Republic of the Marshall Islands Energy Future

Electricity Roadmap

Technical Note 03: Techno-economic Analysis Inputs and Assumptions

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Summary

The technology pathways component of the RMI Electricity Roadmap draws on the findings of techno-economic modelling, which has been performed using HOMER software.

This technical note lists the inputs and assumptions used to populate the HOMER models.

1 Constraints on emissions

The RMI targets for emissions reductions are nationwide, whereas the RMI Electricity roadmap is focused on emissions from the electricity sector. Assumptions about the emissions reduction contributions from other sectors were described in technical note *RMI GHG inventory and electricity sector targets*, which resulted in a requirement that national electricity sector emissions reduce from 2010 levels by 50% by 2025, and by 65% by 2030. As electricity sector emissions are almost wholly from combustion of diesel, this would be achieved by reducing diesel fuel consumption by these levels.

The assumptions chosen of how various islands within RMI contribute to this target, as shown in Table 1, were as follows. Wotje, Jaluit and Rongrong were assumed to reduce diesel fuel consumption for electricity by 90% by 2025 due to USD 15m worth of solar/battery hybrid mini-grid systems as described in *A206 World Bank Marshall Islands RE Options* [1]. Kili, Rongelap and possibly Santos island were assumed to also reduce diesel fuel consumption for electricity by 90% by 2025 due to a further USD 7m worth of solar/battery hybrid mini-grids. Although other outer islands were expected to contribute to electricity emissions reductions by rapidly transitioning to near 100% renewable energy, the result on national fuel savings was considered minor. As a result Ebeye and Majuro together were assumed to need to achieve the remaining contribution, and we proposed that they achieve similar % diesel reductions from 2010 levels as each other by 2025 and 2030.

Table 1 - Proposed contribution of RMI electricity sector to national emissions targets

	2010	2025	2030	2050
Estimated/target national economy-wide emissions (excl fishing)	116 kt[1]CO_2-e	79 ktCO_2-e (32% reduction from 2010)	64 ktCO_2-e (45% reduction from 2010)	0 ktCO_2-e
Estimated/target national diesel fuel consumption for electricity generation	5.84m USG	≤ 2.91m USG (≥ 50% reduction from 2010)	≤ 2.03m USG (≥ 65% reduction from 2010)	0 USG
Estimated/target Wotje diesel fuel consumption for electricity generation	60k USG	4.9k USG (90% reduction from 2016)	4.9k USG	0 USG
Estimated/target Jaluit diesel fuel consumption	47k USG	5k USG (90% reduction from 2016)	5k USG	0 USG
Estimated/target other outer islands diesel fuel consumption (e.g. Eniburr)	Unknown but MEC suggest relatively minor. Only Kili included in electricity inventory (155k USG).	Significant rollout of SHS or mini grids.	Significant rollout of SHS or mini grids.	Complete rollout of SHS or mini grids.
Estimated/target Majuro diesel fuel consumption for electricity generation	4.49m USG (MEC)	≤ 2.34m USG (≥ 48% reduction from 2010)	≤ 1.63m USG (≥ 64% reduction from 2010)	0 USG
Estimated/target Ebeye diesel fuel consumption for electricity generation	1.07m USG	≤ 0.56m USG (≥ 48% reduction from 2010)	≤ 0.39m USG (≥ 64% reduction from 2010)	0 USG

These targets were applied to the modelling by only considering generation mixes which resulted in simulated diesel consumption equal to or less than the upper limits displayed in Table 1.

[1] kt is kiloton, being one thousand metric tonnes, which is equivalent to 1 giga-gram Gg.

2 Electricity generation economics

The HOMER simulation tool was used to identify potential combinations of electricity generation technologies for Majuro and Ebeye which would contribute to the national emissions targets of 2025, 2030 and 2050. All analysis was done in real terms with base year 2018.

Separate simulations were run for years 2025, 2030 and 2050, in order to find an appropriate configuration of generating plant which conformed to emissions targets. The configuration of generating plant was chosen based on the estimated lowest capital expenditure which meets the target. In many cases this configuration also represented the lowest estimated levelised cost of electricity (LCOE). In addition, simulations of year 2022 were also run to include projects already underway by the World Bank, JICA and NZMFAT.

At each of these simulation run years a 25 year techno-economic analysis was performed as if 1) all new equipment required was purchased in the year previous, with any grant funded capital cost included 2) subsequent annual electricity consumption remained constant, and 3) the time value of money remained constant in real terms (i.e. a discount rate of 0% after taking out the impact of inflation). Although none of these three reflect the real world situation, they allowed a configuration of generating plant to be chosen for each target year which would allow the corresponding emissions target to be met.

2.1 Assumed “current-day” LCOE on Majuro

It was not known with high certainty what the 2018 cost of producing electricity on Majuro was. The most detailed breakdown of generation costs available was found in the MEC Financial Statements with Additional Information, and Independent Auditor’s Report Years Ended September 30, 2015 and 2014 [2].

From the 2015 financials an indication of annual operating costs (including generation, distribution and admin, but excluding tank farm, solar, Jaluit and Wotje) was derived.

Annual fixed overhead costs were considered to be $5.16m (Table 2).

Table 2 - Majuro fixed annual operating costs

Generation operating costs	$12.42m
Distribution operating costs	$1.55m
Admin operating costs	$1.91m
Subtract Generation Repairs and Maintenance	- $0.95m
Subtract Generation Fuels and Lubes	- $8.81m
Subtract Generation Depreciation and Amortisation	- $0.96m
Fixed annual costs	**$5.16m**

These fixed costs were assumed to apply across all analysis years (“System fixed O&M cost” in HOMER). A diesel fuel cost of $2.45 per gallon was assumed to apply across all analysis years (Section 5.1). Fuel consumption; lubes, repairs and maintenance; and generator depreciation were handled separately in HOMER.

The MEC 2016 Power Report [3] (the most recent available) stated that in 2016, 3.80 million USG of diesel and $0.26m of lubricating oil was used to produce 53.71 GWh of electricity. Therefore, our “current day” estimate of LCOE (combining fixed annual costs, repairs and maintenance, generation depreciation and amortization, $0.26m lubes and $9.31m fuel) was $ 0.31/kWh.

2.2 Assumed "current-day" LCOE on Ebeye

It was not known with high certainty what the 2018 cost of producing electricity on Ebeye was. The most detailed breakdown of generation costs available was found in the KAJUR Statements of Net Position September 30, 2016 and 2017 [4] (noting that some water utility costs are bundled into these figures). From the 2017 financials an indication of annual operating costs was derived.

Annual fixed overhead costs were considered to be $2.60m (Table 3).

Table 3 - Ebeye fixed annual operating costs

Operating costs	$6.70
Subtract Operations and Maintenance	- $0.12m
Subtract Fuels and Lubricants	- $3.42m
Subtract Depreciation	- $0.56m
Fixed annual costs	**$2.60m**

These fixed costs were assumed to apply across all analysis years ("System fixed O&M cost" in HOMER). A diesel fuel cost of $2.45 per gallon was assumed to apply across all analysis years. Fuel consumption; lubes, operation and maintenance; and depreciation were handled separately in HOMER.

In 2016, MEC supplied KAJUR with 1.25 million USG diesel [5], to generate 16.89 GWh electricity [6]. Therefore, our "current day" working estimate of LCOE (combining fixed annual costs, operations and maintenance, depreciation, and $9.31m fuel) was $ 0.38/kWh (including some water utility costs).

3 Forecast future electricity loads

We assumed that electricity demand on islands other than Majuro or Ebeye will not noticeably increase, given the trend for population declines [7]. While year to year climate patterns may trigger an increase in water desalination, this has not been explored in detail.

3.1 Majuro

Electricity demand on the Majuro grid increased from 2016 to 2017 (see technical note *RMI GHG inventory and electricity sector targets*) and this trend was expected to continue. A forecast was developed to predict possible demand in 2025, 2030, and 2050.

Majuro HOMER simulations were performed using hourly time-steps. The most recent data available at hourly resolution of the Majuro load was the powerhouse generator logs of 2016. This data formed the basis of the load time series used.

A number of assumptions were applied to create forecast hourly load time series for electricity demand in 2022, 2025, 2030, and 2050.

For 2022, it was assumed the load changed from 2016 with the following (sequential) assumptions:

- Demand will increase by 2.2% due to population growth (see 2025 load growth below);
- Demand will decrease by 3% as a result of demand side energy efficiency and energy conservation measures (including metering programs). These measures were assumed to solely save diesel despite any increase in renewable energy;
- As part of a generator replacement project, powerhouse losses will be reduced by 300 kW [12];
- Network upgrades will reduce generation requirements by 3% [12];
- The PPF fish processing factory will move from private generators to the grid. The PPF load will remain as it was in 2017. The private generators currently used are assumed to have an average efficiency of 3.7 kWh/l. This load was approximated using a load factor of 1 - a constant load of 417 kW; and
- A new load is added to the network, consisting of 40ft refrigerated containers. It was assumed that an average of 200 refrigerated containers are running at any given time, this was approximated using a load factor of 1; a constant load of 1.4 MW (7kW each [9]).

It was assumed that the load on generation in 2025 changes from that in 2022 with the following assumptions:

- Demand will increase by 3.3% from 2016 instead of 2.2%, due to population growth (a 9% population increase [7] affecting 36% [8] of demand);
- Demand will decrease by 10% instead of 3% as a result of demand side energy efficiency and energy conservation measures; and
- A number of electric cars and outboards will be charged on the grid, equivalent to the cars and outboards which were fuelled by 10% of the gasoline sold in RMI in 2016. These will be charged in a utility-controlled manner, largely coincident with hours of

typical solar availability, and with only a moderate impact on peak loads[2] (see technical note *Electrification of transport*).

It was assumed that the load on generation in 2030 changes from that in 2025 with the following assumptions:

- Demand will decrease by 20% instead of 10% as a result of demand side energy efficiency and energy conservation measures; and
- A number of electric cars and outboards will be charged on the grid, equivalent to the cars and outboards which were fuelled by 29% instead of 10% of the gasoline sold in RMI in 2016.

Producing a load time series for year 2050 is highly speculative. In particular, the impact of zero emissions transport and industry on electricity generation and peak loads is not well understood. Emissions-free transport would likely require a shift away from just private transport. The energy sources which will power applications such as inter island water borne navigation or domestic aviation is not certain. Generating hydrogen as an RMI energy carrier by electrolysis of water using variable renewable energy sources has not been modelled. Regardless, to generate a 2050 time series, the following assumptions were applied:

- demand from 2030 is unchanged;
- applications currently powered by diesel or jet fuel will not be powered by the electricity sector; and
- a number of electric cars and outboards will be charged on the grid, equivalent to the cars and outboards which were fuelled by 98% instead of 29% of the gasoline sold in RMI in 2016.

3.2 Ebeye

Electricity demand on the Ebeye grid has increased over recent years (see technical note *RMI GHG inventory and electricity sector targets*), and this was expected to continue to a lesser extent. A forecast was developed to predict possible demand in 2022, 2025, 2030, and 2050.

The most recent data available at hourly resolution of the Ebeye load is the powerhouse generator logs of 2017. As some data appeared corrupted, nonsensical number were replaced with the preceding value. As data for the month of June was incomplete, adjacent data was used instead. This time series was then scaled to match the known total generation of 2016, from KAJUR records. This data formed the basis of the load time series used.

A number of assumptions were applied to create forecast hourly load time series for electricity demand in 2022, 2025, 2030, and 2050.

For 2022, it was assumed the load changed from 2016 with the following (sequential) assumptions:

- Demand will increase by 1% due to population growth (see 2025 load growth below);

[2] Note that to avoid high peak loads the utility controlled charging would need to be at a slow rate, which may not be acceptable to customers – further work is required on the impact of EV charging on the future network.

- Demand will decrease by 3% as a result of demand side energy efficiency and energy conservation measures. These measures were assumed to solely save diesel despite any increase in renewable energy;
- A new water desalination plant was commissioned late 2017. This was assumed to add 480 MWh to annual consumption, approximated using a load factor of 1 between hours 0600 – 2400 [11]; and
- A planned upgrade to the elementary school will not add to electricity demand (this information was not ascertained).

It was assumed that the load on generation in 2025 changes from that in 2022 with the following assumptions:

- Demand will increase by 2% from 2016 instead of 1% (a 3% population increase [7] affecting 50% of demand [10]);
- Demand will decrease by 10% instead of 3% as a result of demand side energy efficiency and energy conservation measures. These measures were assumed to solely save diesel despite any increase in renewable energy; and
- A number of electric cars and outboards will be charged on the grid, equivalent to the cars and outboards which were fuelled by 0.2% of the gasoline sold in RMI in 2016. These will be charged in a utility-controlled manner, largely coincident with hours of typical solar availability, and without significant peak load additions (See technical note *Electrification of transport*).

It was assumed that the load on generation in 2030 was the same as in 2025 other than the following assumptions:

- Demand will decrease by 20% instead of 10% as a result of demand side energy efficiency and energy conservation measures. These measures were assumed to solely save diesel despite any increase in renewable energy; and
- A number of electric cars and outboards will be charged on the grid, equivalent to the cars and outboards which were fuelled by 0.6% instead of 0.2% of the gasoline sold in RMI in 2016. These will be charged in a utility-controlled manner, largely coincident with hours of typical solar availability, and without significant peak load additions.

As for Majuro, it was assumed that the load on generation in 2050 was the same as in 2030 other than the following assumption:

- a number of electric cars and outboards will be charged on the grid, equivalent to the cars and outboards which were fuelled by 2% instead of 0.6% of the gasoline sold in RMI in 2016 These will be charged in a utility-controlled manner, largely coincident with hours of typical solar availability, and without significant peak load additions.

3.3 Results

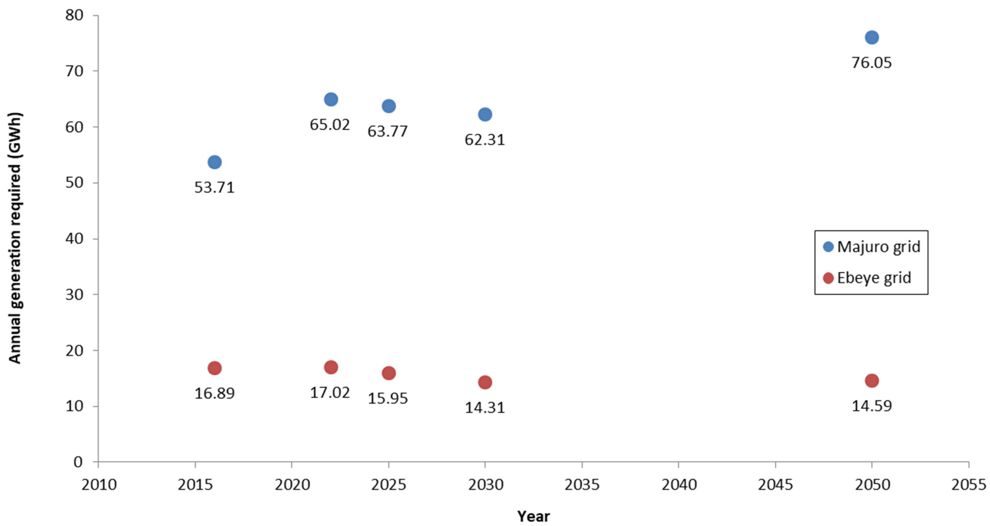

Figure 1: Future load forecasts – annual generation required

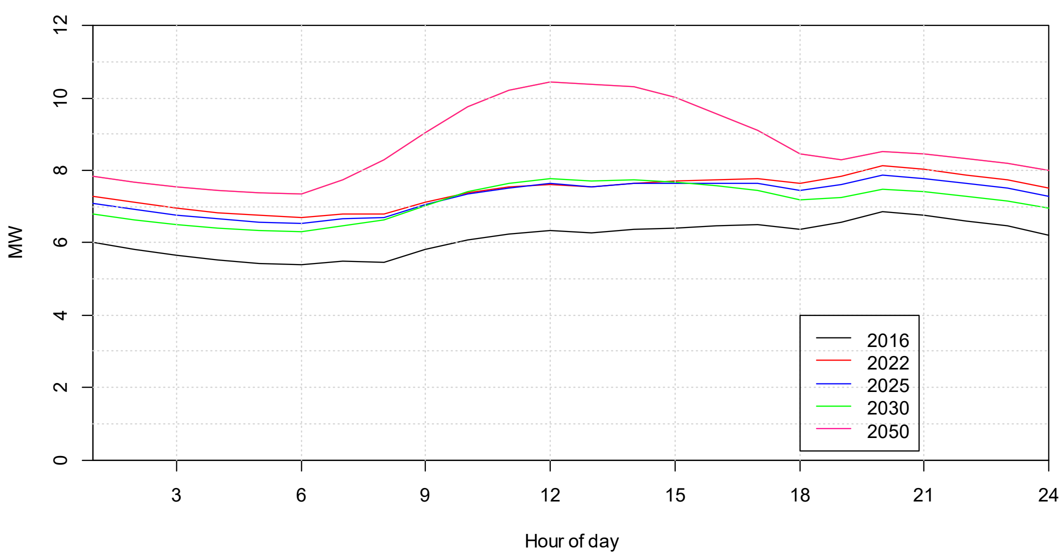

Figure 2: Majuro future load forecasts - average daily load profiles

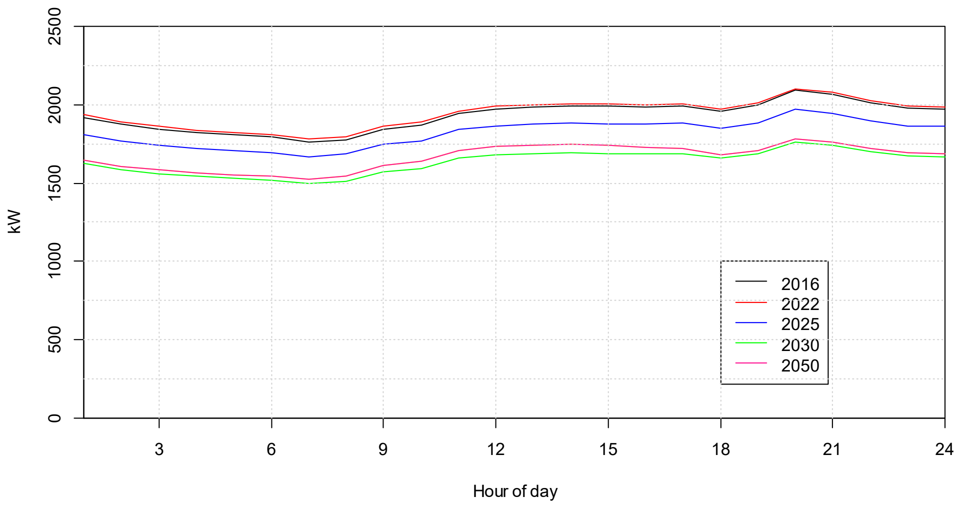

Figure 3: Ebeye future load forecasts - average daily load profiles

4 Network strengthening

Prior to large scale deployment of renewable energy on Majuro and Ebeye, a number of planning and infrastructure steps have been identified [12, 13, 14, 15] to strengthen the existing networks or inform project designs. The capital costs and operating costs of these steps were added to the appropriate HOMER models.

It is important to note the figures in Table 4 and Table 6 were provided by MEC and were taken as is.

Table 4 - Network and system strengthening projects on Majuro

Project	Capex ($)	Opex ($)
Wind resource assessment	337,000	
Powerhouse upgrade	1,500,000	
Replace diesel generators	Modelled separately	Modelled separately
Seawater Pump House Upgrade	50,000	60,000
Dock side bunkering shed rebuild	30,000	2,000
Sludge Storage Bins	40,000	500
Majuro Distribution Transformer Upgrade project	2,000,000	-
Fuel Farm Pipework replacement	50,000	-
Laura Distribution Depot upgrade	30,000	1,500
Station 2 Fuel Storage Expansion	300,000	-
Network upgrades	3,000,000	-
Station 1 Replace and Modify Pipework	200,000	-
Upgrade of MEC fuel Farm and engineering facilities	6,000,000	100,000
Majuro Distribution Network System rehabilitation	2,000,000	-
Vehicle Fleet Upgrade	1,250,000	-
Equipment Fleet upgrade	1,250,000	-
Majuro Distribution Network Manhole upgrade project	3,000,000	500
Power Cable from end of Rita to adjacent Is. Replacement	300,000	500
Majuro Auto Shop Rehabilitation	300,000	10,000
Majuro Distribution Shop Rehabilitation	400,000	10,000
Majuro Fuel Farm Seawall Rehabilitation	1,000,000	10,000
Fuel Farm Fire Fighting Facility	1,000,000	20,000
Administration Office replacement	1,000,000	-
Majuro Hospital Dual Power Supply	250,000	-
Laura Village Pole and Line removal	2,000,000	-
Laura Energy Storage Facility	500,000	15,000
Rita Energy Storage Facility	500,000	15,000
Loop Power Supply to Rita	4,000,000	50,000
Airport to Laura underground cable upgrade	20,000,000	-
Solar Electric Car Fleet and Charging Stations	400,000	20,000
Total	**52,687,000**	**315,000**

While all the projects presented in Table 4 were assumed to be necessary or worthwhile, they will not be done simultaneously; but over a 10-year period, starting with 2020, as presented in Table 5. Two costs – wind resource assessment and Majuro power house replacement are separated from the others, as they are directly tied with generation projects. The remaining capital and operational expenditure was summed up in a network/system strengthening project package and spread across 10 years. Table 5 also provides a split of capital and operational expenses for two modelling scenarios – 2022 and 2025.

Table 5 - Schedule of Network and system strengthening costs in Majuro

Year	Project	Capex ($)	Opex ($)
2020	Wind resource assessment Majuro powerhouse upgrade/replacement Network/system strengthening works – Year 1	337,000 1,500,000 5,085,000	0 0 31,500
2021	Network/system strengthening works – Year 2	5,085,000	31,500
2022	Network/system strengthening works – Year 3	5,085,000	31,500
	Total by 2022	**17,092,000**	**94,500**
2023	Network/system strengthening works – Year 4	5,085,000	31,500
2024	Network/system strengthening works – Year 5	5,085,000	31,500
2025	Network/system strengthening works – Year 6	5,085,000	31,500
	Total by 2025	**32,347,000**	**189,000**
2026	Network/system strengthening works – Year 7	5,085,000	31,500
2027	Network/system strengthening works – Year 8	5,085,000	31,500
2028	Network/system strengthening works – Year 9	5,085,000	31,500
2029	Network/system strengthening works – Year 10	5,085,000	31,500
	Total	**52,687,000**	**315,000**

Likewise, a list of necessary network and system strengthening projects for Ebeye is given in Table 6. Like on Majuro, those projects are spread over a period of 10 years. An exception is renovation of the existing power house and fuel system, which should happen as soon as practicable.

Table 6 – Network and system strengthening projects on Ebeye

Project	Capex ($)
Document existing installations	135,000
Remove abandoned equipment and junk	Unknown
Produce asset data management system	50,000
Meter study	5,000
Street lighting	16,000
Design maintenance procedures	10,000
Electrical testing equipment	5,000
Replace existing HV busbars and protection at the Power Station	1,107,600
Replace the existing switchgear	incl above
Install a powerplant data monitoring system	145,600
Replace all wooden power poles	206,500
Renovate existing power plant building and fuel system	3,539,935
Total	**5,220,635**

Table 7 presents an annual plan of capital and operational expenditure for network and system strengthening projects for Ebeye.

Table 7 - Schedule of Network and system strengthening costs in Ebeye

Year	Project	Capex ($)
2020	Renovate existing power plant building and fuel system Network/system strengthening works – Year 1	3,539,935 168,070
2021	Network/system strengthening works – Year 2	168,070
2022	Network/system strengthening works – Year 3	168,070
	Total by 2022	**4,044,145**
2023	Network/system strengthening works – Year 4	168,070
2024	Network/system strengthening works – Year 5	168,070
2025	Network/system strengthening works – Year 6	168,070
	Total by 2025	**4,548,355**
2026	Network/system strengthening works – Year 7	168,070
2027	Network/system strengthening works – Year 8	168,070
2028	Network/system strengthening works – Year 9	168,070
2029	Network/system strengthening works – Year 10	168,070
	Total	**5,220,635**

Increased opex costs associated with upgrade projects were not known nor estimated for Ebeye. The overall impact of this missing data on the Road Map analysis and LCOE estimates was deemed negligible.

5 Energy resources

The main energy source for electricity in RMI is currently diesel fuel as it was in 2010, which produces GHG emissions. To meet GHG emissions reduction targets, a significant reduction in diesel use will be required; by firstly reducing demand and energy losses, and secondly by replacing significant quantities of this fuel with low emissions or zero emissions energy sources.

Other energy resources considered for the analysis were solar radiation, wind, and local and/or imported biodiesel. Although it may be feasible to combust municipal solid waste for electricity production on Majuro, the emissions benefit would be realised in the waste sector more than in the electricity sector (if at all), and so this was treated as a waste sector project and not included in the HOMER modelling.

Ignoring embodied carbon[3], the electricity produced by solar photovoltaics and wind turbines were considered zero emissions. For the purpose of this analysis, biodiesel was treated as emissions free; i.e. it was assumed to be sustainably sourced and transportation emissions were ignored.

5.1 Diesel fuel

The technical note *RMI GHG inventory and targets* informs the maximum diesel consumption permitted under the applied assumptions. See section 1for further details.

The price of diesel is associated with the price of oil, which has been and remains very volatile. This volatility was assumed to remain over the analyses period, and so no projection of future prices was attempted. Diesel fuel was assumed to cost a steady $2.45 per gallon over all analyses for an indicative comparison against renewable energy technology – this is the supply price to MEC early – mid 2018 when international crude oil prices have been in the range US$65-75 per bbl. [17].

5.2 Solar insolation

The World Bank Global Solar Atlas [16] suggests a long-term average daily global horizontal irradiation (GHI) of 5.42 kWh/m^2 on Ebeye. To produce an hourly time series of a typical meteorological year for Ebeye, irradiance data from a US National Oceanic and Atmospheric Administration pyranometer on Kwajalein was used. Although years 1992 to 2017 are available as 1 minute averages, not all years have complete data. The data set from year 2003 was chosen as being largely complete. All values were scaled to produce match the long-term daily average GHI of 5.42 kWh/m^2.

The World Bank Global Solar Atlas suggests a long-term average daily global horizontal irradiation (GHI) of 4.99 kWh/m^2 on Majuro. Because pyranometer data was not sourced for Majuro, the same data set as Ebeye was used, but scaled to produce the long-term daily average GHI of 4.99 kWh/m^2.

Because solar photovoltaic output is negatively affected by module temperature, an ambient temperature resource was defined. This was automatically downloaded from NASA satellite data, an average of 27°C.

[3] i.e. the carbon emissions associated with making the PV panels/turbines and related equipment, plus installing.

5.3 Wind

The power available for a wind turbine to harness depends on the swept area of the rotor, the density of air, and the velocity of the wind. Changes in air density were ignored.

However, because the power is proportional to the cube of wind speed, the average power available cannot be calculated from the average wind speed - the frequency distribution of wind speeds needs to be known. This is why estimating potential wind turbine production with any accuracy relies on site specific measured data.

As no measured data of wind speed on Majuro or Ebeye was available at the time of analysis, wind speed monitoring performed in Jaluit and Wotje in 2012/2013 was used to estimate the wind resource of the Marshall Islands. The technical note *Wind energy in RMI* described the synthesising of a 12 month hourly time series for Majuro and Ebeye using these data sets. This time series was based on the Jaluit site, which is considered to have a generally lower wind resource than Majuro or Ebeye (see TN-01), and hence this was considered a conservative estimate of wind speed. No long term wind speed data or hindcast concurrent with this measured data was available to correct for the interannual variation. As a result, a sensitivity analysis of a +/- 10% wind speed estimate error was applied.

5.4 Biodiesel

Biodiesel was considered as a fuel to assist with the 2050 target of zero emissions, which would be very expensive to meet with using wind and solar alone. No assessment of local production is included, however importing biodiesel may be an option. The emissions associated with the production and transportation of biodiesel were ignored.

The price of biodiesel in 2050 is completely unknown. Since the price of diesel was assumed to remain constant, a constant premium for biodiesel over diesel was assumed. For the purposes of the analysis, biodiesel fuel was assumed to cost a steady $4.92 (twice the price of mineral diesel used) per gallon over all analyses for an indicative comparison against renewable energy technology and diesel generation.

6 Technologies

6.1 Diesel generators

Entura [6] have previously analysed the least-cost configuration of generating plant to meet a national target to produce 20% of Majuro grid electricity by renewable energy. This work concluded that the best pathway to achieve this target, and to set up for further renewable contributions, included replacing the Majuro generator fleet with six 2 MW gensets. In part, this is because the existing aged generators can only be run within a narrow operating range, severely limiting the opportunity to accept variable renewable energy contributions.

For all Majuro simulations, the assumed generator fleet was 6x 2,050 kW (continuous) sets based on a CAT 3516C datasheet (as an example), with the following fuel consumption:

Table 8 - Assumed fuel consumption of replacement Majuro diesel generators

Load	25%	50%	75%	100%
Fuel consumption (gal/hr)	48.9	80.2	110.3	142.2

Assumed costs were $0.75/W to purchase, and replacement costs at $0.75/W to replace after 75,000 operating hours each. Operating and maintenance costs were assumed to be $12 per operating hour each, excluding fixed annual cost but including major service procedures.

These were assumed to be able to run as low as 30% of capacity, and required a minimum operating runtime of 60 minutes.

For Ebeye, the existing diesel generator models were modelled – four 1,260 kW Cummins generators. Currently two gensets are generally running most of the time, with a third for peak periods. Typical fuel consumption curves were used and adjusted slightly to match the average generator efficiency reported in the Pacific Power Utilities Benchmarking Summary Report, 2016. Although currently these machines are derated, it was assumed that these would be replaced or refurbished to allow full output. It was assumed that these machines could be run as low as 30% of their rating, and required a minimum operating runtime of 60 minutes.

Replacement costs were assumed to be $0.75/W after 75,000 operating hours each, with two in need of immediate replacement. Operating and maintenance costs were assumed to be $10 per operating hour each, excluding fixed annual cost but including major service procedures.

These generator fleets were also assumed to be able to run on up to 100% biodiesel for those scenarios where biodiesel was considered. In these cases, the hourly O&M costs of the generators were doubled, and fuel consumption was modelled as 8% greater than running on mineral diesel.

6.2 Dispatch controller

In order to move from the current manually controlled system with low renewables penetration, a sophisticated control system will be required which can automate the dispatch and output of diesel gensets, PV and wind generators, and battery energy storage systems.

A “load following” dispatch controller was modelled with a capital cost of $1m, and the diesel generators were permitted to be dispatched optimally. Enough operating reserve was required to allow full reduction in the output of variable RE generators (wind and solar).

6.3 Solar photovoltaics

Performance assumptions:

- The temperature effect on module output is -0.4% of capacity per °C above standard test conditions.
- Other losses (such as wiring, inverter efficiency, transformer efficiency, soiling, average degradation) total 15%.
- DC/AC ratio is 1.

Land and suitable rooftop space for PV installations in the RMI are very limited. Initially a series of distributed rooftop arrays will be installed but larger capacities may require an innovative or unusual, and possibly more expensive installation - such as floating arrays in the lagoon in proximity to the powerhouse. Floating solar is not currently proven in a marine lagoon environment, particularly on waters subject to wind chop or swell, although international pilots are currently underway. The current capital cost of PV was assumed to be $3/W (including transmission). This cost was assumed to reduce to $2.5/W by 2025, and to $2/W by 2030 – although PV modules continue to decline in cost, much of the balance of systems may not, particularly for rooftop or floating systems. Should a number of large ground mount locations (>1MW) be identified then costs closer to $1-1.5/W could be expected.

The only replacements considered in the 25 year HOMER analysis periods were inverter replacements each 10 years at $0.20/W, as the rest of the systems are expected to last 25 years. Annual O&M costs were assumed to be 2% of capital costs.

All new PV was modelled as though it was installed horizontally, to simulate the average of the various orientations that PV is likely to be installed at (e.g. various roof orientations, floating arrays are often east/west). At this latitude the loss from non-optimal orientation is minor.

This resulted in a modelled PV capacity factor of 16% on Majuro and 18% on Ebeye.

Existing PV was modelled at 920kW, with sunk capital cost, and replacement and O&M costs as above.

On Majuro, 3 MW of PV (expected to be supplied by the World Bank) was included by 2022 at a total project cost of $22.6m, and replacement and O&M costs as above (plus PV replacement after 25 years at costs above). 137 kW (expected to be provided by NZ MFAT) was included by 2022 at a total project cost of $574k, and replacement and O&M costs as above (plus PV replacement after 25 years at costs above).

On Ebeye, 600 kW of PV (expected to be supplied by JICA) was included by 2022 at a total project cost of $9.75m, and replacement and O&M costs as above (plus PV replacement after 25 years at costs above).

6.4 Wind turbines

The technical note *TN-01 Wind energy in RMI* identified a number of potential wind turbine models which could be considered in more detail for RMI. As HOMER only permits two turbine types, the Vergnet GEV 275 kW and the Windflow 45 500 kW turbine were modelled, as examples of typical wind turbines.

The power curves of these turbines are available within the HOMER standard libraries. Losses (including loss of availability) were assumed to be 15% of production. Both turbines were modelled at 50m hub height.

This resulted in a modelled wind turbine capacity factor of 31% for the Windflow turbine and 29% for the Vergnet turbine on both Majuro and Ebeye.

The cost of installing turbines in these locations is very uncertain since sites are not identified. The costs per turbine will also depend on how many turbines are installed as a single project. The following table of assumed costs was used, based on previous installations of the Vergnet machines in the Pacific, and on Windflow supplier suggestions with extra contingency added (see TN-01). The operating and maintenance cost of the Windflow turbines was based on the manufacturer's estimate of a service contract cost for five turbines.

Table 9 - Assumed costs of wind energy in RMI (USD)

	Vergnet (275kW)			Windflow (500 kW)		
Turbines	Capex ($m)	Opex ($k)	Replace @ 20 yr ($m)	Capex ($m)	Opex ($k)	Replace @ 20 yr ($m)
1	1.73	22.0	1.12	2.53	50.0	1.67
2	2.67	38.5	1.73	3.89	87.5	2.56
3	3.60	55.0	2.33	5.25	125.0	3.46
4	4.53	71.5	2.93	6.61	162.5	4.35
5	5.46	88.0	3.54	7.98	200.0	5.25
6	6.40	105.0	4.15	9.35	238.6	6.15
7	7.30	121.0	4.73	10.66	275.0	7.02
8	8.30	138.0	5.38	12.12	313.6	7.98
9	9.20	154.0	5.96	13.44	350.0	8.85
10	10.10	171.0	6.55	14.75	388.6	9.71
11	11.00	187.0	7.13	16.07	425.0	10.58
12	12.00	204.0	7.78			
13	12.90	220.0	8.36			
14	13.80	237.0	8.95			
15	14.80	253.0	9.60			

These costs were assumed to remain constant over the analysis period, as wind turbines at this size are mature technology, with costs dependent on raw materials and grid integration technology.

Wind turbines will require a dedicated transmission line to transfer power output back to the main powerhouses. It is not certain which sites for installing wind turbines would be utilised on Majuro, and so there is some uncertainty around the cost of this. A possible site is at Ajeltake, a large lagoon-side reef-flat 14 miles from the power station (Figure 4). A dedicated overhead transmission line was assumed at $4.4m ($200k/km - this was added to the capex of Table 9). Underground cable would be less susceptible to storm impacts but comes at a significantly higher cost.

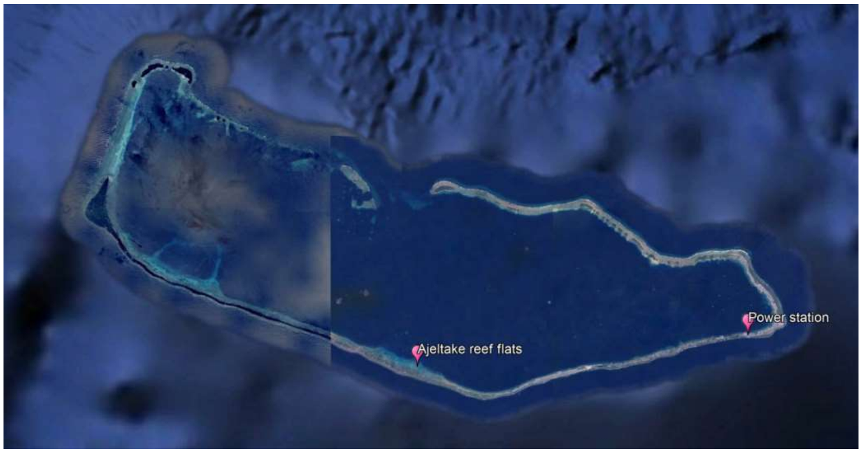

Figure 4: Assumed location of Majuro wind turbines for purpose of estimating wind transmission costs

For Ebeye, the causeway to Guegeegue island was considered a potential candidate for wind (Figure 5). A 1.7-mile overhead transmission line to the powerhouse was assumed to cost $540k (this was added to the capex of Table 9).

Figure 5: Assumed location of Ebeye wind turbines for purpose of estimating wind transmission costs

6.5 Battery energy storage

The behaviour, performance and benefits of utility battery energy storage systems (BESS) is a complex topic. Within the HOMER models, BESS were assumed to be able to provide two benefits:

- Power provision as operating reserve against variable renewable energy
- Energy provision to store excess renewable energy generation to utilise at another time.

Previous iterations of RMI modelling under multiple scenarios suggested that for many scenarios a system which permitted some diesel off operation was the optimum solution to meet the emissions targets. A design philosophy of constraining the battery minimum size to meet peak loads (i.e. the hourly average peaks in the load time series) was chosen, to allow for diesel off operation (it was assumed that diesel-off operation would be viable with a grid forming battery inverter and enabling technologies).

BESS were modelled as discrete quantities of an idealised (i.e. constant voltage and internal resistance) lithium-ion battery with 750 kW power capacity and 1,500 kW of storage capacity, with an average AC-AC roundtrip efficiency of 88%, a 10 calendar-year life, and the following costs:

- Capital and replacement costs: currently $\$450/kWh_{capacity}$, reducing to $\$383/kWh_{capacity}$ in 2025 and $\$325/kWh_{capacity}$ in 2030 and 2050 [18], including installation, enclosure, power conditioning system, transformer and switchgear. It is acknowledged that this is an optimistic price for the Pacific region, with recent tenders pricing installed battery systems significantly higher – however costs are currently reducing rapidly.
- Annual operating costs: currently $\$20/kWh_{capacity}$ reducing to $\$17/kWh_{capacity}$ in 2025 and $\$14/kWh_{capacity}$ in 2030 and 2050.

Although the above costs are for usable capacity, a minimum state of charge of 20% was applied to the BESS models to account for the fact that usable capacity is expected to degrade by 40% over 10 years (i.e. average degradation of 20%).

On Majuro, the World Bank project may include battery storage for grid stability, but the size is not yet known. A battery of 750kW/1,500 kWh was included in the 2022 model, (as chosen through HOMER optimisation with the new diesel generators). Capital costs were already included in the World Bank PV, and O&M and replacement costs as above.

On Ebeye, a battery of 1,200kW/600kWh (expected to be supplied by JICA) was included by 2022. Capital costs were already included in the JICA PV, and O&M and replacement costs as above.

6.6 Other enabling technologies

Although HOMER does not model transient frequencies, voltages and currents, the capital costs of including a synchronous condenser (to compensate for a loss in inertia and fault current as diesel generators are permitted to switch off) were added to the models as shown in Table 10.

Curtailment of excess solar or wind generation is typically performed through inverter control, however in case more rapidly acting curtailment is required, capital costs to include a resistive load bank were added to the models as shown in Table 10.

Table 10 - Capital costs of included synchronous condensers (or similar)

Enabling technology	Majuro	Ebeye
Synchronous condenser	10 MVA, \$5m	3 MVA, \$1.5m
Load bank	10 MW, \$1m	3 MW, \$0.3m

7 Major Assets Replacement Schedule

The RMI Electricity roadmap aims for reaching emissions targets across a couple of decades. All equipment installed must be replaced in regular intervals, to ensure targets will be achieved and sustained. This section describes the assumed level of capital investment in complete replacement required. It does not cover regular operation and maintenance costs.

The following assumptions were made for each of installed technologies:

- Network upgrades, such as distribution lines, transformers, etc will be installed in around 2025 and will not be replaced before 2050,
- Diesel power station house, piping, its electrical infrastructure will be installed in around 2020 and will not be replaced before 2050,
- Diesel fuel depot in Majuro will be refurbished around 2030 and will not be replaced before 2050,
- Diesel generators will be installed in 2022, and completely replaced after ten years, in 2032. After that, due to high renewable contribution and lower utilisation of diesel engines, it is predicted they will not be replaced for another 20 years, which means they won't be replaced again before 2050.
- Solar panels will have their inverters replaced at 12.5 years from installation date. In addition, after 25 years, both solar panels and inverters will be entirely replaced.
- Wind turbines will be installed in 2025, and are not replaced before 2050,
- Batteries installed before and including 2025 will be replaced after 10 years, together with their inverters. Batteries installed after 2025 will be replaced every 15 years, due to battery energy storage technology advance.

For Majuro and Ebeye replacement schedule is as follows:

2025 – Inverter replacement for existing 1MW solar PV (Majuro only)

2032 – Complete replacement of diesel generators installed in 2022

2035 – Complete replacement of existing 1 MW solar PV (Majuro only),

Inverter replacement for solar installed in 2022,

Complete replacement of battery installed in 2022.

2038 – Inverter replacement for solar installed in 2025

2040 – Complete replacement of battery installed in 2025

2043 – Inverter replacement for solar PV installed in 2030,

2045 – Complete replacement of battery installed in 2030.

2047 – Complete replacement of solar installed in 2022.

8 References

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