Broome Clean Energy Study
REPORT

This report demonstrated that electricity generation in the town of Broome can be achieved with over 80% renewable energy at three quarters of the price of gas-fired (LNG) generation. This will achieve total lifetime savings of $321m.

BROOME'S Electricty Generation achieved with **>80%** Renewable ENERGY Costing less than **3/4** Price of LNG Generation

SEN
Sustainable Energy Now

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We acknowledge that the body of this work was produced on the land of the Nyoongar people.

We acknowledge the report was produced for the lands of the Yawuru Native Title holders.

We pay respect to their Elders – past, present and future – and acknowledge the important and continuing role of Aboriginal and Torres Strait Islander people in advancing a more sustainable Australia.

This Update draws on the 2018 Kimberley Clean Energy Roadmap (KCER) produced by SEN. The energy modelling used in the KCER was based on two inter-related software packages, available under open source licenses:

- SIREN: developed by Angus King
- Powerbalance: developed by Ben Rose and Len Bunn, available at http://cleanenergymodelling.com/powerbalance2/.

The energy modelling used in the KCER was performed by independent modelling consultant Ben Rose.

The energy modelling performed in this Report used Powermatch (an extension of the SIREN software). This modelling was validated against Powerbalance. SIREN, including Powermatch, was developed by Angus King and can be redistributed and/or modified under the terms of the GNU Affero General Public License as published by the Free Software Foundation, either version 3 of the License, or (at your option) any later version. SIREN is available from https://github.com/ozsolarwind/siren.

Cover Image: Paul Bell

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Sustainable Energy Now

Sustainable Energy Now (SEN) is an independent, not-for-profit, evidence-based think tank advocating for a clean energy future for WA and powering up the transition from fossil fuels to renewable energy (RE).

We bring together professionals from all sectors – including policy, engineering, science, education, finance and IT – who are passionate about volunteering their expertise to find the most sustainable solutions for WA's energy needs.

Together, we're working to drive the development of a renewable energy-based electricity grid for WA that's secure, cost-effective, reliable and able to safely meet the increased demand for electric-powered transportation, housing and industry in a hotter, drier climate.

At WA State Government level, we're providing research, analysis, modelling and advice to policy and decision makers to ensure power systems can operate effectively with high levels of RE generation.

In the community, we're building the support and political will to improve energy policies and planning, so we can realise the exciting opportunities that exist in RE here in WA. **www.sen.asn.au**

Biographies

Dr Rob Phillips

Dr Rob Phillips is a retired scientist and science educator who played leadership roles in educational technology and university policy development over 35 years. He has a long-term interest in environmental sustainability and a long history of contributing to the broader community.

He has been a member of SEN since 2013, and is currently Vice-Chair. He has been a committee member, policy team leader and outreach team leader. His major role in SEN has been in making SEN's work more accessible to the broader community, including Briefing Notes, submissions to various government inquiries, and two major reports: the Kimberley Clean Energy Roadmap (2018), and the SEN Jobs Report (2020).

Angus King

SEN's Integrated Renewable Energy Network (SIREN) software was developed by experienced software developer Angus King.

Angus has over forty years' experience in information technology, predominantly in software development. His passion for RE technologies over the last twenty years has led him to tertiary studies in the field and to being one of the first people to install a grid-connect PV system in WA. He has been a member of SEN since 2007.

Len Bunn

Len is a retired principal systems engineer and co-founder of Plexal Group, a multidisciplinary engineering services company with operations across Australia and South East Asia. Len has 25 years' experience in the international oil and gas industry, including business case development and concept design through to detailed engineering, construction and commissioning. In the past ten years Len's focus has moved to sustainability across all aspects of society, with a particular application on RE systems.

He has been a SEN Member since 2011, Member of the Technical Team since 2014, Policy Team since 2015 and the Committee from 2018 to 2019.

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1. Executive Summary

This report builds upon the Kimberley Clean Energy Roadmap (KCER) by providing updated, cost-effective, low-emissions electricity generation options for the town of Broome, located in the Kimberley region of WA.

New modelling software enabled a wide range of generation options to be considered, using 2024 cost estimates[2] for fossil-fuel and renewable electricity generators. Levelised Cost of Energy (LCOE) was used to compare various combinations of technologies across their expected lifetimes.

Section 3 outlines the assumptions used in the modelling, including why a carbon price of AU$60/t$CO_2$-e has been applied as the base case. Capital costs in the Kimberley are higher than elsewhere in Australia due to remoteness and severe weather factors.

The results are described in Section 4. The current LNG-only generation has an estimated LCOE of $293/MWh. Gas generation costs are strongly sensitive to variations in carbon and fuel prices. Given the increasing likelihood of a carbon price imposition in the short to medium term, and the high volatility of gas prices internationally and domestically, continuing the LNG-only option represents a high to extreme risk for electricity generation costs in Broome.

This report shows that the lowest estimated LCOE ($215/MWh) occurs at a solar PV capacity of 60MW, combined with 40MW/160MWh battery storage, backed up by the existing 30MW of gas (LNG) generation. This scenario leads to an 82% reduction of LNG consumption.

Table 6 summarises four optimised scenarios, with PV capacities of 40, 50, 60 and 80MW, respectively, where the LCOE differs by only $8/MWh (4%) across the range. The percentage of RE with these scenarios varies from 58% to 88%.

Increasing the amount of PV to 80MW will generate 52GWh per annum of intermittent, surplus energy with only a marginal increase in LCOE, although most of this is available only in the Dry season. This surplus is available for use in innovative applications, which would further reduce the LCOE.

Further modelling showed that wind generation has an LCOE in the same range as the optimal PV options. There is no benefit from adding wind to the generation mix in Broome when climatic, visual, land and wildlife impacts are considered.

Seasonal factors preclude achieving a higher RE percentage at acceptable costs (with or without Wind) with current technologies and costs. From December to March, lower solar radiation results in insufficient energy to meet demand and backup gas generation is needed. Into the future, this generation could be decarbonised.

The optimum 60MW PV outcome with 82% of RE will substantially reduce the amount of fuel needed for generation in Broome. To provide Broome's annual 131GWh of electrical energy, an average of 7.35 LNG road trains are required per week. With only 18% of the original fuel requirement, this equates to an average of only 1.32 shipments a week, or 10.4 tonnes of LNG per day.

The final part of the report considered implementation options – how a transition to large-scale renewables could occur in Broome. One factor was that the modelling did not distinguish between rooftop and utility solar PV. The total costs of utility and rooftop PV can be made comparable by appropriately setting the levels for feed in tariffs.

Section 5.2 discussed why a mixture of rooftop and utility solar PV may be appropriate in Broome, and the pros and cons of each. A certain amount of utility PV and associated battery will need to be installed by 2027 to replace the gas generators at the end of their contract.

[2] AEMO's GenCost Report (Graham et al 2021) and an associated review by GHD (2018)

We identified that in the order to 40MW of PV could potentially be installed on rooftops in Broome. We are unable to comment on the technical requirements for integrating this amount of rooftop PV into the Broome microgrid, but recommend that this is work that will need to be done by Horizon Power. For this reason, this section did not specify the mix of utility and rooftop solar that would be most appropriate for Broome.

In Section 5.3, we explored the logistics and costs of a transition to high levels of RE in Broome, and assumed an indicative mix of 40MW of rooftop PV and 40MW of utility PV.

The total lifetime cost of the assumed RE mix over 25 years is $636m, compared to a lifetime cost of $957m for the new 100% LNG option. While replacing the existing gas generators with new plant is $54m, initially cheaper than the estimated $126m for the assumed RE system with refurbished gas generators, the extra up-front expenditure of $72m is offset by a saving in total lifetime costs of $321m.

1.1 Recommendations

Horizon Power:

- Perform detailed studies to determine the optimal mix of rooftop and utility PV in a high RE scenario for Broome, including the maximum amount of rooftop PV that such a scenario can accommodate.
- Design the battery plants to ultimately accommodate 160-170MWh of Battery (sized for 80MW of PV), but initially install only 130MWh of Battery packs.
- Investigate refurbishing the existing gas generators to save on higher costs of replacement. Gas plant usage will reduce substantially as renewables are rolled out, and continue to reduce as alternative backup options such as hydrogen become available.
- Conduct a detailed investigation into the feasibility of tidal-stream turbines to supplement the electricity supply in Broome. This can potentially reduce the amount of fossil-fuelled generation and increase the duration of battery storage at night time, especially during the Wet season. The Kimberley has high tidal variations, and tidal velocities are relatively high. ARENA or NAIF funding could be sought for detailed studies.
- Explore the use of Flow batteries to potentially extend the storage duration through increased tank sizes.
- Engage with the Yawuru PBC for partnering opportunities.
- Engage in consultation with the Broome community about how best to roll out RE.

WA State Government:

- Negotiate domestic supply commitments with green hydrogen export developers to further support RE and provide an alternative to LNG in the Kimberley.
- Engage with Yawuru PBC.

Broome Community:

- Engage proactively with Horizon Power to ensure that:
    - the proposed solution is implemented by 2027;
    - best use is made of the DERMS te'chnology
- Continue to advocate for higher levels of rooftop PV and supporting battery storage.

2. Introduction

In 2018, SEN produced a renewable energy (RE) roadmap for the West Kimberley: the Kimberley Clean Energy Roadmap (KCER) (Phillips et al., 2018).

SEN and some of the authors of the KCER have completed a new Report about RE options in the town of Broome, given the significant cost reductions in RE technologies since 2018; and likely future adoption of a carbon price.

Broome is a large town in Western Australia's tropical Kimberley region. It has a permanent population of around 14,500, although this increases greatly during the tourism (Dry) season from May to October.

Current fossil-fuelled generation capacity is approximately 40MW, with adequate backup generators available. 8.3 MW of rooftop solar PV has been installed, but up to 40 MW is feasible on the approximately 7,000 buildings in the town.

2.1 Brief

The current contract to supply electricity in Broome ends in 2027. The WA State Government will need to decide on a replacement system which reduces carbon emissions in compliance with its declared commitment to reduce emissions by 2030 (Government of Western Australia, 2022a).

New modelling and optimisation software and 2021 cost estimates for renewable technologies were used to investigate the feasibility of various mixes of RE to replace existing fossil-fuelled generation in Broome.

This study also set out to:

- report on the rollout of RE across the Kimberley since 2018
- investigate the effects of price reductions of RE technologies on the modelling outcomes from 2018
- investigate barriers and enablers to the adoption of wind technology
- report on changes in cost and availability of storage technologies - notably batteries
- summarise the applicability of emerging tidal-stream power technologies in the Kimberley

2.2 Outcomes of the 2018 Kimberley Clean Energy Roadmap

The 2018 study found that it is feasible to reach 80% RE in Broome for a Levelised Cost of Electricity (LCOE)[3] of $197[4]/MWh. The generation mix consisted of:

- 37 MW Wind Farm
- 33 MW Solar Farm
- 8 MW rooftop PV
- 45 MWh battery
- 27 MW of LNG-fuelled backup generation

Subsequent to the release of the KCER, the WA State Government announced funding for several clean energy initiatives broadly in line with the KCER recommendations. In Broome, Horizon Power installed two community batteries (capacity 1.6MW/1.1MWh) in early 2022, and, together with a relaxation of Horizon Power's risk profile, this has led to an additional 2.3 MW of rooftop solar becoming available for property owners to install (Horizon Power, n.d.). The amount of rooftop PV in the Broome region (postcodes 6725 and 6726) is currently 8.3 MW (Clean Energy Regulator, 2022).

3 Different methods of electricity generation are typically compared on a Levelised Cost of Electricity (LCOE) basis. This is an "economic assessment of the average total cost to build and operate a power-generating asset over its lifetime divided by the total energy output of the asset over that lifetime. The LCOE can also be regarded as the average minimum price at which electricity must be sold in order to break-even over the lifetime of the project." (https://en.wikipedia.org/wiki/Cost_of_electricity_by_source)

4 Unless otherwise specified, all currency amounts are in Australian dollars

In the same document, Horizon Power (n.d.) stated:

> *"Our goal is that all Horizon Power households can have access to rooftop solar by 2025"*

Recent information from the WA State Government (2022b) and Horizon Power (2022c) confirms the release of the innovative Distributed Energy Resources Management System (DERMS) technology, that will enable the integration of rooftop solar and battery systems with utility power systems. This is scheduled for release in Broome in 2023.

DERMS will facilitate the adoption of many of the findings of this report, which shows that it is completely feasible to achieve wide penetration of PV, and move towards a future for Broome with more than 80% of RE generation.

More details of the progress made by the WA State Government in rolling out renewables in the Kimberley is provided in Appendix A.

2.3 Structure of this Report

This study developed new modelling, involving a mix of solar PV, Wind, Battery storage and gas-fired backup generation, for the town of Broome. New modelling approaches enable a wider range of generation options to be considered, and various options for a larger RE rollout to be investigated.

The report first summarises the key modelling assumptions, based on a detailed analysis in the associated Technical Report. It then presents the modelling results, initially for fossil-fuelled generation, then mixes of PV and Battery storage, and finally with the addition of wind generation.

The implications of the results are then discussed and conclusions drawn.

Three appendices provide:

- details of the progress made by the WA State Government in rolling out renewables in the Kimberley
- a literature review of the potential in the Kimberley of submarine 'tidal-stream turbines';
- indicative calculations showing that 40MW of rooftop PV in Broome is possible.

3. Modelling

Modelling was conducted using the open source SIREN developed for SEN by Angus King (Sustainable Energy Now, 2016).

SIREN is the SEN Integrated Renewable Energy Network toolkit simulation program, which draws upon Geographical Information System data and NASA's MERRA-2 global hourly climate data. Energy modelling combines these data with the US Department of Energy National Renewable Energy Laboratory's System Advisor Model for detailed models of various renewable technologies. It simulates an electricity network and enables users to create and evaluate scenarios for supplying electricity using a mixture of RE and non-RE sources. SIREN calculates power output for each generator for every hour of the year and subtracts the actual load on the network for each hour. The results are hourly surplus and shortfall of generation for the scenario for a chosen year (8760 hours).

The Powermatch module is then used to apply various storage and backup technologies to balance the power surplus/shortfall with actual demand. Powermatch outputs result in a costed renewable electricity scenario. Powermatch uses a genetic optimisation approach to identify cost minima for various technology mixes. Batch processing is then used to perform calculations 'around the minimum' to investigate trends in various parameters and to create a range of graphs.

3.1 Assumptions

The validity of any computer modelling relies on the accuracy and defensibility of the input data. While the high-level modelling conducted using these assumptions is robust, it must be taken for what it is – a feasibility-level study.

As in 2018, this modelling is based on Horizon Power's actual hourly load data for each location in 2017, along with the corresponding 2017 NASA MERRA-2 satellite wind and solar data. Current load and climate data was not thought to be necessary, because 2020 and 2021 were anomalous years due to the COVID pandemic.

The cost of a particular technology is calculated from the Capital Expenditure (CAPEX) per MW installed, converted to an annualised capital cost. Operational Expenditure (OPEX) costs incurred during the Operations and Maintenance phase are added to give fixed annual costs per MW generated per year. Variable operational costs, made up of fuel costs and other operating costs per MWh, are added to obtain the overall cost of electricity generated.

The modelling costs were derived from the CSIRO GenCost Report[5] (Graham et al., 2021) and an associated review by GHD for AEMO (2018).

The current Energy Developments Pty Ltd (EDL) contract with Horizon Power expires in 2027. Accordingly, technology costs for 2024 were used as a realistic timeframe to sanction projects associated with replacing the current energy mix.

The modelling assumed that new gas generators would be used. An alternative is that existing generators could be refurbished. Costs would then be lower because initial capital costs would be mostly amortised and life extension costs would be less. However, at some stage in the medium term, these generators will need to be replaced, and CAPEX costs incurred. It is simpler to assume that all equipment is new in the modelling. This option is discussed further in Section 5.3.

Full details of the modelling costs are provided in the associated Technical Report. The chosen cost parameters are summarised in Table 1.

5 The 2022 CSIRO Gencost report was released after this work was completed.

Table 1. Summary of the CAPEX and OPEX costs used in this study for each technology.

Name	CAPEX ($/MW)	Fixed OPEX ($/MW)	Variable OPEX ($/MWh)	Fuel ($/MWh)
Fixed PV	1,282,000	26,000	-	-
Rooftop PV	1,261,000	-	-	-
Onshore Wind	2,850,000	38,000	-	-
Gas-LNG	1,794,000	36,000	11.40	193.00
Battery (1hr)*	811,000	12,000	-	-
Battery (2hr)*	507,000	12,000	-	-
Battery (4hr)*	374,000	12,000	-	-
Battery (8hr)*	312,000	12,000	-	-

*($/MWh)

The CAPEX costs used in this work do not solely apply to the generation technology itself. They also include design, engineering studies, land acquisition and approvals.

3.2 Optimisation parameters

The initial maximum value for each technology was informed by the optimal 2018 results: Wind 37MW, PV 41MW, Battery 45MWh. As modelling proceeded, the maximum value input into the optimisation process was extended, as follows.

3.2.1 Utility PV

Maximum capacity: 150MW, increasing in 1MW increments. Separate modelling was not performed for rooftop PV, because the effective costs for rooftop PV can be set to be essentially identical to Utility PV by appropriate feed-in tariff settings. The choice of which type of PV to use is discussed in section 5.2.

3.2.2 Wind

Maximum capacity: 42MW, increasing in 4.2MW increments. This is because the energy modelling was based on Vestas V117-4.2 MW[6] wind turbines. This model is rated for cyclonic winds, and it produces electricity with wind speeds between 3 and 25 m/s, shutting down at higher wind speeds.

3.2.3 Reciprocating gas engine

Maximum capacity: 30MW, increasing in 2MW increments. Exploratory modelling led to various optimal amounts of gas capacity, between 22MW and 30MW. Gas capacity as low as 22MW was sufficient for higher percentages of RE.

However, in the results presented here, gas capacity of 30MW was used in all cases. This simplifies the modelling and comparison of results and supports various transition pathways to RE. For example, the use of a fixed 30MW gas capacity will support both a fast jump straight to high RE and a slower, stepped transition to RE, where the higher gas capacity is required for the lower RE steps. The gas generation is required to provide firming capacity for low RE periods, particularly during the wet season (see Section 5.1). This assumption increases the resulting LCOE by the order of 4%.

3.2.4 Battery

Maximum capacity: 200MWh, increasing in 1MWh increments. Battery discharge capacities of 1, 2, 4 and 8 hours were modelled. We assumed that the battery charge and discharge rates were identical.

Modelling indicated that four and eight hour batteries provided very similar overall LCOE results. However, 4hr batteries seemed to have the best price point and performance characteristics to suit the particular load profile of Broome, and this type of battery was used in the optimisation.

Different battery charge and discharge rates may affect the modelling results, as will modelling for different locations. In more complex modelling, combinations of different battery discharge capacities may lead to different results.

[6] https://www.vestas.com/en/products/4-mw-platform/V117-4-2-MW

3.3 Scope and limitations

The calculated LCOEs in this study are the cost of producing the energy for the load profile and associated generation that arose from different modelling scenarios. They do not include:

- Transmission costs, which are assumed to be minor on the basis that the utility PV plant and battery storage will be located relatively close to the existing gas plant;
- Distribution network upgrade costs to accommodate increased rooftop PV. It is assumed that the tariff paid to private rooftop PV generators will account for the costs of upgrades to the distribution network.
- Essential services costs for network stability requirements, which are already in place via the existing gas generation plant and community batteries. Much of the essential service requirements can be provided by the new PV and battery storage systems, but it is acknowledged that some parts will need to be provided by the existing gas plant or new specialised equipment. Costs for the additional requirements have been assumed to be relatively low;
- Profit or Return on Investment (ROI) considerations.

This basis allows comparison of like to like (i.e. gas only generation to PV and battery with gas).

3.4 Carbon price

Carbon pricing is becoming increasingly accepted in Australia, as it becomes more widespread internationally. Indeed, the Federal Government's Net Zero by 2050 (Australian Government, 2021) documentation included a 'voluntary' carbon price of $24 /tonne[7]. Currently, Australian Carbon Credit Units (ACCUs) (Clean Energy Regulator, 2020) associated with the Emissions Reduction Fund, introduced by the Federal Government in 2014, act as a de facto carbon price.

From 2019 to mid-2021, the spot price of ACCUs was around $16, but increased rapidly to around $57 in January 2022, as demand for carbon credits from industry increased (Jarden Australia, 2022). Extraordinary Federal Government intervention then decreased the value to around $27, and as at October 2022 they are trading at around $30.

Carbon prices in other contexts and jurisdictions are substantially higher.

For example, Woodside allocates a carbon price of $US80 in making investment decisions (CDP International, 2020, P. 39), equivalent to around $A115.

The carbon price in Europe averaged EUR 83 in 2021 (Trading Economics, 2022), equivalent to ~$A125. Carbon price tariff increases planned for application in the EU and US are likely to drive Australian carbon prices to higher levels.

We used a base carbon price of $60 per tonne in the modelling, for the following reasons:

- The modelling is based on costings for 2024, and it is reasonable to expect that ACCUs or other voluntary types of carbon pricing will increase over the next two years;
- It is close to the ACCU prices achieved in January 2022;
- It is a relatively conservative figure compared to overseas prices and those used by industry for its modelling.

The election of a Labor Federal Government in May 2022 increases the probability of a carbon price applying to high emitters. Labor's stated policy is to progressively tighten the Safeguard Mechanism (Commonwealth Parliamentary Library, 2018), requiring ACCUs to be purchased as offsets. This is likely to drive the ACCU price higher, but details are unclear at the time of writing.

However, this is just one factor. Carbon Pricing works in an international market, and with carbon prices rising overseas, supply and demand will almost certainly push prices up in Australia as well.

3.5 Spare capacity

Spare capacity is required to meet infrequent peak demand situations and to enable some generators to be offline/ unavailable due to maintenance, breakdowns, etc. The existing Broome power station has seventeen 2MW Caterpillar gas generators and nine backup diesel generators, for a total operating capacity of 43.2MW (EDL, n.d.).

It is assumed that the existing diesel generator spare capacity will be retained for all modelled scenarios. Diesel generation is robust and, when used infrequently and if well maintained, has a long operational life.

The gas generators also serve as spare capacity for RE generation, so the net effect is very high levels of spare generation capacity, regardless of the amount of RE generation. The gas generation would be used in preference to diesel generation, as it has a lower LCOE and lower emissions.

[7] Abbreviation for tCO_2-e. Dollars per metric tonne of carbon dioxide equivalent – the equivalent greenhouse gas effect of a combination of gases to that of carbon dioxide alone.

4. Modelling Results

Several broad scenarios were explored in the optimisation and modelling, based on three major distinctions:

- Gas-only baseline
- PV and Battery
- Wind, PV and Battery

The 2018 findings indicated that Wind was an essential component in cost-effectively increasing the RE percentage. With the revised costings used in this report, an unexpected finding was that PV and Battery scenarios were largely equivalent to scenarios that also included wind generation. This is because battery prices have reduced comparatively more since 2018, and, therefore, more batteries can cost-effectively be included. This reduces the need for complementary night-time wind generation. In addition, the inclusion of weather factors in the cost assumptions (see Technical Report) resulted in increased costs of wind generation.

Therefore, in the results below, we present the PV and Battery results before the results where wind generation is added. But first, we present the results for 100% fossil fuelled generation. This is the baseline for comparison with the various RE scenarios.

4.1 Fossil fuel only

As at late 2022, the Broome gas generators are fuelled by LNG delivered by road train from Karratha. This is costed at $22/GJ.

As described in the Technical Report, the costs for fossil fuelled generation are derived from the same sources as renewable generation, so the results should be comparable. Note that, as these are modelled results, they will vary somewhat from the actual contractual costs in play in Broome.

The modelled costs (without a carbon price) for fossil-fuelled generation are shown in Table 2, for both 2018 (Phillips et al., 2018) and 2024. Costings for 2024 are comparable with those for 2018.

Table 2. Generation costs in $ per MWh for 100% fossil-fuelled generation.

LCOE	2018	2024
LNG	$241	$249

4.2 Carbon and fuel price sensitivity

The figures in Table 2 are without a carbon price. Models were run for LNG with a range of potential carbon prices, with results shown in Table 3. Table 3 contains a third row where we assumed that the LNG price is $30/GJ, to account for potential future increases in fuel prices and to demonstrate the sensitivity of LCOE to variations in fuel prices.

The LCOE of fossil-fuelled generation is highly dependent on both the cost of fuel and a carbon price. Column 2 of Table 3 shows that changes in fossil gas fuel prices have a $70 impact on the LCOE when the fuel price increases by $8/GJ at a zero carbon price. Similarly, a carbon price of $60 increases the LCOE by $44.

Table 3. Variation in gas generation costs in $ per MWh at different carbon and fuel prices.

Carbon price	$0	$30	$60	$90	$120
Gas-LNG $22/GJ	$249	$271	$293	$314	$336
Gas-LNG $30/GJ	$319	$341	$363	$384	$428

Figure 1 displays trends in LCOE at various carbon prices. Overlaid on this graph are some of the different carbon prices discussed in Section 3.4. There is a close relationship between increasing fuel costs and carbon prices, as shown by the parallel lines in Fig. 1. Both are fixed inputs to the calculations.

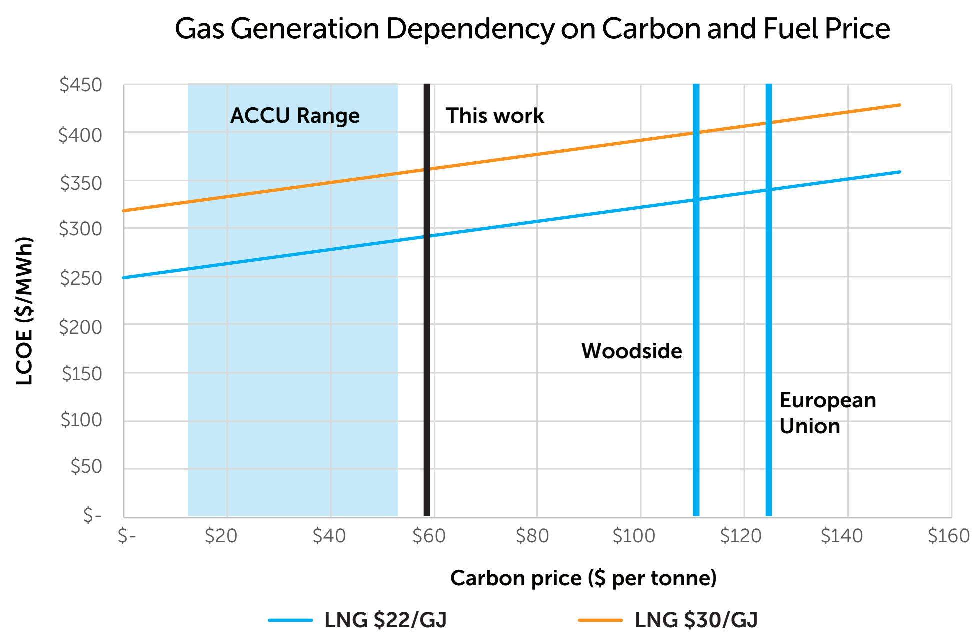

Figure 1. Trends in gas generation costs at different Carbon and Fuel Prices.

In summary, fuel price variations and potential carbon prices have a significant impact on the price of fossil-fuelled generation. Given the strongly increasing likelihood of the imposition of a carbon price (in some form) in the short to medium term, and the high volatility of gas prices internationally and domestically, this represents a high to extreme risk to generation costs in Broome.

4.3 Results for PV and Battery

4.3.1 No carbon price

A range of models were run with varying amounts of PV, optimising for battery to achieve the lowest LCOE for each level of PV. As described in Section 3.2.3, the fossil-fuelled capacity was set at 30MW, even though the modelling found that smaller amounts of gas capacity were possible.

Results with no carbon price are shown in Figure 2, with the PV and Battery results shown in blue. For comparison, the baseline result for LNG is also shown. The initially downwards LCOE trend flattens off at approximately $200/MWh with PV capacity of 25MW, and remains at roughly this level as PV capacity (and associated battery capacity) increases to 55MW. The minimum LCOE is $198 at 35MW of PV. Prices are approximately $50 per MWh lower than LNG over this range.

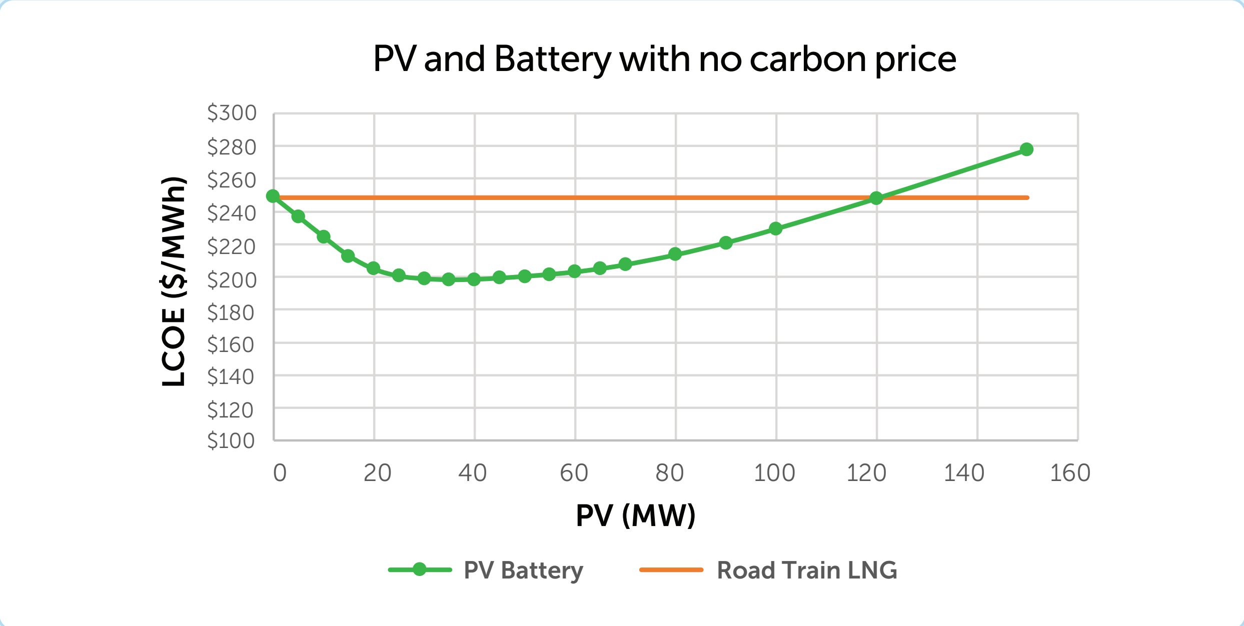

Fig. 2. Optimised battery results with varying amounts of PV and no carbon price.

4.3.2 Carbon price of $60 per tonne

Figure 3 shows analogous results where a carbon price of $60 per tonne applies. The lowest LCOE ($215/MWh) occurs at a PV capacity of 60MW (82% RE). This is 73% of the LNG-only result, or $78/MWh less expensive.

Once again, there is a relatively flat area around the minimum, from 30 - 80 MW of PV, within 5% of the minimum. The right side of Fig. 3 shows the diminishing returns that result from adding more and more PV, even with extensive storage.

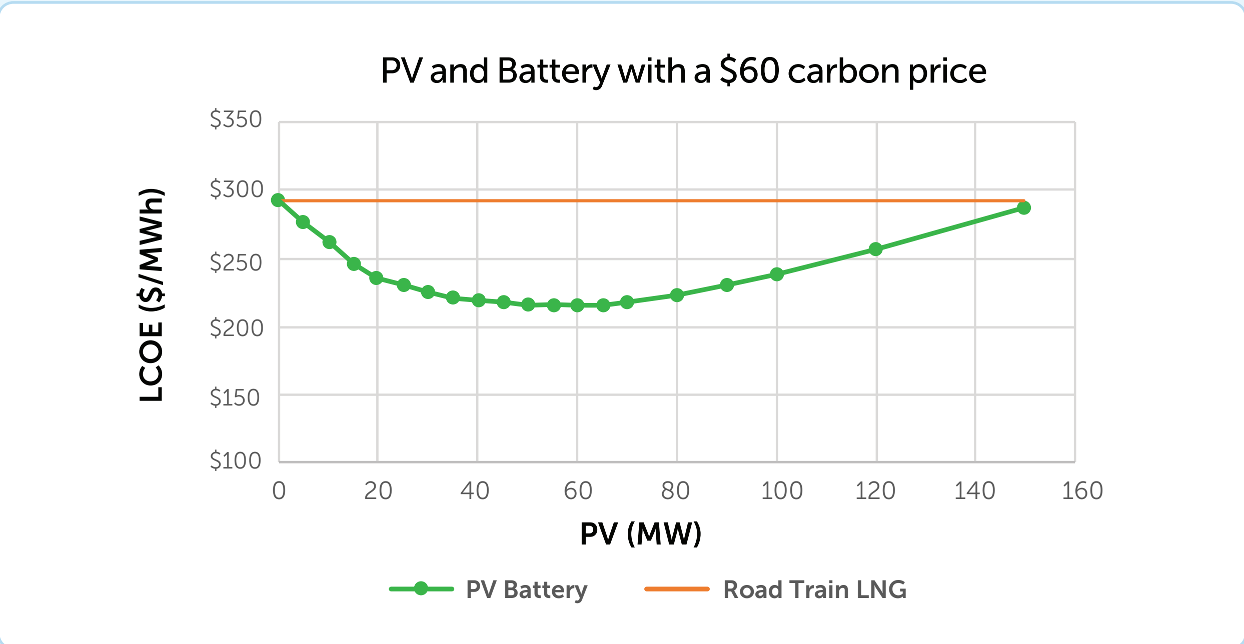

Fig. 3. Optimised battery results with varying amounts of PV and a carbon price of $60.

Table 4. displays relevant numbers associated with Fig. 3, for PV amounts ranging from 20 MW to 150 MW and a fixed 30MW of gas capacity. Column 2 displays the LCOE values, with a $60 carbon price. Column 3 shows the optimised amount of 4hr Battery storage for each increment of PV, which increases from 0 to 172 MWh. Column 4 displays the percentage of the total load contributed by renewable sources.

Table 4. Key generation parameters associated with optimisations for varying amounts of PV and a fixed 30MW of gas capacity with a $60/tonne carbon price.

Fixed PV (MW)	LCOE ($/MWh)	Battery (4h) (MWh)	RE % of Total Load
20	$235	0	32%
25	$229	10	38%
30	$225	30	45%
35	$222	50	52%
40	$220	70	58%
45	$218	100	65%
50	$216	130	72%
55	$215	150	78%
60	$215	160	82%
65	$216	162	84%
70	$218	162	86%
80	$223	164	88%
90	$230	166	90%
100	$239	168	91%
120	$257	170	93%
150	$288	172	94%

The curve in Fig. 3 around the minimum at 60MW of PV is relatively flat. Table 4 shows that, for PV capacities from 30-80MW, the LCOE varies only by $10 (4.8%), from $215 to $225. That is, even a relatively large amount of 4 hour Battery storage is cost effective. These results demonstrate that Battery can be used for real-world energy storage, as well as for firming variations on the Broome microgrid, which is what batteries are currently being used for in Broome.

Even 20MW of PV is $57/MWh less than a 100% fossil fuel solution, for an RE percentage of 32%. The RE% increases to 88% at 80MW of PV.

The last row of Table 4 shows that the LCOE of a system with 150MW of PV is around the same price as modelled for LNG-only generation, but this is with 94% RE.

Figure 4 graphs the amount of load provided by RE for each increment of PV. The RE proportion increases approximately linearly to 80%, and then tapers off, indicating that 100% renewables will be expensive to achieve with just PV and Battery.

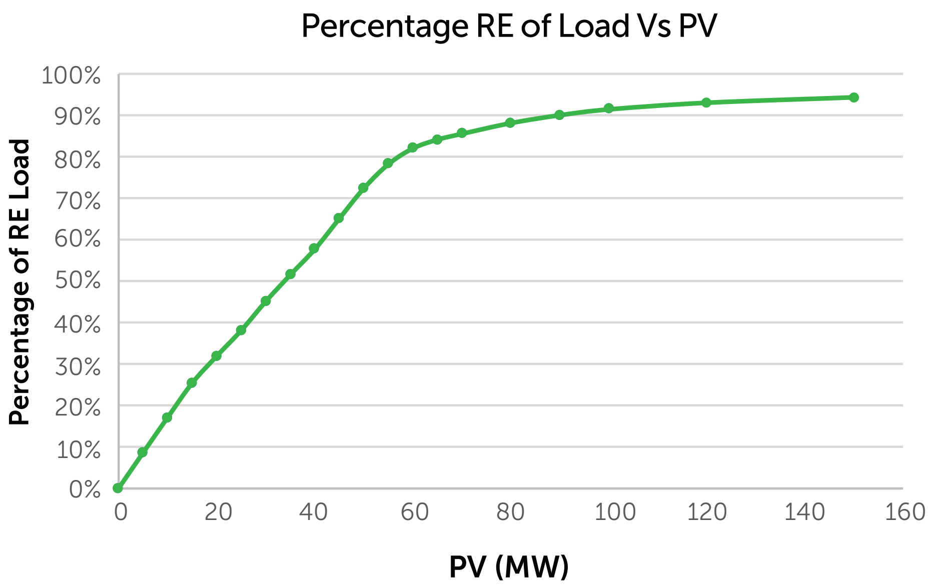

Fig. 4. Percentage RE of load vs PV with a $60 carbon price.

An analogous finding is shown in Fig. 5, where the CO_2 emissions reduce approximately linearly down to around 25,000 tonnes CO_2-e as the PV capacity increases. However, a modest increase in CO_2 emissions can be seen from 100MW of PV, due to increasingly low capacity factors (low utilisation) of the incremental additions of PV. At this point, the relatively low embedded emissions of extra RE is higher than the emissions avoided from burning the increasingly smaller amounts of gas. Emissions will decrease as the carbon footprint of PV and battery storage continues to improve.

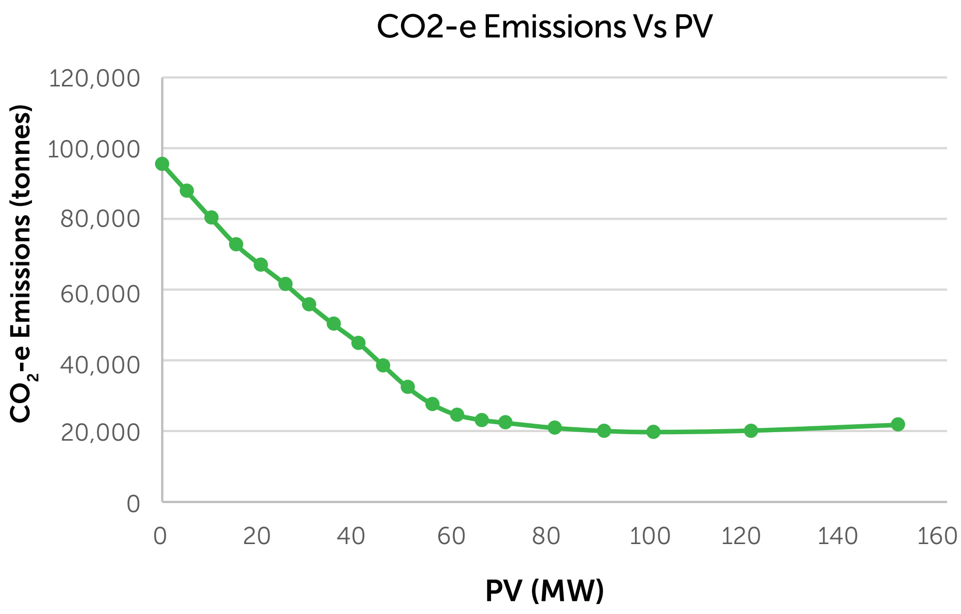

Fig. 5. Variation in CO_2 equivalent emissions in optimised scenarios with increasing amounts of PV and a carbon price of $60.

Figure 6 shows the relationship between LCOE and the percentage of load met by RE. This graph provides a striking illustration of the diminishing financial returns of adding increasingly large amounts of RE beyond the minimum LCOE point of approximately 82% RE.

At 82% RE, 11% of the generation is surplus energy, which is assumed to be spilled (not used). By 88% RE, 29% of the generation is surplus. As more RE is added beyond 82%, the percentage spilled increases and the percentage used decreases. This is largely driven by the seasonal differences between load and available RE (see Section 5.1). In the Wet season, RE is less effective and produces less energy while load is higher. If the spilled energy could be used for other purposes, this would bring the LCOE down – potentially significantly.

As an example, adding another 10MW of PV capacity would help to meet the load during the wet season, but would be effectively wasted during the rest of the year. This makes the marginal cost of adding more RE beyond the optimum point (82% RE in this case) increasingly expensive.

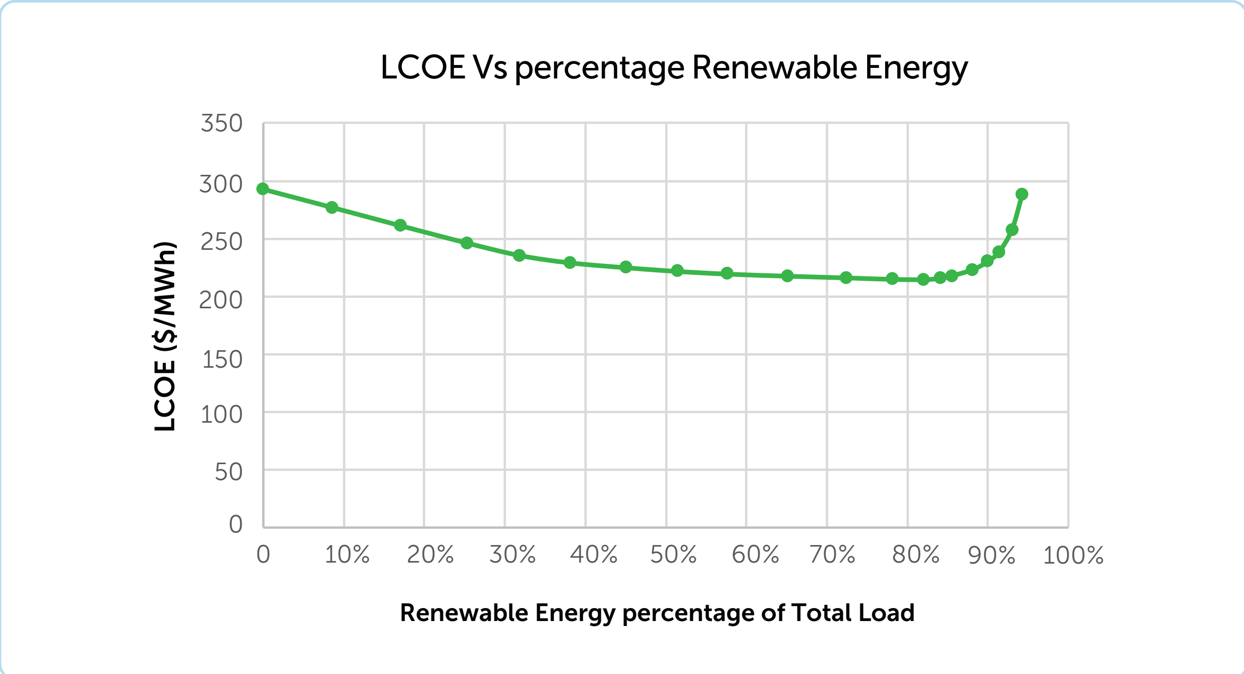

Fig. 6. Trends in LCOE as the percentage of Renewable Energy increases.

4.3.3 Contributions to load

The contributions to meeting load across the year for PV, Battery and LNG are shown in Figure 7, with numerical values presented in Table 5. Also shown is the surplus generation for each increment of PV.

Figure 7 shows that gas use decreases steeply to approximately 60MW of PV. The direct contribution of PV to load increases steeply to around 20MW, after which increasing amounts are passed via the battery storage to allow it to be used at later times. The contribution of battery to load increases more slowly, once there is sufficient battery capacity, to meet daily night-time and early morning load. Beyond that, increased capacity is mostly used for storing energy for longer periods, which becomes increasingly cost-prohibitive due to the reducing capacity factor.

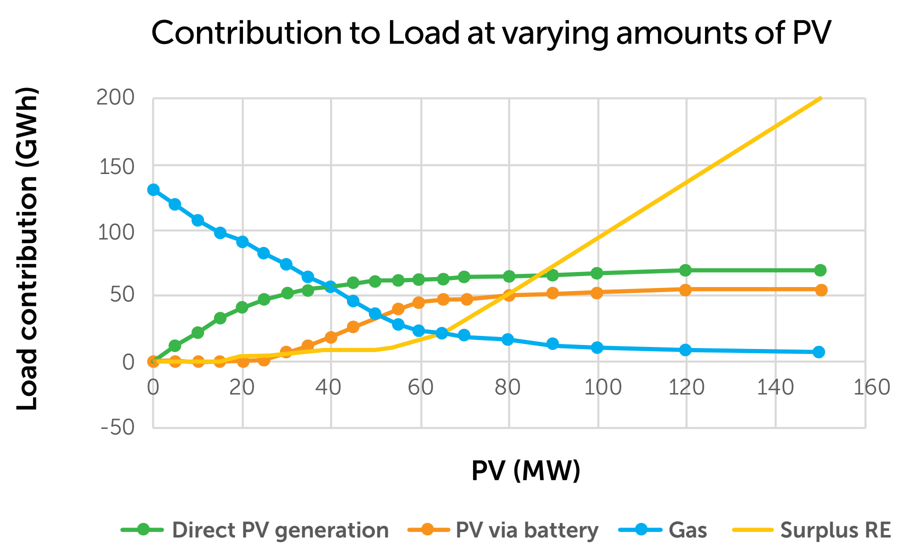

Fig. 7. Contribution to load of each technology as PV increases.

As in Figures 4 and 5, the contribution to load for PV, Battery and Gas tends towards the horizontal as the PV increases. At 80MW of PV, only 16GWh of LNG generation is required over a year, a reduction of 88% over the 131GWh in the LNG-only scenario.

Also of note in Fig. 7 and Table 5 is that the amount of surplus energy increases almost linearly from around 60MW of PV. This energy is fully costed but unused in the modelled scenarios. At 80MW of PV, for example, 52GWh of surplus energy represents an opportunity for use in the dry season (see Section 5.1.2).

Table 5. Contribution to load in GWh for each technology and surplus generation associated with varying amounts of PV.

PV (MW)	Direct PV generation	PV via Battery	LNG	Surplus
0	0	0	131	0
5	11	0	120	0
10	22	0	108	0
15	33	0	98	0
20	42	0	89	3
25	48	2	81	6
30	52	7	72	7
35	55	12	63	8
40	57	18	55	10
45	59	26	46	9
50	60	34	36	9
55	61	41	29	11
60	62	45	24	17
65	63	47	21	25
70	64	48	19	34
80	65	50	16	52
90	66	52	13	72
100	67	53	11	92
120	68	54	9	134
150	69	54	7	200

4.3.4 Section summary

The results of this section are summarised in Table 6, for a carbon price of $60. There are four 'optimal' scenarios, spanning the 'flat' section of Fig. 3.

Table 6. Key parameters for the four 'optimal' scenarios.

PV (MW)	40	50	60	80
LCOE ($/MWh)	$220	$216	$215	$223
Battery (MWh)	70	130	160	164
LNG (MW)	30	30	30	30
RE % of Total Load	58%	72%	82%	88%
Lifetime Emissions (tCO_2-e)	44,834	32,278	24,457	20,756
Contribution to Load				
RE (GWh)	57	60	62	65
Battery (GWh)	18	34	45	50
LNG (GWh)	55	36	24	16
Surplus (GWh)	10	9	17	52

The 40MW PV scenario is $73 cheaper than the LNG-only scenario, and meets 58% of the total load with 70MWh of 4 hour Battery storage. There is only 9.8GWh of surplus generation. The 50MW PV scenario requires almost double the amount of battery capacity, for a slightly lower LCOE, and 72% RE.

The lowest cost scenario is with 60MW PV, achieving an LCOE of $215/MWh, $78/MWh less than the gas-only scenario. This scenario meets 82% of load with 160MWh of 4 hour Battery storage. In this scenario, surplus energy remains relatively low.

The 80MW PV scenario is slightly more expensive than the 40MW PV scenario. A relatively small amount of extra Battery is needed over the 60MW scenario, and the RE percentage also tapers off to 88%. There are two potential justifications for the extra capital expenditure to install this amount of RE:

- to productively utilise the 52GWh of surplus energy produced;
- to reduce emissions further for only a small increase in cost.

4.4 Scenarios including wind generation

A number of scenarios were modelled to investigate the impact of adding wind generation to complement the PV and Battery mix. This study was based on the use of 4.2MW Vestas V117 cyclone rated turbines. Five scenarios were modelled with 4.2, 8.4, 12.6, 16.8 and 21.0MW Wind capacity (1-5 turbines).

For each scenario, batches of models were run with PV increments as in the previous section, with the 4hr battery capacity being optimised. Figure 8 displays the results optimised for lowest LCOE in green, and compared with the PV-only results summarised in Table 6 (orange).

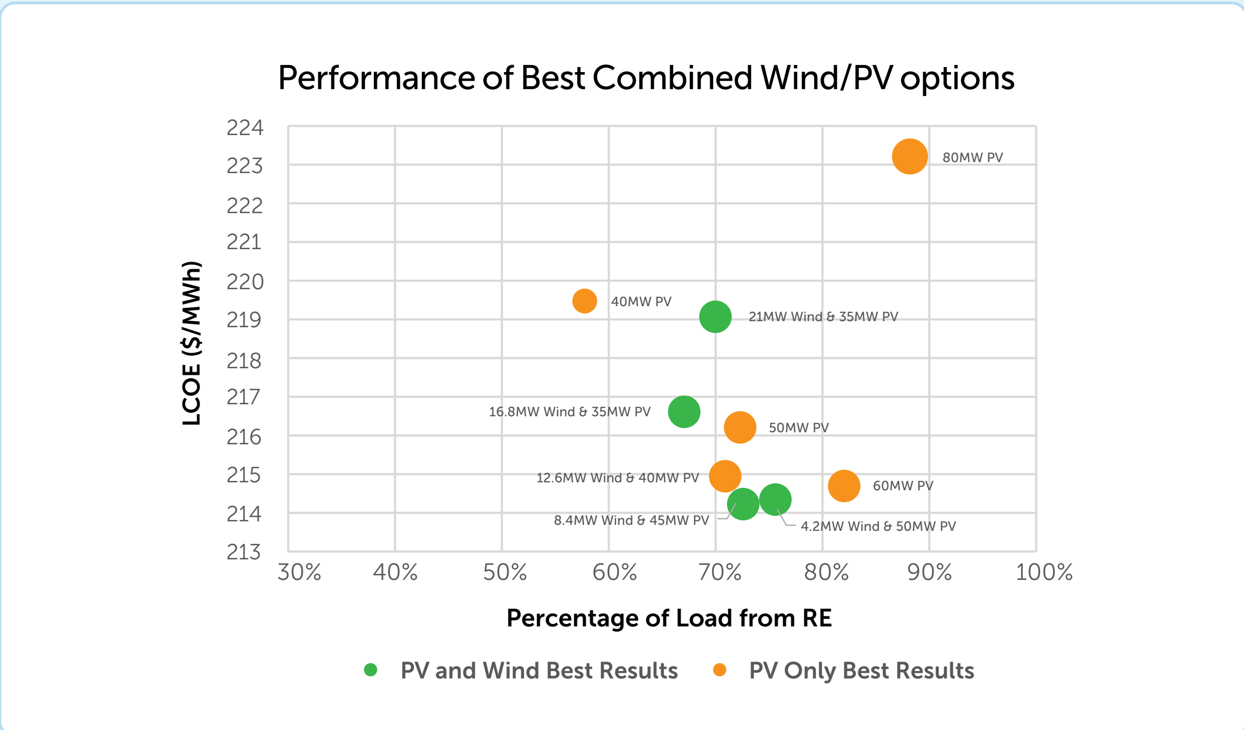

Fig. 8. Cost and RE % of the five scenarios with different amounts of wind generation (green), compared with the four PV-only results summarised in Table 6 (orange). The area of each circle corresponds to the amount of RE generation in MW.

Figure 8 shows that all five Wind scenarios lead to an LCOE within a relatively small range of $214-220 per MWh. The RE percentage clusters around 70%, and the three scenarios with Wind capacity of 4.2, 8.4 and 12.6MW are almost identical, with lower amounts of wind generation offset by increasing amounts of PV capacity. The first three PV-only scenarios all sit within the same boundaries as the Wind scenarios. The 80MW PV scenario is around $10/MWh more costly than the multiple minima, but, as described above, a considerable amount of surplus energy is then available.

A higher RE percentage is achieved with both the 80MW and 60MW PV scenarios.

The similarity between the scenarios is further illustrated in Figure 9, which compares the PV-only results across a range of PV capacities

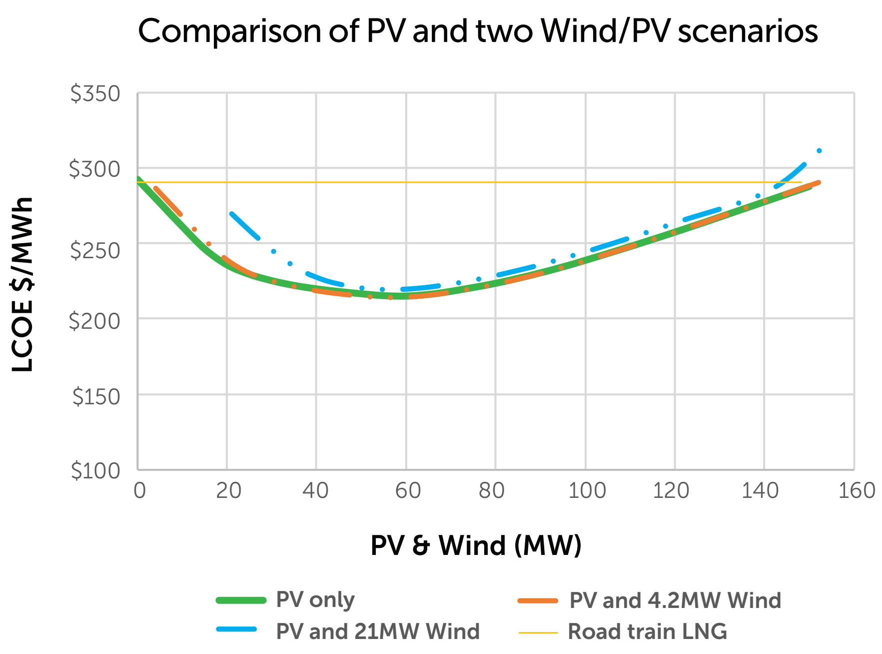

Fig. 9. Comparison of the PV-only results with two scenarios with Wind capacity of 4.2MW and 21MW respectively. The x-axis displays total RE generation (carbon price of $60).

In summary, Figures 8 and 9 indicate that there is no appreciable benefit in adding wind generation to the generation mix in Broome. This finding may seem counterintuitive, in that wind generation at night would be expected to decrease demand on fossil-fuelled generators and increase the RE percentage.

However, the need to have Wind as a complementary power source has been reduced by decreases in published battery costs over the last four years due to reduced CAPEX and increasing lifetimes (from 10 to 20 years). The increased size of batteries made practical by their reduced cost and longer life allows batteries to cover load fluctuations across 24 hour periods in many cases.

Three factors may contribute to Wind having a relatively low impact in Broome:

- our cost analysis for Broome led to relatively higher costs for Wind because of remoteness and weather factors (e.g. cyclone risks)
- wind velocities in Broome are relatively low (apart from occasional extremes), leading to a lower capacity factor and consequently higher LCOE than PV.
- seasonal impacts (see Section 5.1) indicate that the Wind resource is less strong in some months, e.g. February and March.

In larger grids, such as the South West Interconnected System (SWIS), wind generation can complement other renewable sources, because high winds in one area can complement lower winds in other areas and provide a reliable night time generation source during most of the year. In Broome, the wind profile is different across the seasons and does not complement the PV profile very efficiently during the months when it is really needed.

There are further risks and challenges of including wind generation in Broome that argue against its use, especially given that various PV and Battery scenarios are equivalent in cost and total amount of renewables. These challenges include:

- potential damage to sensitive coastal ecosystems;
- risks to wildlife in important bird migration pathways;
- cyclone damage risks and insurance costs.

4.5 Volume of gas required

Table 5 indicates that, in a zero renewables scenario, LNG is required to generate 131GWh of electricity. Table 11 of the Technical Report demonstrates that this corresponds to 21.1 thousand tonnes of LNG. This equates to 57.8 tonnes of LNG per day on average, equivalent to 1.05 road trains per day, or 7.35 per week. It should be noted that there are seasonal variations to the amount of gas used.

The lowest cost scenario of 60MW PV achieves 82% RE. That is, only 18% of generation will come from fossil fuels. This equates to an average of 1.32 shipments a week, or 10.4 tonnes of LNG per day – a significant daily reduction of 47.4 tonnes.

5. Discussion

5.1 Seasonal factors

Broome typically has a hot wet summer (Wet season) and dryer milder winter (Dry season). As a result, its electricity load is higher over summer when solar insolation is reduced and lower over winter when solar insolation is higher. This section explores the impacts of these seasonal variations.

In the Broome context, seasonal factors preclude achieving a higher RE percentage with current technologies and technology costs. Figure 10 uses the detailed modelling results to break down the average daily generation capacities for each technology for each month of the year. For each of the 12 months displayed in Fig. 10, the actual load on the system is shown as a black line. The contribution to that load by each technology is shown in yellow (PV), purple (Battery) and red (Gas). Lighter yellow regions above the black line show surplus PV generation.

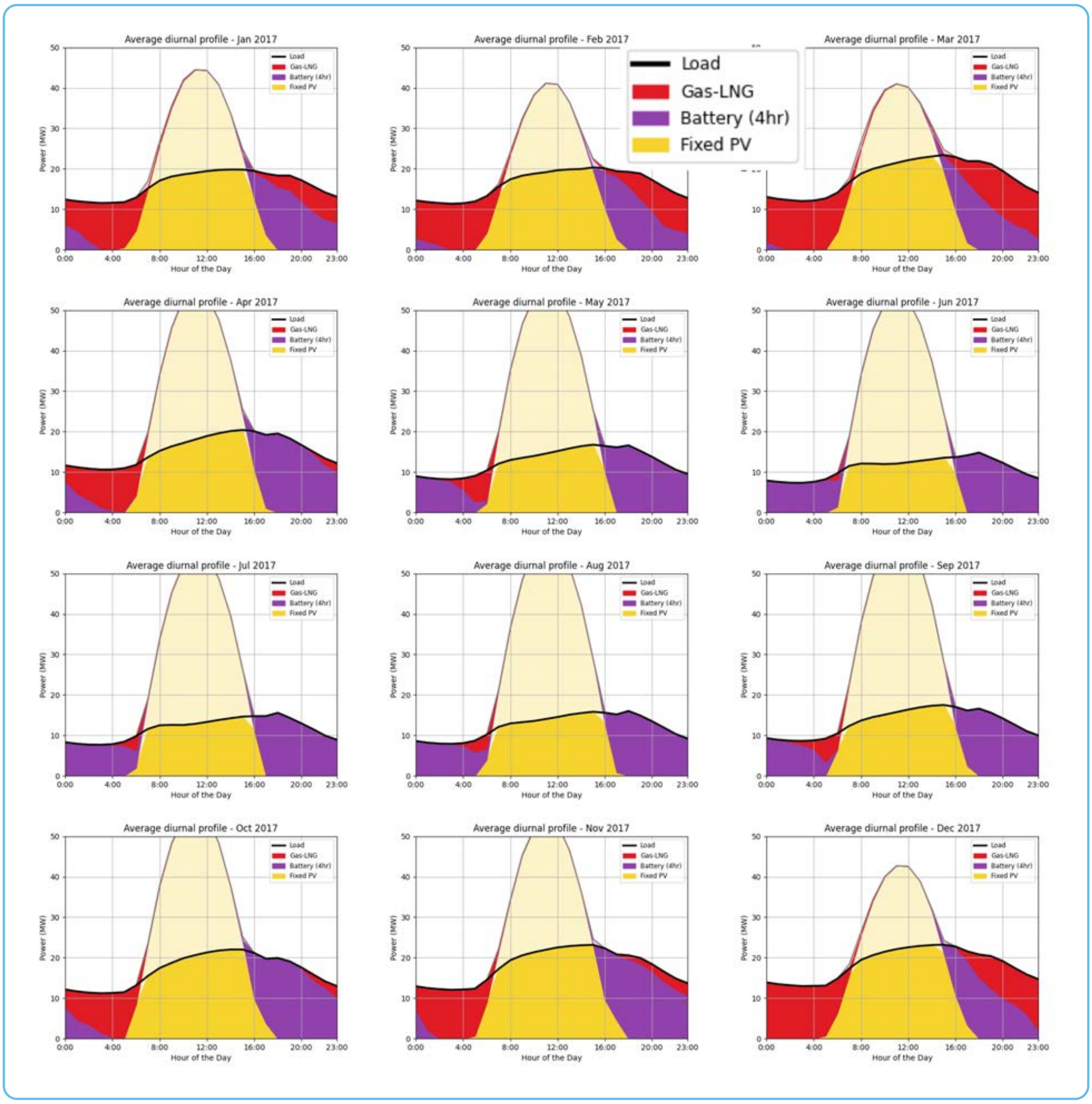

Figure 10. Seasonal variations with the optimal (60MW) PV and Battery scenario.

During the Dry season from May to September, there is very little red evident in the graphs. Solar and Battery are able to meet almost all load during these months. From October, load increases as the weather becomes hotter. At the same time the amount of sunlight (PV generation) decreases. This means that there is insufficient energy to meet load, and more gas generation is needed (the red areas increase in size). This trend is particularly evident from December to March, where peak solar generation is just over 40MW (out of an installed capacity of 60MW).

Figure 10 presents an average view over a month. An alternative, daily presentation is also informative, as shown in Figures 11a and 11b. Figure 11a shows daily generation and load for two weeks in the dry season. PV and Battery meet all load on 7 of the 14 days. For the other 7 days, only small amounts of fossil-fuelled backup are necessary.

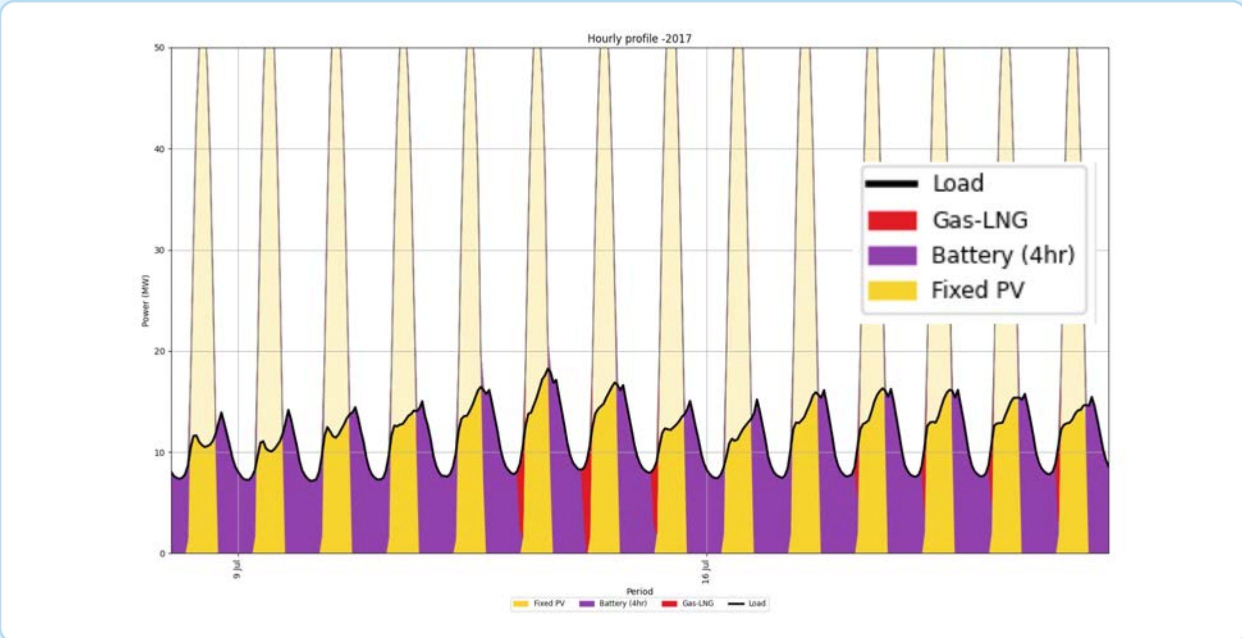

Figure 11a. Daily generation mix for the two weeks of 8-21 July, 2017.

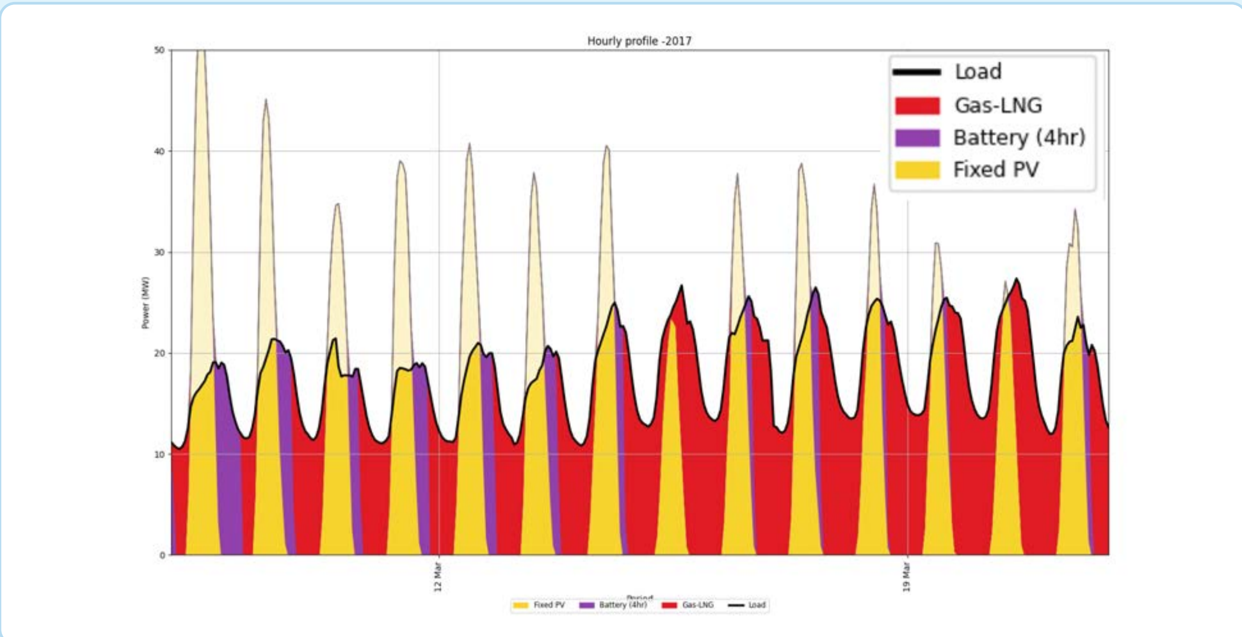

Figure 11b. Daily generation mix for the two weeks of 8-21 March, 2017.

The situation is different during the Wet season, as shown in Fig. 11b. Weather conditions cause variations and overall reductions in PV output. For example, on one day, the PV generation was so low that it could not meet load – even in the middle of the day. On that day, gas generation was required for the entire 24 hour period. The low PV output also meant that the battery storage could not be charged, and gas generation was required for most or all of each night.

These seasonal factors are the reason why it is difficult, and expensive, to move beyond 88% renewable generation in Broome. Section 4.4 showed that adding wind generation will not overcome these seasonal factors.

5.1.1 Potential future options for addressing seasonal variations

Apart from Pumped Hydroelectricity Energy Systems in suitable geographical locations, seasonal Long Duration Energy Storage, which doesn't use fossil fuels, remains a technical problem to be overcome. Over the next decade, Fortescue Future Industries' work on hydrogen-based fuels (e.g. ammonia) in bulk amounts for shipping transport may come to fruition. This may be a suitable long duration fuel for running generators.

Flow batteries may be suitable for intermediate duration storage, by increasing the storage tank size, but are unlikely to meet seasonal needs. However, Flow batteries are worth investigating in the Kimberley, because they are less sensitive to high temperatures.

A third technology which may mitigate the RE shortfall in the Wet season in Broome is in-stream tidal generation. A literature review of this technology is provided in Appendix B. A key finding is that

> *"The cyclic nature of tidal power production is well suited for integration with short-term energy storage (less than 4 h) to help balance supply with local demand"* (Coles et al., 2021, p. 18).

In addition, Penesis et al. (2020) report that the tidal flows in Broome are sufficient to support a trial of in-stream tidal turbines to meet overnight shortfalls, either directly or through battery storage. ARENA or NAIF funding could be sought for a detailed investigation into the feasibility of tidal-stream turbines in Broome.

Further investigation of these technologies is out of scope for this Report.

5.1.2 Seasonal variations in gas use and surplus generation

The seasonal variations in the generation mix led us to investigate the gas use and amount of surplus generation over the year. Five scenarios are plotted in Figure 12. The gas-only (0MW PV) scenario shown in dark blue mirrors the effective load profile for each month. The other four lines correspond to the amount of gas generation required under each of the four 'optimum' RE scenarios, with 40, 50, 60 and 80 MW of PV, respectively.

Existing gas usage varies from a maximum of 14GWh/month in the Wet season to as low as 8GWh/month in the Dry season (green line). As more and more PV and battery is added, the amount of gas required drops significantly in all months of the year. However, the relative difference becomes greater, with very low amounts required in the Dry season (unless there are outages and backup gas generation is required).

This will present logistical and financial challenges to maintaining the required gas supply from Karratha in its current form. Refer to section 5.3.1.2 for further comment on this.

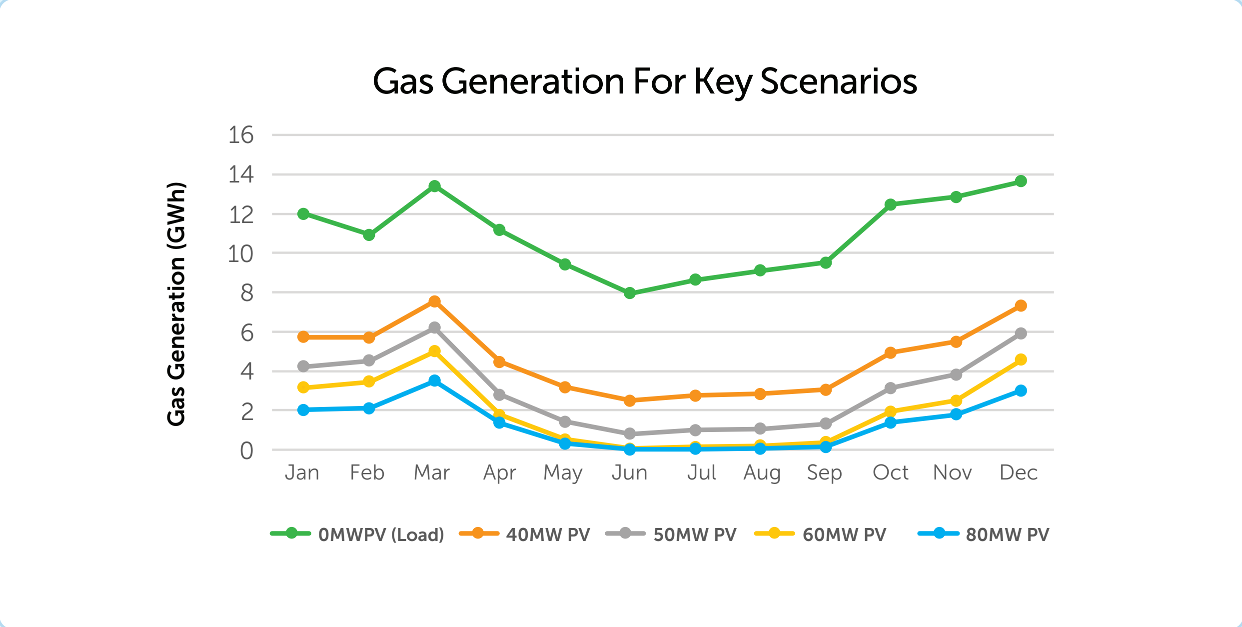

Figure 12. Amount of gas generation in each month of the year, for each of the main scenarios

5.1.3 Surplus energy

As noted in Section 4.3.3, up to 52GWh of surplus energy can be generated with 80MW of PV. The cost of this energy is covered in the modelling, but it is spilled (not used). Figure 13 explores monthly variations in this surplus energy for each of the five scenarios. Over the 5 months from May to September, significant surplus energy is spilled. Lesser amounts are spilled in the shoulder months of April, October and November. While there is some surplus energy in the other months, it is at much lower levels and more intermittent.

In each of the four RE scenarios, surplus energy is available in the Dry season. This represents an opportunity for emerging industries to utilise this (potentially low-cost) energy for productive purposes.

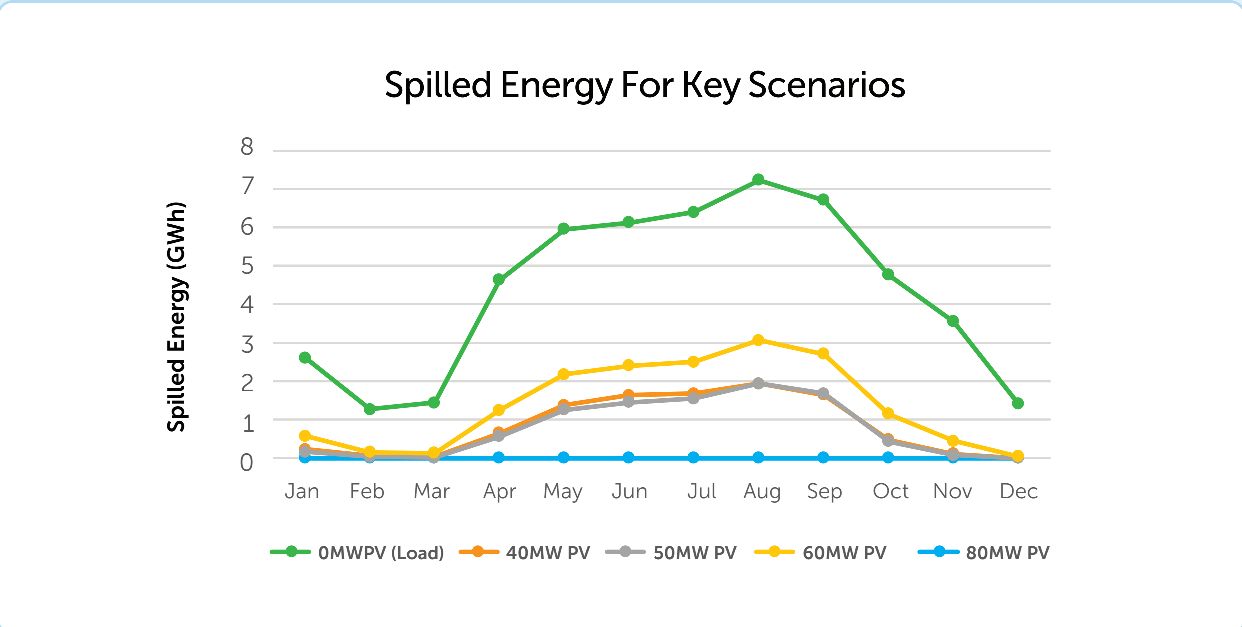

Figure 13. Amount of surplus energy in each month of the year, for each of the main scenarios.

5.2 Types of PV generation

The modelling treated solar PV as one technology. The effective LCOE for rooftop PV can be matched to that of utility PV by setting an appropriate feed in tariff, making it unnecessary to model different mixes of the two technologies.

Our view was that a choice would be made based on other non-cost factors about whether to install utility PV or rooftop PV or a mixture of both.

Utility PV has the disadvantage of requiring land. The land around Broome is relatively intact tropical savannah which is habitat to threatened species, and any new development would require land clearing. Any proposal for utility PV requiring land would likely require consent from Traditional Owners. Community consultation would also be important.

On the other hand, replacing the gas generators at the end of their contract in 2027 will require the installation of a certain amount of utility PV and associated battery. Relying on growth in rooftop PV alone will not provide sufficient energy to meet load. The amount of utility PV required will be determined largely by how much rooftop PV can realistically be installed.

As noted in Section 2.3, there is 8.3MW of rooftop PV in the Broome region as of late 2022, and high customer demand for more rooftop capacity (Lynch, 2021).

This raises the question of how much PV can sensibly be installed on rooftops in Broome. The analysis reported in Appendix C estimates there is potentially in the order of 40MW of PV on the roofs of dwellings and businesses in Broome. This is sufficient to meet the needs of the 40MW PV scenario in Table 6, but not the higher RE scenario of 80MW.

Rooftop PV has the advantage, to Horizon Power and the WA State Government, that it is purchased and maintained by the landowner, whereas utility PV incurs an upfront cost to the energy provider. Utility PV may also incur additional costs to install or upgrade transmission lines.

Technical factors also play a role in terms of managing the output of PV systems. Management of utility PV through centralised control is relatively well-understood, and easy to manage.

On the other hand, managing rooftop PV can be more complex and may require distribution system upgrades. Horizon Power would have to manage the output of potentially thousands of smaller PV installations. This requires communications infrastructure, and individual owners may exercise unpredictable control over the resource.

The technical issues associated with managing rooftop PV are already being addressed by the WA State Government, for example through the Distributed Energy Resources Roadmap and associated implementation activities (Government of Western Australia, 2019). New inverter standards enable solar PV output to be curtailed or shutdown when necessary to balance the grid. Horizon Power's current standards for installing solar PV in Broome require users to purchase battery storage to help balance the grid. This may include individual battery systems or community batteries where users pay for the storage facility.

In 2023, Horizon Power will roll out its Distributed Energy Resources Management System (DERMS) (Horizon Power, 2022c) technology in Broome. Trialled on the Onslow micro-grid, DERMS can "orchestrate generation from customers in real-time" (Government of Western Australia, 2022b), managed through the 4G mobile network.

In summary, the total costs of utility and rooftop PV can be made comparable by appropriately setting the levels for feed in tariffs. Utility PV requires investment to install, but is easier and cheaper to manage. Rooftop PV is paid for by the user, but is more complex and costly to manage, although technical problems have been largely resolved.

The appropriate mixture of utility and rooftop PV for Broome cannot be determined at this stage. Further detailed analysis will need to be undertaken by Horizon Power, to determine how much rooftop PV can be effectively installed and managed. However, key to this will be the timely deployment of battery storage.

The following section explores the logistics and costs of a transition to high levels of RE in Broome. To do this, we assumed an indicative mix of 40MW of rooftop PV and 40MW of utility PV.

5.3 Options for implementation

The results of this study provide some interesting insights about how to transition to large scale renewables in Broome.

Figure 3 showed that the LCOE is within 5% of the minimum of $215/MWh for a range of 30 – 80 MW of PV. Figure 4 showed a steady increase in RE% up to 60MW PV, and a concomitant reduction in CO_2 emissions was shown in Fig. 5. In other words, a range of PV capacities is feasible for around the same LCOE. All of these options are approximately 25% less expensive than a 100% LNG-based solution with a carbon price of $60.

Cost is therefore not the only determining factor in deciding on an optimal RE mix for Broome. Given the flat nature of the LCOE curve over this range, it is more appropriate to make a decision based on the carbon equivalent emissions of each scenario, or alternatively the RE percentage.

There are various ways that PV and Batteries can be rolled out in Broome to minimise emissions and contribute to decarbonisation. The implementation choices are related to two criteria: the mixture of utility and rooftop PV, and whether the roll-out should be staged gradually over a number of years, or 'front loaded'.

Table 4 summarised the LCOE of each amount of PV installed, together with the optimal Battery capacity and RE percentage. In turn, Table 6 summarised the characteristics of four optimised scenarios, with a range of 40-80MW of PV. This is reprised here as Table 7, with some additional information about the required CAPEX of each model.

Table 7. Key parameters for the four 'optimal' scenarios, including CAPEX. All cases include a carbon price of $60/tonne.

PV (MW)	40	50	60	80
LCOE ($/MWh)	$220	$216	$215	$223
Battery (MWh)	70	130	160	164
LNG (MW)	30	30	30	30
RE % of Total Load	58%	72%	82%	88%
CAPEX ($m)	$131m	$167m	$191m	$218m

There is strong community demand (Lynch, 2021) for rooftop PV in Broome, and a potential capacity in the order of 40MW on rooftops. Encouraging Broome residents to install significant rooftop PV is in line with Horizon Power's stated goal to allow all households to have access to rooftop solar by 2025 (Horizon Power, n.d.).

We have assumed this would be matched by an initial 40MW utility solar farm. This would have associated firming battery storage sized to support the utility PV and a staged rollout of rooftop PV.

If planning for the 40MW utility solar farm and battery storage commences in the near future, it is reasonable to have it up and running by 2027 (when the existing LNG-fuelled contract expires). However, this planning could also optionally be future-proofed.

Table 7 indicates that a 40MW PV system is optimally balanced by 70MWh of battery. Given the expected addition of rooftop PV (or more Utility PV if the rooftop utility take up is less than 40MW), we recommend that the battery plants[8] be designed to ultimately have at least 164MWh of Battery, for when the remaining PV is subsequently deployed. This means that the non-battery 'balance of plant' (inverters, substation, cabling, controls etc.) needs to be designed and sized for the future. This does not mean that 164MWh of battery capacity should be installed by 2027; but that the system is sized for this ultimate capacity. Extra battery packs can then be added as needed.

[8] Some capacity will likely be in distributed community batteries to support rooftop PV and some is expected to be in a larger centralised plant associated with the utility PV site.

5.3.1 New vs refurbished gas generators

A further relevant implementation option is discussed in this section, although it is beyond the scope of the modelling performed. The modelling assumed that 30MW of *new* LNG-fuelled generators would be installed. The modelling also found that decreasing amounts of LNG-fuelled generation would be required into the future, as RE percentages increased. Only 22MW of gas generation capacity with lower utilisation would be required to meet seasonal shortfalls.

These factors might discourage a private proponent from tendering for new gas generation.

The cost could be substantially reduced by refurbishing, rather than replacing, some or all of the existing generators. The plant could be taken over by Horizon Power, or retained by the existing private owner, and the risks of financial losses could be ameliorated because the existing machines are already substantially amortised. Retention by the existing owner could provide a 'soft landing', with continuing (albeit reduced) income from the plant.

As at late 2022, there is a reasonable amount of spare generation capacity in Broome to cover maintenance and longer-term unplanned outages, with 34MW of gas generation and approximately 10MW of backup diesel generation. The gas generators were commissioned in 2008 so they will only be 20 years old in 2027. A 25 year service life would be reasonably expected before there is a need to extend service life via refurbishment. In addition, the installed capacity (34MW not including diesel backup) is larger than the maximum demand of 28.6MW, suggesting that the loading on the equipment has not been heavy.

5.3.1.1 Refurbishment considerations

Choosing refurbishment would also lead to much lower regret cost risk if future regulatory/political imperatives require decommissioning the gas generators before the 25 year lifespan of the new equipment is reached.

Gas generation usage will decrease as the RE rollout proceeds, especially in the Dry season when many units will be idle. Overall, the number of duty cycles of the generators will decrease, extending their expected life considerably.

On the other hand, the nature of the workload of the generators may change, with higher ramping, and therefore wear and tear, to cope with fluctuations in PV output. However, because the existing units use reciprocating engines, they are relatively well suited for load following.

The following section explores the capital and lifetime costs of using new or refurbished gas generators to follow the implementation plan discussed here. Some units may be suitable for refurbishment, while others may need replacement. Given these uncertainties, we have *assumed* that the overall cost of refurbishment is 40% of the CAPEX of all new generators, and we have used this figure in Section 5.3.2.

It must be noted that we do not have enough information to unequivocally confirm the suitability, and estimate the costs, of refurbishment. A detailed study would be needed to confirm the current state of the existing gas generators, their suitability for life extension and associated costs. Aspects that could affect this include:

- The quality/quantity of maintenance
- The quality of the working environment – cover, salt, smog, dirt, etc.
- Actual workload to date, and how evenly it has been distributed across units
- Accidents and resulting damage, along with other unplanned events etc
- Suitability for conversion to alternative fuels (gas/diesel or natural gas/H2)

5.3.1.2 Ongoing economics of gas generators

As the amount of RE increases and, consequently, the amount of gas required decreases[9], a point will be reached where the use of LNG from Karratha becomes uneconomic. Options at this stage include:

- Switch to diesel for firming and backup. Diesel is more expensive and has higher emissions, but may be acceptable for a short period to bridge to another longer term option
- Subsidise LNG delivery to keep the gas generators running until hydrogen or another alternative fuel source becomes available. This may be cheaper in the short term
- Add in-stream tidal generation if and when it becomes viable (see Appendix B)
- Switch to hydrogen or hydrogen-based fuels, as these are forecast to be abundant within the next decade in the broader region

[9] See also discussion about seasonal factors in Section 5.1.2.

These factors provide further justification to refurbish the existing gas generators rather than buy new replacements. If new generators are found not to be required in ten years, then there will be a substantial 'regret cost'.

5.3.2 Capital costs

The implementation plan discussed in this report includes the following generation mix:

- 40 MW Utility Solar, operational by 2027
- 40 MW of rooftop solar, built out over a period of years extending past 2027.
- 30 MW of gas generation using new or refurbished existing generators (and existing diesel backup generation)
- Battery Storage plant sized ultimately for 164 MWh, but with up to 130 MWh storage initially installed, to be expanded beyond 2027, as required.

To calculate the capital costs of such a power system, the battery component of CAPEX needs to be split into two components: the battery storage itself, and the 'Balance of Plant' – everything besides the battery packs themselves. Graham et al. (2021) provided this information in their Table B4. A summary of the CAPEX is given in Table 8, based on figures from Table 1 (in column 2). Table 8 also includes figures for both new gas generation and refurbished gas generators at 40% of the CAPEX of the new generators.

Table 8. Comparison of different costing and expenditure options (at Net Present Value).

Technology	CAPEX ($k/MW)	Capacity (MW)	CAPEX New ($m)	CAPEX Refurb§. ($m)
Fixed PV	$1,282	40	$51	$51
Rooftop PV	$1,261	10	$0	0†
Battery 4hr *	$225	130	$29	$29
Battery Balance of Plant *	$149	164	$24	$24
LNG – new gas generation	$1,794	30	$54	$0
LNG – refurbished§ gas generation	$718	30	$0	$22
Total			**$158**	**$126**

* ($/MWh)
† Paid for by the prosumer, an individual who both consumes and produces
§ Assumed to be 40% of the cost of new equipment

Column 5 of Table 8 (where the gas generation CAPEX is 40% of new generation capacity) shows that the total CAPEX with refurbishment is reduced by 20% ($32m).

After 2027, as solar PV is built out to 80MW, a relatively low extra expenditure of $7.6m is required to install a further 34MW of battery packs.

Supplemental modelling was performed for two scenarios: where the CAPEX of the refurbished gas generators was assumed to be 40% of new equipment, and a 'framing scenario' of 10% – a lower limit on the cost of refurbishment. The 10% figure was chosen to demonstrate that, even at extremely low gas generation CAPEX, high RE% scenarios were still financially attractive. Results of this supplemental modelling are shown in Table 9.

Table 9. Comparison of LCOE with the CAPEX of gas generation set at 100%, 40% and 10%, respectively. Carbon price of $60 per tonne.

Technology	LCOE (LNG generation) $/MWh	LCOE (optimal RE, 60MW PV) $/MWh
LNG – new gas generation	$293	$215
LNG – refurbished gas generation at 40%	$271	$193
LNG – refurbished gas generation at 10%	$260	$182

Use of 40% refurbished generators for LNG-only generation led to a drop in LCOE of only $22/MWh, with a carbon price of $60. When the lowest LCOE RE scenario (60MW PV) was recalculated, the LCOE fell also by $22/MWh (still $78/MWh less than LNG-only generation). With the extreme scenario (10% of CAPEX on refurbishment), LNG-only generation remained more expensive than the lowest LCOE RE scenario by the same $78/MWh margin. Apart from these decreases in LCOE, the findings of Section 4 still apply.

The CAPEX figures in Table 8 have implications for the way the new Broome power system is implemented. There are three basic options:

- Continue fossil-fuelled generation with new gas generators, at $54m CAPEX.
- Move to RE with new gas generators, at $158m CAPEX .
- Move to RE but refurbish the gas generators, at $122m CAPEX[10].

Climate considerations and political obligations exclude the first option, and CAPEX for the third option is 20% less than the second, and hence preferable.

In the generation mix proposed here, gas generators service only 28% of the load; and the machines will run for many fewer hours per year, strengthening the argument for refurbishment.

5.3.3 Lifetime costs

The total lifetime cost of each technology is a second relevant factor in determining the economics of various options. The total lifetime cost (shown in Table 10) is a product of the contribution to load, the LCOE and the expected lifetime of the technology, assumed to be 25 years[11].

Table 10. Total lifetime costs for the proposed implementation solution for new and refurbished gas generation (all at Net Present Value, WACC of 7.25% and 25 year lifetime).

Technology	Lifetime cost – New gas. ($m)	Lifetime cost – Refurb.§ gas. ($m)
Fixed PV	$144	$144
Rooftop PV	$36	$36
Battery 4hr *	$158	$158
LNG - new and refurbished	$369	$298
Proposed scenario Total	**$707**	**$636**
100% gas	**$957**	†

* ($m/MWh)
§ Assumed to be 40% of the cost of new equipment
† Refurbished gas generators would not be suitable for a gas only scenario

The total lifetime cost of the proposed RE implementation solution is estimated to be $707m with new gas generation and $636m with refurbishment. The final row of Table 10 shows the total lifetime cost of the 100% gas option with new generators ($957m). If new generators are used, lifetime costs for the RE scenario is $250m less than an LNG-only scenario. If refurbished generators are used, the lifetime savings of the RE scenario are estimated to be $321m. In other words, lifetime costs of the LNG-only scenario are 50% more than the RE scenario.

Instead of spending $54m on new gas generators for an LNG-only scenario, the alternative is to refurbish the existing gas generators for an estimated $22m and move initially to a 70% RE solution, for a total CAPEX of $126m. An extra up-front expenditure of $72m is offset by a saving in total lifetime costs of $321m.

[10] As noted in section 5.3.1.1, a study of the existing generators would be required to confirm they are in suitable condition for refurbishment.

[11] The lifetime of battery storage was extended from the 20 years used in the modelling to facilitate comparison.

Increasing fuel costs provide a further argument supporting the RE solution. A calculation was performed for 100% gas with an artificially low fuel price of $0. This yielded an LCOE of $100/MWh. In other words, of a 100% LNG LCOE of $293, approximately two-thirds ($193) came from the fuel component. Table 3 showed that a 25% increase in fuel price raised the LCOE by $70/MWh with a $60/tonne carbon price. This finding demonstrates how dependent the total cost of generation is on fuel price fluctuations. The financial situation has a much lower risk in a largely RE generation mix.

5.3.4 Practical considerations

A 40MW utility solar farm is relatively small for current conditions. For example, the Merredin solar farm has a capacity of 100 MW, and the Broken Hill solar farm, built in 2015 has a capacity of 53MW.

The land footprint of utility PV is approximately 5.2 hectares per MW. This means that a 40MW solar farm will require 208 hectares of land.

Horizon Power is one of the most progressive power utilities in Australia in terms of RE implementation. It is positioning itself to roll out renewables as generation contracts expire in the regional parts of WA, through the establishment of a Future Energy Systems Group. However, to date, it has only taken relatively small steps towards 'proof of concept'. This Report demonstrates the feasibility for Horizon Power to now take a larger step with a much larger rollout of RE, for a population of 15,000.

There are meaningful opportunities for the Broome community to engage with Horizon Power to make this plan a reality. Horizon Power is already engaging with the community in rolling out community batteries in Broome. It is also undertaking a consultation process with stakeholders in the town of Exmouth to plan for 80% renewables with battery storage.

It is recommended that similar consultation be undertaken with the Broome community.

6. Conclusion

This work conducted new modelling on the power system in Broome, using well accepted national generation cost estimates. The modelling was performed with technology costs forecast for 2024 (in anticipation of a 2027 expiry of the existing generation contract) and a carbon price of $60/tonne of CO2 equivalent emissions.

Batches of models were calculated with increments of 10MW of PV, up to 150MW. The amount of battery storage was optimised for each PV increment to minimise the LCOE.

The lowest estimated LCOE ($215/MWh) occurs at a solar PV capacity of 60MW, combined with 40MW/160MWh battery storage, backed up by existing 30MW of gas (LNG) generation. This scenario leads to an 82% reduction of LNG consumption, and the LCOE is $78/MWh less than a 100% LNG generation result.

Table 6 summarised four optimised scenarios, with PV capacities of 40MW, 50MW, 60MW and 80MW, respectively, where the LCOE differs by only $8/MWh across this range. The percentage of RE obtained for these scenarios varies from 58% to 88%. All are substantially cheaper than the existing LNG solution.

The amount of load met by RE for each increment of PV increases almost linearly to 80%. When broken down into components (see Fig. 7), the contribution to load for PV, Battery and Gas tends towards the horizontal as the PV increases, after 80% RE. From around 60MW of PV, the amount of surplus energy increases almost linearly. Increasing the amount of PV to 80MW will generate 52GWh per annum of intermittent, surplus energy with only a marginal increase in LCOE, although most of this is available only in the Dry season. This surplus is available for use in innovative applications, which would further reduce the LCOE.

Five Wind scenarios were modelled (with batches of PV and optimised for Battery) with 4.2, 8.4, 12.6, 16.8 and 21.0MW Wind capacity, respectively (1 to 5 turbines). All five Wind scenarios led to an LCOE within a relatively small range of $214-220 per MWh in the same range as the optimal PV scenarios discussed above. This indicates that there is no financial benefit in adding wind generation to the generation mix in Broome.

In the Broome context, seasonal factors preclude achieving a higher RE percentage (with or without Wind) at acceptable costs with current technologies and technology costs. From December to March, lower solar radiation results in insufficient energy to meet the load, and more gas generation is needed.

The lowest LCOE 60MW PV outcome with 82% of RE will substantially reduce the amount of fuel needed for generation in Broome. To provide Broome's annual 131GWh of electrical energy, an average of 7.35 LNG road trains are currently required per week. With only 18% of the original fuel requirement, the 60MW PV option equates to an average of only 1.32 LNG ad trains per week, or 10.4 tonnes of LNG per day.

This study treated solar PV as one technology. The effective LCOE for rooftop PV can be matched to that of utility PV by setting an appropriate feed in tariff, making it unnecessary to model different mixes of the two technologies.

Table 6 shows that a range (40 - 80 MW) of PV capacities is feasible for around the same LCOE. We discussed implementation options in detail in Section 5.3, assuming that it is feasible to build a 40MW solar farm, with firming battery, by 2027, when the existing power contract in Broome expires. This should be accompanied by a staged rollout of rooftop PV, facilitated by Horizon Power's (2022c) DERMS technology which will integrate rooftop solar and battery systems with the Broome microgrid.

Given that gas usage will decrease under these scenarios, we recommend that the existing gas generators be refurbished if appropriate rather than replaced at higher cost. Gas plant usage will reduce substantially as renewables are rolled out, and will continue to reduce as alternative backup options such as hydrogen become available.

Detailed planning by Horizon Power will need to commence soon to determine how to maximise the amount of rooftop PV that a high RE generation scenario can accommodate. This will influence the size of the utility solar farm and the amount of battery required by 2027.

We have assumed that it is possible to implement the following by 2027, when the existing power contract expires:

- 40 MW Utility solar farm
- 10 MW extra rooftop solar, to be expanded towards a total of 40MW over time
- 130 MWh of 4 hour Battery storage, with control equipment sized for 160-170MWh
- 30 MW of gas generation using refurbished existing generators (and existing diesel backup generation)

Capital expenditure for such a system is estimated to be $126m, compared to $54m for replacing the existing fossil-fuelled generation with new gas generators. However, the total lifetime cost of the assumed RE solution over 25 years is $636m, compared to a lifetime cost of $957m for the new 100% LNG option. In summary, an extra up-front expenditure of $72m is offset by a saving in total lifetime costs of $321m.

6.1 Recommendations

Horizon Power:

- Perform detailed studies to determine the optimal mix of rooftop and utility PV in a high RE scenario for Broome, including the maximum amount of rooftop PV that such a scenario can accommodate.
- Design the battery plants to ultimately accommodate 160-170MWh of Battery (sized for 80MW of PV), but initially install only 130MWh of Battery packs.
- Investigate refurbishing the existing gas generators to save on higher costs of replacement. Gas plant usage will reduce substantially as renewables are rolled out, and continue to reduce as alternative backup options such as hydrogen become available.
- Conduct a detailed investigation into the feasibility of tidal-stream turbines to supplement the electricity supply in Broome. This can potentially reduce the amount of fossil-fuelled generation and increase the duration of battery storage at night time, especially during the Wet season. The Kimberley has high tidal variations, and tidal velocities are relatively high. ARENA or NAIF funding could be sought for detailed studies.
- Explore the use of Flow batteries to potentially extend the storage duration through increased tank sizes.
- Engage with the Yawuru PBC for partnering opportunities
- Engage in consultation with the Broome community about how best to roll out RE.

WA State Government:

- Negotiate domestic supply commitments with green hydrogen export developers to further support RE and provide an alternative to LNG in the Kimberley.
- Engage with Yawuru PBC

Broome community:

- Engage proactively with Horizon Power to ensure that:
  - the proposed solution is implemented by 2027;
  - best use is made of the DERMS technology
- Continue to advocate for higher levels of rooftop PV and supporting battery storage.

7. Appendix A

Rollout of RE across the Kimberley since 2018

Since the release of the Kimberley Clean Energy Roadmap in 2018, and possibly partly inspired by it, the WA State Government (through Horizon Power) has rolled out several RE initiatives across the broader West Kimberley. These are all likely to provide cheaper and more secure electricity in the Kimberley.

It is clear that Horizon Power is committed to the use of RE in remote parts of WA, including the Kimberley (Horizon Power, n.d.). Actions to date have included the installation of two community batteries in Broome, and the release of new rooftop PV hosting capacity to residents and businesses in February of 2022 (Vorrath, 2021). Both batteries are rated at 800kW/ 400kWh. As well as enabling connected customers to draw on the energy stored from their rooftop PV systems, these batteries will be used by Horizon Power to balance loads and contribute to system security.

Other RE initiatives in the Kimberley are summarised below.

7.1 Kimberley initiatives

7.1.1 Energy storage in regional towns

In 2021, the WA State Government announced $30.8 million for battery energy storage in nine regional towns "to give more people the opportunity to install rooftop solar (Horizon Power, 2021d)". In the Kimberley, this includes two new Battery Energy Storage Systems to be installed in Broome [$10.3M] and Yungngora [$1.7M].

All nine battery systems are planned to be commissioned by December 2022.

7.1.2 Derby solar, battery and smart streetlights

The WA State Government also invested $5.21 million in RE projects across the shire of Derby – West Kimberley (Horizon Power, 2020b). This includes a roof-mounted 364 kW solar PV system and a RE smoothing community battery (400kW/ 200kWh) at the Derby Hospital, and 283 kW of roof-mounted solar PV systems across the Shire's portfolio of buildings (Derby and Fitzroy Crossing). The project, which is operational, has replaced street lights with energy efficient LEDs.

7.1.3 Regional Australia's first Virtual Power Plant

The Smartsun Virtual Power Plant trial announced in 2018 is now complete (Horizon Power, 2021c) (Horizon Power, 2021e). Fifteen participant households in Broome received subsidies to install solar PV with battery storage, and controllable heat pump hot water systems and air-conditioners. In total, 111kW of PV, and 105kW of battery storage was installed. The trial was successful, and customers used 40-70% less from the grid, with daily grid demand and average peak demand lower on the pilot homes.

7.1.4 Solar schools

The Solar Schools initiative involves Horizon Power installing and commissioning 2.1MW of rooftop solar photovoltaic systems on around 30 regional schools across WA for a cost of $5M (Horizon Power, 2020c). The intention is to reduce their electricity bills by over 27%.

In the West Kimberley, four schools were planned to receive an estimated total of $670k:

- Derby District High School for an 80kW system
- Halls Creek District High School
- Looma Remote Community School
- One Arm Point Remote Community School

In addition, 390kW of solar, and associated battery, has been installed in four schools in Broome.

7.1.5 Standalone power systems

Horizon Power is installing up to 50 standalone power systems across WA (Horizon Power, 2020d). $9.92 million has been allocated initially to deploy solar and battery technology for small regional customers. The initial sixteen installations have been in the Esperance region, replacing long and expensive supply lines.

The standalone power systems typically run at 80-90% RE. Diesel backup is only required for 200-250 hours per year.

A larger stand-alone power system (929kW solar farm and 1.78MWh battery) has recently been commissioned in Kalumburu (Horizon Power, 2022a). This means that Kalumburu now runs off 64% RE.

Three other systems are being installed across the Kimberley, but completion dates are not available.

7.1.6 Aboriginal community embedded networks

This project will upgrade the electrical infrastructure across 13 Aboriginal communities in the Kimberley, Midwest and Goldfields (Horizon Power, 2020a). $3.81 million was allocated to upgrade electricity infrastructure in remote communities. In the West Kimberley, this includes Joy Springs, Gillarong, Karnparrmi, Koongie Park and Loanbun.

7.1.7 Summary

While these initiatives are valuable and aligned with the recommendations of the 2018 KCER, they only 'tinker around the edges' of wide-scale adoption of RE in the Kimberley. However, these initiatives provide a valuable proof of concept to support a much wider and faster RE rollout with increased confidence and effectiveness.

At the same time, Horizon Power initiatives in other parts of WA paint a rosy picture for the RE possibilities for Broome.

7.2 Other Horizon Power initiatives

Horizon Power has been working to reduce greenhouse gas emissions in three regional towns: Onslow, Denham and Exmouth.

In Onslow (population 850), a trial of a regional microgrid was able to run "the entire town … on 100 per cent renewable energy for close to two hours" (Horizon Power, 2021f).

In Denham, Horizon Power (2021a) is trialling a green hydrogen demonstration plant that will be integrated with solar and wind energy to power 100 homes, a first for an Australian remote micro grid.

In Exmouth (population 2,500), a process has commenced that will see the town transition to 80% RE by 2024 (Horizon Power, 2021b). This process was triggered by the imminent expiry of an existing power supply contract. Horizon Power has been investigating technical issues and engaging with stakeholders to plan for 80% renewables in the town, made up of a solar farm and a large battery.

The Shire of Esperance has a population of around 15,000, equivalent to that of Broome. A new, integrated power system has just been commissioned there (Horizon Power, 2022b). It consists of 4MW of solar PV, 9MW of wind power (two 4.5MW turbines), a 4MW battery energy storage system, and a 22MW high-efficiency gas power station (Vorrath, 2022). Horizon Power claims that the installation will provide 50% of Esperance's power from renewables. The 4MW battery will be used for short duration grid firming rather than storage.

8. Appendix B

Tidal-stream power technologies in the Kimberley

This report supports a detailed investigation into the feasibility of tidal-stream turbines to supplement the electricity supply in Broome. While costs are currently high, the UK experience indicates that they will fall, and tidal energy is very predictable. The Kimberley has high tidal variations, and tidal velocities are relatively high. ARENA or NAIF funding could be sought for detailed studies.

A 2020 report modelled the feasibility of tidal power in Australia's RE mix (Penesis et al., 2020). This was an outcome of a three-year project (Australian Tidal Energy (AUSTEn)) to map Australia's tidal energy resource in detail and assess its economic feasibility and ability to contribute to the country's RE needs.

The project focussed on submarine 'tidal-stream turbines'[12]. There is a range of these modular devices on the market which generate between 0.1 and 6 MW. Extra generation can be achieved by adding more units. A summary of tidal-stream turbines being trialled in the UK was summarised in (EMEC: European Marine Energy Centre, 2021).

According to the AUSTEn report:

> *"Australia has some of the highest tidal variations in the world. However, tidal velocities are of the order of 2-2.5 m/s, which are lower than seen in other parts of the world (UK, Europe, Canada and the US), where Tidal Energy Converters (TECs) currently installed are deployed in sites with flows of approximately 4 m/s."* (Penesis et al., 2020 Page 5).

Output from Tidal-stream technology may therefore be less in Australia than in some other countries.

Nevertheless, the AUSTEn report identified five potential sites that could be assessed in further detail due to having the strongest tidal resources in Australia. One of these is in King Sound in the Kimberley, with possible sites at Ardyaloon and Derby. The report also contained a case study about the potential of a small tidal power installation to provide a secure emergency power supply in Broome (Penesis et al., 2020 Page 81).

Recent research from the UK (Coles et al., 2021) estimates that tidal turbines could generate 11% of the UK's annual electricity demand. 124MW of prospective tidal-stream capacity was being tendered for in 2021, so the technology is reaching critical mass, which will result in decreasing costs.

As tidal-stream technologies are just emerging, the LCOE is much higher than established RE costs. However, this is counterbalanced by the predictable and reliable nature of tidal generation, and projected cost decreases.

8.1 Tidal power costs

Coles et al. (2021) estimated that the proposed installation of 124 MW of tidal-stream generation

> *"would serve to drive down the levelised cost of energy (LCOE), through learning, from its current level of around 240£/MWh to below 150£/MWh [approximately equivalent to $480 to $300/MWh], based on a mid-range technology learning rate of 17%. Doing so would make tidal-stream cost competitive with technologies such as combined cycle gas turbines, biomass and anaerobic digestion".* (Coles, n.d. Page 2)"

The AUSTEn report estimated LCOE (Penesis et al., 2020) for two locations to be in the range $1,000–$1,750 /MWh. These figures are three to four times higher than the UK estimates, which are, in turn, three to four times higher than other renewable technologies. The most promising tidal-stream generation location identified by Penesis et al. (2020 Page 68) was at Ardyaloon, where tidal flows are high, yielding an LCOE between $250-470 /MWh. Unfortunately, the power system at Ardyaloon has recently been upgraded, so there is little prospect of tidal-stream technology there.

[12] Tidal-stream technology is different to tidal barrage technology, where a man-made lagoon functions like a hydroelectricity dam.

However, the relatively high LCOE of a single technology is not the only relevant factor. Coles et al. (2021) argued that:

> *"The cyclic, predictable nature of tidal-stream power shows potential to provide additional, whole-system cost benefits. These include reductions in balancing expenditure that are not considered in conventional LCOE estimates."* (Page 2); and

> *"The cyclic nature of tidal power production is well suited for integration with short-term energy storage (less than 4 h) to help balance supply with local demand"* (P. 18)

Penesis et al. (2020) argued similarly that studies are needed around combined tidal/ storage scenarios, to provide dispatchable power. This was explored in a case study in Penesis et al. (2020 Page 81) "Broome - Tidal energy to supply high security energy". They proposed to combine a single 0.8 MW tidal generator in deep water relatively close to the Broome port with battery storage *"to supply continuous emergency power to the Kimberley Port Authority or Horizon Power".*

8.2 Environmental impacts

Tidal-stream turbines have a relatively low environmental impact compared to the large 'barrage' systems which have been installed in small numbers around the world since the 1960s. A proposal for a barrage style tidal plant for Derby is still being promoted (Collins, 2021), despite being rejected by the WA Environmental Protection Authority.

Coles et al. (2021) summarised existing work about environmental impacts of tidal-stream turbines, under three categories:

- Sediment dynamics and flow effects
- Collision risk
- Habitat change and displacement

They found few impacts on marine life based on the relatively few studies conducted. They claimed that (Coles et al., 2021 Page 2):

> *"To date, no collisions between animals and turbines have been detected, and only small changes in habitat have been measured. The impacts of large arrays on stratification and predator–prey interaction are projected to be an order of magnitude less than those from climate change."*

However, they explained that not enough is known in practice and *"ongoing field measurements will be important as arrays scale up"* (Coles et al., 2021 Page 2)(P. 2).

The location of a trial site in Broome should be informed by known marine migration paths, and the trial itself should be accompanied by detailed research into the environmental impacts.

9. Appendix C

Rooftop PV capacity in Broome

There is high community demand in Broome for solar PV to be installed on individual buildings. We set out to explore how much rooftop PV could reasonably be installed on Broome rooftops.

Census data from 2011 and 2016 was used to estimate the number and type of buildings in the Broome Urban Centre and Locality. Private dwellings are categorised as Occupied and Unoccupied, and separately categorised as Separate dwellings, Semi-detached dwellings, Flats and Other.

Linear interpolation was used to estimate the number and type of each dwelling in 2021. Table 9.1 summarises the number of dwellings of each type in Row 1. An assumption was made in Row 2 about the percentage of dwellings suitable for rooftop PV. For example, we estimated that 95% of separate (detached) dwellings were potentially suitable for rooftop PV, but 0% of flats were. Similarly, in row 3, we estimated the average rooftop system size as 7 kW[13] for a detached dwelling and 5 kW for smaller dwellings. Row 4 displays the calculated potential rooftop PV capacity for occupied dwellings (27.6 MW) and unoccupied dwellings (4.2 MW), for a potential total of 31.8 MW for the approximately 5,700 dwellings in Broome.

Table C.1. Estimated number of Broome dwelling types and assumptions used in calculating the potential solar PV on residential buildings.

	Occupied						Unoccupied				
	Grand Total	Total	Separate	Semi	Flat	Other	Total	Separate	Semi	Flat	Other
Broome dwellings	5699	4937	3775	418	356	388	762	583	65	55	60
Proportion with rooftop PV			95%	95%	0%	50%		95%	95%	0%	50%
Average system size (kW)			7	5	0	2.5		7	5	0	0
Total Potential Capacity (MW)	31.8	27.6	25.1	2	0	0.5	4.2	3.9	0.3	0	0

There is also a potential for rooftop PV on commercial buildings. A conservative estimate from scanning Google Maps images of Broome indicates that there are 250 commercial buildings. We assumed that 90% of these are suitable for rooftop PV, and further assumed that the average size of each PV installation is 40kW (in a range from 10-50kW). In total, this results in a potential commercial rooftop PV capacity of 9 MW.

In summary, a total of 40.8 MW of potential rooftop capacity is available in Broome.

[13] The average system size for the suburb of Cable Beach is 10kW, so this estimate is conservative.

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11. Glossary of Acronyms

ACCU	Australian Carbon Credit Unit
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
AUSTEn	Australian Tidal Energy. Project to map Australia's tidal energy resource in detail
CAPEX	Capital Expenditure
CO_2-e	Expressed as metric tonnes of carbon dioxide equivalent – the equivalent greenhouse gas effect of a combination of gases to that of carbon dioxide alone
COVID	Coronavirus Disease
CSIRO	Commonwealth Scientific and Industrial Research Organisation
EDL	Energy Developments Pty Limited
EMEC	European Marine Energy Centre
EV	Electric Vehicle
GHD	GHD Group Pty Ltd
GHG	Greenhouse Gas
GJ	Gigajoule
GW	Gigawatt – one gigawatt equals 1,000 MW
GWh	Gigawatt hour — one GWh equals 1,000 MWh
KCER	Kimberley Clean Energy Roadmap
kW	Kilowatt – 1,000 kilowatts equals one megawatt
kWh	Kilowatt hour — 1,000 kWh equals one megawatt hour
LCOE	Levelised Cost of Energy (Electricity). An amortised cost of electricity production: a combination of costs of capital expenditure, operations and maintenance and fuel, over the lifetime of a generation source.
LED	Light Emitting Diode
LDES	Long Duration Energy Storage
LNG	Liquefied Natural Gas
MERRA-2	Modern-Era Retrospective analysis for Research and Applications, Version 2
MW	Megawatt
MWh	Megawatt hour
NAIF	Northern Australia Infrastructure Fund
NASA	National Aeronautics and Space Administration
O&M	Operations and Maintenance
OPEX	Operational Expenditure
PV	Photovoltaic
RE	Renewable Energy
ROI	Return on Investment
SAM	System Advisor Model
SEN	Sustainable Energy Now
SIREN	SEN Integrated Renewable Energy Network Toolkit
UK	United Kingdom
WACC	Weighted Average Cost of Capital

SEN

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