights, and senior citizens support	▪ The Master Plans can contribute to this aspiration by ensuring that different groups within each community have equal voice about future electrification plans
Agriculture	Focuses on protecting terrestrial biodiversity but at the same time allows room for social and economic benefit from terrestrial resources	▪ Improved access and reliability of electricity will support the adoption of technologies to improve monitoring and documenting of terrestrial biodiversity ▪ Increased reliability of electricity supply could lead to adoption of modern agricultural technologies and increase productivity ▪ Reliable electricity supply will be essential for any potential agricultural product processing facilities to produce value-added products. This includes the planned copra processing plant on Tonoas
Private	Economic development through business activities	▪ Improving electricity supply reliability will reduce damage and productivity loss due to outages and allow business to better plan for the future
Energy	Energy sources which provides electrification, fuel and so forth for Chuuk State and the best approach to prevent lack of or shortages	▪ The Master Plan aims to directly develop this sector
Infrastructure	Looks at the various infrastructures needed for development in Chuuk state in all development areas	▪ Reliable access to electricity will help develop communications infrastructure, particularly outside Weno ▪ The Master Plan includes regular service trips to outer islands, which will stimulate increased transport links to these areas

Source: Castalia based on Chuuk State Strategic Development Plan

3.2 Socioeconomic Context

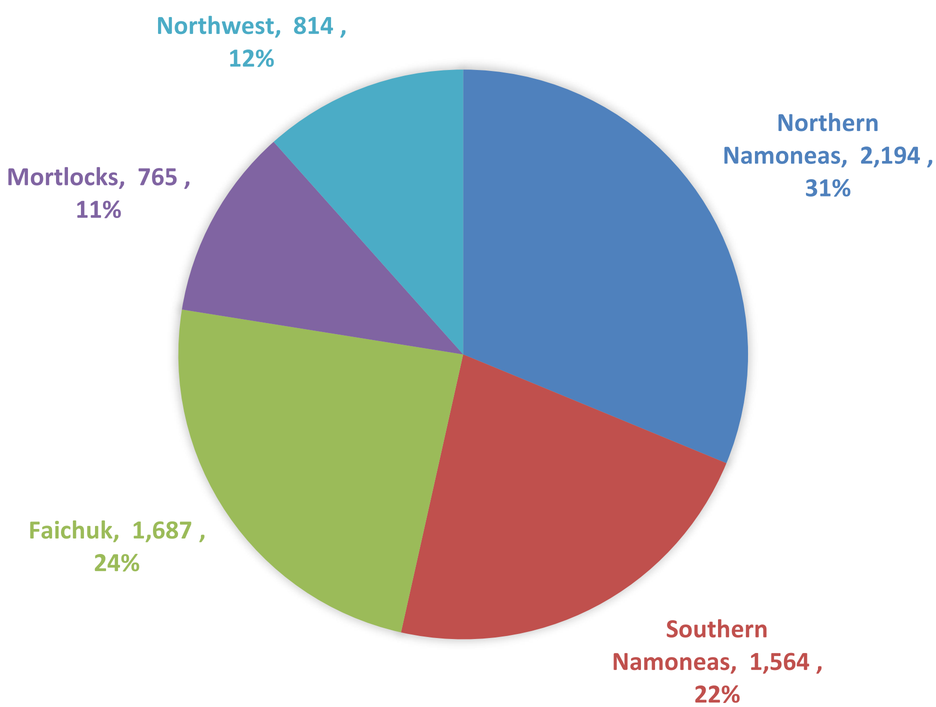
Here we discuss Chuuk's population, incomes, and labor force characteristics. In each section, we highlight how the information was used in the Master Plan.

3.2.1 Population

Chuuk has the largest population of the four states. In 2010, there were 7,024 occupied households, 42 percent of total households in FSM.[11]

The Northern Namoneas has the most households in Chuuk (31 percent). This is mainly from Weno, which has 30 percent of total Chuuk households. Figure 3.1 breaks down the percentage of households in Chuuk by island group.

Figure 3.1: Percentage of Chuuk Households by Island Group

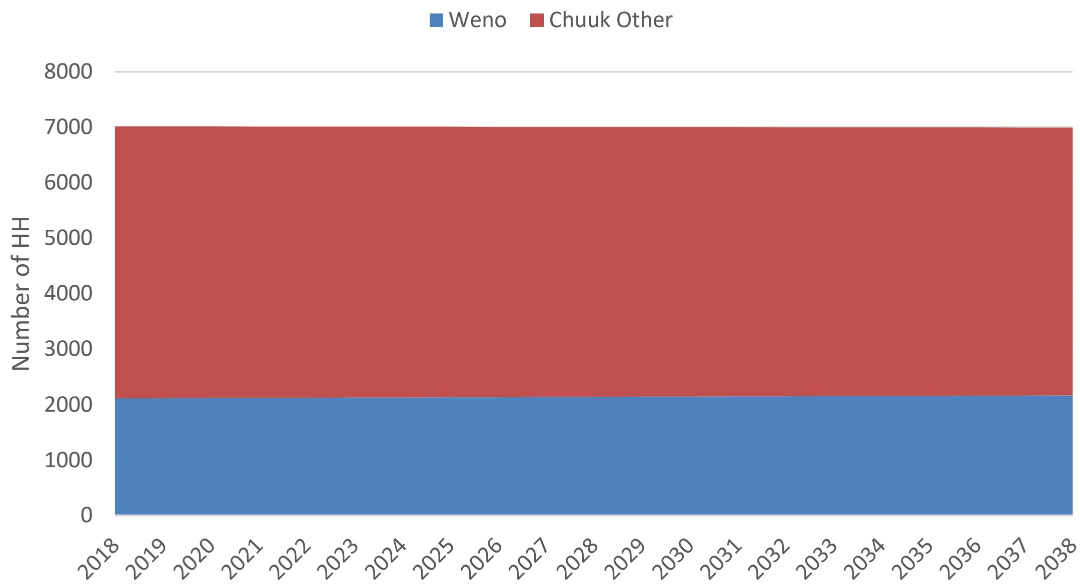


Source: FSM 2010 Census

The number of households in Weno increased at an annual rate of 0.12 percent per year between 1994 and 2010. Elsewhere in Chuuk, the number of households decreased by 0.08 percent in the same period. We used the geometric average historical growth rates to forecast household numbers for the Master Plan. Based on these assumptions, the population changes very little over the next 20 years (as shown in Figure 3.2).

[11] FSM 2010 Census

Figure 3.2: Chuuk Population Forecast



Castalia, based on consultations

The population forecast informed the load forecast in the Master Plan. The load forecast is an estimate of how much electricity needs to be produced to satisfy demand over the next 20 years. Demand depends on population size (as well as ability to pay, discussed in the next section). An accurate load forecast leads to investing in the right amount of infrastructure. Over-investment in infrastructure can increase costs whereas under-investment can lead to unserved demand.

3.2.2 Incomes

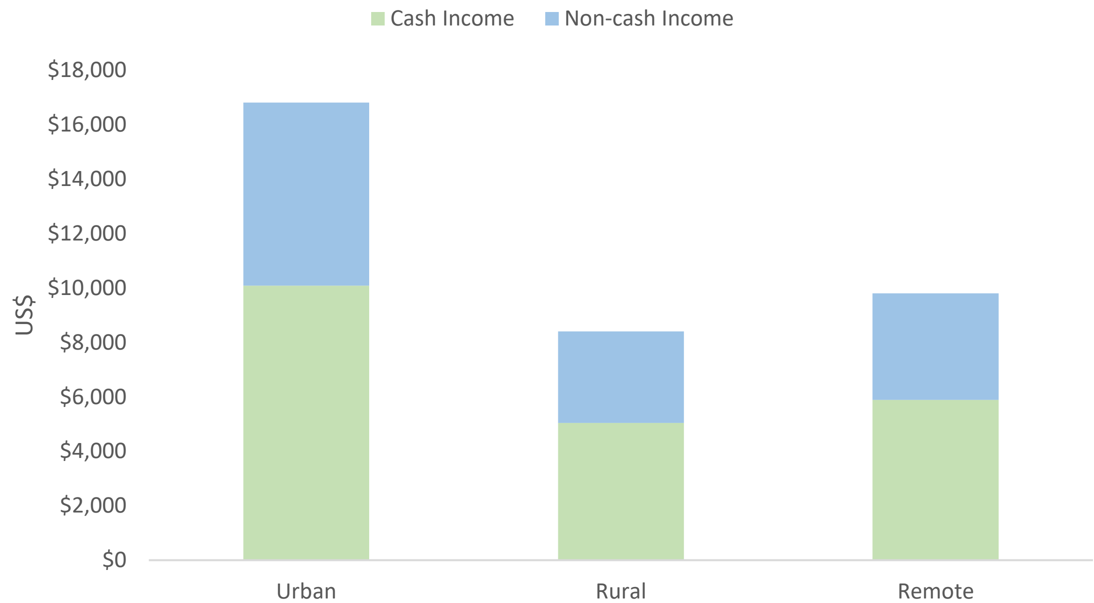
The level of distribution of income are important social considerations.

Average annual incomes are much higher in urban areas than rural or remote areas, shown in Figure 3.3

To assess ability and willingness to pay, we considered only cash incomes, as electricity will be paid for in cash. Cash income accounts for 60 percent of total income in Chuuk. The other 40 percent is non-cash income, which includes all goods consumed that are not paid for with cash (home production, imputed rents, and in-kind transfers).

We do not have a breakdown of cash income for individual strata (or different parts of the state), so we have applied the 60 percent state-average to all three for illustrative purposes. Cash incomes are likely to be lower in rural and remote areas where a bigger percentage of the population is engaged in subsistence farming and fishing.

Figure 3.3: Chuuk Average Annual Household Income



Source: 2013/2014 FSM HIES

The average incomes found by the Balance Group in Satowan are consistent with our estimates based on the HIES. From surveys in Satowan (a 'remote' island) in 2015, the Balance Group found that average household annual cash salaries were US$6,504. This average income is higher than our estimates of US$5,886. However, given the margin of error and the fact that the study was undertaken 2 years later, this appears to be a reasonable estimate.

The Balance Group report also states that 59 percent of the households surveyed reported an annual cash income of less than US$2,600.[12]

3.2.3 Labor force characteristics

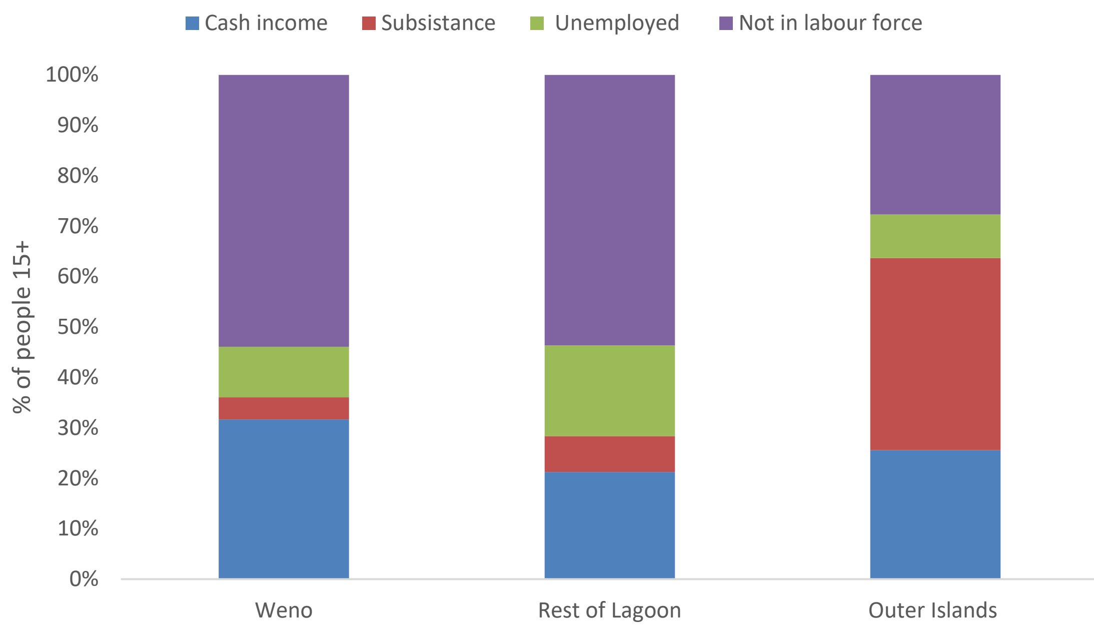
As we do not have cash income by strata for the 2013 HIES, we have considered the labor force characteristics from the 2010 Census. As expected, a higher percentage of people in Weno receive cash income than the other lagoon islands and the outer islands, implying we overestimate cash income for rural and remote residents.

Ability to pay for electricity could be more of an issue for the rest of the lagoon and outer island households than Weno households. In Weno, 32 percent of people over the age of 15 receive cash income, compared to 21 percent in the rest of the lagoon and 26 percent in outer islands. People receiving a cash income are either engaged in formal work or market-oriented home production.

The outer islands in Chuuk have many more people engaged in subsistence work than in the Chuuk Lagoon. They also have fewer people not in the labor force than in the lagoon—indicating that more people have an opportunity to make a productive contribution to subsistence work.

[12] Balance Utility Solutions: Satowan Mini Grid Hybrid Systems, Inception Note and Site Visit Report (May 2015)

Figure 3.4: Chuuk Labor Force Characteristics



Source: FSM 2010 Census

3.3 Energy Consumption

Here we discuss energy expenditure and energy use in Chuuk. We consider how much is spent on energy, what type of energy is consumed, and what the energy is used for. We focus on residential use, but also comment on how much electricity other customer groups use.

3.3.1 Energy expenditure

Households in urban areas spend more on energy in absolute terms, but less as a percentage of their income (see Table 3.2). Since people in urban areas have both better access to electricity and appliances, and have higher incomes, this implies that:

- People in outlying areas spend more on costly (and lower quality) sources of energy than electricity
- People in outlying areas are likely to benefit most from improved access to electricity.

Table 3.2: Chuuk Average Annual Energy Expenditure (2013)

	Urban	Rural	Remote
Estimated cash income	$11,076	$5,044	$5,886
Energy expenditure	$872	$637	$201
Energy expenditure as a percentage of estimated cash income	8%	13%	3%

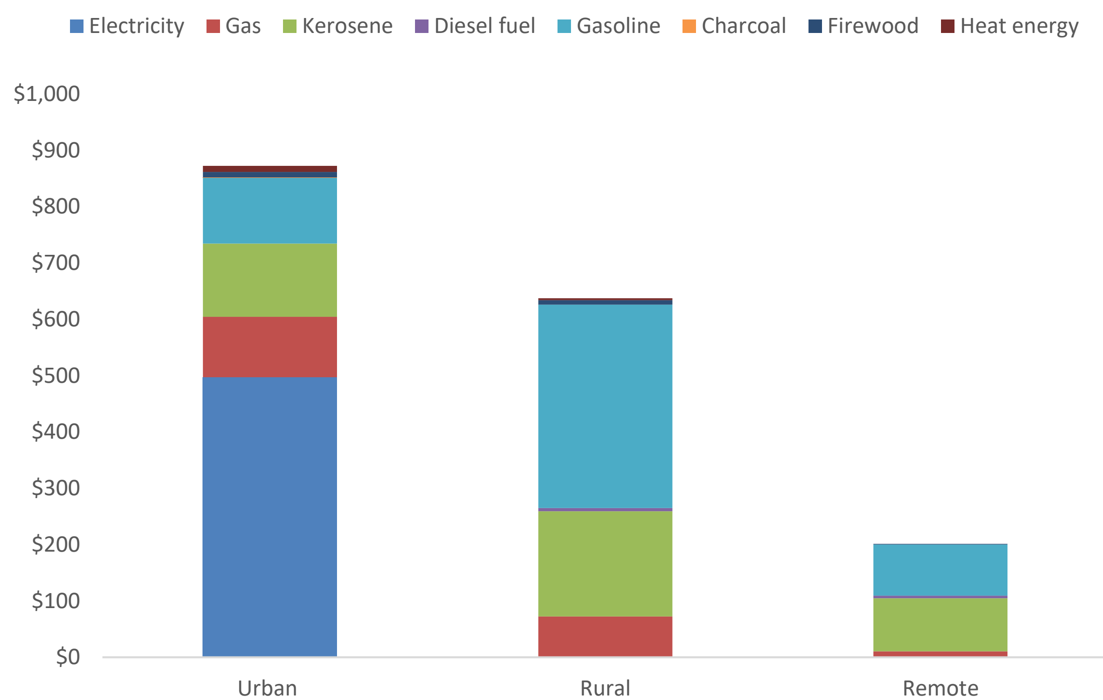
Source: 2013/2014 FSM HIES

The Balance Group surveys found that 49 percent of households in Satowan, a 'remote' island, spend more than US$1,040 on energy per year.[13] This is much higher than the US$201 found for remote islands in the HIES. Again, this confirms that there are significant opportunities for savings from improved access to electricity.

Figure 3.5 breaks down the type of energy that households are buying in urban, rural, and remote areas. People in urban areas spend more money on electricity than other energy sources. Whereas people in rural and remote areas, with less access to electricity, spend more on gasoline and kerosene than other energy sources. Once people in remote and rural areas gain access to electricity, it is likely that it may replace other energy sources.

Firewood accounts for very little energy expenditure across all three strata. This is not because it is not used, but because it is often free.

Figure 3.5: Chuuk Average Annual Energy Expenditure[14]



Source: 2013/2014 FSM HIES

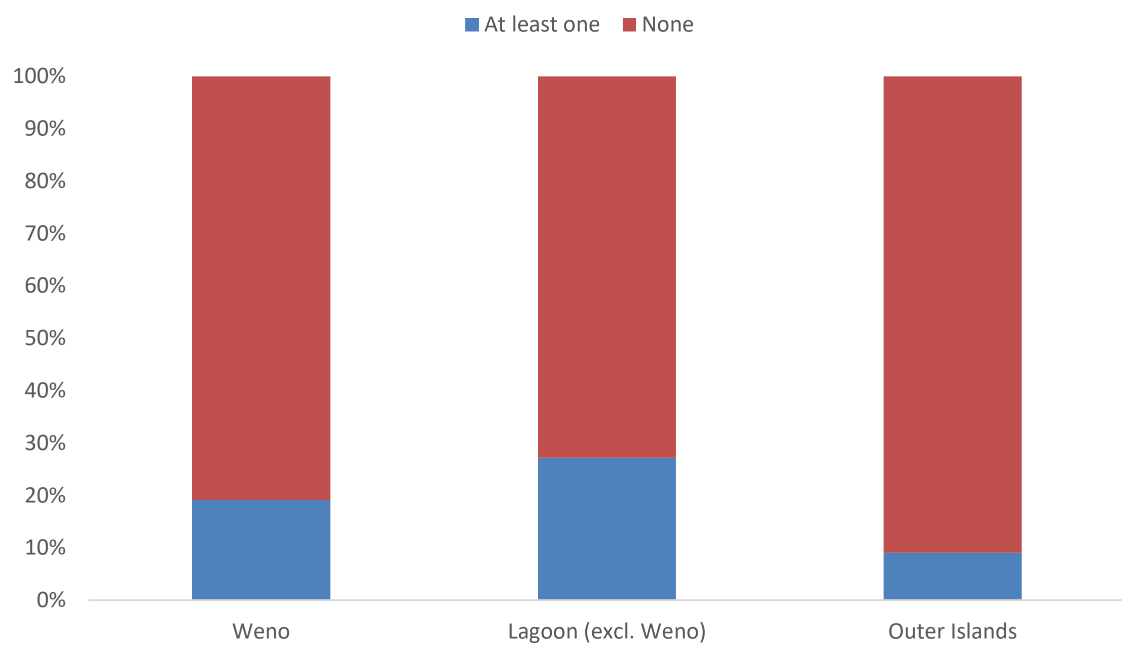
Diesel fuel expenditure is split between diesel used for transport (cars and boats) and for electricity generation. Ownership of diesel generators is highest on lagoon islands outside Weno where diesel is relatively easily to obtain but there is no electricity grid (Figure 3.6). Diesel generators are still more common on Weno than on outer islands. Around 10 percent of Weno's population is not currently connected to the grid, some of whom may own generators. Furthermore, grid-connected residents may own generators as security against

[13] Balance Utility Solutions: Satowan Mini Grid Hybrid Systems, Inception Note and Site Visit Report (May 2015)

[14] Gas includes butane can, propane, and liquid (lpg)

outages. On outer islands, diesel is hard to get so diesel generator ownership is lower than in the lagoon.

Figure 3.6: Diesel Generator Ownership in Chuuk



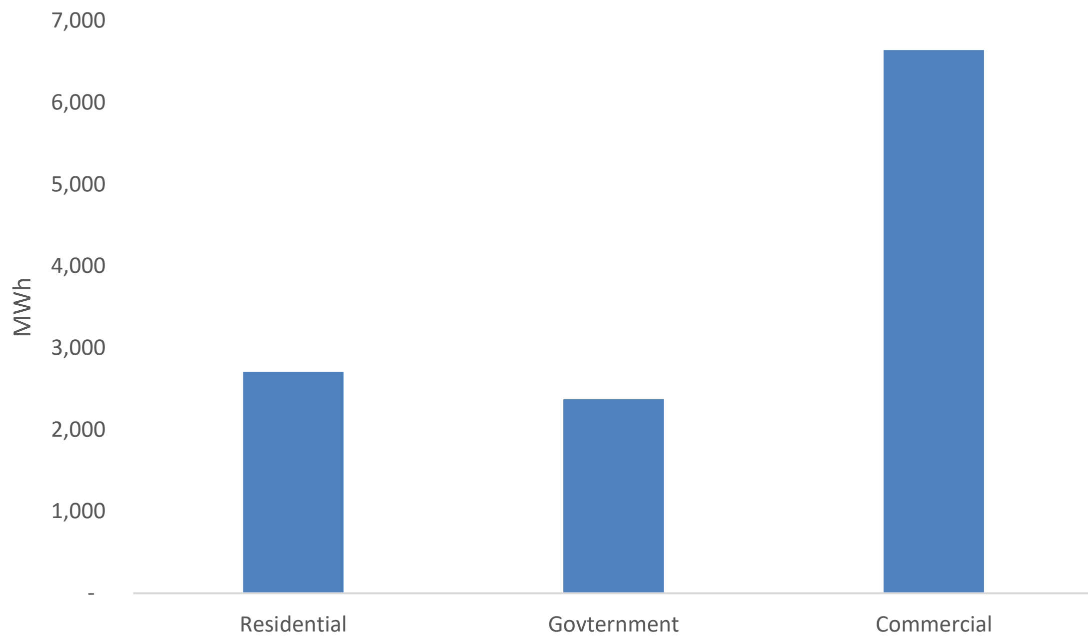
Source: FSM 2010 Census

3.3.2 Energy use

Commercial customers consume the most electricity in Weno out of all customer groups. Figure 3.7 shows how much commercial customers consume per year, as well as residential and government customers.

We used current consumption levels to estimate an electricity load forecast for the next 20 years. The current levels were adjusted for GDP growth, population growth, new commercial projects coming online, and energy efficiency measures, as discussed in the Master Plan.

Figure 3.7: Chuuk Annual Consumption by Customer Group (MWh)



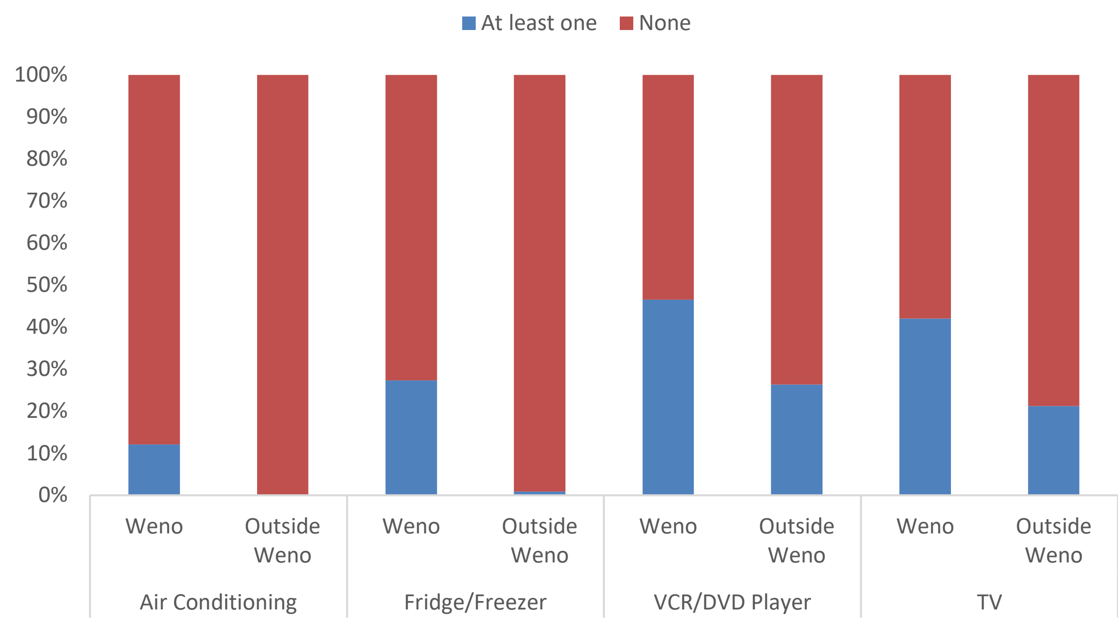
Source: CPUC

Residential use of appliances is different on Weno compared to the rest of Chuuk where there is no grid electricity supply. Less than 1 percent of households outside Weno have air conditioning, while around 12 percent have air conditioning on Weno (Figure 3.8). Across the FSM, residential use of air conditioning is low relative to other appliances. It is likely that residential use of air conditioning will remain low even with improved access and service quality.

Lack of reliable electricity prevents use of refrigerators on the outer islands. Close to 20 percent of homes have a refrigerator in Weno, but only 1 percent have a refrigerator on the outer islands. In our consultations, community members in Udot stated that access to ice for storing food was a priority.

Televisions and DVD players are relatively common outside Weno despite no reliable electricity supply. Each are used by around 20 percent of households outside Weno. In our consultations, residents in remote communities told us that small screens can be charged using solar-lighting kits, and watching movies was common in some areas.

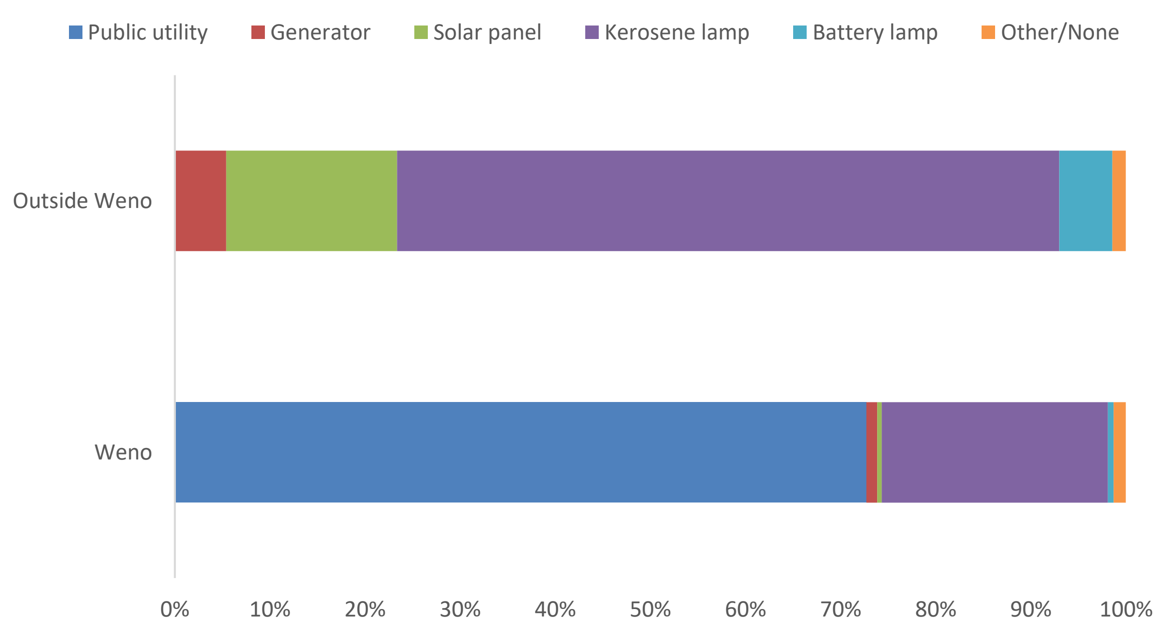
Figure 3.8: Residential Electrical Appliance Use in Chuuk



Source: FSM 2010 Census

Lighting source differs on grid-supplied Weno compared with the rest of Chuuk (Figure 3.9). On Weno public-utility-provided electricity is the main source of lighting for over 70 percent of households. Kerosene lamps are the primary lighting source for households without utility power. Outside Weno, kerosene lamps are the most common source of lighting.

Figure 3.9: Lighting Source on Weno and Areas Outside Weno



Source: FSM 2010 Census

4 Kosrae State Social Assessment

The Kosrae State Social Assessment includes state aspirations, socioeconomic context, energy consumption, and willingness to pay. This information was used to inform different areas of the Master Plan, including the load forecast, affordability, and implementation. Social themes that were common for all states are discussed in the National Social Assessment to avoid repetition.

We used information from our community consultations, the 2010 Census, HIES, as well as other documents to inform this assessment. The HIES considers all of Kosrae as urban, so we do not break down incomes and energy use into strata like we do for the other states.

4.1 State Development Aspirations

The most recent FSM-wide development aspirations were determined in an economic and strategic planning meeting in 2012. [15] In this meeting FSM sought development partner support across four broad development areas: [16]

- Growing the local economy through enhancing agriculture production and the production of value added agriculture products, maximizing benefits of FSM's fisheries resources, promoting tourism, developing clean, renewable energy sources
- Developing economic infrastructure, including transport, communications, and power
- Improving health and education services
- Mainstreaming responses to climate change and mitigating threats to the environment.

Based on these nationwide aspirations, Kosrae has laid out state-specific development aspirations in the Kosrae State Development Plan. There are five designated development sectors in the Kosrae Strategic Development Plan: health, education, environment, private sector, and social and culture. The Kosrae State Energy Master Plan will contribute to all these sectors either directly or indirectly by providing improved service reliability and increasing access. We have assessed how the Master Plan will contribute to each sector in Table 4.1.

[15] The purpose of this meeting was to update and accelerate national development aspirations from the FSM Strategic Development Plan (2004-2023)

[16] Federated States of Micronesia Infrastructure Development Plan FY2016-FY2025 Volume 1

Table 4.1: Kosrae State Strategic Development Sectors

Development Sector	Sector detail	How the Master Plans can contribute
Health	Good health standards – low infant mortality and increasing/higher life expectancy – correlate to higher economic growth and thus equate to a good standard of living	▪ Hospitals and dispensaries need reliable electricity for medical equipment, lighting and refrigeration of medicines and vaccines ▪ Increased and more reliable supply is important for the planned new hospital
Education	Education plays a role in preparing and developing the labor force to support development	▪ Provide lighting to allow students to study when natural light is insufficient ▪ Electricity access will improve access to resources through IT and the internet
Environment	Managing development to ensure sustainable use of the natural environment and resources, and ultimately ensure future generations of Kosraeans also benefit from Kosrae's natural resources and natural heritage	▪ The Master Plan will ensure electricity supply meets required environmental standards and has minimal adverse impacts on the environment ▪ Environmental considerations are: – Disposal of batteries – Fuel storage – Achieving renewable energy targets – Achieving emission reduction targets
Private Sector	Produces jobs, provides incomes, and plays a role in for the economic wellbeing of Kosrae	▪ Improving electricity supply reliability will reduce damages due to outages and allow business to better plan
Social and Culture	Preserving and promoting a way of life that promotes the safety, equality, and social development of the Kosrae citizenry	▪ Increasing electricity access promotes social development by improving education and healthcare facilities

Source: Castalia based on Kosrae State Infrastructure Development Plan FY2016-FY2025

4.2 Socioeconomic Context

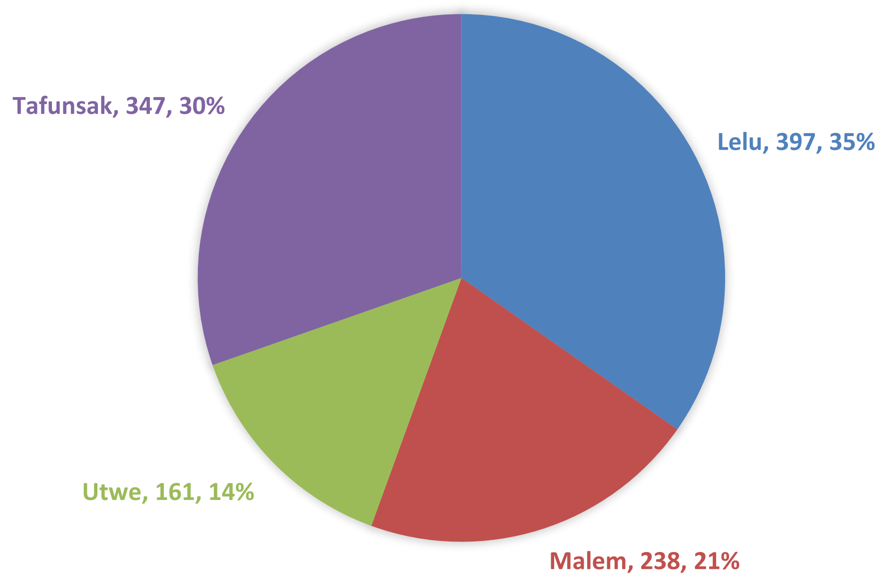
Here we discuss Kosrae's population, incomes, and labor force characteristics. In each section, we highlight how they were used to inform the Master Plan.

4.2.1 Population

In 2010, Kosrae had 1,143 occupied households, 7 percent of total households in FSM.[17] Figure 4.1 breaks down the percentage of households in each municipality in Kosrae. Lelu, which includes the state capital, has the most households (35 percent).

Walung consists of about 23 households and falls within the Tafunsak municipality. Walung is not connected to the main grid and so was considered separately in the Master Plan.

Figure 4.1: Percentage and Number of Households in Kosrae by Municipality

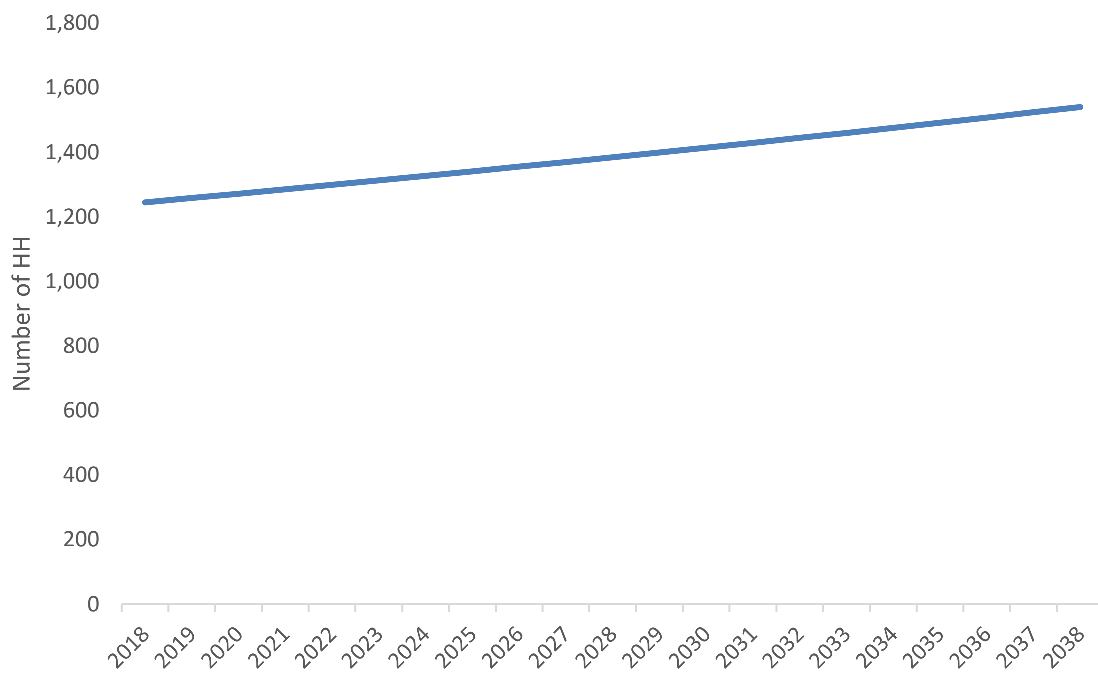


Source: FSM 2010 Census

The number of households in Kosrae increased at an annual rate of 1.07 percent per year between 1994 and 2010. We used the geometric average historical growth rates to forecast household numbers over the next 20 years. The population forecast was used to inform the load forecast in the Master Plan.

[17] FSM 2010 Census

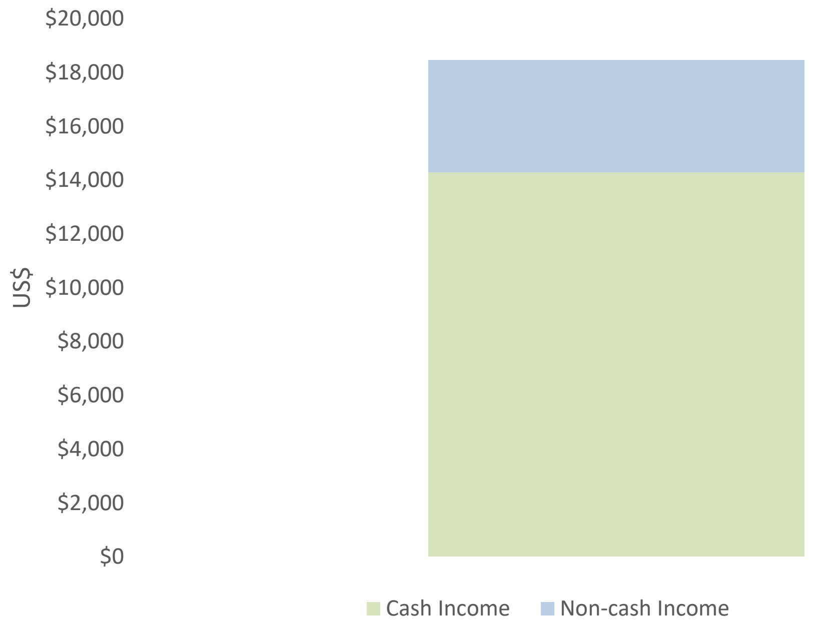
Figure 4.2: Kosrae Forecast for Number of Households



4.2.2 Incomes

Average annual incomes in Kosrae were US$18,466 in 2013 (see Figure 4.3). However, 23 percent of total income was non-cash income, this means it came from home production, imputed rents, and in-kind gifts. To assess willingness to pay, we considered only cash incomes, as electricity will be paid for in cash.

Figure 4.3: Kosrae Average Annual Household Income

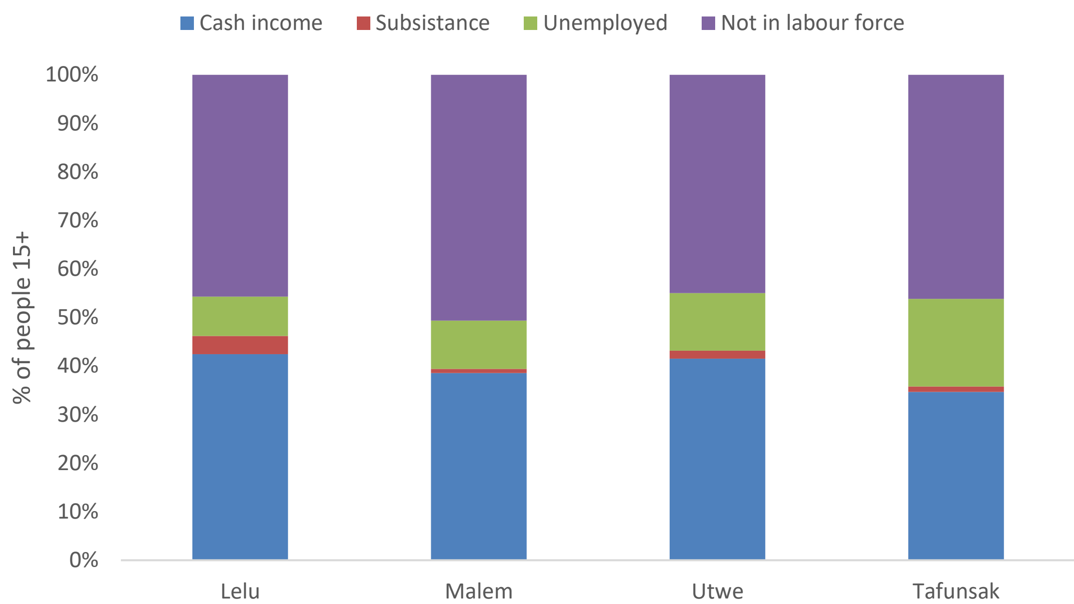


Source: 2013/2014 FSM HIES

4.2.3 Labor force characteristics

The municipalities of Kosrae all have similar percentages of people working for cash income and very little subsistence work (see Figure 4.4). In our consultations, stakeholders mentioned that Walung could be an outlier, with lower cash incomes than the rest of Kosrae. However, as it is part of the Tafunsak municipality, we do not have income data or labor force characteristics for Walung alone.

Figure 4.4: Kosrae Labor Force Characteristics



Source: FSM 2010 Census

4.3 Energy Consumption

Here we discuss energy expenditure and energy use in Kosrae. We consider how much is spent on energy, what type of energy is consumed, and what the energy is then used for. We focus on residential use, but also comment on how much electricity other customer groups use.

4.3.1 Energy expenditure

Households in Kosrae spend 8 percent of cash income on energy on average (see Table 4.2).

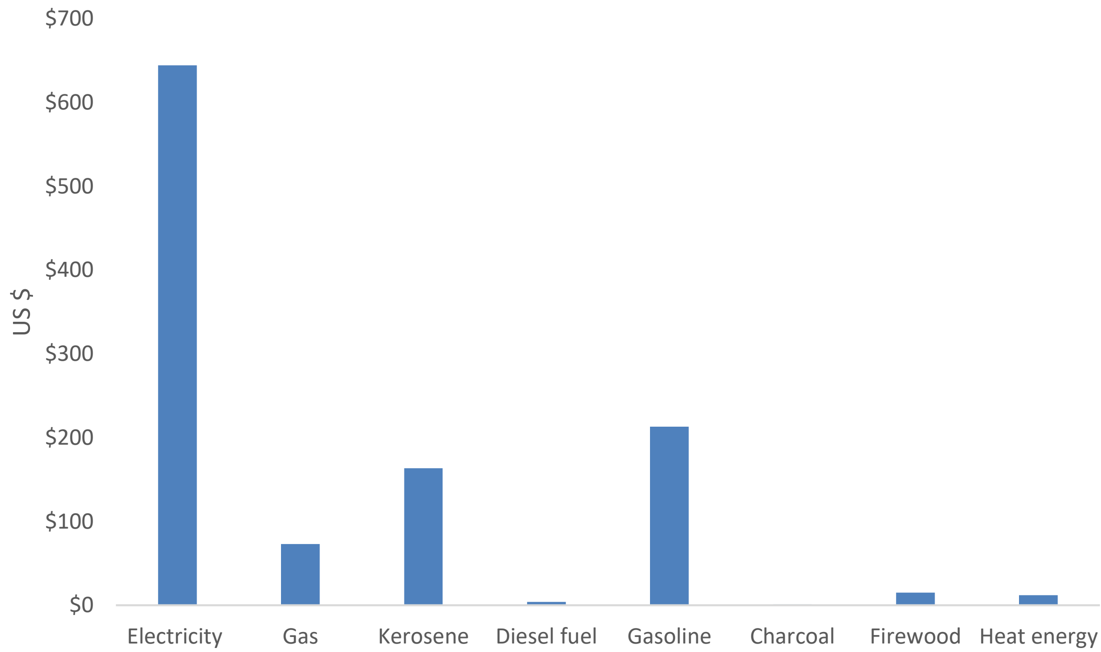
Table 4.2: Kosrae Average Annual Energy Expenditure (2013)

	Urban
Cash income	$14,297
Energy expenditure	$1,125
Energy expenditure as a percentage of estimated cash income	8%

Source: 2013/2014 FSM HIES

Electricity is by far the biggest energy expense, followed by gasoline. Figure 4.5 breaks down the type of energy that people are buying in Kosrae. Firewood accounts for very little energy expenditure. This is not because it is not used, but because it is often free.

Figure 4.5: Kosrae Average Annual Energy Expenditure[18]



Source: 2013/2014 FSM HIES

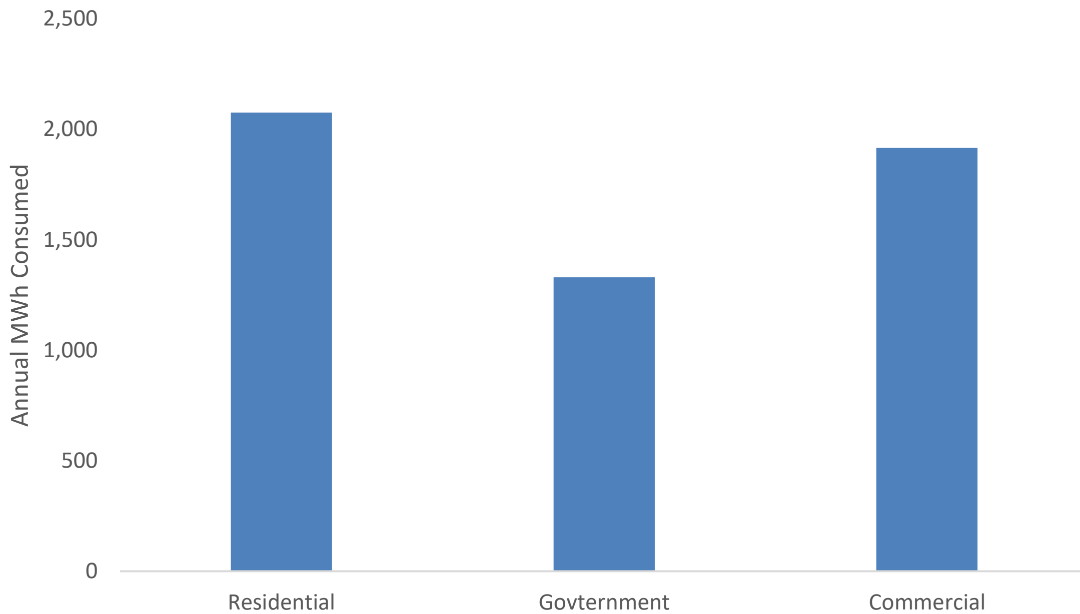
4.3.2 Energy use

Residential customers consume the most electricity in Kosrae out of the customer groups. Figure 4.6 shows how much residential customers consume per year, as well as commercial and government customers.

We used current consumption levels to estimate an electricity load forecast for the next 20 years. The current levels were adjusted for GDP growth, population growth, new commercial projects coming online, and energy efficiency measures as discussed in the Master Plan.

[18] Gas includes butane can, propane, and liquid (lpg)

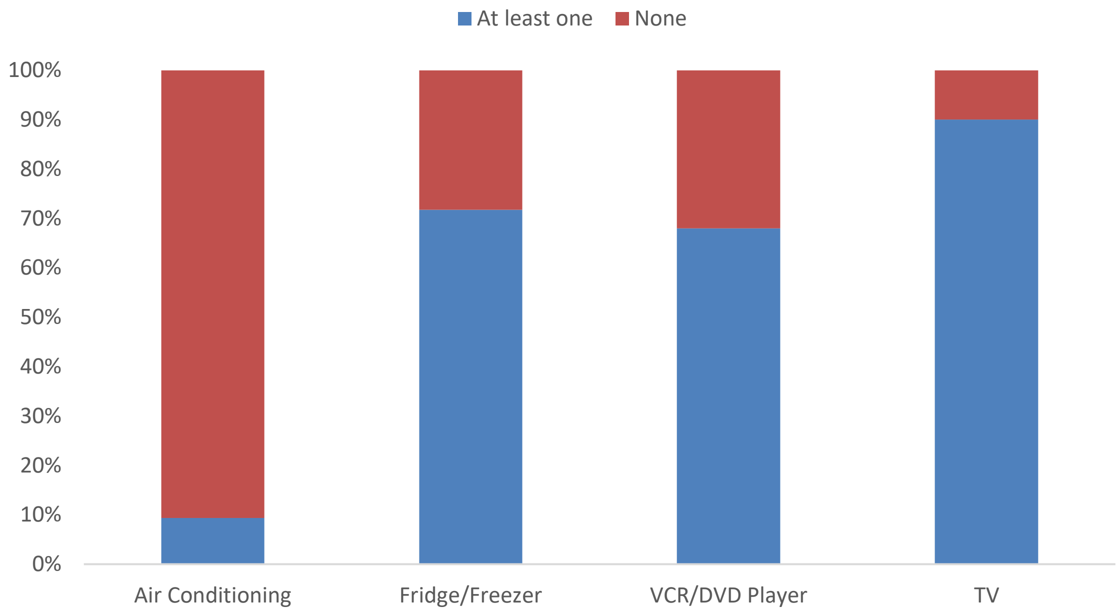
Figure 4.6: Kosrae Annual Consumption by Customer Group (MWh)



Source: KUA

Uptake of electrical appliances is already high relative to the grid areas in other States. Refrigerators/freezers, DVD players, and televisions are each owned by over 60 percent of the population. Use of air conditioning by residential customers is low (less than 10 percent) relative to other appliances, but comparable to air conditioning uptake in other grid areas in the FSM. Across the FSM, residential use of air conditioning is low relative to other appliances. It is likely that residential use of air conditioning will remain low even with improved access and service quality.

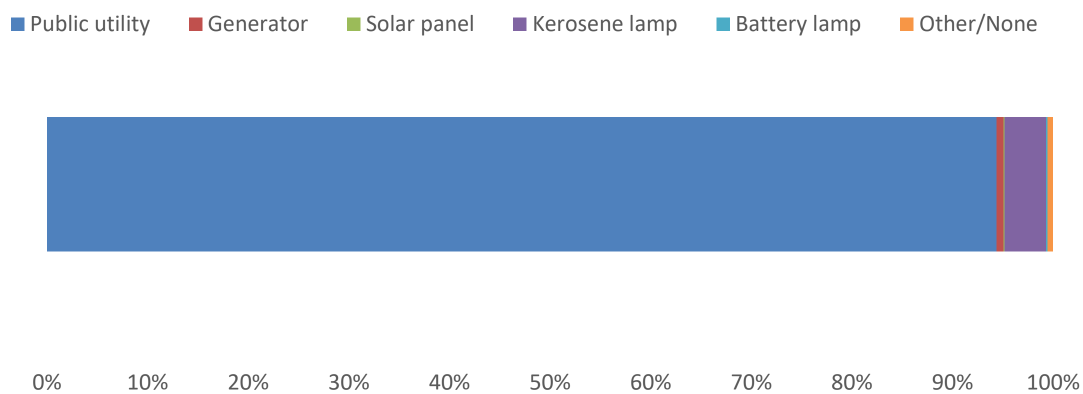
Figure 4.7: Residential Energy Use in Kosrae



Source: FSM 2010 Census

Almost all (94 percent) households in Kosrae use electricity provided by the utility for lighting. Of those who do not use electricity from the utility, kerosene lamps are the most common lighting source (4 percent of households). The proportion of people who do not use electricity provided by the utility for lighting (6 percent) is higher than the proportion of people who do not have grid access (2 percent).

Figure 4.8: Light Source in Kosrae



Source: FSM 2010 Census

5 Pohnpei State Social Assessment

The Pohnpei State Social Assessment includes state aspirations, socioeconomic context, energy consumption, and willingness to pay. This information was used to inform different areas of the Master Plan, including the load forecast, affordability, and implementation. Social themes that were common for all states are discussed in the National Social Assessment to avoid repetition.

We use information from our community consultations, the 2010 Census, HIES, and other documents to gather socioeconomic information. Information from the HIES groups people into three strata:

- Urban: Easy access to essential services and facilities. For Pohnpei, this includes Kolonia and some areas of U
- Rural: Medium access to essential services and facilities. This includes Madolenihmw, Kitti, and selected areas of U, Nett, and Sokehs
- Remote: Rare access to essential services and facilities. This includes all outer islands and selected areas of U, Nett, and Sokehs.

5.1 State Development Aspirations

The most recent FSM-wide development aspirations were determined in an economic and strategic planning meeting in 2012.[19] In this meeting FSM sought development partner support across four broad development areas:[20]

- Growing the local economy through enhancing agriculture production and the production of value added agriculture products, maximizing benefits of FSM's fisheries resources, promoting tourism, developing clean, renewable energy sources
- Developing economic infrastructure, including transport, communications, and power
- Improving health and education services
- Mainstreaming responses to climate change and mitigating threats to the environment.

Based on these nationwide aspirations, Pohnpei has laid out state-specific development aspirations in the Pohnpei State Development Plan. This Plan lists strategic goals that are placed within eight development sectors: agriculture, education, environment, fisheries, health, infrastructure, public, and tourism. Implementing the Energy Master Plan will contribute to all these sectors either directly or indirectly by providing improved service reliability and increasing access. We have assessed how the Master Plan will contribute to these sectors in Table 5.1.

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[19] The purpose of this meeting was to update and accelerate national development aspirations from the FSM Strategic Development Plan (2004-2023)

[20] Federated States of Micronesia Infrastructure Development Plan FY2016-FY2025 Volume 1

Table 5.1: Pohnpei State Strategic Development Sectors

Development Sector	Sector mission	How the Master Plan can contribute
Agriculture	To provide food security, facilitate sustainable agricultural development by promoting best practices, promote cultural uses of foods, and improve nutrition and health	▪ On Pohnpei Proper, increased reliability of electricity supply could lead to adoption of modern agricultural technologies and increase productivity ▪ Improved electricity access and reliability of supply will improve nutrition and health by allowing for increased use of refrigeration
Education	Enable students to develop social, emotional, physical, intellectual, and vocational skills; to master languages in both oral and written forms; to engage in traditional cultural practices; and to prepare all students to contribute to their communities	▪ Provide lighting to allow students to study when natural light is insufficient ▪ Electricity access will improve access to resources through IT and the internet
Environment	Implement a community-based stewardship approach for protecting Pohnpei's natural and cultural resources, to maintain ecosystem functions necessary for all life, and to facilitate livelihoods based on traditional knowledge and modern, environmentally sustainable development practices	▪ The Master Plan will ensure electricity supply meets required environmental standards and has minimal adverse impacts on the environment ▪ Environmental considerations are: – Disposal of batteries – Fuel storage – Achieving renewable energy targets – Preservation of the environment in the context of hydro development
Fisheries	Promote the conservation and sustainable management of our marine resources, employing leading edge technologies while incorporating traditional Pohnpeian knowledge and practices	▪ Improved access and reliability of electricity will support the adoption of technologies to improve fisheries monitoring ▪ Increased service reliability is important for the planned fish processing facility

Development Sector	Sector mission	How the Master Plan can contribute
		▪ Access to refrigeration on the outer islands will help prevent waste and reduce pressure on local fisheries
Health	Provide a holistic, integrated system of health care that optimizes quality of life for Pohnpeian citizens, residents and visitor through effective health promotion/disease prevention efforts and quality health care services	▪ Hospitals and dispensaries need reliable electricity for medical equipment, lighting, and refrigeration of medicines and vaccines ▪ Improved electricity access can improve communication and access to information leading to increased awareness around health
Infrastructure	Provide sustainable economic and social infrastructure development programs and projects	▪ Reliable access to electricity will help develop communications infrastructure, particularly outside Pohnpei Proper ▪ Increased service reliability is important for the planned water pumping and treatment facility and port expansion
Public	To provide quality public services appropriate to the social and cultural environment of Pohnpei with transparency and accountability	▪ Increasing electricity access on outer islands will improve public services such as health centers and schools
Tourism	To develop tourism to become the leading economic activity in the State, and to establish Pohnpei as an international tourism destination	▪ Reliable access to electricity will make Pohnpei a more attractive tourist destination by improving the service provided by hotels, restaurants, and other tourism operators ▪ Increased and more reliable supply is important for the planned hotel and casino

Source: Pohnpei State Strategic Development Plan, Castalia

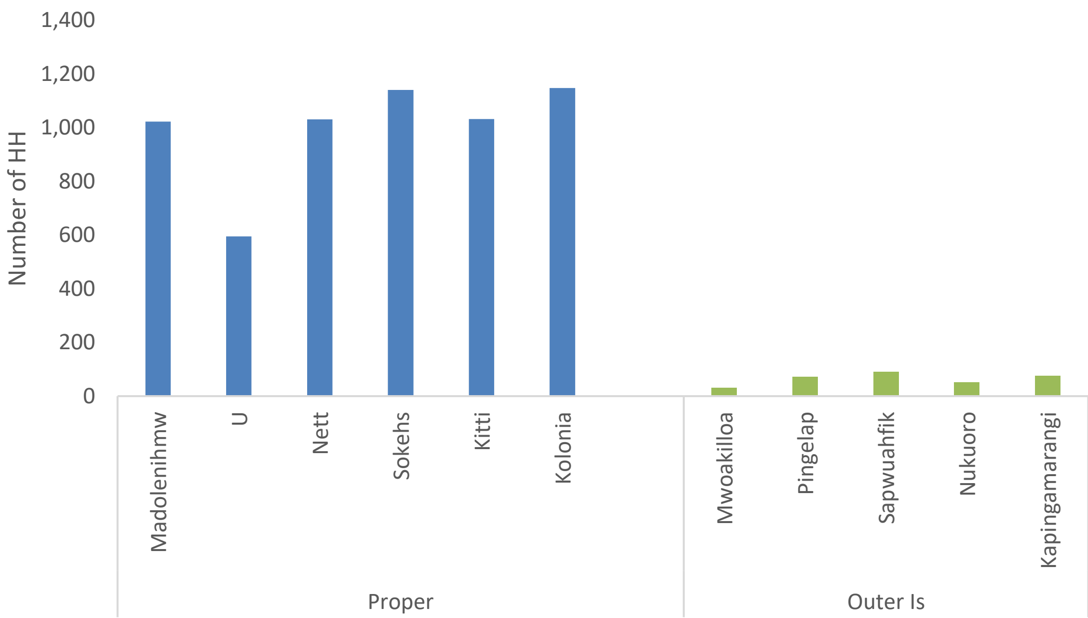
5.2 Socioeconomic Context

Here we discuss Pohnpei's population, incomes, and labor force characteristics, and highlight how they were used to inform the Master Plan.

5.2.1 Population

In 2010, Pohnpei had 6,289 occupied households, 38 percent of total households in FSM.[21] Figure 5.1 breaks down the percentage of households in each municipality in Pohnpei. Ninety-five percent of households in Pohnpei are in Pohnpei Proper. Kolonia, the state capital, has the most households, followed closely by Sokehs.

Figure 5.1: Pohnpei Municipality Household Numbers

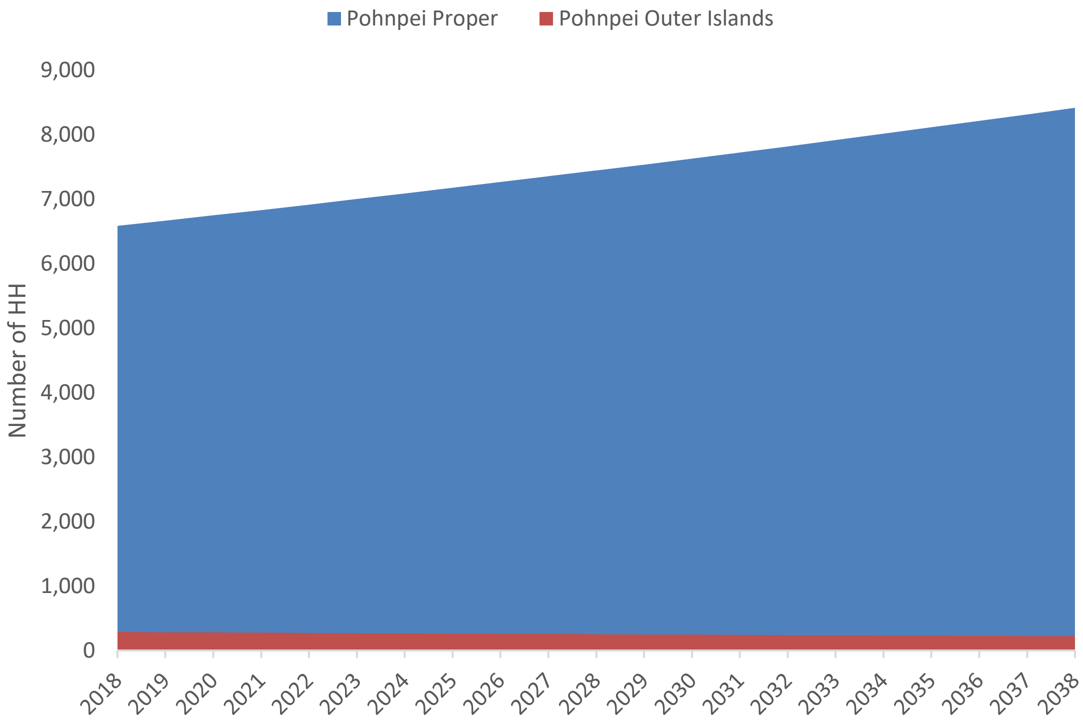


Source: FSM 2010 Census

The number of households in Pohnpei Proper increased at an annual rate of 1.24 percent per year between 1994 and 2010. Outer islands in Pohnpei decreased over the same period by 1.3 percent per year. We used the geometric average historical growth rates to forecast household numbers over the next 20 years. The population forecast was used to inform the load forecast in the Master Plan.

[21] FSM 2010 Census

Figure 5.2: Pohnpei Population Forecast



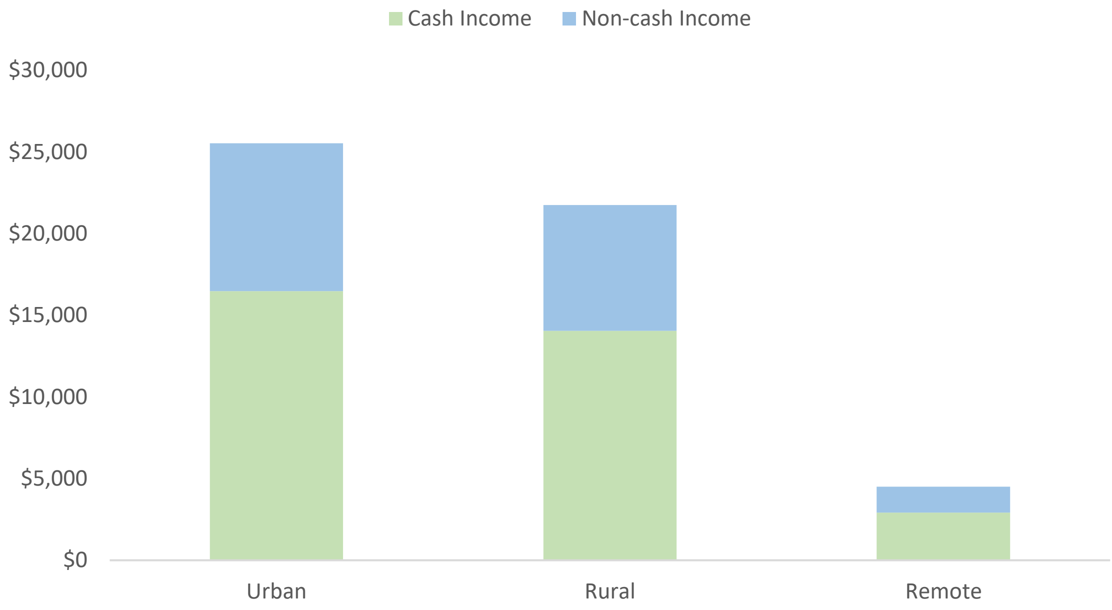
The population forecast informed the load forecast in the Master Plan. The load forecast is an estimate of how much electricity needs to be produced to satisfy demand over the next 20 years. Demand depends on population size as well as ability to pay. An accurate load forecast leads to investing in the right amount of infrastructure. Over-investment in infrastructure can increase costs whereas under-investment can lead to unserved demand.

5.2.2 Incomes

Average annual incomes are much higher in urban and rural areas than in remote areas, shown in Figure 5.3. To assess willingness to pay, we focused on cash incomes, as electricity will be paid for in cash. Cash income accounts for 65 percent of total income in Pohnpei. The other 35 percent is non-cash income, this includes all goods consumed that are not paid for with cash (home production, imputed rents, and in-kind transfers).

We do not have a breakdown of cash income for individual strata, so we have applied the 65 percent to all three for illustrative purposes. Cash incomes are likely to be lower in rural and remote areas where a bigger percentage of the population is engaged in subsistence farming and fishing.

Figure 5.3: Pohnpei Average Annual Household Income



Source: 2013/2014 FSM HIES

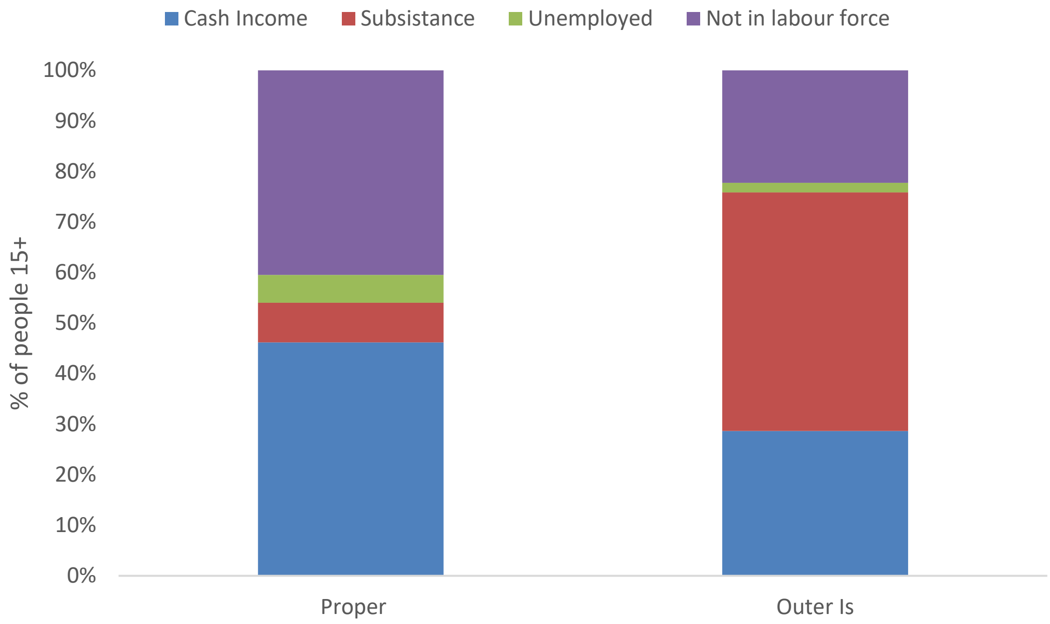
5.2.3 Labor force characteristics

As we do not have cash income by strata for the 2013 HIES, we have considered the labor force characteristics from the 2010 Census. As expected, a higher percentage of people in Pohnpei Proper receive cash income than the outer islands, implying we overestimate cash income for remote residents (Figure 5.4).

Ability to pay for electricity could be more of an issue for outer island households than Pohnpei Proper households. In Pohnpei Proper, 46 percent of people over the age of 15 receive cash income, compared to 29 percent in outer islands. People receiving a cash income are either engaged in formal work or market-oriented home production.

The outer islands in Pohnpei have many more people engaged in subsistence work. They also have fewer people not in the labor force than Pohnpei Proper.

Figure 5.4: Pohnpei Labor Force Characteristics



Source: FSM 2010 Census

5.3 Energy Consumption

Here we discuss energy expenditure and energy use in Pohnpei. We consider how much is spent on energy, what type of energy is consumed, and what the energy is used for. We focus on residential use, but also comment on how much electricity other customer groups use.

5.3.1 Energy expenditure

Households in urban areas spend more on energy in absolute terms, but less as a percentage of their income (see Table 5.2). Since people in urban areas have both better access to electricity and appliances, and have higher incomes, this implies that:

- People in outlying areas spend more on costly (and lower quality) sources of energy than electricity
- People in outlying areas are likely to benefit most from improved access to electricity.

Table 5.2: Pohnpei Average Annual Energy Expenditure (2013)

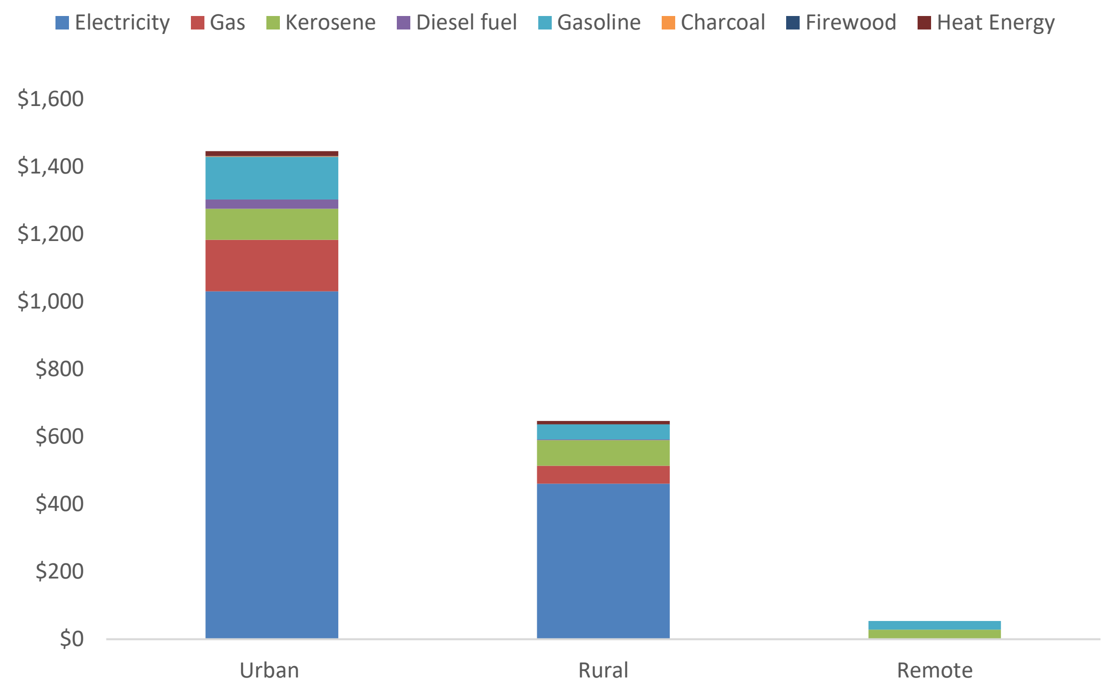
	Urban	Rural	Remote
Estimated cash income	$16,487	$14,052	$2,913
Energy expenditure	$1,445	$647	$54
Energy expenditure as a percentage of estimated cash income	9%	5%	2%

Source: 2013/2014 FSM HIES

People in urban and rural areas spend more money on electricity than other energy sources. Whereas people in rural and remote areas, without electricity access, spend more on gasoline and kerosene than other energy sources. Figure 5.5 breaks down the type of energy that people are buying in urban, rural, and remote areas.

Firewood accounts for very little energy expenditure across all three strata. This is not because it is not used, but because it is often free.

Figure 5.5: Pohnpei Average Annual Energy Expenditure[22]

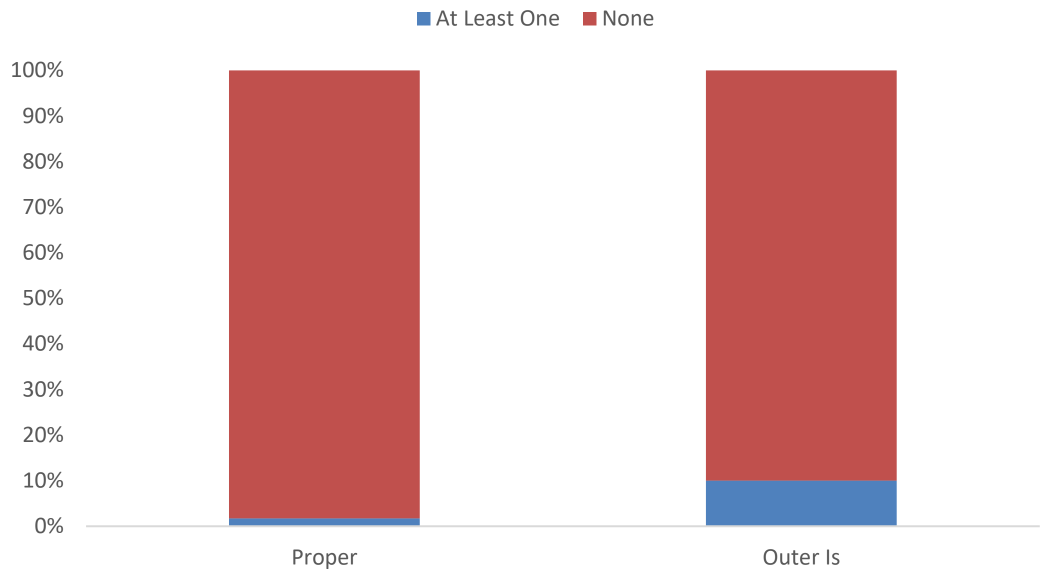


Source: 2013/2014 FSM HIES

Diesel fuel expenditure is split between diesel used for transport (cars and boats) and for electricity generation. Generator ownership in residential households on Pohnpei Proper is low (2 percent) despite the frequent interruptions to the grid power supply. Ownership is higher on the outer islands (10 percent) where there is no grid supply, but still limited due to distance from a diesel supply. Ten percent is comparable to the outer islands of Chuuk where the situation is similar in terms of electricity supply and access to diesel, and less than in the Chuuk Lagoon where diesel is more accessible.

[22] Gas includes butane can, propane, and liquid (lpg)

Figure 5.6: Diesel Generator Ownership in Pohnpei



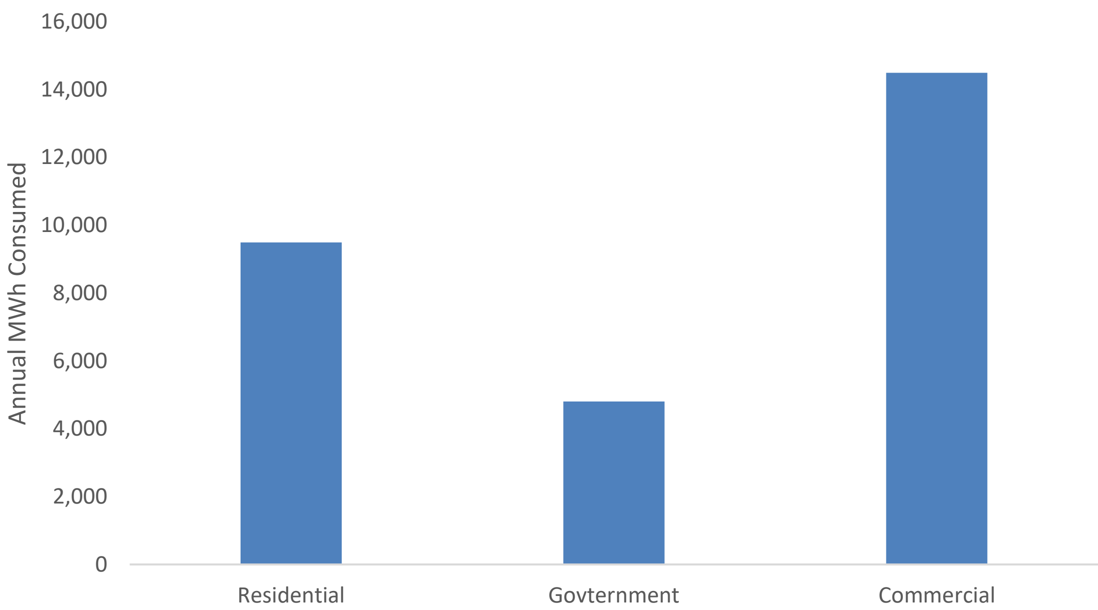
Source: FSM 2010 Census

5.3.2 Energy use

Commercial customers consume the most electricity in Pohnpei Proper out of the customer groups. Figure 5.7 shows how much commercial customers consume per year, as well as residential and government customers.

Current consumption levels were used to estimate an electricity load forecast for the next 20 years. The current levels were adjusted for GDP growth, population growth, new commercial projects coming online, and energy efficiency measures as discussed in the Master Plan.

Figure 5.7: Pohnpei Proper Annual Consumption by Customer Group (MWh)



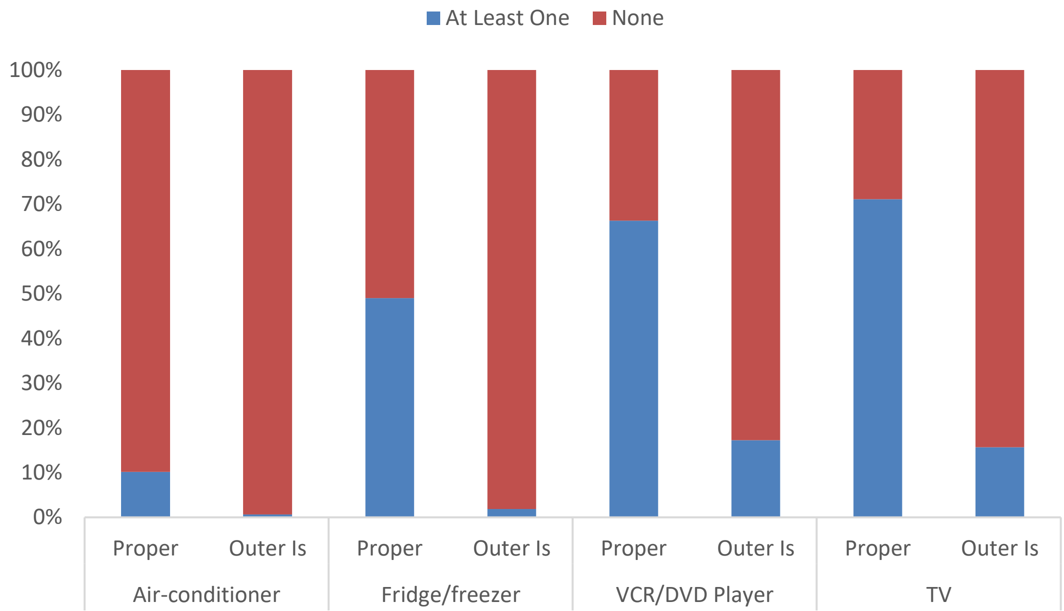
Source: PUC

Residential use of appliances is different on Pohnpei Proper compared to the rest of Pohnpei where there is no grid electricity supply. Less than 1 percent of residential households on the outer islands have air conditioning, while 10 percent have air conditioning on Pohnpei Proper (Figure 5.8). Across the FSM, residential use of air conditioning is low relative to other appliances. It is likely that residential use of air conditioning will remain low even with improved access and service quality.

Lack of reliable electricity prevents use of refrigerators on the outer islands. Close to 50 percent of homes have a refrigerator in Pohnpei Proper but only 2 percent have a refrigerator on the outer islands. In our consultation with the Pohnpei Council of Chiefs, several of the chiefs stated that ice boxes for refrigerating fishing catch were a priority on their islands.

Though much lower than on Pohnpei Proper, ownership of televisions and DVD players is relatively common on outer islands despite no reliable electricity supply. Each are used by around 10 percent of outer islands households. In our consultations, residents in remote communities told us that small screens can be charged using solar-lighting kits, and watching movies was common in some areas.

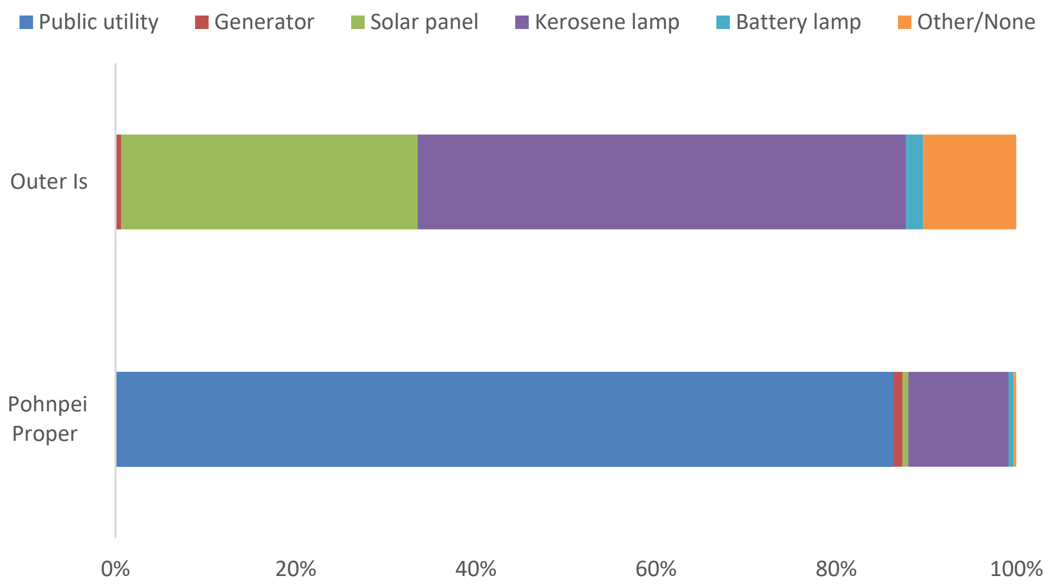
Figure 5.8: Residential Energy Use in Pohnpei



Source: FSM 2010 Census

In Pohnpei Proper, most (86 percent) households use electricity from the public utility for lighting. Of households that do not use electricity from the utility for lighting, most use kerosene lamps (11 percent). On the outer islands, most households use either solar panels (33 percent) or kerosene lamps (54 percent) as their source of lighting. Solar panels on the outer islands of Pohnpei are small solar lighting kits that power one or two bulbs.

Figure 5.9: Source of Lighting in Pohnpei



Source: FSM 2010 Census

6 Yap State Social Assessment

The Yap State Social Assessment includes state aspirations, socioeconomic context, energy consumption, and willingness to pay. This information was used to inform different areas of the Master Plan, including the load forecast, affordability, and implementation. Social themes that were common for all states are discussed in the National Social Assessment to avoid repetition.

We use information from our community consultations, the 2010 Census, HIES, and other documents to gather socioeconomic information. The HIES groups people into three strata:

- Urban: Easy access to essential services and facilities. For Yap, this includes Colonia and most areas of Weloy and Rull municipalities
- Rural: Medium access to essential services and facilities. This includes Maap, Gagil, Tomil, Fanif, Dalipebinaw, Kanifay, Gilman, and remaining areas of Weloy and Rull
- Remote: Rare access to essential services and facilities. This includes all outer islands.

6.1 State Development Aspirations

The most recent FSM-wide development aspirations were determined in an economic and strategic planning meeting in 2012.[23] In this meeting FSM sought development partner support across four broad development areas:[24]

- Growing the local economy through enhancing agriculture production and the production of value added agriculture products, maximizing benefits of FSM's fisheries resources, promoting tourism, developing clean, renewable energy sources
- Developing economic infrastructure, including transport, communications, and power
- Improving health and education services
- Mainstreaming responses to climate change and mitigating threats to the environment.

Yap has not yet produced a state strategic development plan. To assess Yap's development aspirations in the context of the Master Plan we use the sectors outlined in the four nationally-identified development areas. Implementing the Master Plan will contribute to all these sectors either directly or indirectly by providing improved service reliability and increasing access. We have assessed how the Master Plan will contribute to these sectors in Table 6.1.

[23] The purpose of this meeting was to update and accelerate national development aspirations from the FSM Strategic Development Plan (2004-2023)

[24] Federated States of Micronesia Infrastructure Development Plan FY2016-FY2025 Volume 1

Table 6.1: Yap State Strategic Development Sectors

Development Area	Sector	How the Master Plan can contribute
Growing the local economy through enhancing agriculture production and the production of value added agriculture products, maximizing benefits of FSM's fisheries resources, promoting tourism, developing renewable energy sources	Value added agriculture products	▪ Reliable electricity supply will be essential for any potential agricultural product processing facilities to produce value added products
	Fisheries	▪ Increased service reliability is important for the planned fish processing facility
	Tourism	▪ Reliable access to electricity will make Yap a more attractive tourist destination by improving the service provided by hotels, restaurants, and other tourism operators ▪ Increased and more reliable supply is important for the planned hotel
	Renewable Energy	▪ The Master Plan will ensure Yap meets its renewable energy targets
Developing economic infrastructure including transport, communications, and power	Transport	▪ The Master Plan includes regular service trips to outer islands, which will stimulate increased transport links to these areas
	Communications	▪ Reliable access to electricity will help develop communications infrastructure, particularly in Yap Proper ▪ Falalop, Ulithi is an example of the high quality of internet service that can be achieved once electricity access is gained
	Power	▪ The Master Plan aims to directly develop this sector
Improving health and education services	Health	▪ Hospitals and dispensaries need reliable electricity for medical equipment, lighting, and refrigeration of medicines and vaccines ▪ Improved electricity access can improve communication and access to information leading to increased awareness around health

Development Area	Sector	How the Master Plan can contribute
	Education	▪ Provide lighting to allow students to study when natural light is insufficient ▪ Electricity access will improve access to resources through IT and the internet
Mainstreaming responses to climate change and mitigating threats to the environment	Climate change	▪ The Master Plan will assist climate change mitigation ▪ Improved access to electricity will help with climate change adaptation by: – Improving communication – Improving healthcare in remote communications – Providing electricity supply that is more resilient to extreme weather events – Allowing for food storage – Providing the potential for desalinization facilities on islands where groundwater has become brackish due to rising sea level
	Threats to the environment	▪ The Master Plan will ensure electricity supply meets required environmental standards has little impacts on the environment ▪ Environmental considerations are: – Disposal of batteries – Fuel storage

Source: FSM National Infrastructure Development Plan

6.2 Socioeconomic Context

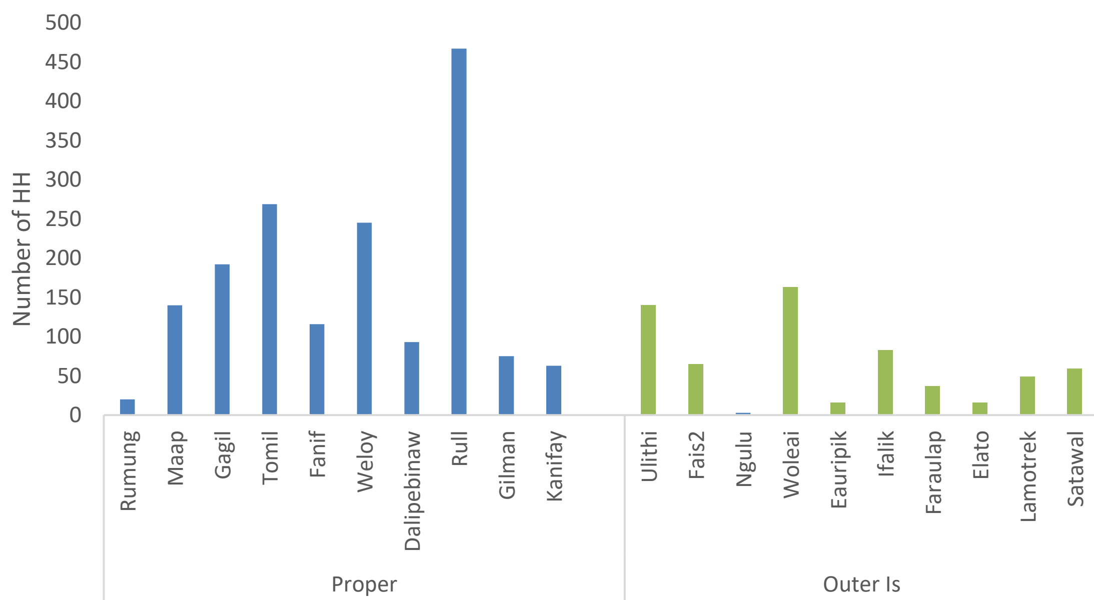
Here we discuss Yap's population, incomes, and labor force characteristics. For each section, we highlight how they were used to inform the Master Plan.

6.2.1 Population

In 2010, Yap had 2,311 occupied households, 14 percent of total households in FSM.[25] Figure 6.1 breaks down the percentage of households in each municipality in Yap. Seventy-three percent of households in Yap are in Yap Proper. Rull is the largest municipality and includes the state capital, Colonia.

Rumung, with 20 occupied households, was not included in the Master Plan, reflecting the community's request not to be provided with electricity.

Figure 6.1: Yap Municipality Household Numbers

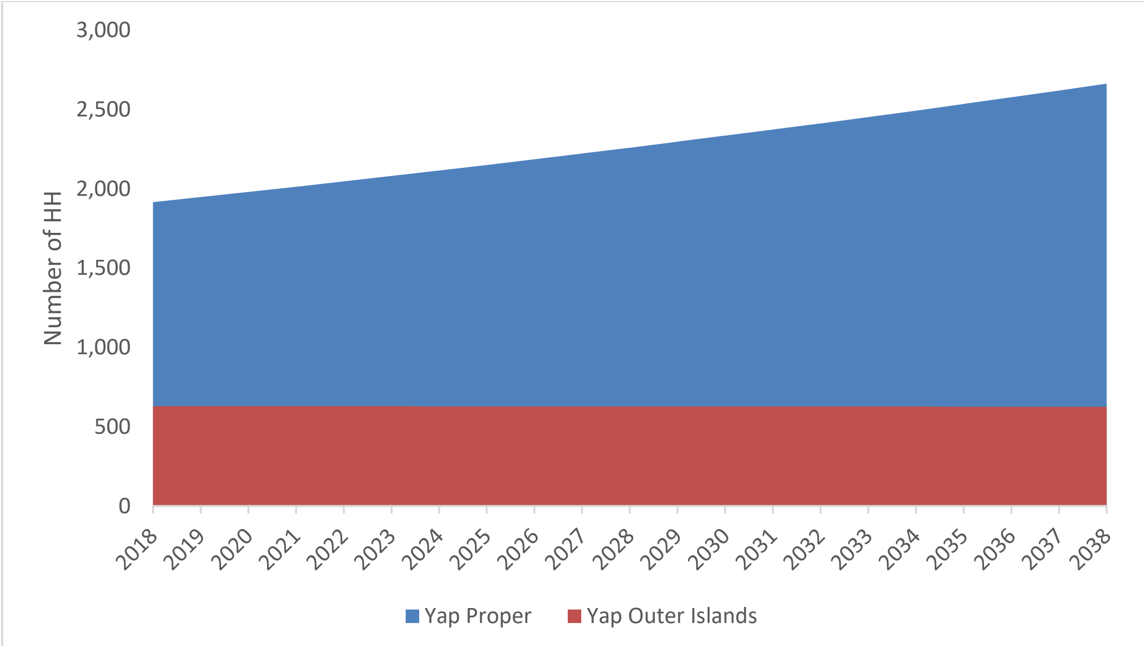


Source: FSM 2010 Census

The number of households in Yap Proper increased at an annual rate of 1.66 percent per year between 1994 and 2010. Outer islands in Yap decreased over the same period by 0.3 percent per year. We used the geometric average historical growth rates to forecast household numbers over the next 20 years (see Figure 6.2). The population forecast was used to inform the load forecast in the Master Plan.

25 FSM 2010 Census

Figure 6.2: Yap Forecast of Households



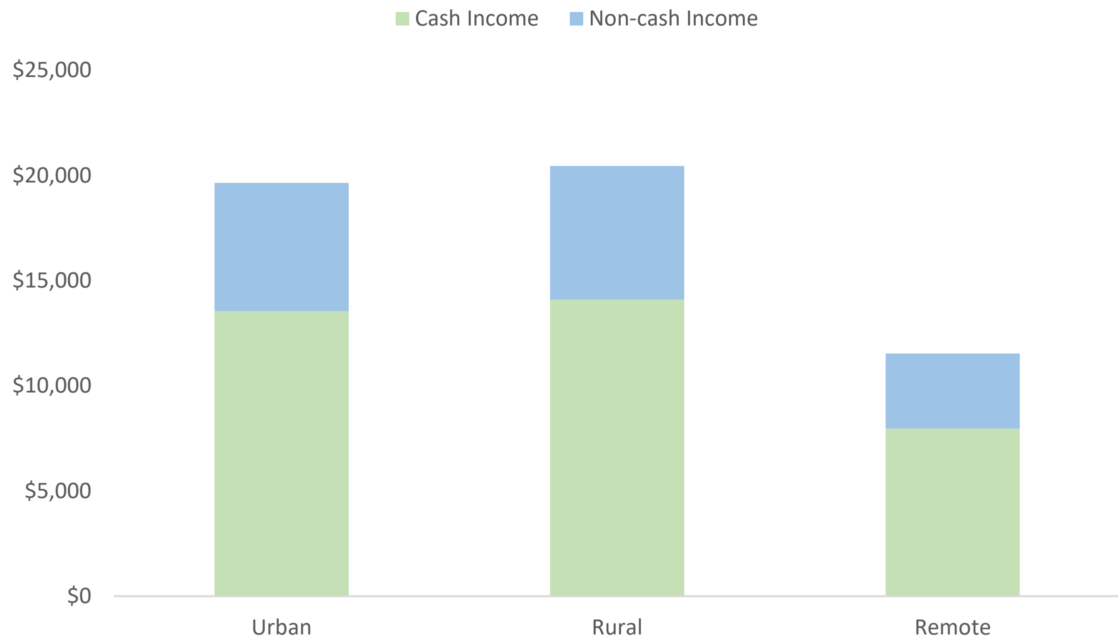
6.2.2 Incomes

Unlike the other states, average annual incomes are higher in rural areas than urban areas in Yap. Figure 6.3 compares average incomes per year in urban, rural, and remote areas.

To assess willingness to pay, we considered only cash incomes, as electricity will be paid for in cash. Cash income accounts for 69 percent of total income in Yap. The other 31 percent is non-cash income, this includes all goods consumed that are not paid for with cash (home production, imputed rents, and in-kind transfers).

We do not have a breakdown of cash income for individual strata, so we have applied the 69 percent to all three for illustrative purposes. Cash incomes are likely to be lower in rural and remote areas where a bigger percentage of the population is engaged in subsistence farming and fishing.

Figure 6.3: Yap Average Annual Household Income



Source: 2013/2014 FSM HIES

6.2.3 Labor force characteristics

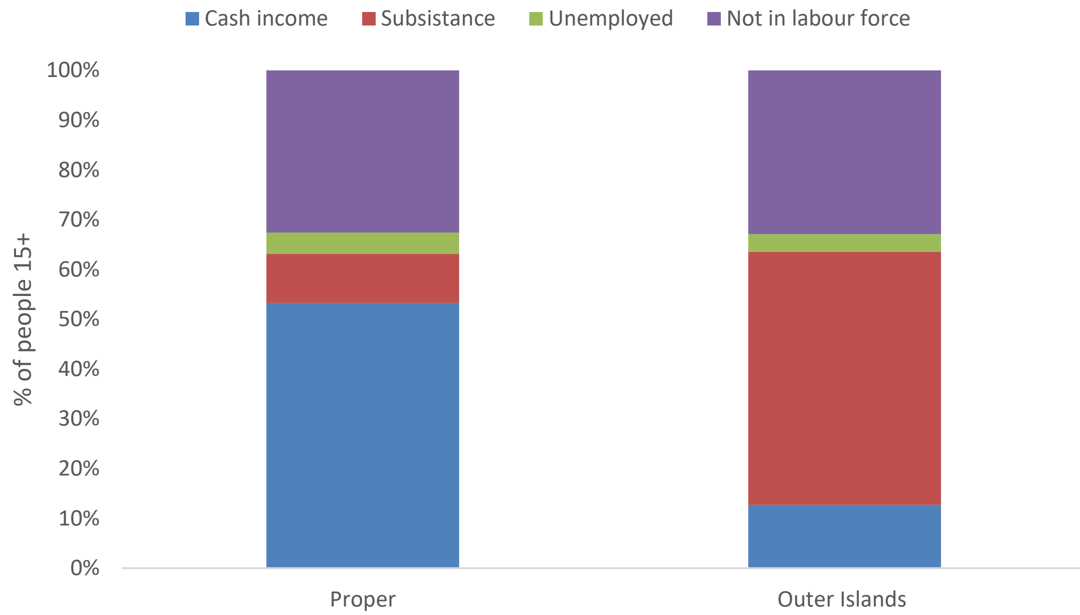
As we do not have cash income by strata for the 2013 HIES, we have considered the labor force characteristics from the 2010 Census. As expected, a higher percentage of people in Yap Proper receive cash income than the outer islands, implying we overestimate cash income for remote residents (Figure 6.4).[26]

Ability to pay for electricity could be more of an issue for outer island households than Yap Proper households. In Yap Proper, 53 percent of people over the age of 15 receive cash income, compared to just 13 percent in outer islands. People receiving a cash income are either engaged in formal work or market-oriented home production.

The outer islands of Yap have a lot more people engaged in subsistence work than Yap Proper. They also have a lot less people not in the labor force.

[26] Rumung was excluded from the Yap Proper numbers

Figure 6.4: Yap Labor Force Characteristics



Source: FSM 2010 Census

6.3 Energy Consumption

Here we discuss energy expenditure and energy use in Yap. We consider how much is spent on energy, what type of energy is consumed, and what the energy is then used for. We focus on residential use, but also comment on how much electricity other customer groups use.

6.3.1 Energy expenditure

Households in urban areas had the highest energy expenditure, even though households in rural areas have higher incomes. Table 6.2 compares estimated cash income with energy expenditure for urban, rural, and remote households.

Table 6.2: Yap Average Annual Energy Expenditure (2013)

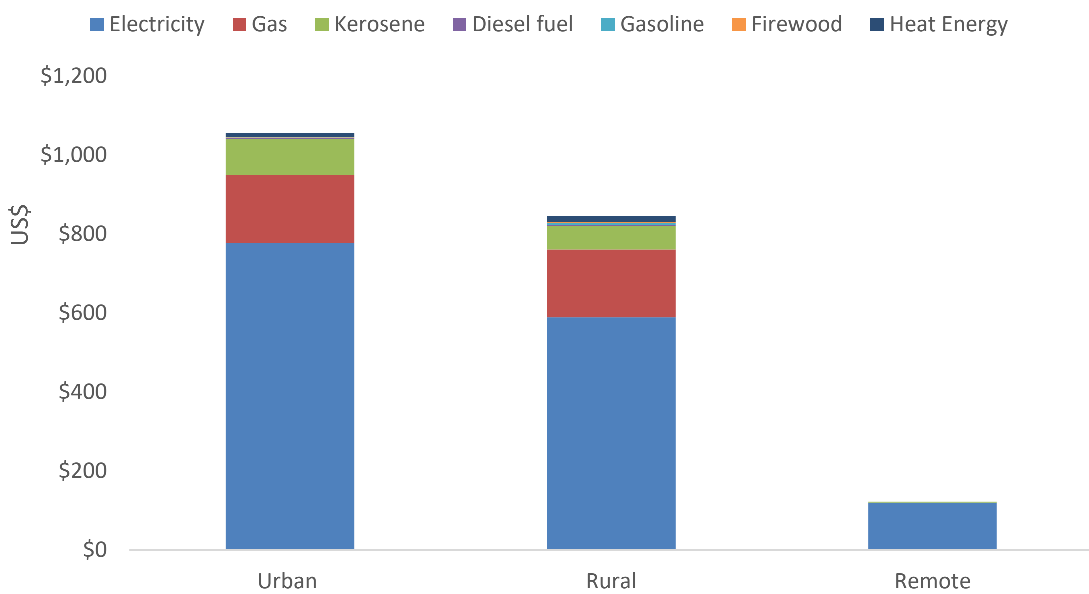
	Urban	Rural	Remote
Estimated cash income	$13,542	$14,097	$7,957
Energy expenditure	$1,056	$846	$123
Energy expenditure as a percentage of estimated cash income	8%	6%	2%

Source: 2013/2014 FSM HIES

Figure 6.5 breaks down the type of energy that people are buying in urban, rural, and remote areas. In all three strata, people spend more money on electricity than other energy sources. Many of the outer islands of Yap already have access to electricity through mini-grids and solar home systems.

Firewood accounts for very little energy expenditure across all three strata. This is not because it is not used, but because it is often free.

Figure 6.5: Yap Average Annual Energy Expenditure [27]

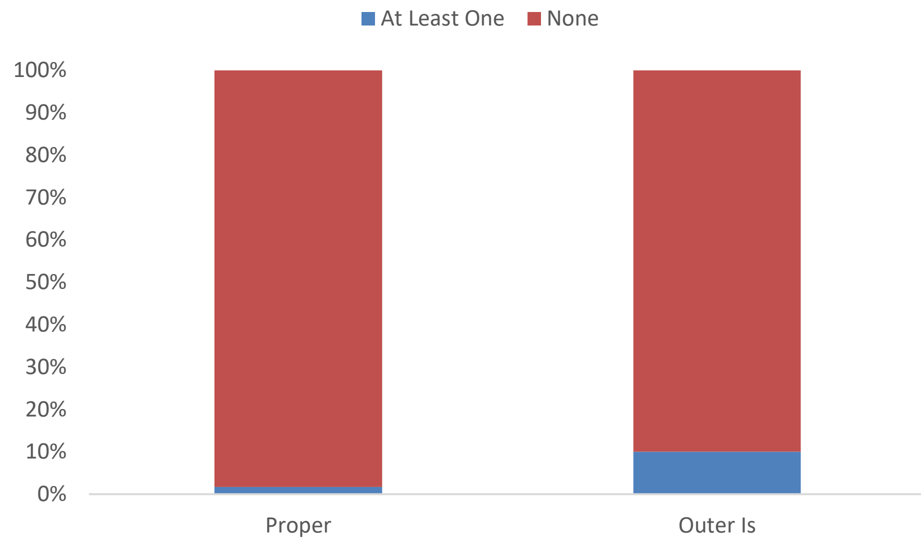


Source: 2013/2014 FSM HIES

Diesel fuel expenditure is split between diesel used for transport (cars and boats) and for electricity generation. Ownership of generators is low both in Yap Proper and on the outer islands (less than 5 percent). Despite having grid access, ownership of generators is higher on Yap Proper than the outer islands. Ownership on the outer islands is possibly low because on islands where there is no mini-grid access to diesel is limited; and on islands where there are mini-grids, generators are not needed.

[27] Gas includes butane can, propane, and liquid (lpg)

Figure 6.6: Diesel Generator Ownership in Yap



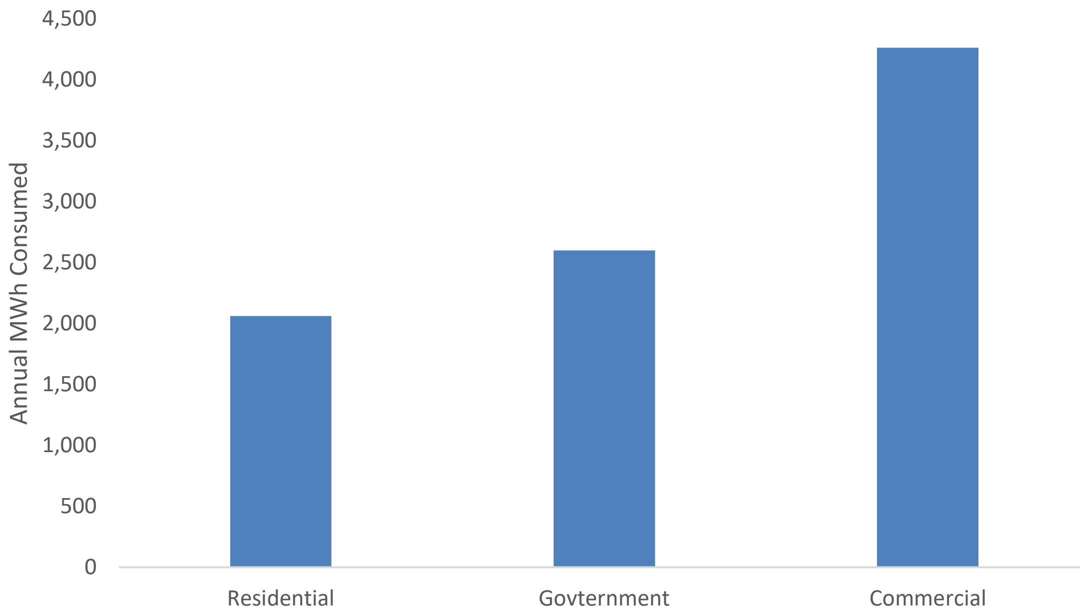
Source: FSM 2010 Census

6.3.2 Energy use

Commercial customers consume the most electricity in Yap Proper out of the customer groups. Figure 6.7 shows how much commercial customers consume per year, as well as residential and government customers.

We used current consumption levels to estimate an electricity load forecast for the next 20 years. The current levels were adjusted for GDP growth, population growth, new commercial projects coming online, and energy efficiency measures as discussed in the Master Plan.

Figure 6.7: Yap Proper Annual Consumption by Customer Group (MWh)



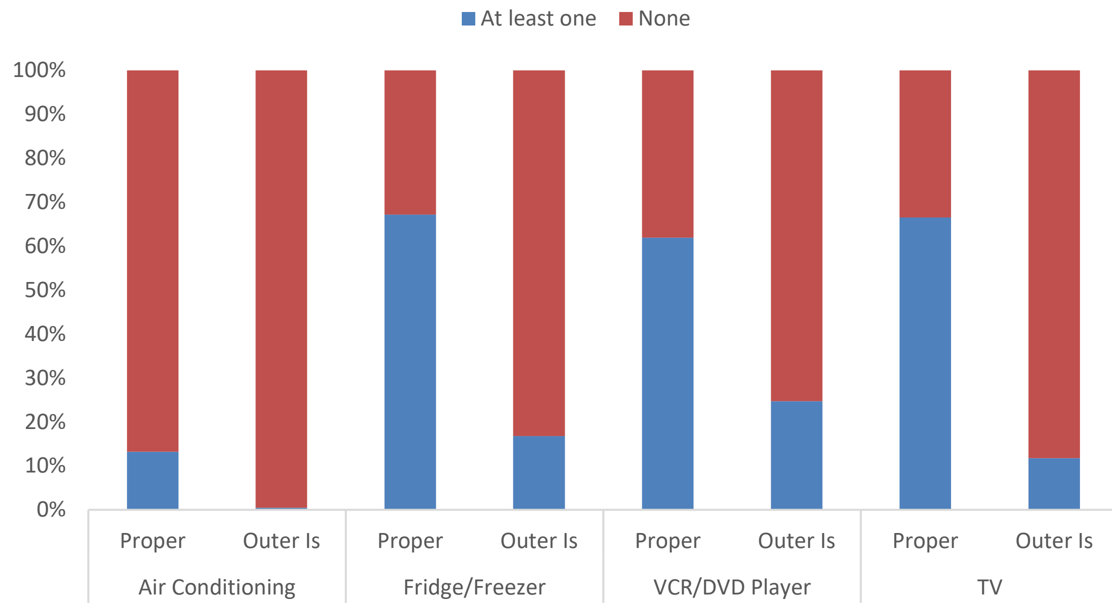
Source: YSPSC

Residential use of appliances is different on Yap Proper compared to the rest of Yap despite access to mini-grids and stand-alone solar systems on outer islands. Less than 1 percent of residential households on the outer islands have air conditioning while around 13 percent have air conditioning on Yap Proper (Figure 6.8). Across the FSM, residential use of air conditioning is low relative to other appliances. It is likely that residential use of air conditioning will remain low even with improved access and service quality.

Mini-grids on some outer islands allow some outer island residents to have refrigerators and freezers to store fishing catch. Ownership of refrigerators and freezers on the outer islands is higher in Yap compared with outer islands in other States. In our consultations with the men's groups and women's groups on Ulithi, several participants stated that freezers to store the fishing catch are a priority use for electricity.

Ownership of DVD players and televisions is lower on the outer islands of Yap compared with Yap Proper. Despite electricity access provided by mini-grids, ownership levels of televisions and DVD players are not notably different on the outer islands of Yap compared with remote areas of other states.

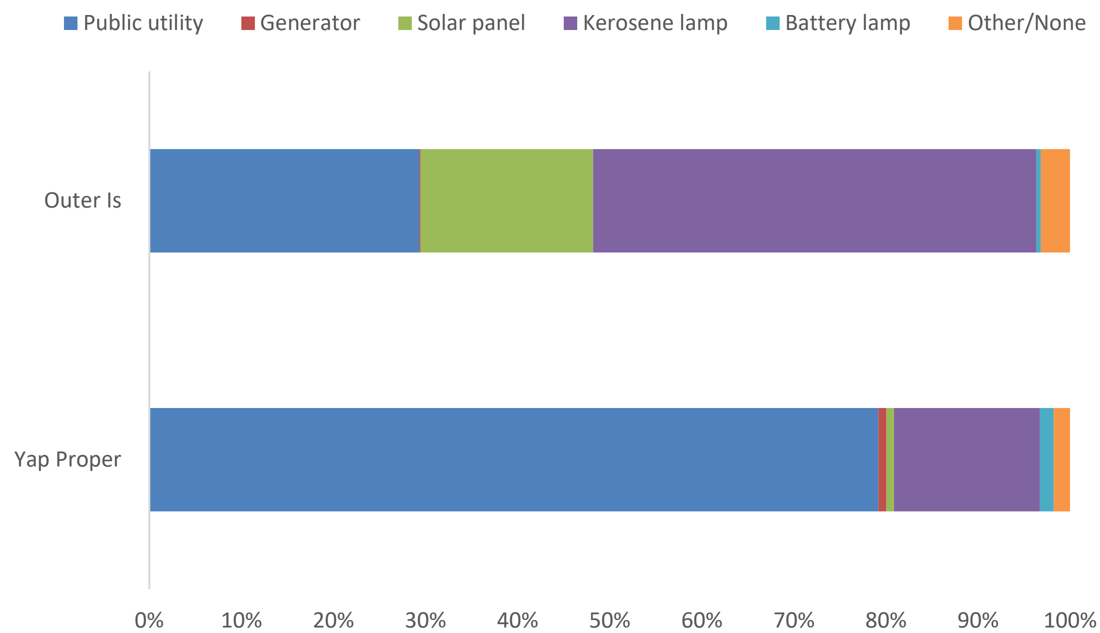
Figure 6.8: Residential Energy Use in Yap



Source: FSM 2010 Census

In Yap Proper, most (79 percent) households use electricity from the public utility for lighting. Of the households that do not use electricity from the utility for lighting, most use kerosene lamps (16 percent). On the outer islands the most common source of lighting is kerosene lamps (48 percent). Twenty-nine percent of outer island households use electricity provided by the public utility for lighting and a further 18 percent use solar panels.

Figure 6.9: Source of Lighting in Yap



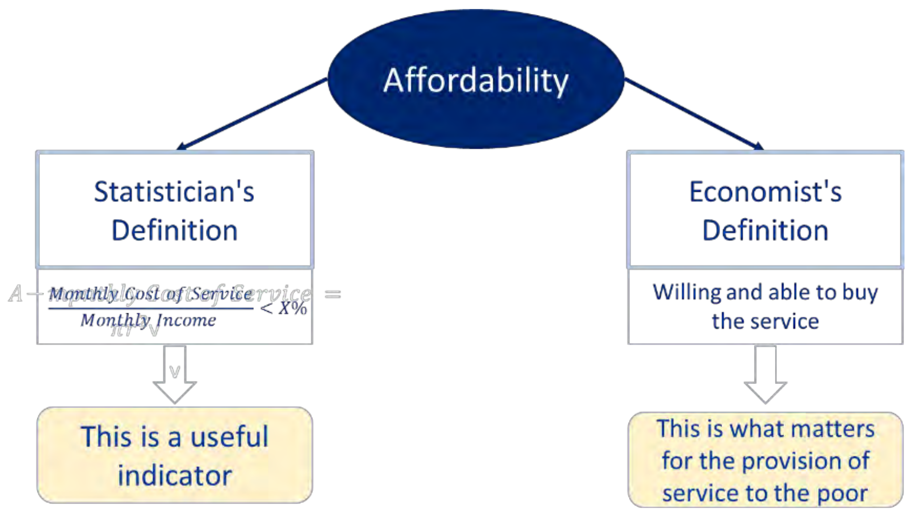
Source: FSM 2010 Census

7 Affordability

7.1 Defining and Measuring Affordability

The literature does not provide a single definition of affordability of infrastructure services, such as energy. The literature also highlights that affordability is a subjective concept that is hard to define[28]. Figure 7.1 describes two alternative definitions of affordability discussed in the literature. The statistician's definition provides a useful indicator to measure affordability but has conceptual limitations. As an alternative, the economist's definition, considers that an infrastructure service is affordable if people are willing and able to pay for it without incurring financial difficulties. We use the economist's definition of affordability for the Master Plans by focusing on identifying if poor people are willing and able to pay for energy of the quality specified in the Master Plans.[29]

Figure 7.1: Affordability: Alternative Definitions in the Literature



7.1.1 Commonly used indicators to measure affordability

In the literature there is no consensus on the best way to measure affordability.[30] However, a common approach is to measure affordability as the percentage share of the household expenditures on an infrastructure service relative to the average household budget or to the median household income, and whether it exceeds a set threshold.[31] For example, in the water sector if the monthly bill of water services as a percentage of monthly household income is more than 5 percent, then the service is considered unaffordable.

There is no scientific basis for setting the thresholds, however based on experience with actual household expenditure patterns and results of willingness to pay surveys, certain thresholds

[28] Estache A, Wodon Q, Loma K, 2014. Infrastructure and Poverty in Sub-Saharan Africa. World Bank

[29] The Treasury of New Zealand, "Affordability of Housing: Concepts, Measurement and Evidence." Published March 2006. Accessed November 2017 at: http://www.treasury.govt.nz/publications/research-policy/wp/2006/06-03/01.htm

[30] Robinson, Mark. 2006 Affordability of Housing: Concepts, Measurement and Evidence. New Zealand Treasury

[31] Sudeshna Ghosh Banerjee, Elvira Morella. 2011 Africa's Water and Sanitation Infrastructure: Access, Affordability, and Alternatives. Directions in development. Infrastructure World Bank

are widely used by practitioners. Table 7.1 lists some of the common affordability thresholds that can be useful in providing a snapshot of the burden of expenditure for an infrastructure service.

Table 7.1: Indicators to Measure Affordability

Sector	Area	Measure of Ability to Pay	Threshold of Affordability
Water and Sanitation	Total utility charge	Monthly bill as % of household income	5% of household income[32]
Transport	Public Transport[33]	Actual spending as % of household income	At most 10% of households spend more than 15% of income on work-related trips[34]
Telecoms[35]	Internet	% of income per capita for monthly bill	2% to 5% of income per capita
	Mobile Phone	% of household income for monthly bill	5% of household income
Housing[36]	Mortgage	Total price of house as % of annual household income	3 to 5 times household income
	Rental	Rent as % of household income	30% of household income
Agriculture[37]	Irrigation	Cost as % of income per capita, per ha per year	Average for Sub-Saharan Africa is about 1.5%
Energy	Off-Grid[38]	Monthly bill as % of household income	20% of per capita household income[39]
Energy[40]	On-Grid	Monthly bill as % of household income	5% of per capita household income

An inherent problem with measuring affordability following the approach in Table 7.1, is the need to invoke a benchmark of the "threshold of affordability" for which there is no objective definition. For example, a household in a very dry region may be willing and able to spend 7

[32] World Health Organization

[33] The World Bank, "Affordability and Subsidies in Public Urban Transport: What Do We Mean, What Can Be Done?", 2007

[34] South Africa uses the threshold of no more than 10% of households spend more than 10% of income on work-related trips.

[35] UN Conference on Trade and Development. "Information Economy Report 2010", 2010. And, Alliance for Affordable Internet. "Affordability Report 2015/16", 2016.

[36] The World Bank, "Stocktaking of the Housing Sector in Sub-Saharan Africa: Summary Report.", 2015.

[37] The World Bank, "Fertilizer Use in Africans Agriculture: Lessons Learned and Good Practice Guidelines", 2007, and "Enabling the Business of Agriculture", 2017.

[38] The World Bank, "Power Tariffs: Caught Between Cost Recovery and Affordability", 2011

[39] The World Bank, "Power Tariffs: Caught Between Cost Recovery and Affordability", 2011

[40] The same measure of ability to pay can be used for traditional on-grid electric as well as mini-grids where payments are still made to a utility company entity on a regular basis. Where mini-grids are meant to be self-sustaining and removed from all traditional electricity infrastructure, they should use off-grid measures of ability to pay.

percent of its income on water services but using the benchmark for water services in Table 7.1 that service would be considered unaffordable.

Other limitations of common measures of affordability result from using average household budget or median household income to estimate the share of household expenditures in an infrastructure service, because:

- The median household income, or household budget are poor indicators of economic distress and bear little relationship to poverty or other measures of economic need within a given population
- They do not capture impacts across diverse populations. If a population has income levels that are not clustered around the median, then the economic hardship associated with paying for an infrastructure service can be concentrated in a few lower-income households within a population
- They are snapshots that do not account for the historical and future trends of a community's economic, demographic, and/or social conditions
- They do not fully capture household economic burdens. Economic burdens are commonly measured by comparing the costs of basic needs to available household income. For example, a population may experience unusually high costs of basic needs or may have a distribution of household income that differs significantly from that in most communities within a population.
- They often ignore differences in cost related to quality and accessibility of a specific service.

7.1.2 Better measures of effective affordability

There is no single measure that can definitively indicate whether a population is unable to afford an infrastructure service.[41] However, more accurate measures of affordability try to provide a detailed picture of a population's economic and social characteristics to identify its ability to afford a service. With more detailed information of actual customers, there are better chances of determining if customers are willing and able to pay for a service at a given price, and therefore it is easier to establish if a service is affordable.

In the absence of consumer surveys, the best measures of affordability are:

- Market comparisons, that is experience of payment for the service in similar market
- Past experience of payments for services
- Comparisons with the costs of deriving the same service in other ways (for example cost of lighting using electricity vs kerosene).

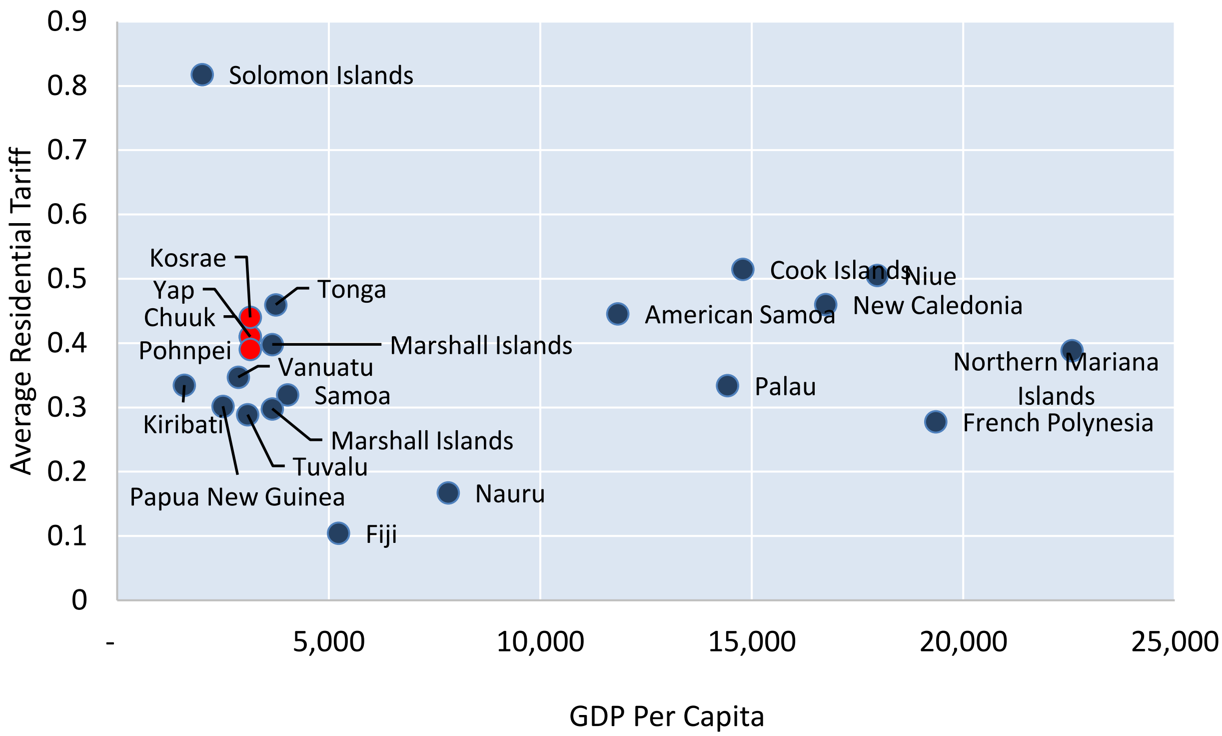
The Master Plans indicate that high-quality universal-access electricity services can be provided at tariffs that are similar to the tariffs that the utilities are currently charging in each State. Below, we assess the social impacts of these tariffs.

[41] Water Environment Federation. "Affordability assessment tool" 2013

7.2 Market Comparisons

We have compared the current tariffs in FSM with electricity tariffs in other Pacific counties. In Figure 7.2 we show how tariffs in different Pacific countries relate to the *per capita* incomes in those countries.

Figure 7.2: Comparison of Residential Tariffs for Pacific Island Nations



Source: Castalia based on data from the Pacific Power Association (June 2017. "Benchmarking Report: 2015 Fiscal Year"), World Bank, and the FSM utilities.

FSM tariffs are within the range of tariffs being charged by the electricity utilities in countries with similar GDP *per capita* levels. FSM tariffs are substantially lower than tariffs in the Solomon Islands.

Market comparisons broadly confirm that the current level of FSM tariffs is affordable.

7.3 Willingness to Pay

In this section we review indirect indicators of willingness to pay, including experience of past payment. We conclude that in each State:

- The expected electricity expenditure for already connected customers is equal to the current expenditure, and will continue to decline as a proportion of income
- The expected electricity expenditure for currently unelectrified customers will be less or equal to their current expenditure on other forms of energy, once electricity replaces other forms of energy.

Table 7.2: Estimated Energy Expenditure as a Percentage of Income in Chuuk

	Main grid	Mini-grid	Stand-alone solar
Estimated monthly bill 2034-2037 (US$)	$97	$38	$20
Estimated annual expenditure	$1,164	$456	$240
Expected income 2034[42]	$16,616	$7,815	$7,815
Electricity expenditure as a % of income	7%	6%	3%

Source: 2013/2014 FSM HIES, FSM 2010 Census, and Castalia

Table 7.3: Estimated Energy Expenditure as a Percentage of Income in Kosrae

	Main Grid
Estimated Monthly bill 2034-2037 (US$)	$87
Estimated annual expenditure	$1,039
Expected income 2034[43]	$21,448
Electricity Expenditure as a % of income	5%

Source: 2013/2014 FSM HIES, FSM 2010 Census, and Castalia

Table 7.4: Estimated Energy Expenditure as a Percentage of Income in Pohnpei

	Main grid	Mini-grid	Stand-alone solar
Estimated Monthly bill 2034-2037 (US$)	$55	$25	$17
Estimated annual expenditure	$660	$305	$201
Expected income 2034[44]	$22,791	$4,370	$4,370
Electricity Expenditure as a % of income	3%	7%	5%

Source: 2013/2014 FSM HIES, FSM 2010 Census, and Castalia

[42] Expected income is based on national average income form the 2013/2014 HIES and assuming income grows with GDP at a constant rate of 1.95 percent per year

[43] Expected income is based on national average income form the 2013/2014 HIES and assuming income grows with GDP at a constant rate of 1.95% per year

[44] Expected income is based on national average income form the 2013/2014 HIES and assuming income grows with GDP at a constant rate of 1.95 percent per year

Table 7.5: Estimated Energy Expenditure as a Percentage of Income in Yap

	Main grid	Mini-grid	Stand-alone solar
Estimated monthly bill 2034-2037 (US$)	$76	$32	$16
Estimated annual expenditure	$915	$381	$188
Expected income 2034[45]	$20,898	$11,937	$11,937
Electricity expenditure as a % of income	4%	3%	2%

Source: FSM 2010 Census, 2013/2014 FSM HIES, and Castalia

45 Expected income is based on national average income form the 2013/2014 HIES and assuming income grows with GDP at a constant rate of 1.95 percent per year

8 Social Impacts of the Master Plans

The Social Assessments have served as significant inputs into the Master Plans.

Health and gender effects

To ensure positive gender effects, the Master Plans propose to ensure that even the most remote households receive sufficient quality of power to enable the use of electric cookers.

Incomes, ability-to-pay, and collection of payments

For electricity access to be meaningful, customers must be able to afford sufficient electricity. The Master Plans provide for all households within a State to pay the same tariff per kWh of electricity based on an assumed level of electricity consumption, regardless of their location.

For the Master Plans to be viable the tariff must be affordable at least up to that level of consumption. In this social assessment we have identified several customer groups where the estimated electricity expenditure from preliminary modeling is higher than current energy expenditure. We have also identified that a significant proportion of the FSM population is at or below the poverty line. Households below the poverty line are likely to face cash constraints that will affect affordability and present barriers to electricity adoption. This issue will be addressed in part through the inclusion of household wiring into the cost of the electrification roll-out, enabling poorer households to repay such costs over time.

In remote communities, the utilities will face difficulties with collecting payment for electricity. Difficulties collecting payments are especially significant in areas where electricity is provided by stand-alone solar systems. To mitigate the challenges with payment collection, we recommend customers in all service areas be provided with cash power meters.

Availability of skilled workers on outer islands

The lack of availability of skilled workers in remote communities needs to be managed for the Master Plans to succeed. For practical and social reasons, we recommend using local staff to manage mini-grids and stand-alone solar systems in the non-grid areas. However, people on the outer islands are unlikely to have the required skills to operate, maintain, and repair generation and distribution assets. These local staff would need to be provided with training from the utilities. For efficiency, staff could attend group training on the main island of each state.

Ability to acquire land

In some remote areas, social conditions could make land for distribution and generation assets difficult to acquire. It is likely that generation units for mini-grids in these areas will need to be located on public land. If generation units cannot be built on public land, it may be problematic in some locations to acquire land. Leasing is an option as the owner gets to retain title. However, people can be wary of leases due to problems experienced with previous arrangements. Land access for mini-grid distribution lines will need to carefully consider the local context on each island.

The level of difficulty varies by state (as well as between main islands and outer islands). During the feasibility studies, we will assess the available space, and identify the need for additional sites.

9 Conclusion

The implementation of the proposed Master Plans will achieve significant social benefits and mitigate social risks by:

- Enabling near 100 percent access to electricity at affordable prices
- Empowering women and improving health outcomes
- Contributing to economic and social development
- Protecting land property rights.

Appendix A: Community Consultation Summary

Chuuk (Udot)	Kosrae (Walung)
Existing power: School has solar power. **Perceived beneficial uses of power:** charging phones/laptops, street lights, ice box **Concerns:** safety was a concern for the women, which is why street lights were a priority. Dispensary is unmanned and has been disconnected from power. **Employment:** teachers **Electricity satisfaction:** The school underutilizes the solar. They have some power but it's difficult to get appliances. They were given laptops but they have all broken.	**Existing power:** Schools and churches have generators. Residential homes have solar lights **Perceived beneficial uses of power:** lighting, printing work sheets/tests at school, watching movies **Concerns:** Changing traditional way of life, the school has a generator and an allocated budget for fuel but it is rarely used, this might be because of lack of appliances but it is probably also because people are used to doing things without power and do not necessarily want to change. **Employment:** mostly fishing and subsistence. Teachers are among a few that have a regular, reliable salary **Electricity satisfaction:** Solar panels were provided to the school 2 years ago but have not been installed because a minor part is missing. KUA was meant to source part but has not yet. Solar lights were provided and the community was meant to pay for them, but everyone refused.
Pohnpei Outer Islands	**Yap (Ulithi)**
Existing power: Some schools and dispensaries **Perceived beneficial uses of power:** lights, water treatment, ice box, machine to process copra **Concerns:** Batteries that are not disposed of properly may contaminate the soil which they rely on for their livelihoods **Employment:** teachers, some copra but they rely on the boat picking it up **Electricity satisfaction:** In Kapingamarangi, the solar system at the school has been down for 4 years. In Sapwuahfik, the radio has been down for about ten months. They can charge it at the school or dispensary but they need a new one.	**Existing power:** Mini grid **Perceived beneficial uses of power**: washing machines, freezers, lighting **Concerns:** Tariffs are much higher than the mainland and they did not understand why. Electricity can change traditional ways of living—for example, people used to share their catch of fish each day because they couldn't preserve it, but when they get ice, they share less and the community works together less. **Employment:** There is construction work happening due to a typhoon, which means there is nearly full employment for males. However, when this work ends, incomes will fall significantly **Electricity satisfaction**: Cash power is bought only when they have spare income. This means they often have periods without power and so cannot rely on freezers

Appendix B: Land Availability by State

Table B.1: Land Availability by State

	Availability of Public Land for Energy Generation	Ability to Buy and Sell Land	Ability to Lease Land
Chuuk	Considering placing solar panels on the land at CPUC power station Considering placing additional solar panels on the airport roof Considering placing solar panels on rooftop of Xavier High School Considering placing solar panels on the roof of the hospital but has been delayed because the roof is planned to be replaced Generation potential from placing further solar on rooftops of public buildings will be assessed	Only to FSM nationals. The utility can compulsorily acquire land as a government entity. However, the eminent domain law requires that lease options must be exhausted first.	People are wary of leases as they have had them in the past but only received first payments CPUC has over 40 leases in place for different assets - so far all are paid up for the next 20 years People get upset when they lose title - leasing is a means of allowing people to retain title and over a period greater than 10 years get more value than eminent domain would give them
Kosrae	Limited public land and roof space available. A large amount of land has not been allocated to individuals yet but there are claims on it and plans to distribute it. It seems unlikely that it will be able to be used for generation, but we need to consider further.	Only to FSM nationals. The FSM Government has an official price, but the utility claims it will be much higher than this in practice and is not a feasible option.	Same as buying, the utility thinks it would be too expensive and not feasible
Pohnpei	PUC has 100 hectares set aside for solar generation. There is also public land and rooftops.	Buying and selling land is illegal	Generally willing to lease land for projects with public benefit. Will involve consultations with the land owner, the chief, and the community

	Availability of Public Land for Energy Generation	Ability to Buy and Sell Land	Ability to Lease Land
Yap	Generation potential from placing solar on rooftops of public buildings will be assessed Private solar systems feed into the main grid, currently there are 7 private grid connected solar arrays—use of private rooftops may be an option for the future	Only to FSM nationals. People are typically willing to give land for community projects. Buying and leasing land (paid compensation) has been needed in some cases, as a result of negotiations between government, landowners, and traditional leaders; and when donors enforce fair payment	Willing to lease land indefinitely without remuneration for projects with public benefit. Will involve consultations with the land owner, the chief, and the community

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Appendix G: Implementation Plans – Environmental Assessment

Appendix E highlighted the main environmental risks associated with implementing the State Energy Master Plans. Here we discuss these risks in more detail and provide background on the FSM context for managing the environmental impact of energy projects in FSM.

The Master Plans envisage a significant reduction in reliance on diesel generation and in increase in the use of solar energy. In other words, least cost investment plan will over time also have positive environmental benefits. The proposed investments are generally in line with the national environmental targets.

We do not anticipate that the investments proposed in the State Energy Master Plans will create major environmental concerns. In general, the supply options that the investment plans include (new diesel generators, solar panels, new distribution lines, and small stand-alone solar systems) are similar to what already exists and/or have a low environmental footprint.

Nevertheless, all proposed investments will need to be screened carefully against the World Bank's and State EPAs' environmental assessment criteria before they can be implemented. The feasibility studies that we are preparing for Weno and Udot in Chuuk, and for Pohnpei Proper, will assess the environmental risks of the State Energy Master Plan investments (specifically the new investments in RE) in more detail. The ADB-funded feasibility studies of other projects across the four states will also assess environmental risks.

Provided the environmental risks are carefully identified, and then properly managed or mitigated, the investment plans should have an overall positive environmental (and social) impact—primarily because of emissions reduction and electricity access.

G.1 Key Environmental Issues for the State Energy Master Plans

The proposed State Energy Master Plans will have positive environmental impacts

It is difficult to compare and equate different types of environmental impact to assess the net impact. Stakeholders in FSM are best-placed to assess the net impact of these, depending on the states' specific environmental objectives.

On the main islands, the much higher share of RE in electricity generation will create significant environmental benefits. It will reduce GHG emissions, local air pollution, waste oil, and risks associated with fuel transport and storage. The expansion of infrastructure could create a need for land use change (such as to accommodate the large amounts of new solar PV envisaged in the State Energy Master Plans). However, this risk will be reduced through careful site selection and the use of sites that are already cleared (for example, the existing Pohnlangas site in Pohnpei, and existing diesel power station sites in Pohnpei and Chuuk).

The currently unserved islands may experience some local environmental impact from the construction of new infrastructure.

Projects on specific islands should be designed carefully in relation to the local environmental context, and—as far as practicable and cost-effective—include measures to minimize or mitigate these impacts. The proposed investment plans already provide for the costs of implementing several such measures (see Table E.1).

The availability of electricity may ultimately reduce the need to use wood as fuel. The investment plans assume that most unserved islands will primarily use solar PV and that the use of fossil fuels will be limited.

We have identified four main environmental risks of State Energy Master Plan implementation

Based on our research and stakeholder consultations, the main environmental risks associated with State Energy Master Plan implementation are: battery disposal, fuel transport and storage, waste oil disposal, and hydropower-related risks (Pohnpei only).

G.1.1 Battery disposal

Battery disposal is a major concern on outer islands. Due to the infrequent transport, getting batteries to the main islands for proper disposal is costly.

The national government has introduced a new policy whereby donors providing new generation must dispose of the batteries from previous donor projects. However, to avoid this potential disincentive to, or burden from, donors, utilities could identify their own strategies for battery disposal or recycling. For example, in Yap, a local company buys and recycles batteries. CPUC sent off lead acid batteries to Taiwan when it scrapped the power plant. Something similar could perhaps be organized for the electrification programs but would need to be coordinated by the State governments.

The State Energy Master Plans factor in the cost of shipping out old batteries from outer islands to a main island when batteries are replaced.

G.1.2 Fuel transport and storage

Stakeholders raised the risk of fuel spill during fuel delivery to outlying (or any) islands when transferring fuel by pipe or in drums from ship to shore. There are safety and environmental considerations around storing liquid fuels on outer islands, especially when infrequent deliveries may require significant storage.

The State Energy Master Plans minimize the use of liquid fuels in remote islands (as they use mainly solar PV), thereby reducing these risks. Nevertheless, the utilities (or other implementing agency) will need to have in place procedures to ensure that any remaining fuel transport is carried out safely and with regard to the environmental risks.

If desired by stakeholders, the use of liquid fuels for mini-grids on remote islands could be eliminated, but this would involve additional costs for battery storage.

G.1.3 Waste oil disposal

Waste oil is an environmental and fire hazard. Aside from Chuuk (which gives its waste oil to a dive boat), the FSM utilities have been accumulating waste oil. The Pohnpei Energy Assessment, for example, identified that the volume of waste oil stored at the Nanpohnmal power station has reached an unsustainable level, and there is a clear risk to the local environment from leakage from damaged waste oil drums. The volume of waste oil at the Nanpohnmal power station is currently about 110,000 gallons.

It will therefore be important to identify options to deal with waste oil as it accumulates in both major island power stations and outer island power stations. Although, the rate of waste oil accumulation will fall as the use of diesel generators declines.

The disposal of waste oil is very costly for island utilities. Technology is currently available that can continuously re-condition engine oil on site, and re-inject waste oils into the diesel fuel stream at small concentrations. This can both extend engine service intervals, and reduce the quantities of waste oil produced. However, this method of disposal is not an option for all generators because of conditions in supplier warranties. As an alternative, it may be possible to give the waste oil to the two national ships that periodically visit several ports in each state. This option would need to be explored in more detail.

The Secretariat of the Pacific Regional Environment Programme (SPREP) has an initiative, dating from around 2012/13, to prepare a waste oil management and removal strategy for all SPREP members. However, our observation from recent reports[30] is that, while strategies and country agreements have been established, there has been no substantial progress on delivering specific waste oil removal actions for FSM utilities. To ensure that waste oil can be adequately managed throughout the State Energy Master Plan period, the utilities and the states will need to be proactive.

We recommend that key stakeholders in each state coordinate to initiate a focused strategy to reduce the volume of waste oil to a more sustainable level, and implement measures to keep it at a reduced level in the future.

SPREP has recently (October 2017) advertised for consultants to help SPREP and Pacific Island countries assess options for managing waste oil. This is a regional project and may not analyze FSM's situation in detail, but is worth keeping track of as the utilities explore the options themselves.

The quantity of waste oil from the mini-grids outside the main islands will be very small, so the utilities will need to put in place procedures to ship out drums of waste oil on the regular supply boat. This would then need to be disposed of appropriately by the utilities on the main islands.

G.1.4 Hydropower

Lehnmesi hydropower facility

The Pohnpei State Energy Master Plan includes 2.7MW of hydropower capacity at the Lehnmesi site. Assessing the potential environmental impacts of such a project is complex and would need to be done in detail as part of a more detailed feasibility assessment for the project. We understand that the ADB/Entura team is doing a feasibility study on run-of-river hydro at this site in Pohnpei, which will provide useful information.

Below we outline the results of our preliminary assessment of the environmental impacts of this development.

Approximately 3.5 hectares of dense forest would be flooded. It is unlikely that this area would encompass species not common in the surrounding area. However, species should be surveyed during the planning phase. The impact on land-based fauna would be minimal as these would be expected to relocate successfully.

The proposed scheme would remove the majority of current stream-flows from approximately 5km of the river. Worst affected would be the river immediately downstream of the dam, which would only see environmental releases and occasional spill from extreme rain events. As tributaries join the river downstream of the dam, the river condition would improve. Modelling suggests that approximately nine percent of stream flow would be spilled and this would take place over approximately eight percent of the year, so the river would still experience some variability and flushing.

[30] GEF, UNEP, and SPREP. "GEF ID 4066: Mid-Term Review - Pacific POP's release reduction through improved management of solid and hazardous waste." www.ppa.org.fj/wp-content/uploads/2017/10/201017SPREP-Annex1_MTR_POPs.pdf.

The proposed storage dam may affect the ability of aquatic species to move upstream. However, there are existing waterfalls that would present similar (natural) barriers. Studies on aquatic life would be required as part of assessing the scheme's feasibility.

Dam building would potentially release silt and sediment into the river during construction. Following construction, downstream silt loads would be reduced. New roads would be built, and the penstock route would be cleared and benched. These activities will all have an environmental impact that must be quantified and managed during the planning phase.

Knight Piesold (1994) examines the environmental impact of the scheme, but this does not factor in the proposed storage.

Nanpil enhancements

We considered the possibility of upgrading the Nanpil hydropower scheme to provide a storage buffer and improve the capacity factor, but found that this would deliver energy at a higher cost than the Lehnmesi system. We therefore do not include enhancements to Nanpil in the Pohnpei State Energy Master Plan.

However, if a decision was made to proceed with this project, additional environmental issues would be minimal as the Nanpil River already has an operating hydro scheme.

Enhancement 1: Dam construction activities would potentially impact the environment during the construction phase. During operation, the river flows between the dam and the power station would be significantly lower than their current level due to the regulation of releases. Modelling suggests that 26 percent of river flow would still spill over 17 percent of the year.

Enhancement 2: The environmental impact from construction is minimal as all activity is contained within the existing powerhouse. There will be some small impact on river flows, with less spill at higher flows, and virtually eliminated spill at lower flow.

G.2 Institutional and Regulatory Context for Managing Environmental Risks

The state and national governments have various institutions and regulations in place that will help manage the risks. Environmental risk management will need to be considered at the stage of project assessment and design, during construction, and once projects are operational.

G.2.1 Environmental Policy and Regulation

The State Energy Master Plans must adhere to the Environmental Social Monitoring Framework (ESMF) agreed by the World Bank and the Government of FSM. The ESMF document sets out the principles, policies, and procedures for environmental and social protection over the course of the project. It aims to ensure the protection of natural habitats, physical cultural resources, indigenous peoples, and forests, as well as the safety of dams and the impacts of involuntary resettlement.

As the ESMF sets out operational procedures based on FSM's environmental laws and regulations, we describe FSM's institutional processes for environmental decision-making.

Environmental policy and regulation occur at both federal and state levels

At the federal level, the Division of Environment and Sustainable Development (within the Office of Environment and Emergency Management) develops national policy and has responsibility for national legislation such as the FSM Environmental Protection Act.

Each State has an Environmental Protection Agency (EPA) and has autonomous responsibility for State Environmental Impact Assessment (EIA) Regulations and other environment-related legislation. Their jurisdiction extends seaward to the 12-mile limit.

The Division of Environment and Sustainable Development does not have supervisory or enforcement powers over the State EPAs. There is, however, close coordination and cooperation between the State EPAs and the Division. For example, the Division supports the State EPA to review complex EIAs and the State EPAs share knowledge and tools with each other.

Activities undertaken by the national government, or its agencies, are assessed under the National Act. Otherwise, activities are assessed under the state-level Acts and regulations.

For donor-funded energy sector projects, the Energy Division—as the Implementing Agency—is ultimately responsible for implementing the safeguards instruments.

The states take the lead role in ensuring that development is avoided in vulnerable areas and ensuring critical natural systems are protected. Although there is still much to be done, most of the states have made initial efforts to guide sustainable development by creating land-use plans, coastal zone plans, environmental impact assessment acts, environmental impact regulations (including earthworks regulations and, in Pohnpei, air-quality regulations), and other relevant legislation and regulations.[31]

The state EPAs manage environmental assessment and management of projects. Projects require an EIA to be completed before implementation can begin. An initial statement of potential impacts and mitigation is required to identify potential environmental risks. If no potential risks are raised in the initial assessment, then the project can proceed. If the initial assessment identifies potential issues, then a full assessment is required.

All stages of project implementation must be assessed to ensure there are no unforeseen issues. Project sites can be shut down if environmental issues arise. However, local sub-contractors often do not have the capacity to manage mitigation actions.

[31] See *Federated States of Micronesia Agriculture Policy 2012–2016*, Department of Resources and Development, 2011.

Appendix H: Implementation Plans – Outsourcing Options

Outsourcing Some Functions May Increase Value for Money

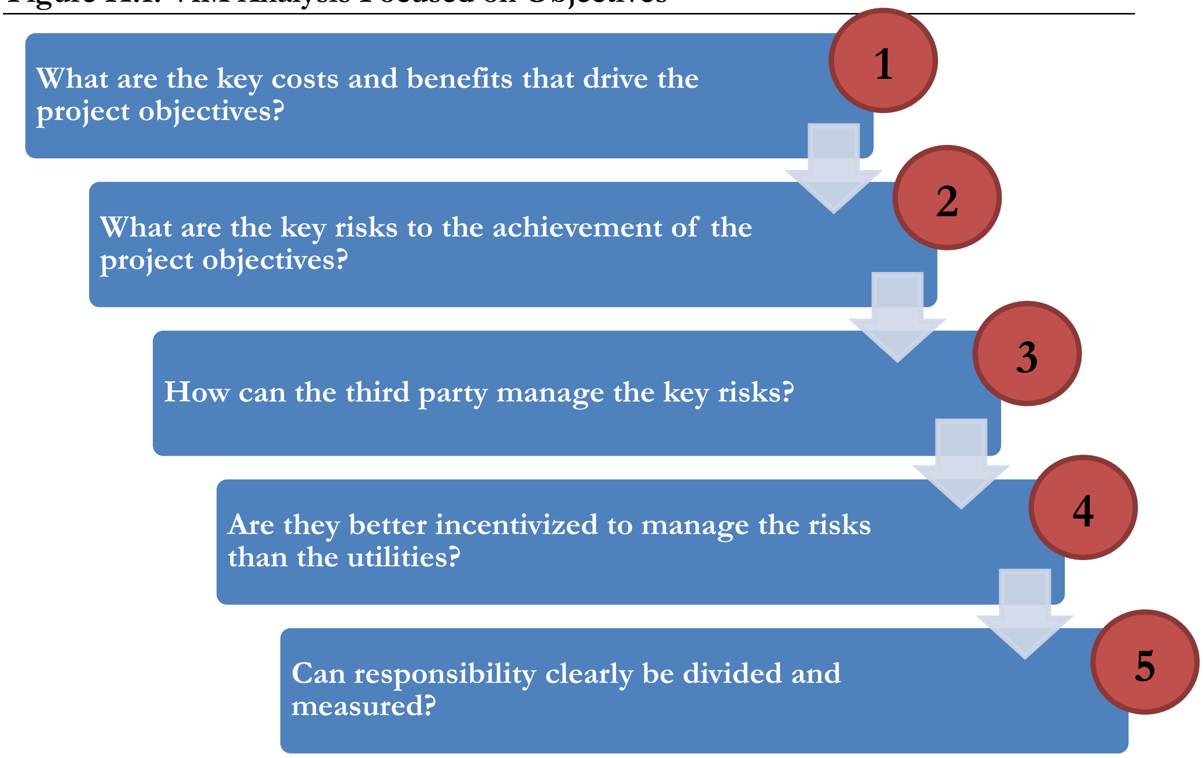
Functions such as generation, maintenance, or collection of fees could potentially be outsourced. These would not be outsourced because the utility doesn't have the resources, but rather because outsourcing can deliver superior VfM than the utility performing the function internally.

Here, we present a value for money (VfM) framework to assess outsourcing different functions. We then apply the framework in a high-level assessment of IPPs and of community engagement in managing off-grid systems.

H.1 Value for Money Framework

We put forward a principles-based framework to evaluate VfM of outsourcing. The framework focuses on understanding if the third-party has the incentives to deliver the project's objectives better than the utility. There are five stages to this analysis, outlined in Figure H.1 and explored in detail in the remainder of this section.

Figure H.1: VfM Analysis Focused on Objectives



What are the key costs and benefits that drive objectives?

A project may deliver a range of benefits and incur a variety of economic costs, but its overall economic viability will generally only be sensitive to a few of these. Such key costs and benefits will be identified in the economic appraisal.

The key costs are those that are the most significant over the life of the project. They will be relatively simple to identify, and in some cases, will be clear even without looking at the economic model.

The key benefits are those that directly lead to the delivery of the project objective. Secondary benefits that are contingent on the delivery of key benefits do not need to be considered.

What are the key risks?

There will be a range of risks that may influence the project, but only a few will have a significant impact on the key costs and benefits. Therefore, the next step in the appraisal will be to identify the key risks that impact economic outcomes by leading to excess costs and/or avoided benefits.

A simple three-step approach can be applied to deliver this analysis:

- List the key project costs and benefits identified in the previous step
- Identify the risk events that will affect the key cost or benefit.
- Understand the economic impact of the event. Is it likely to be so significant that the project will not achieve its objective? Or will it simply lead to excess costs or less-than-anticipated benefits?

What is the ability to reduce risks?

The third-party should only be allocated risks if it has the ability to reduce that risk. We need to look into specific actions the third-party can take to reduce the key risks.

What are the incentives to manage risks?

To understand if it is in the third party's interests to manage the risks, we consider both the upsides and downside of risk management:

- What profits can be generated by managing the risk? There are various remuneration options that can incentivize service delivery, which in effect, are an upside to effective risk management.
- What will be the cost of not managing the risk, and how does this compare with the cost of managing the risk? The private party is unlikely to manage risk events unless the risk impact will affect their profitability. Therefore, the private party will only manage risks when the cost of managing the risk is less than the cost of a risk event.

Even if the private party is incentivized to manage the risk, it is also important to determine if they will manage the risk better than the utilities. To do this, we consider if the public sector has access to similar or better incentives.

Can the risk be transferred?

To complete this analysis, we need to think critically about whether the risks best suited to the third party can actually be transferred. There are instances where poor project design means that risk transfer is ineffective, for example:

- Volume based risks cannot be effectively transferred unless outputs can be clearly defined and measured, and the contribution of the concessionaire can be isolated
- Operating cost based risks cannot be effectively transferred unless there is a clear division of responsibility.

Conclusion

If the private party is allocated key project risks and if it is incentivized to manage these risks better than the public sector, the project can reasonably show VfM. Otherwise, the project may need restructuring with consideration to the VfM principles. If, after restructuring the PPP still does not deliver VfM, it is reasonable to assume that procuring the project using a PPP is not suitable.

H.2 Local communities Could Manage their Own Stand-alone Solar Systems

On islands with stand-alone solar systems, it may be more efficient to allow each local community to deal with the installation, tariff collection, and maintenance of the systems. Here we apply the VfM framework to outsourcing stand-alone solar system management to communities.

Engaging local communities would mean that the utilities do not have to collect tariffs themselves (which could be challenging).

Technical training would be needed. This could be done by the utility or another option is the Barefoot College in India. Several FSM women have already received training on solar panel maintenance from there.

What are the key costs and benefits that drive objectives?

The key costs here will be services to manage and maintain the solar home systems.

The key benefits will be a high collection rate and limited outages.

What are the key risks to the achievement of the project objectives

Table H.1 shows the key costs and benefits, the risks, and impact of outsourcing management of stand-alone solar systems to communities.

Table H.1: Community Management of Solar Systems: Impact of Each Key Cost and Benefit

Key project cost/benefit	Risk event	Impact
▪ Services to maintain solar systems ▪ Limited outages	People hired do not have the technical skills to provide maintenance	Solar systems break and are either left unrepaired or the utility has to go repair them
▪ Services to collect payment ▪ High collection rates	People not understanding why they have to pay for solar and not paying	The solar system is either taken away or is left and not maintained until it breaks

What is the ability to reduce risks?

Do communities have more ability than the utility to make people pay?

- They are based locally, so can visit households to collect money in person. However, it is likely that the utility would hire a local person as well, so this risk would not be reduced.
- Communities would also face the same pressure as the utilities when collecting from family or friends.
- Social pressure could improve payment rates (e.g. because of respect for community leader or other authority) but it is unclear whether this would work.
- If people refuse to pay, they face the same challenge as the utility where removing solar systems requires too much administration.

Communities are unlikely to be able to reduce the risk of staff having the technical skills required. They would be relying on the utilities or donor training programs which they have little control over other than being willing to learn.

What are the incentives to manage risk?

- The person nominated to collect income will be incentivized to manage the risk of people not paying so that he gets paid by the utility. Especially if he gets paid depending on collection rate.
- The incentive for ongoing maintenance for the community is the same whether the utility or the community manages this risk

Can the risks be transferred?

- Collection rates can easily be measured so targets can be set and tracked.

Conclusions

The communities may be incentivized to manage tariff collection and able to affect collection rates better than the utility. However, for maintaining the systems, the utility is better placed with more incentive for this function.

There are a few success stories of community-managed electricity systems from elsewhere in the Pacific (notably in Tuvalu, the Cook Islands, and Tonga) that FSM could learn from. However, experience suggests that the most appropriate approach, and the degree of success, depend on the particular characteristics of the communities involved.

Nevertheless, some general lessons are:

- Training needs to be very hands-on and repeated regularly. It should be assumed that the local staff will not read technical manuals to solve problems
- Support from head office is very important, so that local staff can call for advice if they cannot solve a problem
- The responsible person needs to be someone fairly senior/respected in the community if he or she is to collect and enforce payments. Family and social obligations can be a barrier, so sometimes it is easier for the utility (as a more neutral party) to carry out this function.

H.3 IPPs can Harness Private Sector Incentives

IPPs can provide value by harnessing private sector incentives. Here we apply the same framework to IPPs to assess whether they might provide VfM.

Pohnpei is the only state in FSM that explicitly incorporates IPPs into state law. Other states do not have explicit provisions for IPPs, but we understand that IPPs are implicitly allowed in Chuuk.

There has been one IPP in FSM, between PUC and Vital. CPUC has recently signed an IPP agreement with Vital for a generation facility in Tonoas that would supply islands in Faichuk. These IPPs may have been used as a substitute for utility borrowing and not necessarily transfer much risk. As the Vital IPP in Pohnpei was signed at the time of a power generation emergency, the terms of other IPPs may be different. We note that the existing IPPs were not procured competitively.

There are three key requirements for the outsourcing through IPPs to achieve value for money for FSM utilities:

- IPP contracts need to be carefully prepared and reviewed to ensure that the risks and responsibilities are allocated efficiently between the utility and the IPP. In particular, since the utility remains ultimately accountable for the delivery of services, the security of supply commitment by the IPP need to reflect the ability of the utility to manage supply risks
- All future IPPs must be procured through transparent competitive tenders. We strongly recommend against entering into any directly negotiated IPPs
- To reduce the cost of financing IPPs, the utilities must be credible and bankable contract counterparties. In general, the cost of finance to IPPs will mirror the cost of finance available directly to the utilities. If banks do not wish to finance the utilities because it is seen as too risky, they will similarly not wish to finance IPPs contracted to those utilities.

Outsourcing requires the utilities to be proficient in many aspects of project development and implementation, including financial modeling, risk allocation, and contract management. Utilities cannot do away with these specialized functions because performing them increases the likelihood that a project's outcomes will be achieved at least-cost.

What are the key costs and benefits that drive objectives?

- The key costs are generation infrastructure, fuel costs, and maintenance costs.
- The key benefits are having the generation capacity to satisfy demand and having the optimal mix of different generation types.

What are the key risks to the achievement of the project objectives

- Table H.2 describes the impact of each of the key costs and benefits that drive the objectives

Table H.2: IPPs: Impact of Each Key Cost and Benefit

Key project cost/benefit	Risk event	Impact
Generation infrastructure	Financing conditions	Increased interest and therefore overall costs
Fuel costs (if applicable)	Oil price spikes	Generation costs increase
Maintenance costs	Cannot find skilled labor	Decreased life of infrastructure
Generation capacity to satisfy demand	Invest in under or over capacity	Generation costs increase
Optimal mix of different generation types	Invest in a non-optimal mix of generation types	Generation costs increase
Consumer demand	Demand is lower than forecast	Tariffs do not cover costs

Is the third party able to manage the risks?

- The private company can influence some financing conditions by being low risk and able to negotiate conditions with banks. However, interest rate increases and decreases from global events during the contract cannot be influenced.
- The risk of oil price spikes is not something that can easily be managed.
- The risk of not being able to find skilled labor can be managed through training programs.

- Both investing in the optimal capacity and type of generation can be managed by having experts evaluate options.
- The private party cannot influence consumer demand.

What are the incentives to manage risk?

- The private party has an incentive to manage all the risks discussed as this directly affects the profitability of the project. The private party will be paid based on outputs, so reducing input costs is the only way to increase profit margins.
- The utility might be better placed to manage financing conditions as donor funding is more likely to be available to it.
- The government puts pressure on utilities to provide people with least-cost electricity. However, if they do not, the costs are passed on to the consumer and the utilities themselves do not lose anything. The private party, with profits at stake, may have better incentives to reduce costs.

Can the risks be transferred?

- Generation volumes can easily be measured, and responsibility can easily be divided and made clear in a contract
- The risk of oil price spikes cannot easily be transferred to an IPP, so the utility would need to bear it (or pass it on to consumers)

Conclusion

The utilities may wish to consider the role of IPPs in implementing the State Energy Master Plans. IPPs' profit incentives could increase efficiency and lead to value for money for the utility. The private party would not have influence over the oil price and energy demand, and so these risks should still be borne by the utility.

Appendix I: Demand-Side Management

Demand side management involves two components:

- Active response from consumers in response to time-of-use pricing incentives to reduce system peaks and manage security of supply
- Long-term response to incentives and information to increase the efficiency of demand.

Our assessment is that there are no viable opportunities for active demand management in the FSM:

- The daily load profile is relatively flat, so there is limited benefit from reducing daily peaks
- Security of supply issues are generally not caused by daily peaks
- Residential consumers are generally too small to justify the cost of installing smart meters that would be required to implement demand management
- There are no industrial consumers with the ability to offer demand response services
- Commercial and government consumers are well placed to increase energy efficiency over time but are not well suited to short-term demand response.

Hence, we recommend that limited policy and management resource be focused on achieving medium term changes in energy efficiency rather than on attempting to develop short-term demand response. Achieving the National Energy Policy EE objectives will require changes in energy users' appliance purchases and use. Here we describe what we see as the main areas of potential.

I.1.1 Air conditioning in government buildings

The government sector accounts for 18 percent to 28 percent[32] of electricity consumption in the FSM states, and air conditioning is the main cause of this. Improving air conditioning design and efficiency—both in terms of the equipment used, and user behaviors—can offer savings of 15 percent to 40 percent of building energy consumption.

We understand that an audit of the National Government complex in Palikir was conducted in 2016 and that one of its main recommendations was using more efficient air conditioners. We would welcome a copy of this audit report. Based on the recommendations of the audit report, SPC has recently advertised for a supplier of High-Efficiency Inverter-Type Air Conditioning units for the complex.

The Yap State Government has also recently completed an audit of government buildings, which provides recommendations.

I.1.2 Commercial refrigeration

During our research mission, we observed many refrigerated containers ("reefers") outside restaurants, shops, and hotels. These are being used for bulk food refrigeration. Reefers are very inefficient compared to purpose-built cool rooms, and many are also sitting in the sun. Previous studies[33] have found that replacing reefers with cool rooms can reduce energy

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[32] Castalia calculations based on data from CPUC, KUA, and YSPSC. Does not include PUC because of insufficient data.

[33] ITP completed reefer replacement studies for Tuvalu and Tonga in 2012 and 2014.

consumption by 50 percent to 60 percent. Further studies would be needed to quantify reefer energy consumption in FSM and develop a program for replacement.

Many of the reefers are owned by commercial operators (shops and restaurants) and are used for bulk storage of chilled food at both refrigeration and freezer temperatures. We do not know exactly how many reefers are used at each premises, but small shops and hotels typically use 1 reefer to 5 reefers per site. The reefers offer a flexible means of storing food but are very energy inefficient.

Research from Tuvalu shows that reefers typically use about 800kWh per reefer per month when stored outdoors in the sun.

Commercial premises can achieve large cost savings by installing purpose-built cool rooms to replace reefers. This is dependent on shops having sufficient space for a cool room, and a willingness to alter their operations to use a cool room rather than reefers.

Cool rooms are likely to cost US$15,000 to US$30,000 per site. They operate much more efficiently than reefers at the wharf, offering large electricity cost savings. Reefers, by contrast, have no upfront costs as they are typically rented on a weekly or monthly basis. Simple payback periods for cool rooms as reefer replacements are typically less than 3 years.

Assuming refrigeration accounts for 30 percent to 40 percent of commercial energy consumption, savings of about 12 million kWh per year are theoretically possible in FSM. The cost of this would be in the order of US$15 million across all states.

On Kosrae, there are 20 x 40ft reefers used for fish storage near the wharf. On Pohnpei, the number is unknown, but we estimate 100 reefers. In Chuuk, we estimate 60 reefers. In Yap, we estimate 30 to 40 reefers plus wharf reefers.

I.1.3 Buildings

Building design standards can have a major impact on energy consumption. Standards that mandate sealed buildings and use of concrete lead to very high energy consumption compared with more traditional styles that rely on natural ventilation and low thermal mass. A review of building standards would help to identify locally appropriate designs that can help reduce air conditioning use in the long-term.

Some of the State Energy Action Plans already include actions in this area. For example, Chuuk's State Energy Action Plan proposes to: "Formulate and establish legislation for an Energy Efficient Building Code to improve living standards, health and education by 2017". We understand that this has not yet been done.

I.1.4 Other areas

Lighting replacement programs for government and commercial customers are already underway, so it is unlikely that further savings can be achieved by additional government initiatives in this area. The 2016 audit of the National Government complex in Palikir identified using energy efficient lights as a priority. SPC recently advertised for a supplier of LED T8 19W lights to replace the existing T12 linear fluorescent lights in the complex.

Providing incentives for commercial and residential customers to **replace older, low-efficiency refrigeration and air conditioning units** with modern, high-efficiency inverter-controlled air conditioners and refrigerators/freezers is an option. However, we have no data on refrigeration energy consumption, the efficiency of current stock, or the prevalence of poor seals.

Implementing **star rating systems for appliances**, and programs to encourage (or even mandate) retailers to only provide high-efficiency appliances to the market.

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