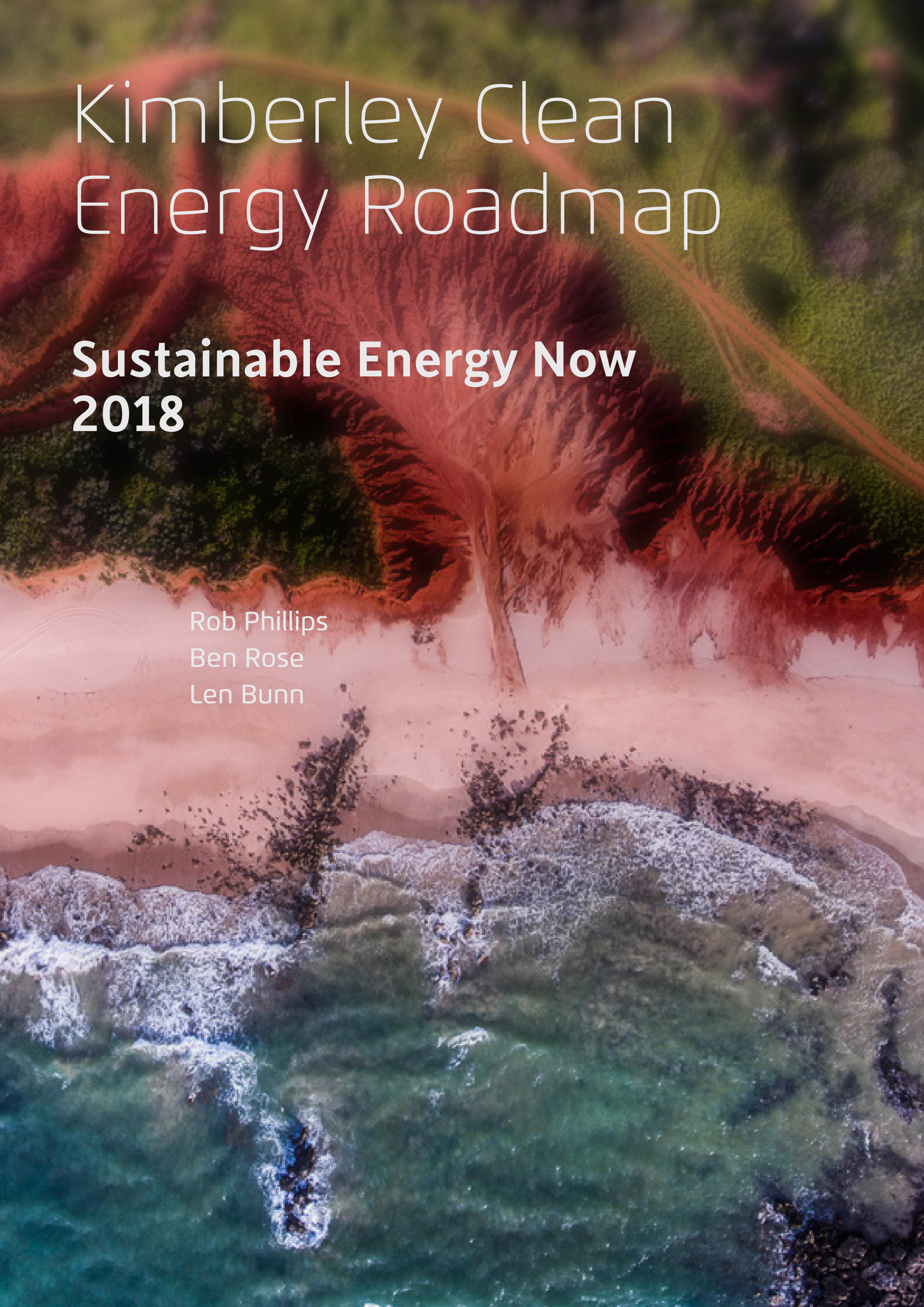

Kimberley Clean Energy Roadmap

Sustainable Energy Now 2018

Rob Phillips
Ben Rose
Len Bunn

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Sustainable Energy Now and associated consultant Ben Rose were commissioned to produce this report by The Wilderness Society (WA), Environs Kimberley and the Lock the Gate Alliance. Funding was provided by The Wilderness Society (WA) and private donors.

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Sustainable Energy Now

Sustainable Energy Now Inc. (SEN) is a not-for-profit association advocating for the utilisation of sustainable energy sources within Western Australia (WA). SEN brings together a mix of multidisciplinary knowledge and capability, providing independent advice on renewable energy (RE).

SEN members' professional backgrounds include engineering/science, business, education and the environment. They have committed thousands of hours, mostly voluntary, to developing evidence-based solutions toward transitioning WA's energy use from fossil fuels to renewables for the good of humanity, the economy and the environment. They are committed to helping WA to play its part in the global transition to a more sustainable future.

This Report, and the energy modelling used in it, were produced by consultants associated with SEN.

The energy modelling was based on two inter-related software packages, available under open source licenses:

- SIREN: developed by Angus King
- Powerbalance: developed by Ben Rose, Len Bunn and Steve Gates

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Image: Les Pullen

Glossary

Term	Explanation
AEMO	Australian Energy Market Operator
BREE	Bureau of Resource and Energy Economics
CAPEX	Capital expenditure
CF	Capacity Factor - average power generated, divided by the rated peak power.
CNG	Compressed Natural Gas
CO2	Carbon dioxide. The primary greenhouse gas.
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrating Solar Thermal technology: focused sunlight heats molten salt to generate electricity via steam turbines
DERMS	Distributed Energy Resources Management System: developed by Horizon Power
Fracked gas	Gas extracted by hydraulic fracturing of the rock layers in which it is contained
FNG	Fracked natural gas
Genset	Fuelled, IC powered modular generator
GIS	Geographic Information System
GJ	Unit to measure the energy of gas
	1 GJ = 1 Giga Joule = 1 billion joules
GPS	Global Positioning System
Grid	High voltage electricity transmission lines connecting widely separated generation and load centres
HVAC	High Voltage Alternating Current (Electricity transmission)
IC	Internal combustion
kV	Kilo volts (1000 volts)
kVA	Kilo volt amperes. A measure of power
kW and MW	Units of power used to measure electricity generation capacity. 1 megawatt (MW) = 1000 kilowatts (kW)
kWh; MWh	Unit used to measure electricity used or generated. One megawatt hour (MWh) = 1000 kilowatt hours (kWh).
	1 kWh = 1 kW of power for one hour or 1 'unit' of electricity .
	$30/MWh is equivalent to 3c/kWh, or 3c per unit of electricity.

Term	Explanation
LCOE	Levelised cost of energy or Levelised cost of electricity. Equivalent for the purposes of this study.
LGC	Large-scale energy generation certificate. Value of one MW of large scale RE generation, tradeable at a market price under the RET scheme.
LNG	Liquefied Natural Gas
MERRA	Modern-Era Retrospective analysis for Research and Applications: NASA global hourly weather data
MMscf/d	Million standard cubic feet per day.
MS	Molten salt – typically used with CST technology
NASA	National Aeronautics and Space Administration (USA)
OCGT	Open Cycle Gas Turbine
OPEX	Operating expenditure
Power–balance	Renewable energy modelling software developed by SEN members
PPA	Power Purchase Agreement between an energy retailer and a generator or a user, with price and conditions usually set for 10 years or more
PV	Photovoltaic solar panels generating electricity from sunlight
PVB	Combined solar PV and battery system
RE	Renewable Energy: all forms of clean energy not derived from non-renewable, i.e. fossil/ nuclear fission fuels. In this study it means wind, solar PV and solar CST. Renewable Electricity is generated from RE.
RET	Renewable Energy Target
SEN	Sustainable Energy Now Inc.: non-profit association advocating RE use in WA.
SIREN	Renewable energy modelling software developed by SEN members
STC	Small technology certificates: apply to residential & commercial PV systems < 100 kW capacity
SWIS	South West Interconnected System
TAFE	Technical and Further Education – Australian education institution
WA	Western Australia
WACC	Weighted Average Cost of Capital
WPVB	Combined wind, solar PV and battery system

Section 1

Executive Summary

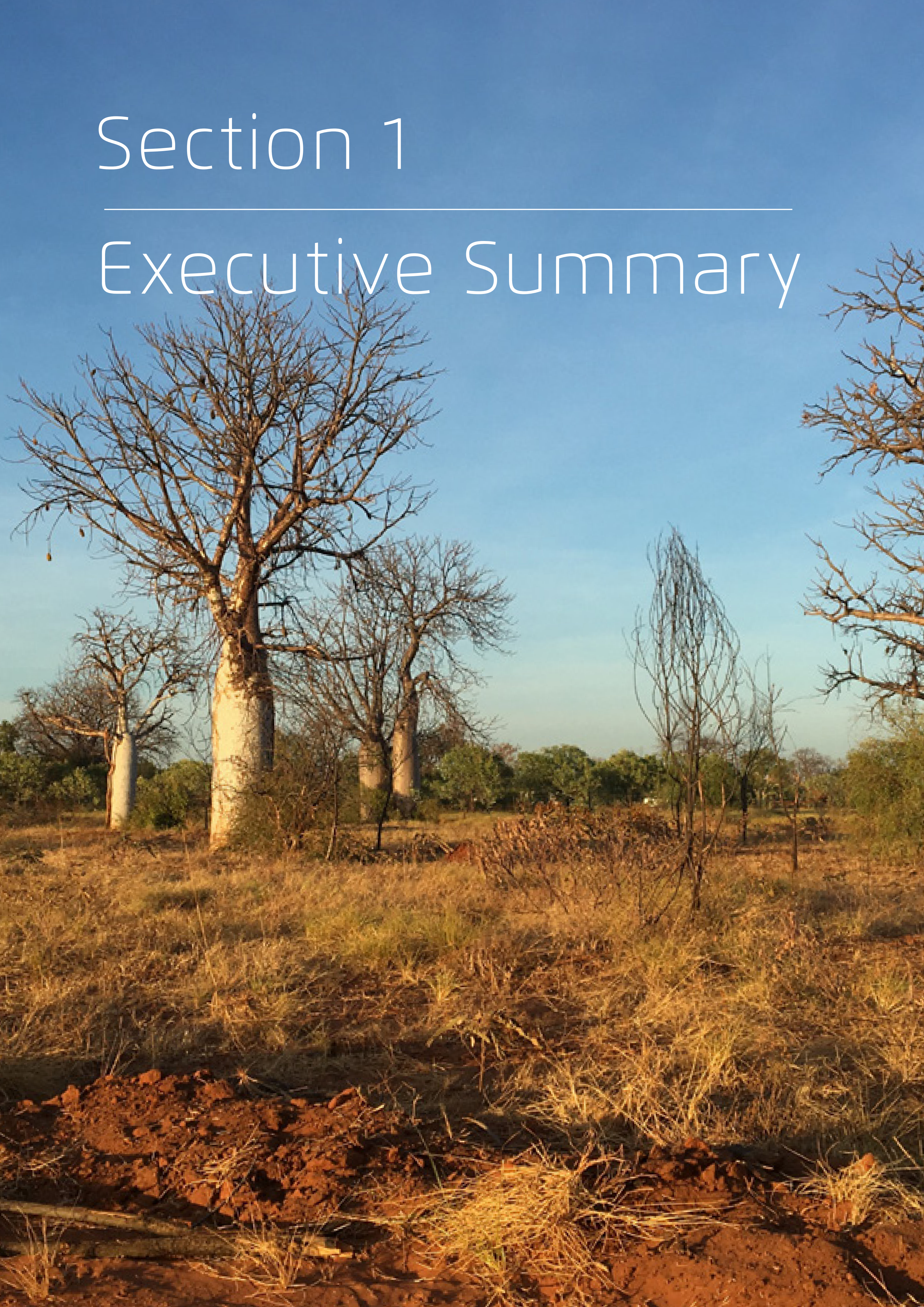


Image: Jenita Enevoldsen

1.1 Introduction

The Kimberley Clean Energy Roadmap was commissioned by The Wilderness Society (WA), Environs Kimberley and the Lock the Gate Alliance. This study considered a geographical region extending from Broome in the west to Halls Creek/Warmun in the east, and from Bidyadanga in the south to Kalumburu in the north. Nevertheless, the majority of population and population centres are in the West Kimberley, encompassing Broome, Derby, Fitzroy Crossing and numerous smaller communities.

The brief for the Roadmap was to analyse energy options and deliver a comprehensive, fully costed, clearly articulated renewable energy (RE) roadmap to achieving a cleaner, and ultimately cheaper, energy future for the towns, a proposed mine, and communities of the Kimberley region. Open source modelling software, SIREN and Powerbalance, developed by SEN members, was used to produce the RE modelling which underpins this Report.

1.1.1 Kimberley Context

Providing electricity to the remote Kimberley region of Western Australia (WA) currently poses significant challenges in terms of fuel costs and plant maintenance. The tropical climate and cyclone-prone nature of some areas pose additional challenges for electricity distribution and ability to deliver fuel.

On the other hand, the region has significant RE resources which can offset some of these challenges, and ultimately provide cheaper and more environmentally-friendly energy solutions. This Report explores these options.

1.1.2 Isolated Microgrids

Like much of regional WA, the Kimberley has no electricity grid, per se. Each town or community is essentially an isolated microgrid in terms of electricity supply.

Managing energy supply in such a context is fundamentally different than in a large grid, like the South West Interconnected System (SWIS) in the south-west of WA. If load increases on one part of a larger grid, or generation decreases, any shortfall in one area can be met by other areas of the grid (given adequate transmission and reserve generation capacity), which provides system operators an opportunity to more easily balance supply and demand.

The variability of solar and wind generation on an isolated microgrid presents unique challenges which do not exist on a distributed grid like the SWIS. Clouds obscuring solar photovoltaic (PV) panels can reduce output very quickly, and battery systems need to be in place to 'balance' this as existing internal combustion (IC) technologies cannot respond quickly enough. For this reason, Horizon Power has constrained the amount of rooftop solar PV which can be installed in towns like Broome. This is one compelling argument to modernise the electricity system in the Kimberley with properly integrated renewable and storage technologies.

1.1.3 Weather conditions

Wind patterns across the day are fairly stable during the Wet season. Average wind patterns during the Dry season tend to be more variable. However, the strongest winds are at night and the weakest winds are during the afternoon, when solar radiation is highest. During the Dry season, wind and solar therefore complement each other.

Cyclonic conditions pose a risk in the Kimberley. Most of the West Kimberley can expect occasional category 2 cyclones, with wind strengths up to 160 kph. The coastal areas south of Broome are in the path of occasional cyclones up to category 4 (>200 kph).

Cyclonic wind strength decreases with distance from the ocean. To minimize cyclone risk and construction cost, proposed wind farms have been located at least 10 km from the ocean and are not recommended for coastal areas south of Broome. The proposed concentrating solar thermal (CST) plant location is 70 km from King Sound and 150 km from open ocean; it has never recorded wind speeds in excess of 100 kph.

1.1.4 Existing Power Purchase Agreements (PPAs)

Most of the generators that Horizon Power uses in the Kimberley are governed by PPAs, which expire between 2023 and 2027. These generators will still be needed as backup for the RE scenarios recommended in this study. As they will be used much less, the existing PPAs will need to be amended or bought out. This relatively distant time horizon also provides time for planning for a managed transition. Fuel provision is outside the PPAs, and Horizon Power is responsible for these costs.

1.1.5 Technologies

Cyclone-rated wind and solar technologies exist that can be used in the Kimberley. The Kimberley region is no longer considered remote, as it is serviced by two ports, with a major sealed highway connecting the towns. The port at Broome is capable of handling large wind turbine components, for example, tower sections and blades up to 70 m long, and nacelles weighing up to 70 tonnes.

This Report has explicitly considered the following technologies: onshore wind; rooftop solar PV; utility scale PV; utility scale batteries; CST generation; and fossil-fuelled IC generators powered by diesel, liquefied natural gas (LNG) and piped unconventional fracked natural gas (FNG).

1.1.6 Horizon Power's Role

Horizon Power appears to be positioning itself to be a leader in the transition to RE. It has developed:

- A 'distributed energy resources management system' (DERMS), designed to manage and optimise the technical operations of grid-connected renewable generators, *"**to dynamically manage supply and demand, maintain system stability and optimise long-term economic efficiency**"*
- Its own advanced microgrid roadmap, forecasting the levelised cost of electricity (LCOE) over time for different 'business futures', for each of its 38 systems
- 'Micro power systems' (off-grid, utility-scale power systems) that can be remotely managed.

Horizon Power has been slowly taking control of power provision in larger communities over the last few years, e.g. Kalumburu and Yungngora. Access to subsidised power and innovative tariff arrangements have reduced prices for community customers.

It is encouraging that Horizon Power is working progressively to integrate RE in its areas of responsibility, and lobbying for legislative and regulatory reform to facilitate this. While Horizon Power has developed some plans for rolling out renewables, its ability to implement these plans appear to be constrained by being unable to install its own assets, by being forced to 'go out to market', and by needing to tender for each individual generation asset – removing the ability to benefit from economies of scale.

The absence of a mature RE construction industry in the Kimberley has led to very high quotes for RE generation projects, mainly because no substantial RE industries operate in the Kimberley. However, if there were a 'pipeline' of works, industry would set up to meet the demand. Government action is required to adopt a Kimberley Clean Energy Roadmap, help establish RE industries in the Kimberley and provide greater regulatory and financial flexibility for Horizon Power to effectively roll out renewables.

Engaging with Horizon Power about the Kimberley Clean Energy Roadmap will be an important factor in developing and implementing rollout of RE across the Kimberley. Similarly, advocacy with Government and other stakeholders should promote the adoption and implementation of Horizon Power's "Distributed Energy Resources" blueprint.

1.2 Modelling

This Report is built upon three sets of modelling:

- The region between Broome and Derby, as the largest source of electricity demand, both as a new High Voltage Transmission Grid (see *Figure 1.2*), and as stand-alone centres
- Two smaller towns – Fitzroy Crossing and Halls Creek
- Two Indigenous communities – Beagle Bay (medium-sized community) and Kalumburu (remote community). Results were extrapolated for six other medium-sized communities, and to the 57 smaller communities with populations of less than 200.

Five general scenarios were explored in the modelling:

- CST for the Grid scenario, supported by solar PV generation, and augmented by battery storage and fuelled backup
- Combinations of wind and solar PV generation, supported by battery storage and fuelled backup (WPVB)
- Solar PV generation, supported by battery storage and fuelled backup (no wind)
- Internal combustion engines fuelled by LNG or diesel with the existing small amount of rooftop PV ('business as usual')
- Internal Combustion engines fuelled with piped FNG with existing small amount of rooftop PV.

We have used conservative cost assumptions, especially for batteries.

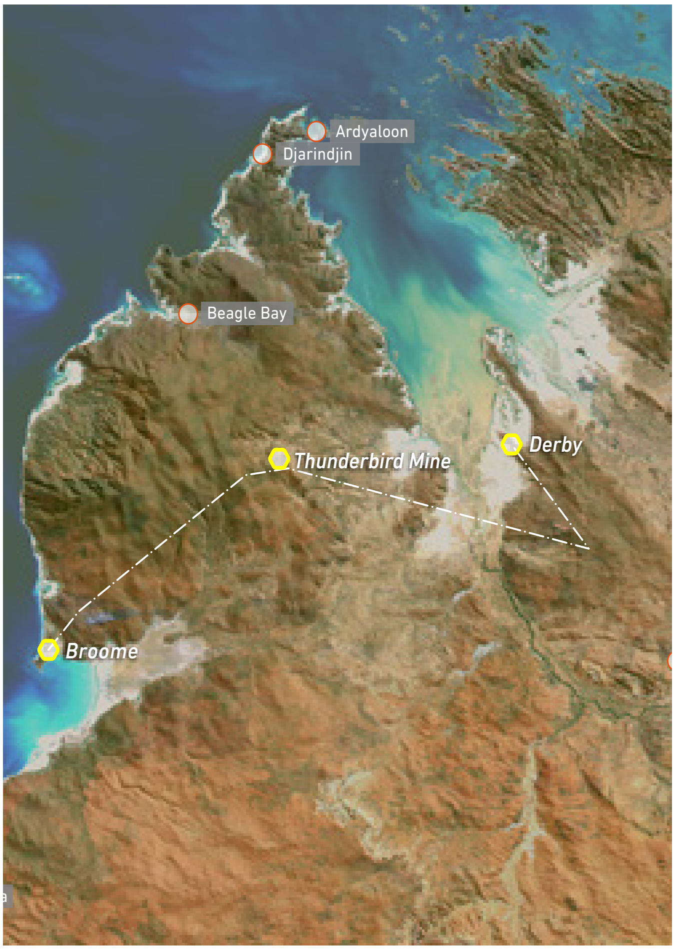


Figure 1.2 Major locations on the potential Broome – Derby Grid

1.3 Results

A detailed summary of the modelling results is shown in *Table 1.3.4*. The key points are summarised below.

1.3.1 Model 1: Cost-minimised

The model optimised for minimum cost resulted in around 50% RE, but, compared to the modelled fuelled scenario, LCOE values were less expensive, as follows:

Broome: $53 per megawatt-hour (MWh) less than the modelled fuelled scenario

Fitzroy Crossing: $58/MWh less than the modelled fuelled scenario

Beagle Bay: $40/MWh less than the modelled fuelled scenario

The Broome-Derby Grid scenario was $65/MWh less expensive than its fuelled equivalent, but $20-30/MWh more expensive than the stand-alone alternatives, mainly due to the cost of the transmission lines.

1.3.2 Model 2: $30/MWh Lower Cost Than Generation

Optimising the renewable mix to be $30/MWh less than the modelled fuelled generation results in 74-88% renewables in larger centres and 60-71% RE in communities, saving 153,000 tonnes of CO_2 emissions per annum.

Wind turbines are an important part of the generation mix, to reduce battery requirements and fuelled generation at night.

1.3.3 Model 3: Lower Cost Assumptions

A third round of modelling was performed with the most recent Australian Energy Market Operator (AEMO) price predictions, which predict 25% lower prices for utility solar PV and CST by 2021-22, and a lower cost of capital. Under these new assumptions, the savings from the Grid CST scenario more than double to $65/MWh less than the LNG Grid equivalent. Furthermore, the cost of the Grid CST scenario reduces to around the same as the stand-alone WPVB scenario, making it a viable option.

1.3.4 Overall Summary

This study demonstrates that it is possible to transition to 60-90% RE in the Kimberley while creating savings of a minimum of $30/MWh in the wholesale price of electricity. The generation mix modelled is for solar, wind and batteries to be rolled out across every town and community in the West Kimberley region. In total, 117 MW of Wind and 97 MW of utility-scale solar PV generation can be installed, with battery storage of 132 MWh, whilst retaining some fossil-fuelled backup. A graphical overview is shown in ***Figure 1.3.4***.

Table 1.3.4 expands on this summary. It combines the results of Models 2 and 3 for stand-alone population centres. For most population centres, ***Table 1.3.4*** displays Model 2 results with price predictions for 2019, optimised to be $30/MWh less than the modelled fuelled generation. For Broome, Derby and the Thunderbird Mine, Model 3 results are presented, using 2021-22 AEMO price predictions. This results in a cost $40-44/MWh less than the equivalent fuelled cost.

Table 1.3.4 also provides details of the physical size of the renewable installations at each location. In Broome, the largest centre, less than 12 sq. km is required for the 19 wind turbines and 41 MW of solar panels. Most of this land can also be used for other purposes, because only a fraction of the available surface area is taken up by wind turbines and associated infrastructure. There is much flexibility in where RE generation facilities can be sited. A mutually-agreed location on aboriginal-managed land could be a win-win proposition.

An investment of $449 m in RE ($560 m total investment), amortised over 25 years, would save more than $45 m in fuel costs per year. When loan repayments (from higher capital expenditure for renewables) and operating costs are accounted for, overall annual savings are estimated at $14.8 m per year.

Figure 1.3.4 Overview of the Kimberley Clean Energy Roadmap **(See overleaf on p5)**

Sustainable Energy NOW

Kimberley Clean Energy Roadmap: Key Findings

	City/Town/ Community	Population	RE as portion of Gen. (%)	Savings $p.a.	Total RE Invest-ment ($)	LCOE ($/MWh)	Wind (MW)	Wind Farm Area (ha)	Turbine size (MW)	Number of Wind Turbines	PV (MW)	PV Farm Area (ha)	Number of Panels	Battery Capacity (MWh)	Fossil-fuelled Capacity. (MW)	CO2-e saved (kilo-Tonnes)
Towns and Industry	Broome*	14,000	80%	$5.8 m	$168 m	$197	37	962	2.0	19	41	172	132,000	45	27	54.0
	Thunderbird*	N/A	85%	$6.0 m	$203 m	$204	49	1456	2.0	28	45	198	152,000	61	18	61.5
	Derby*	3,300	82%	$1.3 m	$46 m	$225	9.5	247	2.0	5	12	58	44,400	13	6.0	13.5
	Fitzroy Crossing	1,140	74%	$419 k	$17 m	$223	4.2	109	0.5	9	3.9	20	15,600	1.8	2.8	5.5
	Halls Creek	1,550	74%	$380 k	$16 m	$223	3.8	99	0.5	8	3.5	18	14,179	1.6	2.5	5.0
	Abattoir	N/A	77%	$353 k	$15 m	$218	3.0	78	0.5	6	3.0	16	12,000	5.5	1.8	4.5
Medium Sized Communities	Beagle Bay	350	60%	$49 k	$2.0 m	$247	0.30	7.8	0.23	2	0.39	2	1,560	0.36	0.40	0.7
	Kalumburu	400	69%	$62 k	$3.1 m	$278	0.54	14.0	0.23	3	0.58	3	2,320	0.44	0.38	1.0
	Ardyaloon	350	62%	$56 k	$2.3 m	$247	0.34	8.9	0.23	2	0.45	2	1,783	0.41	0.46	1.0
	Bidyadanga	600	62%	$92 k	$3.7 m	$247	0.56	14.5	0.23	3	0.72	4	2,898	0.67	0.74	1.5
	Camballin	550	62%	$73 k	$3.0 m	$247	0.45	11.6	0.23	2	0.58	3	2,318	0.53	0.59	1.0
	Djarindjin	450	62%	$49 k	$2.0 m	$247	0.30	7.8	0.23	2	0.39	2	1,560	0.36	0.40	0.7
	Warmun	200	71%	$90 k	$3.7 m	$278	0.56	14.5	0.23	3	0.72	4	2,898	0.67	0.74	2.0
	Yungngora	400	62%	$99 k	$4.0 m	$247	0.60	15.6	0.23	3	0.78	4	3,120	0.72	0.80	1.5
Total		**23,290**	**N/A**	**$14.8 m**	**$449 m**	**N/A**	**117**	**3046**	**N/A**	**95**	**97**	**505**	**388,636**	**132**	**62**	**153**

Table 1.3.4 Full details of the stand-alone scenarios, for all towns and communities supplied by Horizon Power (plus industrial sites), using AEMO price predictions for 2019, and optimised to be $30/MWh less than the equivalent fuelled cost. The figures provided here result from evidence-based assumptions. RE generation is not subsidised.
*** Modelled on the latest, lower AEMO price predictions for solar PV for 2021-22. This results in a cost $40-44/MWh less than the equivalent fuelled cost.**

If the Federal Government's RET subsidy was added, further savings of approximately $4.7 m p.a. are achievable.
If a hypothetical $20 /Tonne Carbon Price on fossil-fuelled generation is also included, savings of approximately $2.6 m p.a. are also possible.
Electricity generation capacity is measured in Kilowatts (kW) or Megawatts (MW). Electricity energy use is measured in kilowatt hours (kWh) or Megawatt hours (MWh) – the amount of electrical energy consumed.

1.3.5 Subsidies and Incentives

Further calculations were carried out on Model 2, to ascertain the effects of subsidies: the existing Renewable Energy Target (RET) large-scale generation certificate (LGC) mechanism; and a hypothetical 'carbon price' of $20 per tonne of carbon emissions.

When both subsidies are applied at the same time, renewables become between $52 and $56/MWh (~5.5c/kWh) less expensive than the modelled LNG generation. This is equivalent to a wholesale price reduction of 20%.

1.3.6 Hourly Analysis

An analysis was performed of the hourly generation mix across the year for the two Grid scenarios. In the WPVB scenario (82% RE WPVB), fuelled generation is needed throughout the year, but less so in the Dry season. The CST Grid scenario (88% RE) has less need for fuelled backup, because the molten salt storage can meet night time demand on many occasions. In fact, during the Dry season, molten salt from CST, and some battery drawdown, can meet all modelled demand. However, fuelled backup will still be needed on cloudy days during the Wet season. Of the two grid scenarios (CST and WPVB), the CST option provides the greater proportion of RE and requires less fuelled backup. The CST scenario is therefore preferred in the following discussion.

1.3.7 Best-case Costings

Both the addition of subsidies and incentives, and the use of lower cost assumptions, have a significant impact on the outcome of the modelling for Broome, Derby and the Thunderbird mine. ***Table 1.3.7*** displays the Model 2 results in column 2 and the fuelled scenario with a carbon price (column 3). The best-case scenario (column 6) combines the cost benefits of Model 3 (column 4) with those from the subsidised scenario with LGCs (column 5). Columns 7-9 compare the best-case situation and the LNG-fuelled equivalent with a carbon price.

This shows that the best-case scenario is between 24 and 32% less expensive than the fuelled equivalent (a reduction of 6.6-8.9c/kWh on the wholesale price). The overall annual savings would be $28.2 m for the Grid scenario, and $20.4 m for stand-alone generation for Broome Derby and the Thunderbird mine.

Location	Base case [1]	LNG with Carbon Price [2]	Low cost	Base case with LGCs	Best case [3]	LCOE Savings best case [4]	LCOE Change [4]	Total Savings [4] best-case
Grid CST	$240	$281	$205	$226	$192	$89	32%	$28.2 m
Broome WPVB	$211	$251	$197	$197	$185	$66	26%	$8.6 m
Thunderbird WPVB	$217	$257	$204	$200	$188	$69	27%	$9.7 m
Derby WPVB	$235	$276	$225	$219	$210	$66	24%	$2.1 m

Table 1.3.7 Comparison of the Model 3 scenario with subsidies (LGC's and a Carbon Price) with the LNG-fuelled equivalent. LCOE in $/MWh.

[1] Model 2 scenario – optimised for $30/MWh less than the unsubsidised LNG equivalent
[2] Modelled LNG scenario with a $20 per tonne Carbon price
[3] Best case scenario, with low-cost assumptions (Model 3), LGCs and a Carbon Price.
[4] compared to LNG with a Carbon Price

1.3.8 Comparison with Piped FNG

The best-case RE options for the Broome-Derby region are compared with existing generation fuelled by piped FNG from the Canning Basin. The modelling assumes gas will be supplied via spur-lines from a future large pipeline from Kimberley gas fields to a large liquefaction/ export plant.

Generation fuelled by piped FNG is cost equivalent to the cost-minimised RE scenario for the Broome-Derby region. It is also roughly equivalent to the best-case (80-88% RE) scenario.

However, such a large pipeline is unlikely. The proposed James Price Point gas hub was terminated in 2013, and an agreement to support a pipeline from the Canning Basin to Dampier was terminated by the WA Labor Government in August 2018.

A second option, to build a smaller pipeline from the Canning Basin to the major centres, is unlikely to be economical for the required volumes. Other methods of delivering FNG, by trucking LNG or compressed natural gas (CNG), are only slightly less expensive than the current approach of trucking LNG from Dampier.

Should unconventional gas fracking be permitted by the State Government, other factors are likely to make FNG extraction more expensive than the modelled cost assumptions, for example, through the costs of monitoring and offsetting the risks of methane leakage and pollution of fresh water aquifers.

In summary, this research demonstrates that the only way that FNG generation can compete with RE is if it is provided by spur lines from a future major pipeline, but this seems an unlikely outcome. Further, renewables can be installed and commissioned in a shorter timeline.

1.4 Implementation

There are too many unknowns at the current stage of development of the Kimberley Clean Energy Roadmap to develop a comprehensive timeline. Certainly, there is a need for solid transition planning, feasibility studies and updating of policy settings to facilitate a roll-out of RE in the Kimberley.

Existing PPAs complicate timelines, but we suggest ways they can be circumvented.

We suggest a suitable starting point would be a staged roll-out plan across the 57 small communities, moving to the larger communities and towns as time passes. In the larger centres, 50% RE could be the initial aim, with a subsequent round of development bringing RE up to 70-80%. There is no current prospect of moving to 100% RE.

A major political and technical decision will be related to the Broome-Derby region, in particular whether or not to build a high voltage grid between Broome, the Thunderbird mine and Derby, powered predominantly by a CST plant with molten salt storage. The decision is basically about replacing existing town infrastructure with renewable equivalents, or pursuing a nation-building agenda, with the potential to open up other economic opportunities in the Kimberley.

1.4.1 Employment

The Kimberley Clean Energy Roadmap, if implemented, will potentially result in numerous long-term jobs within WA, made up as follows (see also ***Table 1.4.1*** for details):

- 88 long-term jobs in Construction and Installation
- 26 long-term jobs in Manufacturing across WA
- 70 ongoing Operations and Maintenance jobs
- 162 long-term jobs in the Kimberley
- 184 long-term jobs across WA

Thus, if this clean energy roadmap for the Kimberley is adopted by the WA Government, a new a sustainable workforce of ongoing local jobs could be created.

1.4.2 Indigenous Benefits

The Kimberley Clean Energy Roadmap provides significant opportunities for employment and benefit sharing/investment arrangements for Native Title holders and/or communities.

Long term, 160+ jobs in manufacturing, construction, installation, operations and maintenance will be available in the Kimberley.

The major providers of electricity supply services in the Kimberley (Horizon Power, Department of Communities, Kimberley Remote Service Providers and potentially EMC Kimberley) have committed to training and employing Indigenous workers as part of their activities.

1.5 Conclusion

This study provides a comprehensive, fully-costed RE roadmap for the West Kimberley. Wind, PV and CST are all currently viable electricity technologies for the West Kimberley, combinations of which will provide substantial cost savings over the current LNG and diesel generation.

1.5.1 Economics

When the scenarios were modelled for minimum cost, approximately 50% RE generation could be achieved for $40-60/MWh less than fuelled generation. When modelling was optimised for savings of $30/MWh over fuelled generation, 60-90% RE generation can be achieved, depending on the location.

More recent cost assumptions for 2021-22, and the use of subsidies, makes RE $65/MWh cheaper than existing fossil fuel generation. There is reason to expect that RE costs will continue to fall, making the RE option even more favourable.

A mixture of wind (117 MW) and 97 MW of utility-scale solar PV generation, with battery storage (132 MWh) and fossil-fuelled backup can achieve ongoing annual net savings of $14.8 m compared to the existing fuelled generation. An investment of $449 m in RE over 25 years would save more than $45 m in fuel costs per year.

Combustion emissions of CO_2 in the West Kimberley would be reduced by at least 150,000 tonnes per annum, the equivalent of taking 25,000 petrol-powered cars off the roads each year.

Long term, 160+ jobs in manufacturing, construction, installation, operations and maintenance are estimated to be available in the Kimberley.

This Roadmap is clearly in alignment with the WA Labor Government's Jobs Plan, which focusses on:

- Local jobs and content
- Creating jobs in regions

Construction, Installation and Manufacturing (Job-Years)		Total (Job-Years)	Towns & Industry (Job-Years)	Medium Communities (Job-Years)	Small Communities (Job-Years)
Employment by sector (Job-years)	Construction and Installation	**879**	794	47	38.1
	Manufacturing (Kimberley)	**36**	33	2	N/A
	Manufacturing (Rest of WA)	**221**	209	8	4
Construction phase period (years)		10	10	10	10
Long-term Jobs		**Total Jobs**	**WK Towns & Industry**	**WK Medium Communities**	**WK Small Communities**
Employment by sector	Construction and Installation (Kimberley)	88	79	5	4
	Manufacturing (Kimberley)	4	3.3	0.2	N/A
	Manufacturing (All of WA)	26	24	1.1	0.4
	Operations (Kimberley)	70	65	3	2
	Total long-term jobs (Kimberley)	**162**	**148**	**8**	**6**
	Total long-term jobs (All of WA)	**184**	**169**	**9**	**6**

Table 1.4.1 Jobs modelling results for renewables in the Kimberley

- An innovation economy
- Integrated, coordinated infrastructure planning
- Supporting a Renewables Industry

This research shows that significant amounts of surplus RE will be generated. This energy could be used for new industry opportunities, such as to produce liquefied hydrogen fuel, which could be used to fuel IC generators or other engines.

In summary, substantial amounts of RE, from 50% to 80%, depending on specific locations) can be justified on purely financial grounds. When non-financial aspects are also considered (e.g. carbon pollution reduction; increased employment), RE in the Kimberley has a strong justification.

The majority of the investment required for the Kimberley Clean Energy Roadmap need not come from the Government. RE investment projects with long-term PPAs are attractive 'fortress investments' for superannuation funds and other investors.

1.5.2 Prospects for Fracking

There is no economic benefit in using FNG generation for electricity in the Kimberley. While supply from spur lines from a new major export pipeline is competitive with two of the RE scenarios presented, this option is unlikely in the medium term, given that the current State Government has terminated an agreement to support a pipeline from the Canning Basin to Dampier, and the proposed James Price Point gas hub was terminated in 2013. Furthermore, renewables can be installed and commissioned in a shorter timeline than gas pipelines and processing.

The alternative of using road trains to deliver either fracked LNG or CNG to sites offers no significant cost savings over the existing North-West Shelf LNG and imported diesel fuels.

Should unconventional gas fracking be permitted by the State Government, other factors are likely to ensure FNG extraction is more expensive than the modelled cost assumptions. This is due to the high costs of stringent regulations, monitoring and offsetting methane fugitive emissions, as well as the potentially significant costs of remediating any contamination of freshwater sources.

1.5.3 Implementation

The implementation of the Kimberley Clean Energy Roadmap will need to include agreements and partnerships with Native Title groups and Indigenous communities, based on the principles of free, prior and informed consent. The involvement of other local stakeholders, and the State Government and Horizon Power, will also be crucial.

Implementation of the Kimberley Clean Energy Roadmap will be easier to achieve if there is political direction for a broad transition across the Kimberley. A long-term plan for a staged rollout of renewables across the Kimberley will enable economies of scale to be realised. Mechanisms need to be put in place to provide investment certainty for businesses, and local long-term employment. A mature RE industry in the Kimberley can be encouraged, for example, by letting tenders for numerous installations concurrently.

Some legislative and regulatory barriers may need to be resolved to allow Horizon Power to realise these economies of scale and roll out renewables across the Kimberley. Achieving these changes requires clear political direction from the Western Australian Government.

Horizon Power's submission to the Legislative Assembly Microgrid Inquiry identified a need:

- For coherent regulation encompassing all owners of microgrids – generators, distributors, and retailers
- To address the inconsistencies in information that exist between Horizon Power and the Government
- To update generation rules to reflect current and emerging market requirements and become more flexible
- For more flexible tariff structures to support current and emerging market requirements.

Once regulatory barriers are resolved, a **managed transition plan** is key to maximising the benefits from implementing this RE roadmap. Such a plan would:

- Build upon the groundwork already begun by Horizon Power
- Put appropriate control and monitoring structures in place, to enable a secure and stable supply of electricity to consumers
- Provide investment certainty and economies of scale to reduce installation costs
- Have the potential for co-investment by Indigenous communities or Native Title groups
- Map out the creation of a new sustainable regional workforce, providing training opportunities and boosting local indigenous employment opportunities
- Create a sustainable regional workforce
- Reduce reliance on fossil fuels, such as gas and diesel

Some RE training opportunities are available in the Kimberley, but there is scope to extend training opportunities in Remote Services and Utilities Maintenance. The Kimberley Clean Energy Roadmap can act as a catalyst for this Indigenous training and employment initiative.

1.5.4 Recommendations

That the WA Government:

- Adopts a West Kimberley Clean Energy Roadmap
- Supports implementation of Horizon Power's advanced microgrid roadmap
- Develops a Kimberley Electricity Transition plan from this Roadmap
- Updates policy settings to enable Horizon Power to facilitate a RE transition in the Kimberley (update generation rules, adopt microgrid standards, and enable an ongoing pipeline of RE installation, enabling economies of scale)
- Conducts in-depth feasibility studies for the uptake of renewable electricity in the Kimberley as soon as possible
- Conducts a feasibility study into the viability of a Broome-Derby Grid
- Conducts a feasibility study into suitable wind turbine models (of different sizes) for Kimberley weather conditions
- Allocates funding in the forward estimates to develop the managed transition plan and implement a Kimberley Clean Energy Roadmap
- Pre-approves RE development zones and transmission corridors to enable rapid implementation
- Develops plans/ support for a Kimberley RE construction industry
- Develops tender requirements, reverse auction conditions and PPA criteria
- Develops staged plans of works for the towns and industry, medium communities and small communities.

This Report demonstrates that the commitment to a RE future for the Kimberley will create a reliable, economically-favourable source of electricity for the future, reduce electricity costs for consumers, and create ongoing jobs.

If adopted by the WA Government, this visionary model could be rolled-out to other parts of regional and remote WA. It can also provide case experience and an incentive for wider adoption of RE across the south-west corner of the State.

Image: Coober Pedy, Les Pullen, Professional Photographer

Section 2

Introduction

Image: Ben Little, Little Duo Photography

The Kimberley Clean Energy Roadmap was commissioned by The Wilderness Society (WA), Environs Kimberley and the Lock the Gate Alliance. Due to renewable Ord River Dam hydroelectricity being available in Kununurra and surrounds (East Kimberley), this study was restricted to the broader 'West Kimberley'. This was defined to extend from Broome in the west to Halls Creek/ Warmun in the east, and from Bidyadanga in the south to Kalumburu in the north. Nevertheless, the majority of population and population centres are in the West Kimberley, encompassing Broome, Derby, Fitzroy Crossing and numerous communities.

The objective was to deliver a comprehensive, fully costed, clearly articulated (RE) roadmap, to create a cleaner, and ultimately cheaper, energy future for the towns and communities of the Kimberley region. The report was derived from research by SEN energy consultants and the use of the modelling software SIREN and Powerbalance, developed by SEN members.

This report has analysed the costs of various RE scenarios and has compared them to fossil-fuelled alternatives in a range of locations.

2.1 Scope of Work

The scope of work included in the analysis and report includes:

- Reviewing the current energy sources, related information and future needs;
- Describing the unique characteristics and constraints of the Kimberley context, in relation to renewables;
- Developing a visual map of the proposed general locations of the RE sources showing:
  a. locations of the specific remote communities
  b. larger mining sources and towns;
  c. minimal disturbance of threatened species habitat in siting RE sources.
- Determining the most economic and fit-for-purpose RE system for the West Kimberley region between Broome and Derby, including the proposed Thunderbird sand mine and abattoir. Options include:
  - Model and cost individual RE micro-grids at Broome, Derby, Thunderbird mine and abattoir
  - Model and cost a new West Kimberley grid, including Broome, Derby, Thunderbird mine, and abattoir, possibly using onshore and offshore wind, solar PV and/ or Concentrating Solar Thermal (CST)

  - Reference the proposed Pilbara Solar PV Export project
- Costing and evaluating scenarios for supplying electricity microgrids in larger and smaller remote communities, using a mixture of RE sources and batteries. Modelling will be carried out for a sample of communities of varying sizes in a range of locations. Results will be extrapolated to other communities.
- Outlining a specific transition roadmap for RE and storage (solar/wind/batteries) in the region, based on comprehensive weather data;
- Reporting briefly on the issues related to the Broome minigrid: current Horizon Power initiatives; rooftop solar and behind-the-meter storage; microgrid options, including peer-to-peer trading;
- Develop a costed implementation plan, which includes:
  - Estimates of jobs created on a local and regional scale, including indigenous jobs;
  - General information about training options for indigenous Australians

2.2 Modelling Software

Modelling was conducted using the open source SIREN – Powerbalance software developed by SEN with three of the main developers contributing to this study.

2.2.1 SIREN

SIREN is the SEN Integrated Renewable Energy Network Toolkit simulation. SIREN draws upon Geographical Information System (GIS) data and NASA's MERRA[1] global hourly weather data. The MERRA data is derived from satellite remote sensing and is averaged over each grid element rather than being specific for particular weather stations. This means data is available for any location, even those remote from weather stations.

Energy modelling combines this data with the US Department of Energy National Renewable Energy Laboratory's 'System Advisor Model; (SAM) for various renewable technologies. It therefore simulates an electricity network and enables users to create and evaluate scenarios for supplying electricity using a mixture of renewable and non-RE sources. SIREN modelling has been correlated against existing wind and solar PV generation and verified to have acceptable accuracy for general planning purposes.

SIREN calculates power output for each generator for every hour of the year and compares this with the load on the network. The results are hourly load and hourly generation data for modelled power stations for a chosen year (8760 hours).

The grid resolution used in SIREN for weather data is of the order of 55x55 km, so RE generators can be located at any environmentally and politically suitable point on that grid with overlays such as GIS or Google Maps.

2.2.2 Powerbalance

Powerbalance consists of programmed spreadsheets that enable users to balance power surplus/shortfalls by adding various balancing power technologies, i.e. fuelled generation, various types of storage and demand-side management (DSM). Load and generation data from SIREN are loaded into Powerbalance, to complete a costed Renewable Electricity scenario. Powerbalance uses the mix of generation and storage to calculate for each scenario:

- Hourly average power (MW) - equivalent to energy generated in that hour (MWh)- for each energy source for the entire 8760 hours of the modelled year
- Annual energy generation amounts and energy costs for each technology
- Total energy cost and the amount of surplus RE generation
- Weighted average Levelised Cost of Energy (LCOE)
- CO2 emissions for the whole scenario

Scenarios can be optimised for various criteria, for example, for a set cost point, to minimise costs, to minimise CO_2 emissions, or to maximise renewables.

2.3 Levelised Cost of Electricity (LCOE)

Different methods of electricity generation are typically compared on a 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***"[2].

The LCOE of a RE technology is inversely related to the wind or solar energy resource at its location, all other factors being equal. For example, the LCOE of a wind turbine in the Kimberley, operating with a Capacity Factor (CF) of 24%, would be double that of the same turbine located in a high wind area, operating with a CF of 48%

A detailed description of the LCOE methodology is given in Appendix A.

2.4 Kimberley Context

Providing electricity to the remote Kimberley region WA currently poses significant challenges in terms of plant maintenance and fuel costs. The tropical climate and cyclone-prone nature of some areas pose additional challenges for electricity distribution and ability to deliver fuel.

On the other hand, the region has significant RE resources which can offset some of these challenges, and ultimately provide a reliable, cheaper, and more environmentally-friendly energy solution. Various renewable technologies are described below.

However, first, we explore other factors which are relevant in the Kimberley context.

2.4.1 Isolated Microgrids

Managing energy supply in such a context is fundamentally different than in a large grid, like the South West Interconnected System (SWIS) in the south-west of WA. If load increases on one part of a larger grid, or generation decreases, any shortfall in one area can be met by other areas of the grid (given adequate transmission and reserve generation capacity), which provides system operators an opportunity to more easily balance supply and demand.

Managing the variability of solar and wind generation on an isolated microgrid grid presents unique challenges which do not exist on a distributed grid like the SWIS. Clouds obscuring solar PV panels can reduce output very quickly, and systems need to be in place to 'balance' this. On the other hand, when there is too much solar PV generation, it can exceed customer load, and excess power flows back to the power station and can trip the generators. The older technologies currently in use cannot adapt quickly enough, and that is why Horizon Power has imposed 'generation management' in its jurisdiction[3]. Generation management requires that new systems meet specific technical requirements, including behind-the-meter batteries and inverters that can be controlled by Horizon Power. In some cases, e.g. Broome, the technical capacity of the existing grid has been reached and no more rooftop solar PV can be installed. This forms a compelling argument to modernise the electricity system in the Kimberley with renewables.

Modern energy management systems are available, and required to complement RE at high levels of generation. In particular, emerging battery storage technology and associated software will enable more responsive balancing, but costs are still relatively high compared to other options. This issue will be discussed in more detail later in the report, but it was raised here to foreshadow that there are technical reasons why renewables cannot be installed at will.

2.4.2 Geography

Figure 2.4.2 shows the area of the Kimberley covered by this report. It shows the major towns and communities with power generation managed by Horizon Power. There are a further 57 smaller communities (with populations of less than 200 and greater than 10), which are managed by the WA Department of Communities.

The West Kimberley region is no longer considered remote, as it is serviced by two ports and sealed highways

The Kimberley region has significant renewable energy resources which can offset some of the challenges in providing electricity distribution and fuel delivery in a tropical climate with periodic cyclone activity. Ultimately renewable energy provides a reliable, cheaper, and more environmentally-friendly energy solution

Image: Ben Little, Little Duo Photography

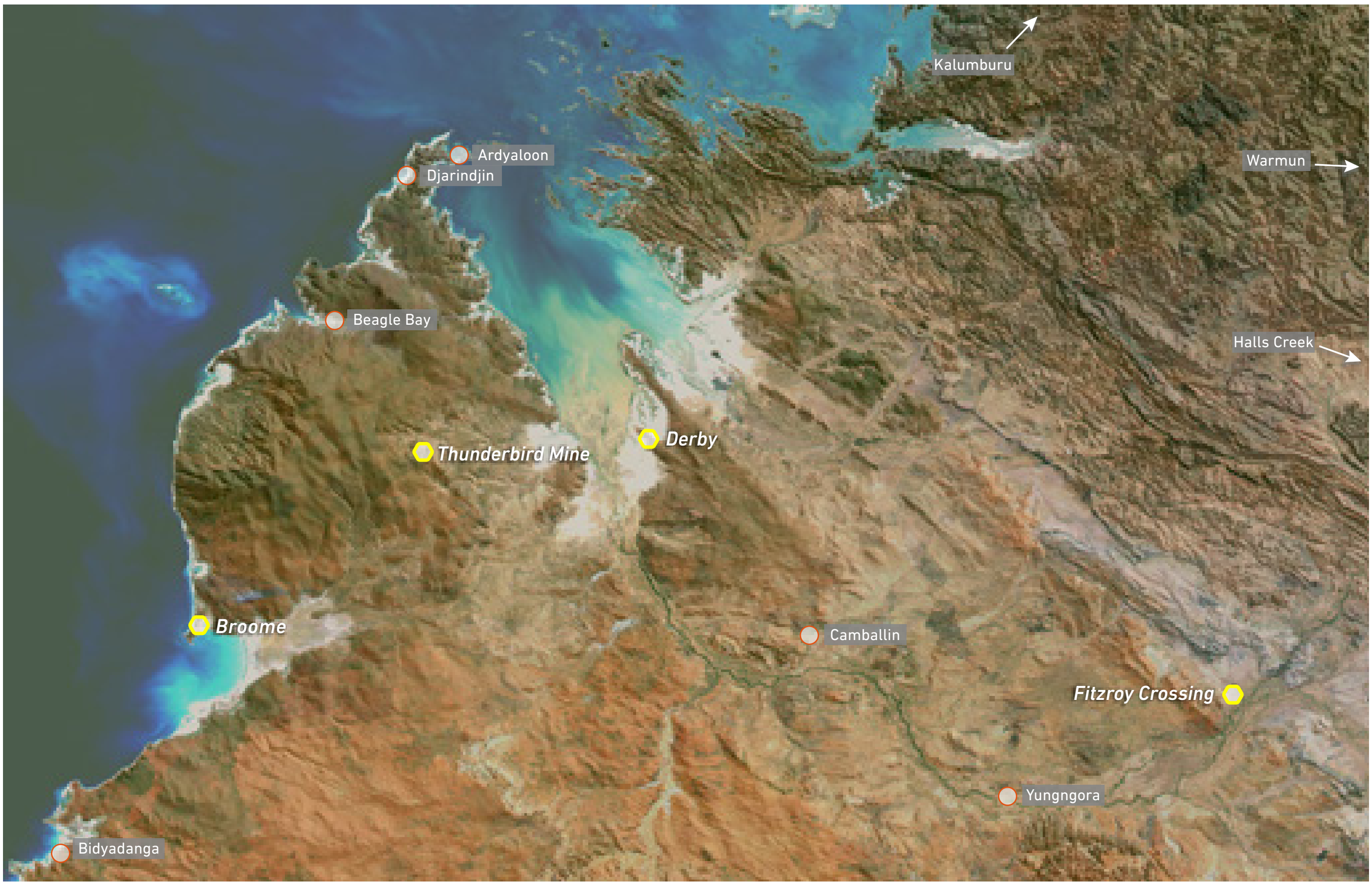


Figure 2.4.2 The area of the Kimberley considered in this Report.

connect the towns. Broome is a substantial regional centre with a population of 14,000 and an international airport. All services are available. There is an established light industrial area and rents are similar to the Perth metropolitan area. The port at Broome is closer to Asia and Europe than the Australian capital cities and is capable of handling large wind turbine components – tower sections and blades up to 70 m long, and nacelles weighing up to 70 tonnes. The major centres of Broome, Derby and Thunderbird Mine are within 240 km of each other by road.

The terrain throughout the West Kimberley is mainly extensive undulating plains with deep clay sand soils vegetated with acacia and spinifex. It presents no significant challenges for construction. The higher areas on which the projects would be constructed have minimal flood hazards.

2.4.3 Horizon Power Generation Assets

The power generation assets provided by Horizon Power in the West Kimberley are shown in *Table 2.4.3*. The major loads in the West Kimberley region are in Broome (~40 MW), Derby (~13 MW) and the proposed Thunderbird Mineral Sands Mine (16 MW, expanding to 32 MW). All other load locations are substantially smaller.

Horizon Power tends not to own or manage its assets directly, but enters into commercial-in-confidence Power Purchase Agreements (PPAs) with the entities which own, manage and maintain the generators. The length of these agreements is sometimes public.

Generators in the five larger towns (Broome, Camballin/ Looma, Derby, Fitzroy Crossing and Halls Creek) were owned and managed by the company DUET (formerly Energy Developments Pty Ltd (EDL)). They are fuelled by liquefied natural gas (LNG), which is trucked from Dampier in what the company calls a 'virtual pipeline' but which is actually a constant stream of road-trains transporting explosive material. These generators were installed in 2008, with PPAs expiring in 2027[4, 5].

New diesel generation capability was installed in 2007 in five smaller communities (Ardyaloon, Beagle Bay, Bidyadanga, Lombadina/ Djarindjin and Warmun). They are also owned and managed by DUET. The expiry date for the PPAs for these generators is not completely clear. A standard 20 year PPA would result in an expiry in 2026. However, a 2013 report from the WA Department of Planning[6] about Bidyadanga reported a Horizon Power forecast "***that the existing power station has sufficient capacity to meet the settlement's electricity generation needs up to 2023***", implying that the PPAs expire in 2023.

However, informal discussions with Horizon Power staff indicate that there is scope for re-negotiating aspects of PPAs.

While generation assets are operated by external bodies, Horizon Power purchases and provides the fuel for them. Horizon Power is therefore exposed to fossil fuel price fluctuations. Increased use of renewables would reduce this risk.

Some geographically adjacent locations are connected by a small distribution grid: e.g. Camballin-Looma; Derby-Mowanjum; Djarindin-Lombadina; Fitzroy Crossing-Bayulu.

During the last decade, Horizon Power took over power provision at Kalumburu and Yungngora (formerly Noonkenbah), and new generation capacity has recently been installed. The only Horizon Power RE generation asset in the West Kimberley is the 200 kW solar PV/ battery system installed at Yungnora in 2015. Horizon Power is currently considering solar PV for Kalumburu and Lombadina-Djarindin. Some locations have installed their own community-scale solar PV (Ardyaloon; Mowanjum).

Small amounts of rooftop solar PV exist in Broome and Derby, but this is constrained, as discussed in Section 2.5.4.

2.4.4 Smaller Communities

In addition to the eight communities with populations greater than 200 (serviced by Horizon Power), there are numerous smaller communities in the Kimberley. Data from the Department of Communities[7] indicates that there are 164 communities north of -18.789 degrees and west of 126.9 degrees. When town-based communities or reserves are excluded, and only communities with populations greater than 10 are considered, the number reduces to 57.

Station Name	Technology	Max. Capacity (MW)	Operator	PPA Expiry
Ardyaloon	Fossil Distillate Solar	0.8 0.075	EDL	2026*
Beagle Bay	Fossil Distillate	0.7	EDL	2026*
Bidyadanga	Fossil Distillate	1.3	EDL	2026*
Broome	Fossil Gas	39.6	EDL	2027
Camballin/ Looma	Fossil Gas	1.04	EDL	2027
Derby	Fossil Gas	12.53	EDL	2027
Fitzroy Crossing/ Bayulu	Fossil Gas	4.06	EDL	2027
Halls Creek	Fossil Gas	3.69	EDL	2027
Kalumburu	Remote control Diesel	1.2	Horizon	2036^
Lombadina/ Djarindjin	Fossil Distillate	0.7	EDL	2026*
Mowanjum	Solar	0.13 solar		
Warmun	Fossil Distillate	1.3	EDL	2026*
Yungngora	Remote control Diesel Solar	1.2 0.2	MPower	2035^

Table 2.4.3 Power generation assets provided by Horizon Power in the West Kimberley

* Generators installed in 2007. A 20 year PPA is assumed, but it may terminate earlier.

^ New generators installed in 2015/2016. Assume a 20 year PPA

Of these, 48 have a population of less than 50. Communities with populations over 50 are serviced under the Remote Essential and Municipal Services program, which is run by the Department of Communities. The characteristics of these 57 communities is provided in Appendix B.

There are nine communities with populations greater than or equal to 50 and less than 200. Two of these communities (Yakanarra and Joy Springs) have had tenders let to install a solar/ battery system.

Information to hand about the electricity generation situation in these smaller communities is patchy, and dated. Incomplete information was able to be sourced from only 14 communities, as shown in *Table 2.4.4*. In particular, no load data is available, so SIREN/ Powerbalance modelling cannot be performed directly.

Site name	Population	Nearest Town	Known Capacity
Bidan	12	Broome	48.1 kWh/day solar / diesel power station. 30kW diesel backup.
Imintji	45	Derby	215kW. 45 kW; 70 kW and 100 kW.
Jarlmadangah Burru	87	Derby	70kVA generator plus standby
Joy Springs	60	Fitzroy Crossing	Horizon Power's Fitzroy Crossing grid. Solar/ Battery upgrade underway
Kandiwal	25	Kununurra	New system may have been installed in 2010
Kupungarri	92	Derby	Three variable speed generators
Moongardie	26	Halls Creek	32.5kW. 22.5kW and 10kW diesel generators
Muludja	163	Fitzroy Crossing	100kW, 70kW and 40kW gensets
Ngalingkadji	42	Fitzroy Crossing	110kW. Two gensets 4kW; 70kW
Ngallagunda	75	Derby	Three diesel generators
Ngurtuwarta	40	Fitzroy Crossing	60kW. Two gensets
Pandanus Park	135	Derby	Three power generators of a capacity varying between 60 and 80 KW. Consumption peaks at around 60 KW with day time loads ranging from 30 to 60 KW
Yakanarra	134	Fitzroy Crossing	Solar/ battery upgrade underway
Yiyili	101	Halls Creek	370kW via 3 diesel generators

Table 2.4.4 Small communities for which some information about generation capacity was available.

2.4.5 Weather Issues

The Kimberley region is characterised by two seasons – the Wet season, from November to April; and the Dry season, from May to October. The heavy rains of the Wet season bring a significant risk of flooding with communities, in particular, likely to be isolated by road closures. Cyclones, while less likely than in the Pilbara, also pose a risk of destructive winds and flooding during the Wet season.

Road closures due to flooding threaten the delivery of fuel supplies to Kimberley communities, thereby threatening electricity supplies. Less reliance on fossil fuel supplies due to increasing RE provision is expected to contribute to improved electricity security during the Wet season. In particular, existing fuel storage facilities will last longer before requiring refills.

On the other hand, RE technologies, such as solar PV and wind turbines, are susceptible to cyclonic conditions, especially in coastal areas of the Kimberley. Consequent risks to electricity supply and security need to be accounted for, and installation costs are therefore higher.

Fixed solar PV installations need to be securely anchored to prevent damage during cyclones. In the past, this has led to very expensive concrete foundations being used to mitigate against cyclonic damage. Current best practice uses less expensive 'screw-pile' mountings.

Solar radiation is high in the Kimberley region as it lies in the hot tropics between 14 to 19 degrees south. Sunny days are generally constant during the long winter dry season, but there are cloudy periods during the four-month summer cyclone season.

More efficient solar mounting approaches, using single- or double-axis tracking, may be less appropriate in the Kimberley due to the risk of cyclonic damage. They are also less necessary in a region that is relatively close to the equator.

Ideally, wind turbines should be sited close to the coast, where winds are generally stronger, but this increases risk of cyclone damage, particularly on the coast south west of Broome. However, there are cyclone-rated wind turbines suitable for use in the Kimberley. All of the technologies proposed in this study can be constructed to withstand wind speeds of at least 160 kph, the maximum wind speed expected during cyclones. The strongest wind gust recorded at Broome since 1939 is 161 kph[8].

Cyclonic wind strength decreases with distance from the ocean. To minimize cyclone risk and construction cost, proposed wind farms have been located at least 10 km from the ocean and the proposed CST installation is 70 km from King Sound and 150 km from open ocean.

Kimberley locations can experience frequent lighting strikes for periods of up to 30 minutes during summer storms. However, all modern wind turbines have lightning earthing systems for protection.

The high tower and solar-tracking mirrors used in CST plants are susceptible to cyclone damage, but can be engineered to resist damage. Cyclone proofing has been costed into this modelling.

More details about weather issues are provided in Appendix C.

2.4.5.1 Weather Patterns

Image: Damian Kelly Photography

The MERRA weather data used by SIREN enables an analysis of the weather patterns for different regions, in particular, the amount of solar insolation and the wind strength. ***Figure 2.4.5*** summarises the average values of these over a year across the 24 hours of a day during both the Dry and Wet seasons for two towns at opposite ends of the Kimberley – Broome and Halls Creek.

The pattern of solar insolation is similar for both locations and similar across seasons – being slightly less during the cloudier Wet season.

Wind patterns across the day are fairly stable during the Wet season at both locations – in other words, there is, on average, an available wind resource throughout the day and throughout that season. Average wind patterns during the Dry season at both locations tend to be more variable. However, the strongest winds are at night, and the weakest winds are during the afternoon, when solar insolation is highest. During the Dry season, wind and solar therefore complement each other.

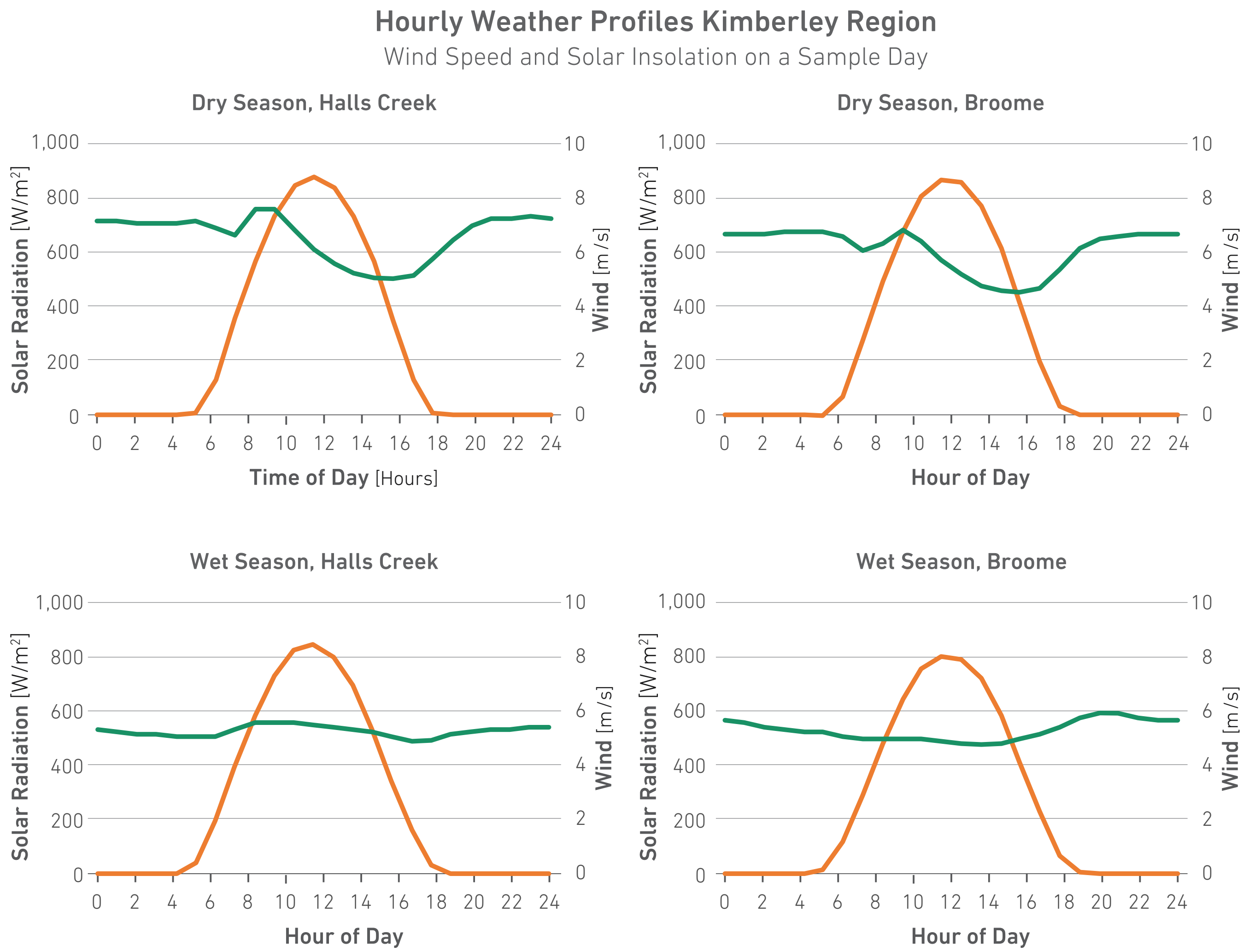


Figure 2.4.5 Wind and solar insolation patterns for Broome and Halls Creek during both the Wet and Dry seasons.

2.4.6 Environmental and Indigenous Issues

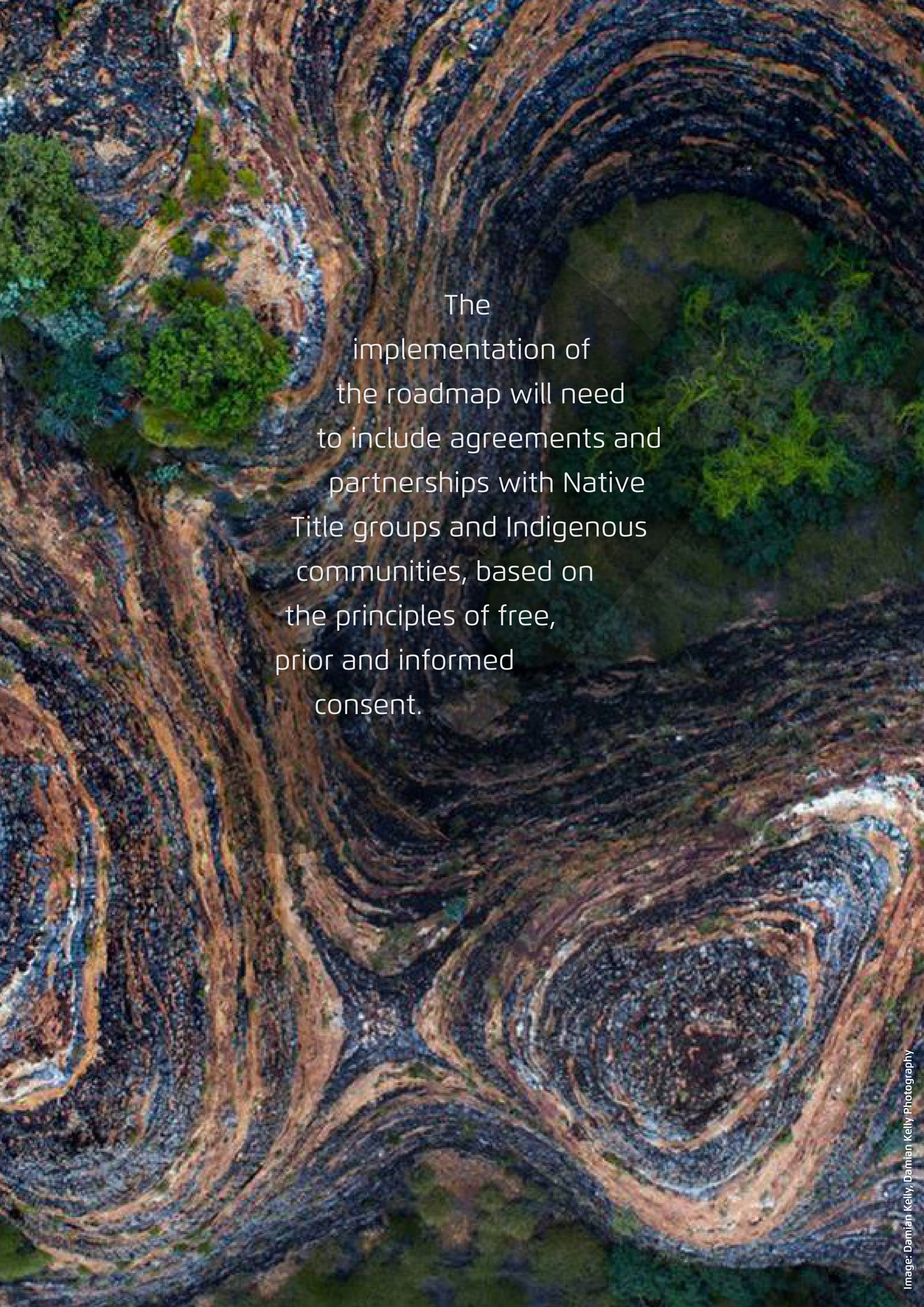
The grid scale of the SIREN data is approximately 55x55 kms. Currently, generation locations have been nominally chosen to optimise outputs, e.g. wind turbines on elevated ground; and minimised installation costs, e.g. not on sand-dune country.

Further consultation with relevant stakeholders on the most appropriate locations should include:

- Whether there are any Aboriginal or tourism issues that would rule out any of the suggested site locations, and, if so, where could they be relocated in order to avoid any possible land use conflicts
- Environmental issues, such as disruption of threatened species habitat and bird flyways

Relocation of generation facilities is unlikely to change the basic economics of any RE installation.

The implementation of the roadmap will need to include agreements and partnerships with Native Title groups and Indigenous communities, based on the principles of free, prior and informed consent. The involvement of other local stakeholders, and the State Government and Horizon Power, will also be crucial.



The implementation of the roadmap will need to include agreements and partnerships with Native Title groups and Indigenous communities, based on the principles of free, prior and informed consent.

Image: Damian Kelly, Damian Kelly Photography

2.4.7 The State and National Context

The traditional, centralised approach to electricity provision is being disrupted by:

- The emergence of cost-competitive RE technologies, intelligent digital systems and battery storage
- The need to reduce human carbon emissions and other environmental impacts from energy demand
- Consumer expectations that the provision of electricity can be democratised.

While some governments and some incumbent fossil fuel electricity generation and fossil fuel companies are resisting this disruption, a transformation of the electricity network has already begun around the world. These trends apply equally in Australia generally, and in WA.

Significant work has been done in recent years to prepare the nation for a RE future. This includes:

- Beyond Zero Emissions Stationary Energy Plan[9] (2010)
- Sustainable Energy Now (SEN) Clean Energy WA[10] study (2016)
- The CSIRO & Energy Networks Australia's Electricity Network Transformation Roadmap[11] (2017)
- The Climate Council's Clean & Reliable Power: Roadmap to a Renewable Future[12] report (2018)
- The Australian Conservation Foundation's Repower Australia Plan[13] (2018)
- ANU Energy Change Institute "Australia's Renewable Energy industry is delivering rapid and deep emissions cuts"[14] (2018)

In WA, the State Government is slowly engaging with transformation of the electricity market. The Public Utilities Office, although under resourced, is conducting modelling of the electricity sector. The Economics and Industry Standing Committee of the Legislative Assembly in WA is conducting an Inquiry into Microgrids and Associated Technologies[15] in 2018. Because microgrids are an intrinsic part of electricity supply in the Kimberley, this Inquiry was timely although it is unlikely to report back before March 2019.

2.4.7.1 Unconventional Gas Supply

At the same time that work is being done on new ways of supplying electricity, some in industry and politics are attempting to retain the status quo, putting forward a narrative that natural gas is essential for electricity supply and economic development, and that new gas supplies need to be opened up. This is relevant to this study, because there are significant potential unconventional gas deposits in the Canning Basin in the West Kimberley.

Proposals are in place to extract unconventional (fracked) gas (FNG) and use it to fuel electricity generators in the Kimberley potentially via pipeline, by liquefying or by compressing it. One of the objectives for this study is to present alternatives to continuing with fuelled generation through FNG.

This study has demonstrated on a purely economic basis, that using fracked gas as a fuel is less attractive than using renewable sources.

Further, the future availability of FNG is questionable. There is currently a moratorium on fracking in WA, and this may turn into an ongoing ban, subject to the outcomes of the State Government's current Independent Scientific Panel Inquiry into Hydraulic Fracture Stimulation[16] in Western Australia.

SEN's submission[17] to that Inquiry demonstrated that:

- There is a global gas glut, and demand is predicted to fall globally. Demand is already falling in Australia.
- Fugitive methane emissions can make this fuel source potentially as greenhouse-gas polluting as coal (see also Appendix D)
- Even if fracking is permitted, regulations required to monitor and mitigate risks of fracking (fugitive emissions, water pollution, etc.) would make an extraction proposal uneconomic

The latter proposition was reiterated in the final report of the Northern Territory inquiry into Hydraulic Fracturing[18], which recommended that life cycle greenhouse gas emissions must be reduced, and must be "offset to ensure that there is no net increase in life cycle greenhouse gas emissions in Australia from any onshore shale gas".

In 2018, Climate Analytics[19] also cast doubt on the future viability of new investments in unconventional gas, stating that they "would likely become stranded assets, as they face a global gas market that is softening or even declining". They also claimed that the emissions from the Canning Basin resources would be equal to double Australia's national carbon budget.

Hundreds or even thousands of pads (each of about 20 hectares) with well equipment, waste water dams, water bores and long access roads would need to be cleared in the development of the Kimberley 'tight gas' fields. These would likely incur a land footprint of 10,000 hectares for 500 wells (potentially 100,000 hectares if 5,000 wells), plus the added drainage and wildlife impacts of over a thousand kilometres of new access roads.

For all of these reasons, the provision of FNG from the Canning Basin is problematic.

A further factor is that public opposition to the fracking process has meant that companies engaging in fracking have lost their social license[20].

On the other hand, the uptake of RE does have a strong social license. Numerous surveys over numerous years have indicated strong public support for RE. A recent example[21] found that "More than 70% of Australians want the government to set a high renewable energy target".

2.4.7.2 The Role of Horizon Power

While WA's power utility bodies in the south-west (Synergy and Western Power) talk in general terms about how they are approaching the renewables transformation, it is the third power utility, Horizon Power, which appears to be positioning itself to be at the head of the curve in terms of a transition to RE.

In doing this, it has drawn heavily on the 2017 ENA/CSIRO report[11], and on best practice from Hawaii and California, emphasising the "need to integrate microgrids and [renewables] as a key component of the future energy system".

In its 2018 submission[22] to the WA State Government's Inquiry into Microgrids and Associated Technologies[15] in WA, it covered many of the issues needing to be addressed in order for renewables to be adopted in regional WA.

These include:

- Developing what Horizon Power calls 'distributed energy resources management systems' (DERMS), designed to manage and optimise the technical operations of thousands of grid-connected renewable systems, "***to dynamically manage supply and demand, maintain system stability and optimise long-term economic efficiency***".
- Developing its own advanced microgrid roadmap (System Blueprints Model), forecasting the LCOE over time for different 'business futures', for each of its 38 systems
- Developing a new utility asset class of 'micro power systems' (off-grid, utility-scale power systems) that provides remote customers with a full electric utility service capable of being 'fleet-managed' by utilities.

As mentioned in Section 2.4.1, modern energy management systems are essential for wide roll-out of RE in regional locations. Horizon Power argues, justifiably, that DERMS can ***"ensure power reliability with high amounts of renewables, lower costs, and create new value streams for other local utilities, their customers, service providers, developers and site owners"***.

It is encouraging that Horizon Power is working progressively in this area, and lobbying for legislative and regulatory reform to facilitate this. They claim that renewables will play ***"a significant role in reducing costs, but this must be balanced with pricing reform … and a new regulatory framework"***.

They argue that a legislative and regulatory framework built for old, centralised models needs to adapt for a renewable future, citing the need for ***"a future-focused compass"***.

Other comments indicate that it is not as progressive as it might be, predicting that:

> ***"a timely transition, at the expiry of the different power purchase agreements, will result in an increase in levels of renewables (77 per cent of combined [renewables] and off-grid by 2050) and decrease in cost to supply, resulting in a 46 per cent reduction in carbon emissions and a $150M reduction in net State debt."***[22]

In SEN's view, a target date of 2050 is far later than could be easily and reasonably achieved with the appropriate political and managerial will and direction.

However, Horizon Power has done a lot of the ground work for a RE transition in the Kimberley.

> ***"For each of its 38 systems, Horizon Power now has a System Blueprint designed to guide new investment decisions like contract renewal, asset management, and network expenditure."***[22, p. 68]

While Horizon Power has developed what seem to be extensive plans for rolling out renewables, its ability to implement these plans appear to be constrained in some ways:

- Constraints on installing its own assets, by being forced to 'go out to market'
- Need to tender for each individual generation asset, and accept the lowest price – removing ability to benefit from economies of scale and implement common standards across sites
- Need for coherent regulation encompassing all owners of microgrids – generators, distributors, and retailers
- Need to address the inconsistencies in information that exist between Horizon Power and the State Government

- Need for updating generation rules to reflect current and emerging market requirements and become more flexible
- Tariff structures and restrictions on how they can be adapted to support current and emerging market requirements

Further, there are few design standards for the 91 smaller communities across remote WA that are managed by the Department of Communities. ***"These systems are highly subsidised and characterised by ad hoc infrastructure and capital works planning and unregulated electrical safety and reliability standards"*** [22]. Application of DERMS standards to these communities would enable a managed transition to renewables, as well as reducing costs.

Engaging with Horizon Power about the Kimberley Clean Energy Roadmap will be an important factor in developing and implementing rollout of RE across the Kimberley. Similarly, advocacy with Government and other stakeholders should promote the adoption and implementation of Horizon Power's DERMS blueprint.

In order to bring about energy reform in the Kimberley, some political vision is required. Some legislative and regulatory barriers need to be resolved, and Horizon Power should be encouraged to pursue its reform agenda more rigorously. For example, a relaxing of rules to allow generation assets to be purchased as part of a package could reduce costs through economies of scale.

2.4.8 RE Supply Chain Capability in the Kimberley

Horizon Power's Microgrid Inquiry submission[22] identified a significant barrier to widespread roll-out of small scale renewables across the Kimberley. That is, the absence of a commercial vendor (or utility) that can provide "***a full utility-grade offering that is ready to deploy at scale***". Horizon Power believes that the supply chain is just evolving from a cottage industry, and "***scale efficiencies and cost reductions – without compromise to safety and system longevity***" are not yet available.

Tendering for the approximately 200 MW of large-scale RE projects identified in this study for the Broome-Derby region as one project could be done in such a way as to establish a RE installation and manufacturing industry in those towns. This would also be used for the small-scale community installations.

The absence of a mature RE construction industry in the Kimberley has led to very high quotes for RE generation projects. For example, a tender for a solar PV installation on a remote community in 2016 quoted a cost in the order of $4.5m/MW. A company based elsewhere in Australia is likely to charge a premium for a once-off, small scale installation in a remote location. However, if there was a guaranteed pipeline of work over a number of years, economies of scale would bring prices down.

Horizon Power claims[23] that the cost needs to come down to $2.5 m/MW to be competitive with fuelled generators. The modelling in this Report identifies that lower prices than this are achievable, and the research shows that a price of $2.5 m/MW for PV is already available for Kimberley communities.

However, a 'chicken and egg' situation applies here. If there was a pipeline of work, industry would set up to meet the demand. However, since there is no industry, there is no pipeline of work. This is why Government action is required to adopt a Kimberley Clean Energy Roadmap, and provide greater flexibility for Horizon Power to effectively roll-out renewables across the Kimberley.

Some relevant capability exists already in the Kimberley. The Kimberley Remote Service Providers provide a casual and sub-contract workforce to perform maintenance, upgrade and installation of utilities in Kimberley communities.

Energy Made Clean Kimberley and Generators and Off Grid Solutions are established in Broome, and provide RE installation services.

2.5 Renewable Technologies

This Report only considers mature RE technologies which are available at a commercial scale. Most renewable technologies are, by their very nature, variable, and other complementary technologies are needed to balance this with demand. The mature technologies which are considered are summarised below.

2.5.1 Onshore wind

Wind turbines are a mature RE technology, with many thousands installed around the world. Unlike solar panels, which rely on daylight, they can function around the clock, whenever the wind blows. There is a suitable wind resource in the Kimberley, and many turbine models now come with storm ratings of 160 kph, and some extreme wind models are coming onto the market. For example, the high-wind V117-4.0/4.2MW takes the Vestas platform into typhoon territory for the first time and is designed to withstand wind gusts of up to 80 m/s (288 km/hr). Extreme weather risks are part of the normal risk assessment and insurance processes associated with financial approval of a project.

The wind turbines modelled are rated for winds up to 160kph. These are:

- Vestas 2 MW for the major locations
- Vestas 0.5 MW for the smaller towns
- Vestas 0.225 MW for the remote communities.

The proposed wind farm locations are on extensive undulating plains. The 'pindan' clay sand soil profiles 4- 8 m in depth over sandstone should present no significant technical impediments to installation of the turbine towers.

Wind farms occupy a land area of 26 sq. km per 100 MW, but turbine pads and access roads are a small portion of this, and the rest is not cleared or disturbed. Wind turbine costs are still falling slowly, but are becoming stable as the technology matures.

Wind generation will be an important factor in high penetration of RE in smaller communities. Wind turbines rated at 10 or 20kW exist, but further research is required to establish their durability in high-wind situations.

2.5.2 Offshore wind

Wind farms can also be sited offshore. This typically occurs in heavily populated countries, e.g. Europe, where there is a shortage of available land. Large offshore wind turbines can be economical in large installations, but the scale of Kimberley needs does not warrant this. The relatively low wind resource available in the Kimberley also mitigates against offshore wind. There is also plenty of space on-shore, so offshore wind farms have not been considered in this report.

2.5.3 Utility-scale solar PV

Utility-scale solar farms have been installed all over the world. They consist of arrays of solar PV modules pointed at the sun. The simplest technology – fixed PV, which was modelled in this study – has all panels fixed at the average best angle to the sun. More complex technologies enable the panels to rotate on a single axis to maximise solar insolation. Double-axis tracking is more energy-efficient, but more complex and expensive, with increased risks of mechanical failure. The relative proximity to the equator and cyclone risks indicate that fixed solar panels are most appropriate.

The effectiveness of solar PV can be increased by angling half of the panels to the east and half to the west, thus broadening the generation curve into the early morning and evening while making it less 'peaky' at midday.

The land footprint of ground mounted fixed PV is 5.2 hectares per MW. The number of panels were calculated assuming a standard panel size of 250 W.

The efficiency of output and production of solar PV panels has been increasing rapidly over the last decade (with consequent price reductions), and this is likely to continue.

Utility-scale solar PV installations in the Kimberley have been costed at $4.5 m/MW, a price that is not competitive. Premiums for once-off projects and over engineering of foundations seem to have led to this high price.

Installers have stated that GPS guided, machine-driven screw piles have superseded concreted supports for the racking systems and this has been a major factor in reducing installed cost by over 50% in the last decade. There is a need for engineering research to lower deployment cost, but still provide fit-for-purpose renewable installations.

SIREN models the capacity factors of both fixed rooftop and ground mounted PV systems in the Kimberley at about 24%.

The installed cost of utility PV is still falling rapidly with single axis tracking technology projected to fall below $1.5 m/MWh by 2021 and $1.2 m by 2027[24], with fixed PV being even lower in cost.

2.5.4 Rooftop Solar

Rooftop solar PV uses the same technology as utility-scale solar, but it is installed in smaller quantities on residential and commercial premises.

In regional locations managed by Horizon Power, consumers are restricted in the amount of rooftop solar PV they are able to install, because too much rooftop PV can affect system stability without 'balancing' technology being in place (see Section 2.4.1). It is likely that future expansion of rooftop PV would need to be accompanied by behind-the-meter batteries, as is being trialled in LandCorp's Waranyjarri Estate[25] in Broome North.

Rooftop PV is a 'democratic' technology, in that individual consumers invest in their own system and have control of their own generation and consumption. However, due to difficulties in grid integration and control, the amount that can be installed is limited.

2.5.5 Concentrating Solar Thermal (CST)

CST generators use the heat of the sun to store heat in the form of high temperature molten salt. A circular array of mirrors is controlled to follow the sun, so that all reflected light is focussed on the top of a collector tower, where the collector heat exchanger adds heat energy to the molten salt. The molten salt is used to create steam to run a conventional steam turbine generator. See ***Figure 2.5.5*** for an example.

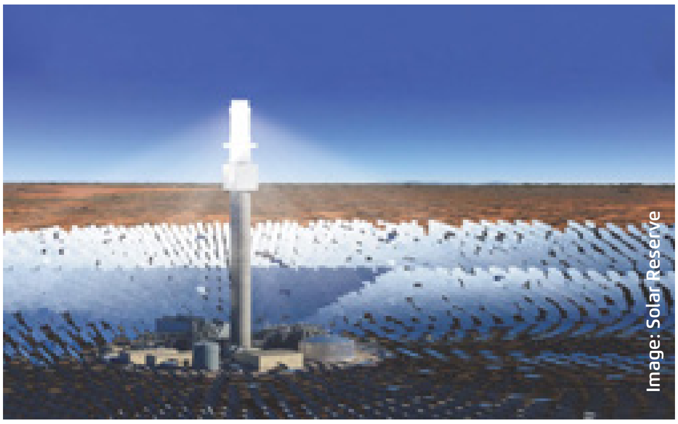


Figure 2.5.5. Concentrating Solar Thermal (CST) plant.

The advantage of molten salt storage is that it enables all of the thermal energy to be stored to enable overnight generation. Large scale molten salt storage is relatively inexpensive – about $20/MWh compared to more than $200/MWh for batteries – and this is the main reason for the cost competitiveness of CST. Its major disadvantage is that thermal energy generation (but not electricity generation) falls to zero when there is cloud cover, as the technology relies on direct sunlight to focus the radiation on the receiver. In the Kimberley which has very high sunlight hours, this only reduces generation for about 50 days, mainly during the Wet season.

The benefit of this technology is that the heat from solar radiation is retained in the molten salt, enabling power to be generated at its rated output for 10 hours without sunlight, or longer at lower power outputs. There are numerous installations around the world, for example a >100 MW power station that has been operating for three years in Nevada and another in Spain. One is currently under construction in South Australia.

Heliostats (mirrors) installed in CST plants are rated for wind speeds up to 100 m/h (160kph), and current recommendations are to locate plants 150km from the coast line, as cyclonic wind speeds reduce once they cross the coast. A detailed engineering review of any proposed site will be required to determine whether heliostats will survive for their design life given expected wind speeds. The proposed site for the CST-MS installation modelled in this study – near Curtin Airport south of Derby - is >70 km from the coast and has maximum recorded wind gust of only 98 kph.

CST has a footprint of about 9.5 sq. km per 100 MW. The 40 MW CST plant modelled in this study would occupy less than 4 sq. km (400 ha).

Significant CST-MS installed cost reductions are forecast, falling from $4.3m in 2018 to $3.3m/MWh in 2021-22 and, for this reason, an additional low-cost scenario has been modelled

2.5.6 Internal Combustion Generators

Electricity generators, powered by 1.5 – 2 MW LNG fuelled IC engines, currently provide over 95% of generation in the Kimberley towns and communities. The LNG is imported by road train from Karratha. In smaller communities (and as backup in larger centres), the IC generators (gensets) are powered by diesel transported from Broome in smaller articulated and rigid tanker trucks. This heavy vehicle traffic has a significant impact on the regional and local roads, which would be reduced in proportion to the percentage of RE installed.

While existing generation comes almost exclusively from IC engines, in any renewable scenario, some fuelled capacity will be required to provide backup when weather conditions are unfavourable. Because they will be used less frequently in a renewable scenario, the overall lifetime of generators will be extended and fuel costs will be lower.

2.5.7 Batteries

Battery systems are essential components of all utility PV and wind installations as they can respond instantly to sudden changes in load, such as those caused by sudden cloud shading. Battery storage sufficient to supply maximum PV generation for at least 15 minutes has been included in all scenarios, to allow fuelled backup generators to 'ramp up'.

Battery technologies have been developing and improving over the last decade.

The most common new battery types are based on various Lithium chemistries. Prices of these batteries are starting to fall to the point where they are economical at the personal and utility level, particularly in remote locations such as the Kimberley.

The largest, and most discussed, utility-scale battery in Australia is the 129 MWh Tesla battery installed in South Australia to smooth out grid instability issues. The capital cost of this battery system has been reported to be AU$698,000/MWh[27]. A more conservative cost of $717,000/MWh for large scale Li-ion battery systems has been used in this report, with a life of 15 years.

Small Li-ion batteries (sub-2 kW) have been modelled for the communities, and a higher capital cost of $1m/MWh has been assumed, due to reduced economies of scale.

This Report takes a conservative view in terms of battery prices – it is possible that, over time, prices may decrease more than predicted. This will improve the economics of renewable options.

Previous SEN work on the SWIS showed that it is not economical to meet all RE shortfalls with battery storage alone. Other types of backup are also needed, typically through fossil-fuelled generation.

Even if the costs of battery cells continue to fall, switching and inverter costs are a significant component of overall battery system costs. These are relatively mature technologies, so prices of these components are more stable.

An alternative battery technology, that is maturing and potentially suitable for the Kimberley, is the Vanadium Flow battery. This battery chemistry takes up more physical space, but has a rated longer lifetime (20 years compared to 10 years for lithium batteries). A further benefit is that vanadium batteries can also be fully discharged and recharged multiple times without damaging them[28]. Their disadvantage is unsuitability for constant high power delivery.

2.5.8 Open Cycle Gas Turbines (OCGTs)

Aero-derivative OCGTs were also modelled for the grid scenarios, as all fuelled generation can be located at a single larger scale power station. This type of generation may be practical in this situation.

OCGTs use the Brayton thermal cycle without energy recovery by way of exhaust gas heat utilisation. The turbine is either of 'heavy' (industrial) design (efficiency of 28-32% thermal efficiency) or aircraft derivative (~33-37% thermal efficiency at full power). The aero-derivative options are basically jet engines connected to a generator.

OCGT units are suitable for fast start/fast ramping (10 MW/minute) and offer the best response to peak load demands in the power network. These turbines can be fuelled from liquid or gas fuels. Their lower efficiency means they are not suited to baseload operation.

They require relatively low capital expenditure, but are expensive to run because of the relatively low efficiency and high cost of fuel.

2.5.9 Other Technologies not considered

The following RE technologies are not considered, because they are either not appropriate for the Kimberley, or not yet at a commercial scale.

2.5.9.1 Pumped Hydroelectricity

Pumped hydroelectricity is where RE is used to pump water from a low reservoir to a high reservoir, for subsequent release when needed, through a hydroelectric generator/ pump. This storage technology enables a large amount of energy to be stored to be converted into electricity relatively quickly.

A recent ANU report[29] identified potential pumped-hydro sites in Australia, including the Kimberley. None of the potential sites are near enough to the high load centres in the Broome-Derby region to be feasible.

2.5.9.2 Wave

Wave generation has not been considered because available wave energy is low in the tropics, and technologies are not yet commercially available.

2.5.9.3 Tidal

A small number of tidal barrage generators have been installed across the world. While the Kimberley has very large tidal flows, tidal barrage approaches are environmentally contentious. A tidal barrage proposal for the Derby region was rejected by the Environmental Protection Authority because of the risk to mangrove ecosystems. Other tidal technologies are being trialled but are only just becoming commercially available, for example Orbital Marine Power's 2 MW tidal turbine[30], commissioned in 2016.

2.5.9.4 Geothermal

The use of near-surface hot areas of the Earth's crust provides an opportunity to generate geothermal energy, through injecting water underground and using the generated steam to power turbines. There are significant hot spots in the West Kimberley region, but the technique is not yet approaching commercial reality.

2.5.9.5 Hydrogen Fuel

A potential zero-emissions fuel is Hydrogen gas, generated by splitting water molecules with RE. This can then be used as a renewable fuel to power backup generators, or to power electric vehicles through fuel cells. However, hydrogen is extremely explosive and hard to compress, and the technology is still emerging. For example, the CSIRO recently announced a process whereby hydrogen could be stored as ammonia - easier to compress and non-explosive – although toxic to breathe.

Hydrogen was not explicitly considered in this report, because our modelling is only about mature, proven technologies. There are too many unknowns with emerging technologies.

2.5.9.6 Virtual Power Plants

In extensive grids, such as the SWIS, it is feasible for individual householders with appropriate battery and solar technology to trade electricity among themselves – peer-to-peer trading. This approach is less applicable in smaller grids, such as in Broome or Derby.

Virtual Power Plants are a more practical approach, where a utility manages the flow of power to and from households to balance supply. Horizon Power is developing its own Virtual Power Plant approaches, for example, in LandCorp's Waranyjarri Estate[25] in Broome North, and managing them through their DERMS standard.

2.6 Approaches to Subsidising Renewables and Reducing Carbon Emissions

The Australian Renewable Energy Target (RET) has two mechanisms for subsidising uptake of RE.

2.6.1 Large-scale Generation Certificates (LGCs)

LGCs are created annually, based on the actual amount of power generated by an accredited and registered RE power station. An LGC represents one MWh of net RE generated and exported to the electricity grid by a solar, wind or other RE system of more than 100 kW capacity, or more than 250 MWh generated.

LGCs can be claimed annually at the market price. The market price is likely to reduce over time. This scheme is set to expire in 2030.

Technical details are provided in Appendix E.

2.6.2 Small-scale Renewable Energy Certificate (STCs)

Small-scale RET certificates (STCs) are for residential and smaller commercial systems. For solar PV systems, the capacity must be less than 100kW, while for wind systems, a smaller 10kW capacity is specified. Certificates are created at the time of commissioning, calculated over an assumed 15 years of electricity production.

STCs are like a RE currency, and the value fluctuates with supply and demand. Under the current RET scheme, STCs can be claimed immediately on installation of small residential and commercial projects. The scale of systems eligible for STCs is so small that only the smallest remote communities may be eligible.

2.6.3 Carbon Pricing Mechanisms

Attempts to put a price on pollution caused by burning fossil fuels have been a source of much political dissent in Australia over the last decade. Although the RET is still in operation, the carbon trading scheme introduced by the Federal Labor Government was abolished by the Coalition Government in 2014, so there is currently no carbon pricing mechanism in Australia. For this reason, modelling for this study was based on unsubsidised RE prices. Nevertheless, the RE systems were still found to be substantially more cost effective than the exiting LPG and diesel fuelled systems.

However, carbon pricing mechanisms send a powerful signal to the market that fossil fuels should be phased out to meet Australia's 'Paris carbon emissions target'. This might be government-imposed, or it might come from industry itself.

A price on carbon is increasingly being built into financial investment decisions by corporations, independent of government requirements. This may be in terms of an explicit cost of carbon, or through abatement programs that imply a cost of emitted carbon. Globally, a study[31] undertaken in 2016 found 1,249 companies disclosed their practice of pricing carbon emissions, or their plans to soon do so.

A possible future change in the Federal Government may result in the reintroduction of a price on carbon.

In either case, whether explicitly or implicitly, a price on carbon needs to be considered in this report. In the discussion which follows, a price of $20 /tonne has been assumed. This makes the use of fossil-fuelled generation even less attractive.

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Image: Prue Little, Little Duo Photography

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Section 3

Modelling Approach

Modelling was conducted the using the open source SIREN – Powerbalance software described in Section 2.2. Hourly generation data was obtained from Horizon Power for the Kimberley region. SIREN modelling was conducted for four towns, two industrial sites and two typical communities.

The generation and load data generated by SIREN was transferred into the Powerbalance spreadsheets. This was combined with the cost assumptions described in Section 3.3, and modelling was conducted to optimise RE output according to various criteria.

This Report is built upon three sets of modelling:

- The region between Broome and Derby, as the largest source of electricity demand
- Two smaller towns – Fitzroy Crossing and Halls Creek
- Two indigenous communities – Beagle Bay (medium-sized community) and Kalumburu (remote community). Results were extrapolated for six other medium-sized communities, and to the 57 smaller communities with populations of less than 200.

Combinations of the following RE technologies have been included in our RE modelling (see Section 4):

- Onshore wind farms (W)
- Utility scale solar photovoltaics (PV)
- Concentrating solar thermal (CST)
- Grid connected battery (B)
- Rooftop solar photovoltaics (rooftop PV)
- Fuelled generation as backup for RE.

Existing fuelled generation was modelled for the business-as-usual case, with three options: LNG; fracked natural gas (FNG delivered by pipeline); and diesel (D).

This Section describes the scenarios which were explored for these locations. Results are provided in Section 4.

3.1 Broome-Derby Region

The major loads in the Kimberley region are in Broome (~40 MW), Derby (~13 MW) and the proposed Thunderbird Mineral Sands Mine (16 MW possibly expanding to 32 MW). Only the 16 MW scenario has been modelled in this study – 32 MW would entail doubling the installed technology capacities.

The Thunderbird Mine is located approximately 100 kms from both Broome and Derby. Thunderbird is unlike the population centres, in that the load will be fairly constant over the 24 hours in each day.

Sand mines have large electric motors and operate 24 hours a day, which will means that fuelled generation and/ or energy storage will be needed for overnight operation. Some decline in excavation and haulage would be expected in boggy conditions during the Wet season, and this may or may not affect the electricity loads from the large pumps that operate the slurry lines, dredges and separation plant. However, without actual load data or even a mine design, it is not possible to estimate daily and seasonal load variations. For this reason the Thunderbird Mine has been modelled with a constant load throughout the year.

The modelling has taken two directions:

- Model and cost a new West Kimberley grid, including Broome, Derby, Thunderbird mine, using onshore wind, solar PV and/ or CST
- Model and cost individual RE micro-grids at Broome, Derby and the Thunderbird mine.

The grid scenarios have been costed with above-ground 132 kV High Voltage Alternating Current (HVAC) transmission lines built to cyclone category 2 rating[1]. The stand-alone scenarios for the major load centres all have 10 km of 33 kV below-ground transmission lines. The communities are assumed to have short, lower-voltage, above-ground transmission lines.

All scenarios have rooftop PV installation limited to a maximum 20% of Broome and Derby demand, as any more may incur stability and cloud occlusion problems, as discussed in Section 2.4.1.

Figure 3.1.1 Major locations, the potential Broome-Derby grid

Scenario	Characteristics
CST	• Concentrating Solar Thermal (central receiver) with 14 hours molten salt storage co-located with fixed PV south-east of Derby • Utility fixed PV near Thunderbird and Broome • Minor amount of rooftop PV at Broome and Derby • Grid battery and LNG fuelled generation as backup
WPVB*	• Wind near Broome and at Curtin • Utility fixed PV near Thunderbird, Curtin and Broome • Minor amount of rooftop PV at Broome and Derby • Grid battery and LNG fuelled generation as backup
PVB^	• Utility fixed PV at Curtin, Thunderbird and Broome • Minor amount of rooftop PV at Broome and Derby • Grid battery and LNG fuelled generation as backup
LNG	• Internal combustion engines fuelled with LNG with existing small amount of rooftop PV.
LNFG	• Internal combustion engines fuelled with piped FNG with existing small amount of rooftop PV.

Table 3.1.1 Grid scenarios: Broome – Derby Region.
* combined wind, solar PV and battery system
^ combined solar PV and battery system

3.1.1 Grid Options

Thunderbird is unlike population centres, in that the load will be fairly constant over the 24 hours in each day. Grid connected CST with molten salt storage may be more appropriate for the mine, due to the high night time loads which would be better serviced by high-capacity, low-cost molten salt storage.

Figure 3.1.1 shows the two towns and the mine, linked by a potential single 132 kV above-ground transmission line. Four generation precincts are shown at Broome, Derby and Thunderbird, with a CST installation south-east of Curtin Airbase, 180kms from the coast, which has low risk of extreme weather.

Suitable sites for wind and solar PV have been located ~10 km from each load centre, but many more siting options are feasible.

Five grid scenarios were considered, as shown in *Table 3.1.1*.

3.1.2 Stand-alone Scenarios

In the absence of a transmission grid, three or four scenarios at each of the major load centres were modelled, for a total of eleven scenarios, as summarised in *Table 3.1.2*.

The CST option is not suitable for stand-alone applications due to its inability to be scaled down sufficiently and its unsuitability for areas closer to the coast with higher cyclone risk.

In both Broome and Derby, four stand-alone scenarios are modelled, with RE power stations connecting to the load centres by 10km underground 22 or 33 kV distribution lines. Two RE scenarios are explored, both with the existing, small amount of rooftop PV and fuelled backup. The third scenario is the 'business as usual' case, and the fourth explores fuelling existing generators with FNG piped from the Canning Basin.

Only three stand-alone scenarios have been modelled for the Thunderbird mine, as shown in *Table 3.1.2*. A solar PV scenario would not be suitable for the Thunderbird mine, with its nearly constant load throughout the day and night.

Scenario	Characteristics
WPVB*	• Wind • Fixed utility PV • Existing rooftop PV • Utility battery and LNG fuelled generation as backup
PVB^	• Fixed utility PV • Existing rooftop PV • Utility battery and LNG fuelled generation as backup
LNG	• Internal Combustion engines fuelled with Liquefied Natural Gas • Existing small amount of rooftop PV
LNFG	• Internal Combustion engines fuelled with piped Fracked Natural Gas • Existing small amount of rooftop PV

Table 3.1.2 Stand-alone scenarios in the Broome – Derby region.

* combined wind, solar PV and battery system
^ combined solar PV and battery system

3.2 Small Towns

Initial modelling was performed for Fitzroy Crossing, as a representative example of a small town (population >1,000). Halls Creek has a similar load and population profile to Fitzroy Crossing.

Three scenarios were explored for Fitzroy Crossing, as for Broome and Derby, but excluding the FNG pipeline option, as shown in *Table 3.2*.

Halls Creek was modelled by scaling the Fitzroy Crossing data according to existing fuelled capacity. Similarly, Thunderbird Mine data was scaled for the Kimberley Meat Company Abattoir near Willare Bridge.

Scenario	Characteristics
WPVB	• Wind • Fixed utility PV • Utility battery and LNG fuelled generation as backup
PVB	• Fixed utility PV • Utility battery and LNG fuelled generation as backup
LNG	• Internal Combustion engines fuelled with Liquefied Natural Gas

Table 3.2 Stand-alone scenarios: Small towns

3.3 Communities

Initial modelling was performed for Beagle Bay, as a representative example of a medium community (population between 200 & 1000). Beagle Bay has a similar load and population profile to the other seven medium communities: Ardyaloon, Bidyadanga, Camballin/ Looma, Lombadina/ Djarindjin, Kalumburu, Warmun and Yungngora.

Table 3.3 summarises the three scenarios for this location. Once again, there is a wind-dominant scenario and a PV-dominant scenario. Both are supported by small amounts of battery storage, with diesel generation as a backup.

After initial modelling identified the most appropriate RE option, further modelling was performed on Kalumburu, as a remote scenario. Findings for Beagle Bay were extrapolated to the other medium communities.

Scenario	Characteristics
WPVB	• Wind • Fixed utility PV • Smaller battery and diesel fuelled generation as backup
PVB	• Fixed utility PV • Smaller battery and diesel fuelled generation as backup
D	• Diesel-fuelled generating plant

Table 3.3 Stand-alone scenarios: Medium Communities.

3.3.1 Small Communities

Modelling was not specifically performed for small communities. Instead, modelling results from Beagle Bay and Kalumburu were scaled down for the 48 communities with populations between 10 and 200.

3.4 Assumptions

The validity of any computer modelling relies on the accuracy and defensibility of the input data. Recently published cost data, from reputable sources, for the various technologies has been used. Input parameters have been chosen based on international, Australian and local evidence, Australian best practice and their relevance to the remote Kimberley context. Full details of the modelling assumptions are provided in Appendices F & G, and summarised here.

3.4.1 General Assumptions

This modelling is based on Horizon Power's actual hourly load data for each location in 2017, along with the corresponding 2017 NASA MERRA satellite wind and solar data. Wind and solar generation varies by a few percent from year to year, depending on weather conditions. Wind, CST and solar PV generation from a given investment in plant could therefore vary by several dollars per MWh, depending on the weather conditions for the year modelled.

Rainfall and global solar exposure during the cyclone season months of December and January to March are good indicators of solar generation in a year. The 2017 Wet season was significantly wetter and less sunny than average. This means that the LCOE values derived for 2017 may be a little higher than would be expected in an average year.

Other general considerations and assumptions are:

- All scenarios have at least enough internal combustion generation capacity to supply maximum power demand, plus at least 10% in reserve (existing fuelled generation in Broome and Derby far exceeds this)
- Rooftop PV installations in Broome and Derby are limited to 20% of demand, as any more may incur stability and cloud occlusion problems
- Utility PV generation is fixed and ground mounted (i.e. does not use single or double-axis tracking)
- The minimum battery capacity modelled is sufficient to enable generation at maximum PV capacity for 15 minutes, to enable backup generators to start up and come online

A further consideration is that costs of generation are continually changing. For example, during the course of this study, the Australian Energy Market Operator (AEMO)[2] released new lower cost estimates for large-scale fixed-utility PV and CST, predicted for 2022. A similar downward trend is expected for battery storage costs. Conversely, fossil fuel costs are predicted to rise, and wind turbine costs have stayed relatively constant.

3.4.2 RE Cost Assumptions

Base-case RE costs for the main load centres use median capital expenditure (CAPEX) figures for Australian dollars in 2018-19, assuming that the project agreements would be struck in that financial year. These CAPEX figures are deliberately conservative, as agreements are more likely to be settled nearer to 2021-22, when some costs (e.g. for PV and CST) may be lower. However, utility-scale wind and PV projects are new to the Kimberley region and may incur some additional cost due to their relatively small scale. Therefore, the conservative 2018-19 costs are used as our 'base case'.

Assumed technology costs are based on reputable sources (see *Table 3.4.2*):

- average 2021 CAPEX figures cited by the Bureau of Resource and Energy Economics (BREE) for the Pilbara[3]
- Lazard's average 2017 wind LCOE in Australian dollars[4]
- Bloomberg Energy Finance[5] Fixed axis solar PV forecasts (estimate for 2019)

Published project costs were used for cross-reference e.g.[6,7,8]. The Weighted Average Cost of Capital (WACC) for all RE projects is 7.1%.

A major assumption of this study is that all installations at major towns and industry centres would be bundled under a few large contracts maximizing economy of scale. For example, 106 MW of wind over three locations in a single contract.

Base-case PV and battery costs for small-scale projects on communities are based on estimates from an experienced PV installer in the Kimberley. For communities, this is $2.25 m /MW and for remote communities $2.5 m /MW. As there are no examples of small scale wind to draw on, a 34% premium was added to the large scale project cost making the base case cost $2.5 m /MW installed.

Another assumption is that many community projects would need to be bundled together under single contracts, for example 50 communities, each with 10 MW of solar PV with batteries under a single contract. Again this would maximize economies of scale and make it viable for installation and maintenance businesses to establish bases in the Kimberley.

Technology	Base-case CAPEX (2018-19, installed)	Low-cost CAPEX forecast (2022, installed)
Rooftop solar PV	$2.1 m /MW	n/a
Fixed utility PV large scale	$1.74 m /MW	$1.3 m /MW
Fixed utility PV small scale	$2.25 m /MW	n/a
Onshore Wind farms large scale	$1.86 m /MW	n/a
Onshore Wind farms small scale (<0.5 MW)	$2.5 m /MW	n/a
CST large scale	$4.32 m /MW	$3.3 m /MW
Internal Combustion LNG gensets - base load; backup	$1.4 m /MW	n/a
Internal Combustion diesel gensets – remote base load; backup	$1.47 m /MW	n/a
Molten salt storage	$0.064 m /MWh	n/a
Battery storage large scale > 5 MWh	$0.7254 m /MWh	n/a
Battery storage small scale <5 MWh	$1.00 m /MWh	n/a
Transmission 132 kV AC above-ground	$0.75 m / km	n/a
Transmission below-ground 33 kV	$0.40 m / km	n/a
Transmission above-ground low voltage	$0.013m / km	n/a

Table 3.4.2 Kimberley RE installations
Assumed base-case and low-cost data assumptions and LCOE by technology

As explained in Section 2.4.2, there are no adverse access, terrain or serviceability issues in the main load centres of Broome, Thunderbird Mine and Derby. No costs additional to the median installed technology CAPEX have been factored in. Higher CAPEX and fuel costs have been estimated for the communities to account for transport costs and adverse economies of scale

Base case costs for internal combustion engines are from Parsons Brinkerhoff[9] and local industry sources, with 5% added for communities to account for higher installation costs.

RE technology CAPEX and Cost of Capital assumptions are discussed in more detail in Appendix F.

3.4.2.1 Outlook for Re Costs – Low-Cost Scenario

A low-cost scenario was modelled for the large projects in the major load centres only (see Section 4.7). It captures the cost reductions for solar PV and Concentrating Solar Thermal (CST) forecast over the next 3-4 years, citing AEMO[2] 2021-22 median CAPEX's for those technologies. It also uses the lower WACC of 6% from the same AEMO modelling assumptions workbook. CAPEX of wind, battery and internal combustion engines remains the same in the low cost assumptions.

3.4.3 Cost of Capital

The WACC averages the rate of return required by the investor and the borrowing rate. For example a project 50% financed by an investor requiring a rate of return of 10%, and 50% financed by banks at 5.0% would have a WACC of 7.5%.

WACC figures from the 2018 Finkel Report[10], and, where appropriate, Government finance rates were used.

The amortization period is set at the expected minimum working life of the project – 25 years for wind and PV, 30 years for transmission and CST, and 15 years for batteries. These are summarised in Appendix F.

3.4.4 Fuel Cost Assumptions

Fuel costs are an important variable in the business-as-usual fuelled generation scenario. Unlike RE technologies, where construction costs are high, but operations costs are minimal, fuel costs are a significant component of ongoing operations costs. Increasing fossil fuel costs over time will therefore add significantly to the LCOE of traditional generation capacity.

Horizon Power and contracted independent power providers supply the LNG and diesel for the power station contracts in the Kimberley, and have long term hedged contracts of at least 10 years. Current LNG and diesel prices are likely to be low because the contracts may have been struck when domestic gas prices were set at a rate of around $4.50 /GJ, and when the oil price was lower than it is now. The AEMO forecasts[11] that future domestic contracts will increase in line with rising LNG export prices to about $8 /GJ in 2027, as described in Appendix G.

LNG supplied to Broome is liquefied in a small plant at Karratha. The cost of the natural gas supply in Karratha is a minor part of the total LNG cost, which also includes liquefaction, transport by road train and receival (refrigerated storage) costs. Receival costs are additional to the price delivered to Broome and are paid by the independent power providers. Estimates of the breakdown of costs for LNG and diesel can be found in Appendix G.

The modelling for piped FNG assumes it to be supplied via spur-lines from a future large pipeline from Kimberley gas fields to a large liquefaction/ export plant. There are no forecast prices for possible future Kimberley FNG from a pipeline. For the purpose of this modelling, the base case estimate for FNG is assumed to be near the higher forecast cost for natural gas in 2027 (Appendix G) of $9 /GJ, plus a pipeline cost of $2 /GJ. See Section 5.3.3 for further discussion of methods of supply of FNG.

Diesel is also purchased by Horizon Power at low cost in contracts struck several years ago. The diesel price is assumed to be 76c per litre ($19.70 /GJ), with fuel excise and GST not payable. Transport to communities was costed at between $3.58 /GJ and $7 /GJ, based on the charge for a 10,000 litre rigid tanker truck with a return journey time of one to two days[12]. Total rounded current cost of diesel, including transport, was assumed to be $23 /GJ for communities within 400-500 km of Broome, mainly accessible by good roads, such as Beagle Bay and Yungngora, and $27 /GJ for more remote communities such as Kalumburu (see Appendix G).

3.5 References

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Image: Coober Pedy Renewable Hybrid Project, Les Pullen, Professional Photographer

Section 4

Modelling Results

Image: Rita Phillips

4.1 Introduction

Unless specified otherwise, all modelling results are derived from the 'base-case' costing assumptions summarised in Section 3.4, and described in detail in the Appendices.

Unless specified elsewhere, these results include no subsidies or disincentives.

No attempt was made to model a 100% RE option. The costs of various types of storage required to meet seasonal and nightly shortfalls are considered too expensive to be feasible.

Existing Rooftop PV (4.5 MW in Broome and 1.9 MW in Derby) is included in the percentages of RE for the Broome, Derby and Kimberley Grid scenarios, but is not included in the LCOE calculations because it is 'behind the meter', and is already subtracted from the 2017 modelled loads.

The modelled LCOE values of the RE scenarios in the Kimberley range from $180-$290/MWh, compared to values for RE scenarios on the SWIS of $100-$130. This reflects the remoteness of the region, higher running costs of fuelled generation, lower wind speeds, higher construction costs due to more extreme weather conditions and lower economies of scale. Where transmission costs are also included, they are proportionately higher than for the SWIS as no existing transmission infrastructure currently exists in the Kimberley.

4.1.1 RE Locations in the Broome-Derby Region

Four nominal generation locations were chosen, according to the rationale described in *Table 4.1.1*. **Note that these sites can easily be moved in accordance with Aboriginal land, tourism or other considerations.** As explained in Section 2.2.1, the weather grids used in SIREN cover an area of approximately 55km by 55km, so any suitable site within that envelope could be chosen. In any case, specific locations will have to be selected as part of the detailed planning processes for renewable generation.

Location	Coordinates	Rationale
Broome wind and solar PV	-17.847 S, 122.319 E	12 km NE of town on slightly higher ground (52 m elev.), 2.5 km N of Highway. This appears unused and is not in the way of tourism operations
Thunderbird wind and solar PV	-17.447 S, 122.843 E	19 km W of mine site, chosen because it is about 50 m higher than the mine (elev. 154m), as this would increase wind generation.
Curtin CST	-17.619 S, 123.865 E	49 km SE of Derby, 2 km N of Highway, 14 km ESE of Curtin Air Base. Chosen because it is 170 –180 km inland of open ocean (thus having lower cyclone risk than the other two sites), on slightly higher ground (elev. 106 m); land appears unused and does not have sandhills.
Derby wind and solar PV	-17.378 S, 123.719 E	In the stand alone scenario, some wind and PV would be located 10 km SE of Derby between the Highway and Gibb River roads. Land appears unused, and is elevated by 40 m, thus having no flood risk.

Table 4.1.1 Nominal generation locations with rationale.

4.2 Model 1: Cost Minimisation

The first set of modelling focussed on minimising the total cost of each RE scenario, that is, the RE and fuelled mix which minimised the total cost.

First, the wind-PV-battery (WPVB) scenarios are compared to that without a wind component (PVB), as shown in *Table 4.2*. The benchmark for comparison is the fuelled generation 'business as usual' case, with trucked LNG gas or diesel.

Both renewable scenarios are between $38 & $69/MWh less expensive than the fuelled scenario. This gives reason to believe that RE is a cost-effective option for the West Kimberley and is worth further exploration.

Examination of the percentage of renewable electricity achievable in each option shows that the WPVB scenario can meet approximately 50% of demand. The PVB option, without wind, meets only around 35% of demand, and is also slightly more expensive than the WPVB scenario. This is because there is no RE generation at night without installed wind capacity, meaning that fuelled generation is used more often. Battery storage is currently too expensive to meet overnight demand.

Since our objective is to maximise RE use while minimising costs, the PVB (no wind) option has only been considered in a small number of cases in this Report.

City/Town/ Community	Scenario	LCOE, $/MWh	% RE
Broome	WPVB	$178	54%
	PVB	$186	37%
	LNG	$241	0%*
Thunderbird	WPVB	$169	58%
	PVB	$184	34%
	LNG	$235	0%
Derby	WPVB	$197	52%
	PVB	$204	38%
	LNG	$265	0%*
Fitzroy Crossing	WPVB	$209	48%
	PVB	$212	35%
	LNG	$267	0%
Beagle Bay	WPVB	$252	46%
	PVB	$253	37%
	D	$292	0%

Table 4.2 Cost-optimised scenarios for the five representative locations.

* Excluding existing rooftop PV installations

4.2.1 Comparison of Grid and Stand-Alone Scenarios – Cost Minimisation

This Section discusses the Grid and stand-alone scenarios within the Broome-Derby region. ***Table 4.2.1*** provides a comparison of the LCOE cost per MWh and the proportion of renewables. A graphical representation of the same figures is shown in ***Figure 4.2.1***, with the LCOE shown in columns for the different scenarios.

There are two renewable scenarios for the Grid: one including a CST plant, and the other with a combined wind, solar PV and battery (WPVB) system. The first two rows show that the LCOE for the CST and WPVB scenarios are equivalent, but the CST approach achieves 74% renewables because the overnight storage capability reduces the need for fossil-fuelled generation. Both options are over $50 cheaper than the business as usual fossil-fuelled generation, but slightly more than FNG generation.

In terms of the stand-alone scenarios for the three major centres, in each case the WPVB scenario is substantially cheaper than the business as usual scenario and is cost-equivalent with the FNG scenario.

Using the base-case costing assumptions, the stand-alone RE LCOE values for all three centres are $20-30/MWh less than the two RE Grid scenarios, because of the cost of building the high-voltage transmission lines. This data suggests that it may not be cost effective to build a West Kimberley Grid unless it can be justified on other grounds such as opening up other economic

Location	Scenario	LCOE, $/MWh	% RE
Grid	CST	$207	74%
	WPVB	$205	57%
	LNG	$270	0%*
	FNG	$198	0%*
Broome	WPVB	$178	54%
	LNG	$241	0%*
	FNG	$178	0%*
Thunderbird	WPVB	$169	57%
	LNG	$247	0%
	FNG	$164	0%
Derby	WPVB	$197	52%
	LNG	$265	0%*
	FNG	$194	0%*

Table 4.2.1 Comparison of the LCOE cost per MWh and the proportion of renewables for the grid and stand-alone scenarios for the Broome-Derby region

* Excluding existing rooftop PV installations

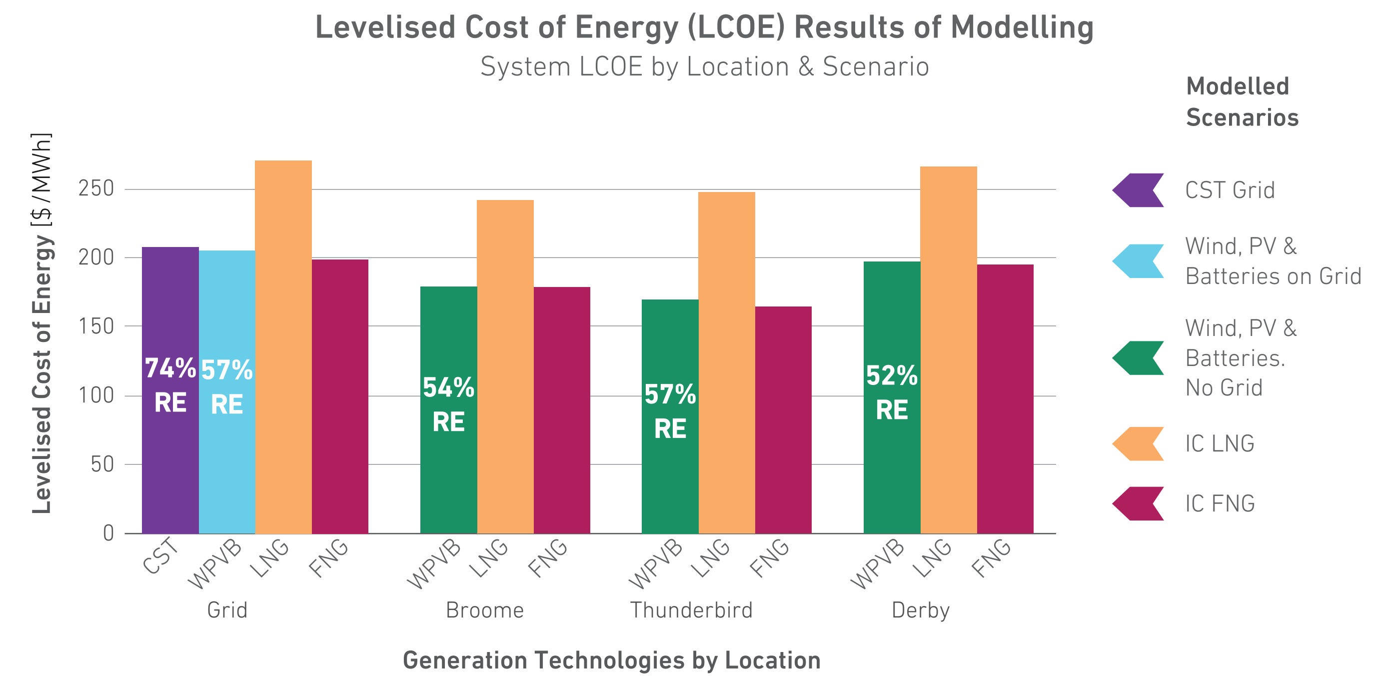

Figure 4.2.1 Cost-optimised LCOEs of RE scenarios compared to LNG Options

possibilities in the region. However, more recent and optimistic costing assumptions may make a CST-powered grid as attractive as the stand-alone scenario. This will be discussed further in Section 4.8.

In summary, the first round of modelling establishes that a mixture of wind and PV is the most appropriate technology mix, and that it is more economical to install it in individual centres rather than on a grid. The cost-optimised results are substantially less expensive than the LNG fuelled results.

4.3 Model 2: $30/MWh Lower Cost Than Fuelled Generation

A second, more detailed round of modelling was conducted, in which the RE scenarios are optimised for a nominal LCOE 'cost point' of $30/MWh less than the modelled value for fuelled generation . Wind, solar and storage capacities are optimised to give maximal percentage of RE for that cost point. Modelling is extended to include Halls Creek and Kalumburu, as 'remote' locations, and extrapolated to the Abattoir and the six other medium communities.

By choosing a 'cost point', rather than an equally arbitrary percentage of RE, this Report demonstrates the savings that can be made from RE in the Kimberley.

4.3.1 Renewable Generation

Table 4.3.1a displays LCOE figures for Kimberley towns and industry at a cost point $30/MWh below the fuelled equivalent. It also shows the percentage of RE generated at this price point, and the annual reduction in CO_2 emissions. Once again, the Grid scenarios are more expensive than their stand-alone equivalents, by approximately 10%. The RE percentage in the major centres is over 80%, and around 75% for Fitzroy Crossing, Halls Creek and the Abattoir.

Table 4.3.1b shows analogous results for the eight medium communities. Modelling was performed for Beagle Bay (a typical community) and Kalumburu (a remote community) and extrapolated for the other six communities. LCOE values per MWh are assumed to be the same as Beagle Bay for five of these communities, with the exception being Warmun, which is assumed to have the same LCOE as Kalumburu.

RE percentages vary from 60-71%, less than that achievable in the larger centres, due to economies of scale.

Kalumburu has very high fuel costs (estimated at $27 /GJ as opposed to $23 /GJ at Beagle Bay), due to it being 1200 km from Broome with unsealed road access, and this has raised the LCOE per MWh. A higher percentage of RE is cost effective here due to the higher fuel price, with 69% RE being achievable for about $30/MWh less than the existing diesel generation.

Location	LCOE $30 less than existing	RE %	CO2 reduction, tonnes/ year
Grid CST	$240	88%	141,728
Grid WPVB	$240	82%	133,067
Broome	$211	80%	53,908
Thunderbird	$217	85%	61,408
Derby	$235	82%	13,374
Fitzroy Crossing	$223	74%	5,375
Halls Creek	$223	74%	4,885
Abattoir	$218	77%	4,640
Total			143,590

Table 4.3.1a LCOE figures for Kimberley towns and industry at a price point $30/MWh below the fuelled equivalent.

All scenarios are for the wind-PV-battery (WPVB) option, except the Grid CST scenario.

Location	LCOE $30 less than existing	RE%	CO2 reduction, tonnes/ year
Beagle Bay	$247	62%	721
Kalumburu	$278	69%	1,056
Ardyaloon	$247	62%	824
Bidyadanga	$247	62%	1,339
Camballin	$247	62%	1,071
Djarindjin	$247	62%	721
Warmun	$278	71%	1,961
Yungngora	$247	62%	1,442
Total			9,135

Table 4.3.1b LCOE figures for medium communities at a price point $30/MWh below the fuelled equivalent.

4.3.2 Cyclone Prone Locations

Analysis of Bureau of Meteorology records shows that the coastline south from Broome to Port Hedland is in the path of occasional intense (Category 3-4) cyclones, with potential winds in excess of 200 kph having destroyed settlements in that area[1]. The communities affected are Bidyadanga and Wanamulnyundong. These events have not been recorded in other areas of the Kimberley (see Section 2.4.5).

Due to the risk of cyclone damage, wind turbines are not recommended for coastal communities south of Broome, unless small wind turbines can be sourced that can withstand 240 kph winds. Small turbines are available that can be lowered to the ground during storms, but an engineering feasibility study is needed to determine their suitability.

In the absence of suitable wind turbine models, a PV-battery system is recommended, although they are less cost-effective. For a cost point of $30/MWh less than fuelled generation, 44% RE generation can still be achieved with PV and battery.

4.3.3 Annual electricity costs and cost savings

The savings of renewables of $30/MWh for the RE scenarios was multiplied by the actual demand on the system in each location to arrive at a total annual saving from renewables, as shown in ***Table 4.3.3***. This leads to a total saving of $10.7 m per annum.

Table 4.3.2 also contains estimates of the CAPEX on renewables and the total capital expenditure if each scenario is to be developed from scratch. For the non-Grid scenario, an investment of $489 m in will be needed for renewables, for a total investment of $600 m. Appendix F discusses the different elements of CAPEX for each location (RE investment; transmission lines; fuelled investment) in more detail.

	2017 demand MWh	Savings on fuelled generation	RE CAPEX	Total CAPEX
Grid CST	316,000	$9.5 m	$427 m	$716 m
Grid WPVB	16,000	$9.5 m	$415 m	$660 m
Broome	131,000	$3.9 m	$168 m	$210 m
Thunderbird Mine	140,000	$4.1 m	$203 m	$233 m
Derby	32,000	$960 k	$46 m	$60 m
Abattoir	14,000	$420 k	$17 m	$20 m
Fitzroy Crossing	13,000	$380 k	$16 m	$26 m
Halls Creek	12,000	$350 k	$15 m	$24 m
Beagle Bay	1,650	$49 k	$2.0 m	$2.2 m
Kalumburu	2,100	$62 k	$3.1 m	$3.3 m
Ardyaloon	1,900	$56 k	$2.3 m	$2.5 m
Bidyadanga	3,100	$92 k	$3.7 m	$3.9 m
Camballin	2,450	$73 k	$3.0 m	$3.2 m
Djarindjin	1,650	$49 k	$2.0 m	$2.2 m
Warmun	3,100	$90 k	$3.7 m	$3.9 m
Yungngora	3,300	$99 k	$4.0 m	$5.6 m
Total annual savings (non-Grid)		$10.68 m		
		Total CAPEX	$489 m	$600 m

Table 4.3.2 Annual electricity cost savings

4.4 Generation Mix Breakdown

A summary of the generation mix for each location for the '$30 less than existing' scenario is shown in *Table 4.4*. Greater detail for each town, industry site and community is explained in the following sub-sections.

4.4.1 Major Centres

4.4.1.1 Broome

Population 14,000

In Broome, 80% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 37 MW Wind Farm of 962ha with nineteen 2MW turbines
- 33 MW Solar Farm of 172ha with 132,000 solar panels
- 8 MW Rooftop PV
- 45 MWh battery
- 27 MW of LNG-fuelled backup generation

Potentially located 10 km NE of town on slightly higher ground (52 m elev.), 2.5 km N of Highway. This appears unused and is not in the way of tourism operations

This will save 54 k tonnes of emissions p.a., and provide annual savings of $3.91 m for an investment of $168 m.

4.4.1.2 Derby

Population 3300

In Derby, 82% RE can be achieved for $30/MWh less than estimated current costs.

Location	Population	RE in Mix (%)	Wind (MW)	Utility PV (MW)	Rooftop PV (MW)	CST (MW)	Molten salt storage (MWh)	Battery (MWh)	Fossil-fuelled (MW)
Grid CST		88%	0.0	84	12	58	570	17	53
Grid WPVB		82%	108	82	12	0	0	85	53
Broome	14000	80%	37	33	8	0	0	45	27
Thunderbird		85%	49	45	0	0	0	61	18
Derby	3300	82%	10	11.1	1	0	0	13	6
Fitzroy Crossing	1140	74%	4	3.9	0	0	0	1.8	2.8
Halls Creek	1550	74%	4	3.5	0	0	0	1.6	2.5
Abattoir		77%	3	3.0	0	0	0	5.5	1.8
Beagle Bay	350	60%	0.3	0.4	0	0	0	0.36	0.4
Kalumburu	400	69%	0.5	0.6	0	0	0	0.44	0.38
Ardyaloon	350	62%	0.3	0.4	0	0	0	0.41	0.46
Bidyadanga	600	62%	0.6	0.7	0	0	0	0.67	0.74
Camballin	550	62%	0.4	0.6	0	0	0	0.53	0.59
Djarindjin	450	62%	0.3	0.4	0	0	0	0.36	0.40
Warmun	200	71%	0.6	0.7	0	0	0	0.67	0.74
Yungngora	400	62%	0.6	0.8	0	0	0	0.72	0.80

Table 4.4 The generation mix for each of the locations.

The RE mix will consist of:

- 10 MW Wind Farm of 247 ha with five 2 MW turbines
- 11.1 MW Solar Farm of 58 ha with 44,400 solar panels
- 1 MW Rooftop PV
- 13 MWh battery
- 6 MW of LNG-fuelled backup generation

Potentially located 10 km SE of Derby between the Highway and Gibb River road. Land appears unused, and higher than near town (elev. 40 m), thus having no flood risk.

This will save 13.4k tonnes of CO_2 emissions p.a., and provide annual savings of $958,000 for an investment of $46.2 m.

4.4.1.3 Thunderbird Mine

Proposed mineral sands mine.

At the Thunderbird mine, 85% RE can be achieved for $30/MWh less than estimated fossil-fuelled costs.

The RE mix will consist of:

- 49 MW Wind Farm of 1274 ha with twenty-five 2 MW turbines
- 45 MW Solar Farm of 234 ha with 180,000 solar panels
- 61 MWh battery
- 18 MW of LNG-fuelled backup generation

Potentially located 10 km West of mine site, chosen because it is about 50 m higher than the mine (elev. 154 m) as this would increase wind generation.

This will save 61 k tonnes of CO_2 emissions p.a., and provide annual savings of $4.13 m for an investment of $203 m.

4.4.1.4 Fitzroy Crossing

Population 1140

In Fitzroy Crossing, 74% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 4 MW Wind Farm of 109ha with nine 0.5 MW turbines
- 3.9 MW Solar Farm of 20.3ha with 15,600 solar panels
- 1.8 MWh battery
- 2.8 MW of LNG-fuelled backup generation

This will save 5.4 k tonnes of CO_2 emissions p.a., and provide annual savings of $419,000 for an investment of $17.2 m.

Potentially located at a suitable location within a 10 km radius of the centre and near existing services.

4.4.1.5 Halls Creek

Population 1550

In Halls Creek, 74% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 4 MW Wind Farm of 99 ha with eight 0.5 MW turbines
- 3.5MW Solar Farm of 18.4ha with 14,200 solar panels
- 1.6 MWh battery
- 2.5 MW of LNG-fuelled backup generation

This will save 4.9 k tonnes of CO_2 emissions p.a., and provide annual savings of $380,000 for an investment of $15.6 m.

Potentially located at a suitable location within a 10 km radius of the centre and near existing services.

4.4.1.6 Kimberley Meat Company Abattoir

Proposed Abattoir near Willare Bridge.

At the Kimberley Meat Company Abattoir, 77% RE can be achieved for $30/MWh less than estimated fossil-fuelled costs.

The RE mix will consist of:

- 3.0 MW Wind Farm of 78 ha with six 0.5 MW turbines
- 3.0 MW Solar Farm of 15.6 ha with 12,000 solar panels
- 5.5 MWh battery
- 1.8 MW of LNG-fuelled backup generation

This will save 4.6 k tonnes of CO_2 emissions p.a., and provide annual savings of $353,000 for an investment of $15.0 m.

4.4.2 Medium Communities

4.4.2.1 Ardyaloon

Population 350. Existing 75kW community solar system.

In Ardyaloon, 62% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 340 kW Wind Farm of 8.9 ha with two 225 kW turbines
- 450 kW Solar Farm of 2.3ha with 1,800 solar panels
- 410 kWh battery
- 460 kW of diesel backup generation

This will save 0.82 k tonnes of CO_2 emissions p.a., and provide annual savings of $56,000 for an investment of $2.27 m.

Potentially located at a suitable location within 500 m of existing services.

4.4.2.2 Beagle Bay

Population 350

In Beagle Bay, 60% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 300 kW Wind Farm of 7.8ha with two 225 kW turbines
- 390 kW Solar Farm of 2.0 ha with 1,560 solar panels
- 360 kWh battery
- 400 kW of diesel backup generation

This will save 0.72 k tonnes of CO_2 emissions p.a., and provide annual savings of $49,000 for an investment of $1.99 m.

Potentially located at a suitable location within 500 m of existing services.

4.4.2.3 Bidyadanga

Population 600

In Bidyadanga, 62% RE can be achieved for $30/MWh less than estimated current costs.

The WPVB RE mix will consist of:

- 560 kW Wind Farm of 14.5ha with three 225 kW turbines
- 720 kW Solar Farm of 3.8ha with 2,900 solar panels
- 670 kWh battery
- 740 kW of diesel backup generation

This will save 1.34 k tonnes of CO_2 emissions p.a., and provide annual savings of $92,000 for an investment of $3.69 m.

Potentially located at a suitable location within 500 m of existing services.

Careful consideration will need to be given to the engineering requirements for wind generation, given Bidyadanga's location in a cyclone-prone area.

A PVB RE mix with only solar PV and batteries will consist of:

- 930 kW Solar Farm
- 280 kWh battery
- 740 kW of diesel backup generation

4.4.2.4 Camballin/Looma

Population 550

In Camballin/Looma, 62% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 450 kW Wind Farm of 11.6 ha with two 225 kW turbines
- 580 kW Solar Farm of 3.0 ha with 2,300 solar panels
- 530 kWh battery
- 590 kW of diesel backup generation

This will save 1.07 k tonnes of CO_2 emissions p.a., and provide annual savings of $73,000 for an investment of $2.95 m.

Potentially located at a suitable location within 500 m of existing services.

4.4.2.5 Djarindjin/ Lombadina

Population 450

In Djarindjin/ Lombadina, 62% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 300 kW Wind Farm of 7.8ha with two 225 kW turbines
- 390 kW Solar Farm of 2.0 ha with 1,560 solar panels
- 360 kWh battery
- 400 kW of diesel backup generation

This will save 0.72k tonnes of CO_2 emissions p.a., and provide annual savings of $49,000 for an investment of $1.99 m.

Potentially located at a suitable location within 500 m of existing services.

4.4.2.6 Kalumburu

Population 400

In Kalumburu, 69% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 540 kW Wind Farm of 14.0 ha with three 225 kW turbines
- 580 kW Solar Farm of 3.0 ha with 2,320 solar panels
- 440 kWh battery
- 380 kW of diesel backup generation

This will save 1.06 k tonnes of CO_2 emissions p.a., and provide annual savings of $62,000 for an investment of $3.10 m.

Potentially located at a suitable location within 500 m of existing services.

4.4.2.7 Warmun

Population 200

In Warmun, 71% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 560 kW Wind Farm of 14.5 ha with three 225 kW turbines
- 720 kW Solar Farm of 3.8 ha with 2,900 solar panels
- 670 kWh battery
- 740 kW of diesel backup generation

This will save 1.96 k tonnes of CO_2 emissions p.a., and provide annual savings of $90,000 for an investment of $3.69 m.

Potentially located at a suitable location within 500 m of existing services.

4.4.2.8 Yungngora

Population 400

In Yungngora, 62% RE can be achieved for $30/MWh less than estimated current costs.

The RE mix will consist of:

- 600 kW Wind Farm of 15.6ha with three 225 kW turbines
- 780 kW Solar Farm of 4.1ha with 3,120 solar panels (200 kW already installed)
- 720 kWh battery
- 800 kW of diesel backup generation

This will save 1.44k tonnes of CO_2 emissions p.a., and provide annual savings of $99,000 for an investment of $3.98 m

Potentially located at a suitable location within 500 m of existing services.

4.5 Small Communities

The modelled results for Beagle Bay and Kalumburu were used to calculate potential RE options for the 57 smaller communities (population between 10 and 200).

4.5.1 Methodology

The values used to scale the generation needs for the small communities are presented in ***Table 4.5.1***. Communities are categorised as 'Remote' or 'Not-remote' and LCOE values are based on the $247 value for Beagle Bay (typical community) and $278 for Kalumburu (remote community), respectively. Communities are classified as remote when their nearest town is Halls Creek or Kununurra. Communities whose nearest town is Broome, Derby or Fitzroy Crossing are classified as not-remote.

In smaller communities, economies of scale are not available, and prices are consequently higher. A System Size Multiplier has been used to account for this. A multiplier of 125% has been used for the communities with populations greater than 50, and

150% for those with a population less than 50. The relevant base LCOE from *Table 4.5.1* was multiplied by the System Size Multiplier to derive an LCOE estimate for each community (shown in *Table 4.5.2*).

The amount of generation required was calculated on a per-capita basis, scaled from modelled per-capita generation for Kalumburu (Remote) and Beagle Bay (Not-remote). The per-capita battery requirement was calculated in the same way. The wind-PV-fuelled generation mix for the two base communities was then used to calculate the required system size for wind, PV and fuelled generation for each small community, as shown in *Table 4.5.2*.

The scaled generation figures were broadly in line with what is known about current generation capabilities in the small communities. However, it should be noted that these are broad estimates only. The particular needs of each community may vary substantially from the figures provided here. The relative affluence of each community, and consequent use of air conditioning, will play a major role in the electricity requirements of a community.

4.5.2 Results

Table 4.5.2. summarises the projected RE costs and generation mix for the 57 smaller communities.

Note that, even in the smallest communities, wind generation is an important component in reducing the use of fossil fuels. This requires the use of relatively small, community wind turbines, rather than the utility-scale turbines used in the larger communities. Feasibility studies are needed to identify suitable models and manufacturers with supply chains in Australia to meet maintenance needs. The size of the turbines should be such that a minimum of two is installed at each location, so wind generation can continue during mechanical failures and maintenance.

Three small community examples are discussed in more detail below.

4.5.2.1 Muludja

Population 163, Not-remote

In Muludja, 64% RE can be achieved at an estimated cost of $247/MWh.

The RE mix will consist of:

- 140 kW Wind Farm
- 180 kW Solar Farm
- 165 kWh battery
- 185 kW of diesel backup generation

4.5.2.2 Pandanus Park

Population 135, Not-remote

In Pandanus Park, 64% RE can be achieved at an estimated cost of $247/MWh.

The RE mix will consist of:

- 115 kW Wind Farm
- 150 kW Solar Farm
- 135 kWh battery
- 155 kW of diesel backup generation

4.5.2.3 Yulmbu

Population 15, Remote

In Yulmbu, 75% RE can be achieved at an estimated cost of $417/MWh.

The RE mix will consist of:

- 20 kW Wind Farm
- 20 kW Solar Farm
- 20 kWh battery
- 15 kW of diesel backup generation

Base Community	Category	Base LCOE (MWh)	Per capita generation (kW)	Wind	Utility PV	Fossil-fuelled	Per capita battery use (kWh)
Kalumburu	Remote	$278	3.8	36%	39%	25%	1.1
Beagle Bay	Not-remote	$247	3.1	28%	36%	37%	1.0

Table 4.5.1 Details of the scaling methodology used for the small communities

Site name	Population	Base LCOE ($/MWh)	Total generation (kW)	Wind (kW)	Utility PV (kW)	Fossil-fuelled (kW)	Battery (kWh)
Totals	2057		6535	1871	2363	2301	2080
Balginjirr	21	$371	65	18	23	24	21
Bawoorrooga	11	$371	34	9	12	13	11
Bidan	12	$371	37	10	13	14	12
Bidijul	15	$371	47	13	17	17	15
Billard	72	$247	223	61	80	82	72
Biridu	30	$309	93	26	33	34	30
Bobieding	16	$371	50	14	18	18	16
Budgarjook	20	$371	62	17	22	23	20
Dodnun	43	$309	133	37	48	49	43
Embalgun	29	$309	90	25	32	33	29
Galamanda	20	$371	62	17	22	23	20
Galeru Gorge	28	$309	87	24	31	32	28
Ganinyi	25	$348	78	21	28	28	25
Gilaroong	40	$309	124	34	44	46	40
Girriyoowa	42	$348	160	57	62	40	46
Gnylmarung	15	$371	47	13	17	17	15
Goolarabooloo	27	$309	84	23	30	31	27
Gullaweed	15	$371	47	13	17	17	15
Gulumonon	20	$371	62	17	22	23	20
Gumbarnun	15	$371	47	13	17	17	15
Gurrbalgun	17	$371	53	15	19	19	17
Honeymoon Beach	17	$417	65	23	25	16	19
Imintji	45	$309	140	38	50	51	45
Jarlmadangah Burru	87	$247	270	74	96	99	87
Jimbalakudunj	31	$309	96	26	34	35	31
Joy Springs	60	$247	186	51	67	68	60
Kandiwal	25	$348	95	34	37	24	28
Koorabye	45	$309	140	38	50	51	45
Kupungarri	92	$247	285	78	102	105	92
La Djardarr Bay	27	$309	84	23	30	31	27
Larinyuwar	30	$309	93	26	33	34	30
Loongabid	15	$371	47	13	17	17	15
Maddarr	12	$371	37	10	13	14	12
Mimbi	17	$371	53	15	19	19	17
Mingalkala	47	$309	146	40	52	53	47
Monbon	28	$309	87	24	31	32	28

Table 4.5.2 Summary of RE costs and generation mix for 57 smaller communities [cont.].

Site name	Population	Base LCOE ($/MWh)	Total generation (kW)	Wind (kW)	Utility PV (kW)	Fossil-fuelled (kW)	Battery (kWh)
Moongardie	26	$348	99	36	38	25	29
Muludja	163	$247	505	139	181	185	163
Munget	10	$371	31	9	11	11	10
Munmarul	14	$371	43	12	16	16	14
Neem	10	$371	31	9	11	11	10
Ngalingkadji	42	$309	130	36	47	48	42
Ngallagunda	75	$247	233	64	83	85	75
Ngamakoon	30	$309	93	26	33	34	30
Ngumpan	40	$309	124	34	44	46	40
Ngurtuwarta	40	$309	124	34	44	46	40
Nillygan	14	$371	43	12	16	16	14
Nyumwah	10	$371	31	9	11	11	10
Pandanus Park	135	$247	419	115	150	154	135
Rarrdjali	12	$371	37	10	13	14	12
Tappers Inlet	12	$371	37	10	13	14	12
Tirralintji	13	$371	40	11	14	15	13
Wanamulnyundong	20	$371	62	17	22	23	20
Windjingayr	30	$309	93	26	33	34	30
Yakanarra	134	$247	415	114	149	152	134
Yiyili	101	$278	384	138	148	97	111
Yulmbu	15	$417	57	21	22	14	17

Table 4.5.2 Summary of RE costs and generation mix for the 57 smaller communities.

4.5.2.4 Pay-back Periods

Renewable systems in small communities can be paid off in relatively short periods. For example, Energy Made Clean Kimberley reported a payback time of less than seven years for a solar/battery/diesel microgrid installed for the Meta Maya Aboriginal Corporation[2] in the Pilbara in 2015. This featured a:

- 100kW Solar PV system
- 110kVA Diesel Generator
- Pre-assembled and pre-commissioned 20 ft POD, 64kWh Sony lithium iron phosphate

In addition, the local Aboriginal community was trained for system operations and maintenance

4.5.3 Generation Standards for Small Communities

Horizon Power's submission to the Parliamentary Microgrid Inquiry[3] raised concerns about the way that remote power supplies are planned and managed, claiming that they are largely unregulated. See Section 2.4.7.2.

They further claimed that:

Power, water and wastewater service delivery in remote communities is characterised by:

- *diffuse accountability;*
- *lack of clarity in respect to ownership and compliance obligations;*

- *a high cost to supply in remote areas;*
- *high subsidy requirements;*
- *affordability problems and ad hoc user-pay arrangements; and*
- *lack of regulation or application of standard regulatory framework*

Horizon Power recommends that the Government applies world best practice microgrid approaches in remote communities, so there is a standardised approach and economies of scale can be achieved.

Likewise, informal contact with the Department of Communities indicates an interest in a standardised approach to rolling out RE in communities.

Currently, the cost of diesel is split 50/50 between the Department of Communities and each of the communities. The State Government pays for the infrastructure. Previously, the Federal Government paid for the infrastructure then left it to the State Government and communities to make it work. The current structure allows the State Government to put proper long-term plans in place.

A rollout of RE across communities will enable smaller communities to significantly reduce their fuel costs. It will also decrease infrastructure costs for the State, and reduce fuel subsidies.

4.6 Large Scale Generation Certificates and a Carbon Price

The initial results do not include any financial subsidies. This Section analyses the impact of Large Scale Generation Certificates (LGCs) and a Carbon Price on renewable costs, as shown in *Table 4.6*. LGCs reduce the cost of renewables, while a Carbon Price increases the cost of fossil fuelled generation. We have assumed a Carbon Price of $20 per tonne of CO_2 emissions. *Table 4.6* shows that, for the '$30 less than existing' renewable scenarios, the addition of LGC's make renewables between $14/MWh & $17/MWh more attractive. A carbon tax makes the fuelled scenarios between $8 & $9/MWh less attractive. When both subsidies are applied at the same time, renewables become between $52/MWh and $56/MWh (~5.5c/kWh) less expensive than the modelled LNG generation. This is equivalent to a wholesale price reduction of 20%.

4.7 The Need for Fuelled Backup

RE technologies are inherently intermittent. The sun does not shine at night, and wind speeds fluctuate by day and season, and these cause shortfalls in electricity production.

In this study, these shortfalls are met by fuelled generation from backup generators. This Section graphically explores this intermittency and how often fuelled backup is

	LCOE base-case (/MWh)	LCOE base-case with LGCs (/MWh)	LCOE base-case with Carbon Price (/MWh)	LCOE base-case with LGCs & CO2 price (/MWh)	LCOE LNG (/MWh)	LCOE LNG with CO2 price (/MWh)	LCOE Savings* (subsidies & incentives) (/MWh)	Total Savings* (subsidies & incentives)
Grid CST	$240	$226	$241	$227	$270	$281	$54	$17.0 m
Grid WPVB	$240	$225	$242	$226	$270	$281	$55	$17.2 m
Grid WPVB	$211	$197	$213	$200	$241	$251	$52	$6.8 m
Thunderbird WPVB	$217	$200	$219	$201	$247	$257	$56	$7.8 m
Derby WPVB	$235	$219	$237	$221	$265	$276	$55	$1.8 m

Table 4.6 Comparison of selected Broome-Derby Region results with and without subsidies and incentives.
* compared to the relevant fuelled option

needed. In our modelled scenarios, on some windy days, renewables will provide all the power needed. On others, significant amounts of fuelled backup will be required.

Figures 4.7a and *4.7b* show modelled power generation every hour over typical two-week periods in the Wet season and the Dry season, respectively, for the Grid WPVB scenario. Output from wind and PV is shown in green and yellow, respectively. Fuelled backup is shown in orange. The contribution of batteries is shown in purple. The hatched areas show the amount of surplus electricity that is generated at times.

During the Wet season, in the first week shown in *Figure 4.6a*, solar PV meets all the load during the middle of the day, but wind strengths are weak, so most of the night-time load has to be met by fuelled generation. Note that battery storage meets demand in the early evening, but only for a short period.

During the second week, it is very windy, and wind meets all demand, day and night, for several days. Solar PV output causes a large surplus during the day.

During the Dry season (*Figure 4.6b*), wind, solar and batteries are able to meet all demand for most of the period shown. Fuelled backup is only required on eight nights. This is because, in the Dry season, solar PV is generally more consistent and load is

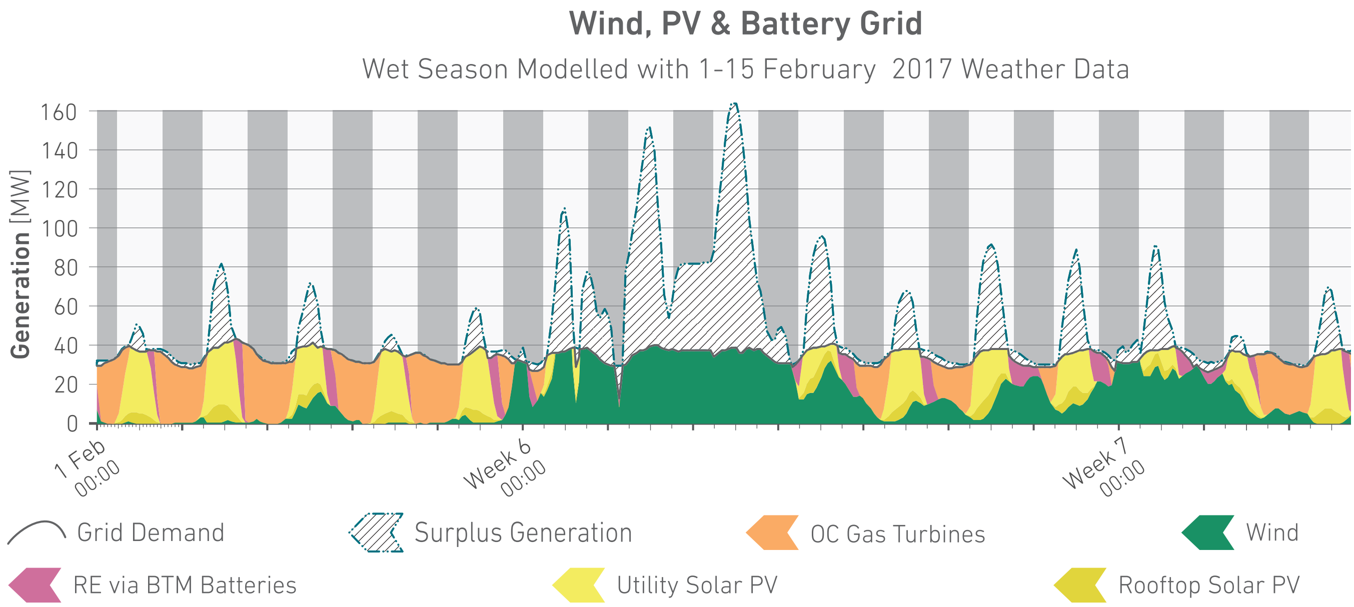

Figure 4.7a. Hourly generation, load and surplus, Grid WPVB scenario: 82% RE. 2 weeks in Wet season, February 2017

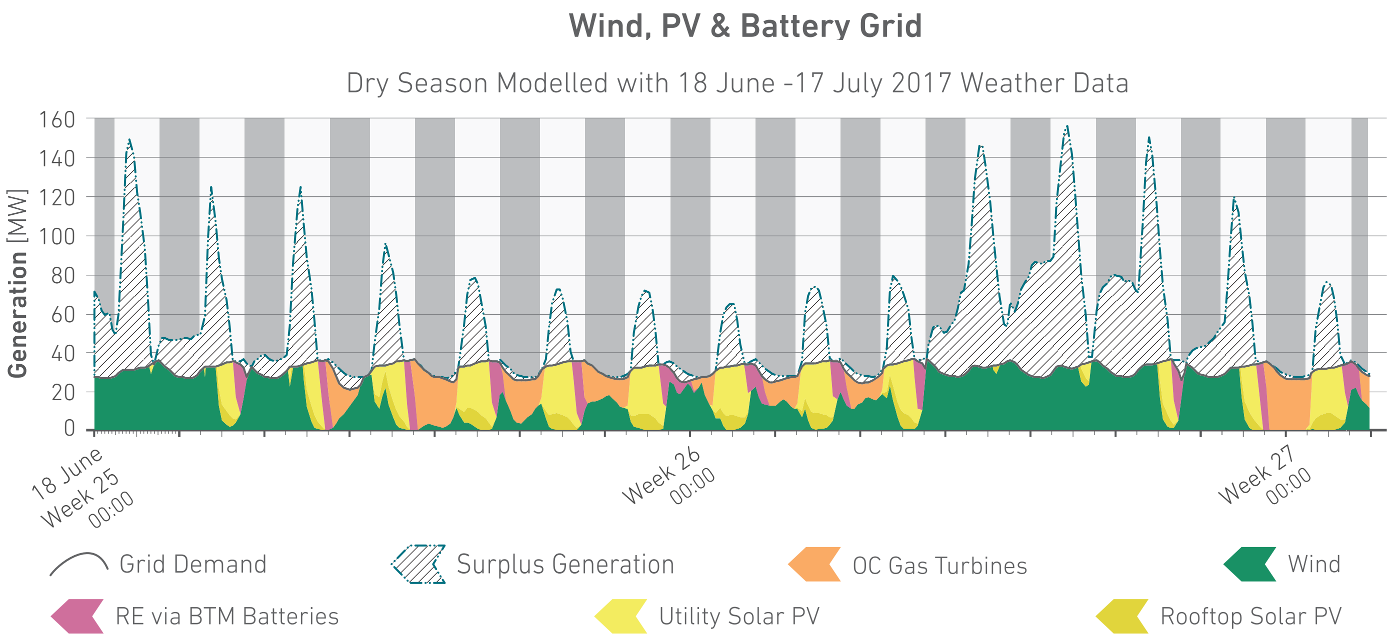

Figure 4.7b. Hourly generation, load and surplus, Grid WPVB scenario: 82% RE. 2 weeks in Dry season June-July 2017.

generally lower in the Dry season than it is in the Wet season, when more air conditioning is used.

Figures 4.7c & *4.7d* show analogous graphs for the Grid CST scenario during the same time periods. CST plants store surplus solar energy as molten salt for use overnight, therefore reducing the need for fuelled generation.

In this scenario, solar PV meets most demand during the day (*Figures 4.7c&d*), while the CST plant stores energy for the night-time.

However, during the Wet season, there can be numerous cloudy days, with little direct sunlight and hence little generation from CST (second week of *Figure 4.7c*). On these occasions, the system is reliant on fuelled generation (orange) during the night.

CST is very effective during the eight-month Dry season, with *Figure 4.7d* showing that CST and solar PV provide most generation, with a small amount of battery backup. Minimal fuelled backup is predicted to be needed during the Dry season.

Figures 4.7 a-d show significant amounts of surplus RE (hatched) which would normally be 'spilled' – i.e. not used. This energy, which is fully costed in the models, but not used, could be used to produce hydrogen fuel, which could be liquefied and used to fuel internal combustion generators or other engines.

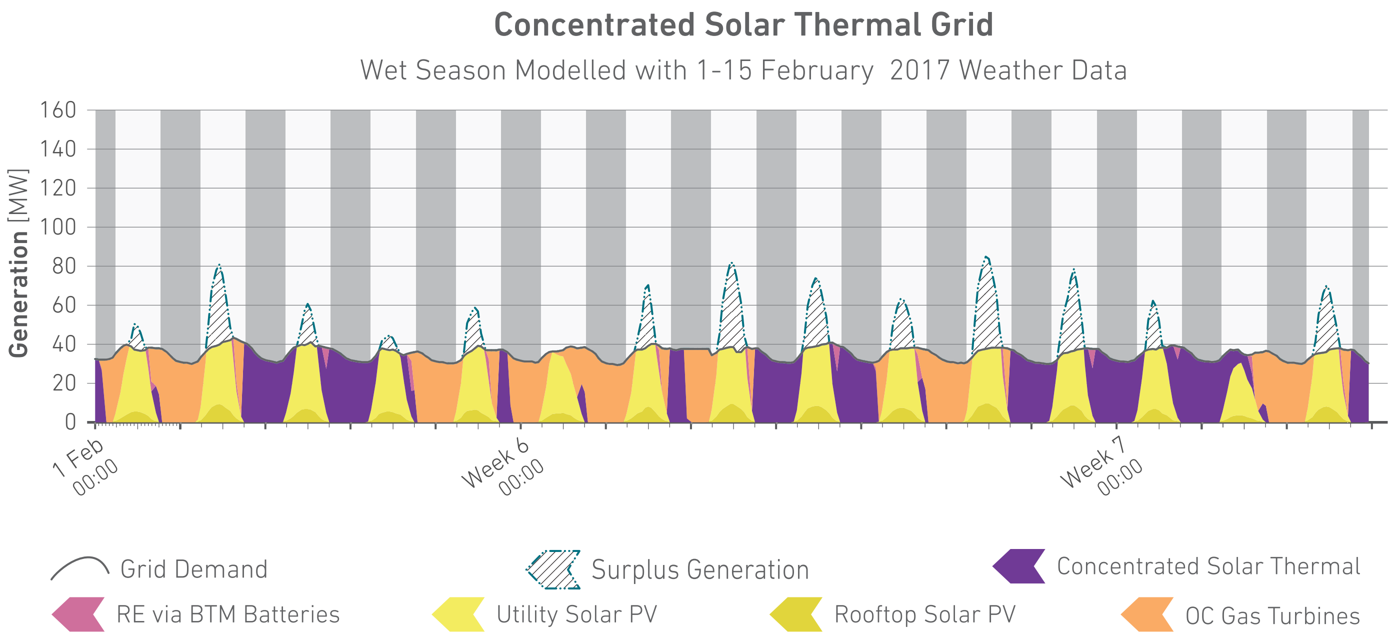

Figure 4.7c. Hourly generation, load and surplus, Grid CST scenario: 88% RE. 2 weeks in Wet season February 2017

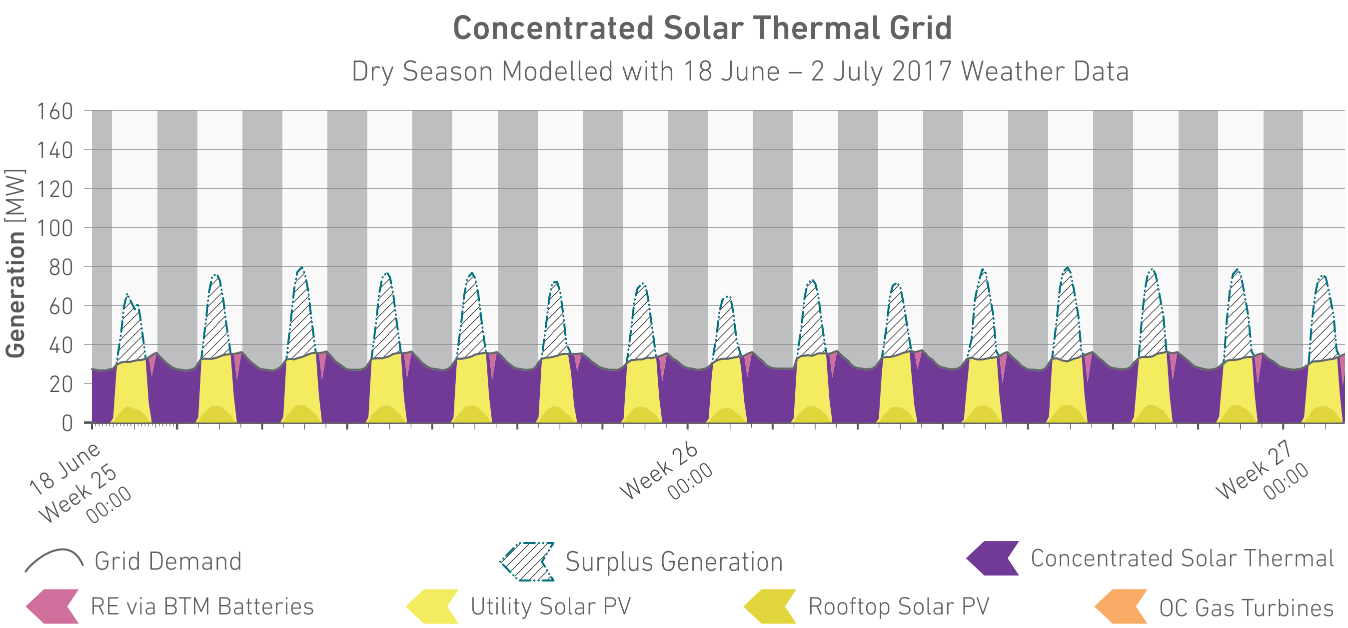

Figure 4.7d. Hourly generation, load and surplus, Grid CST scenario: 88% RE. 2 weeks in Dry season June-July 2017

4.8 Model 3: Lower Cost Assumptions

The previous Section indicates the effectiveness of a grid in the Broome-Derby region, predominantly powered by CST generation, in reducing the need for fuelled generation (88% RE). However, Section 4.3.1 indicates that the Grid option in the Broome-Derby region was $20-30/MWh more expensive than a stand-alone option.

However, the AEMO[4] released new reduced CAPEX figures during the course of this study (see also Section 3.4.1). These show that the cost of solar PV and CST are currently falling rapidly, while the outlook for wind power CAPEX is forecast to remain flat. A further set of modelling is made using these 'low cost – 2022' costings. These changes, accompanied by a predicted lower cost of capital[4], could significantly alter the balance of technologies used in optimising our modelling. This change is expected to have most impact in the Broome-Derby region, where the projects are medium to large scale.

Table 4.8 compares base-case costing (original assumptions) with the 'low cost 2022' figures (for more details, see Appendix F). These costings are approximately 75% of the values used in the base-case analysis.

Technology	Base-case CAPEX	Low CAPEX 2021-22 AEMO forecast
Fixed utility PV large scale ($million /MW installed)	$1.74 m	$1.3 m
CST large scale ($million/MW installed)	$4.32 m	$3.3 m
Weighted Average Cost of Capital	7.1%	6%

Table 4.8 Comparison of base-case and 2021-22 AEMO forecast costings.

4.8.1 Low-cost Case Results for the Broome-Derby Region

Modelling results indicated that the Grid CST scenario is indeed competitive under the new costings. This led to a reconsideration of the fuelled backup capability in a grid situation, and Open-cycle Gas Turbines (OCGTs) were modelled in place of the existing LNG-fuelled internal combustion engine backup. All OCGTs can be located in a single large-scale installation in the Grid, enabling the economies of scale and lower maintenance costs of this technology to be realized.

Several 15 to 20 MW units located at Broome are likely to have slightly lower CAPEX than existing fuelled generators, will have much lower fixed annual costs and slightly higher efficiency. There will also be savings on fuel transport.

A low-cost scenario is therefore modelled with lower PV costs at each location, with cheaper CST costs, and with new OCGT generation for the Grid options. These results are shown in ***Table 4.8.1***.

Location	RE in Mix (%)	LCOE base-case ($/MWh)	LCOE low-cost ($/MWh)	LCOE LNG ($/MWh)	Savings (base-case)	Savings (low-cost)
Grid CST OCGT	88%	$240	$205	$270	$9.5 m	$20.6 m
Grid WPVB OCGT	82%	$240	$220	$270	$9.5 m	$15.8 m
Broome WPVB	80%	$211	$197	$241	$3.9 m	$5.8 m
Thunderbird WPVB	85%	$217	$204	$247	$4.1 m	$6.0 m
Derby WPVB	82%	$235	$225	$265	$1.0 m	$1.3 m

Table 4.8.1 Comparison of the base-case and low-cost costing scenarios.

The LCOE figures for base-case and LNG in ***Table 4.8.1*** are the same as those in ***Table 4.3.1a***: optimised to be $30/MWh less than the predicted LNG-fuelled generation.

Under the low-cost case assumptions, the Grid CST LCOE is $35/MWh below the base-case, and $65/MWh less than the LNG-fuelled option. The Grid CST option is also comparable to the stand-alone options under the new assumptions.

The annual cost savings for the low-cost case Grid CST scenario are more than doubled, increasing to $20.6 m p.a., largely because the CAPEX on CST is reduced from $430 m/MW to $330 m/MW, and WACC for RE is reduced from 7.1% to 6%.

With these lower figures, a Grid CST scenario is cost competitive with wind-PV-battery for the West Kimberley. The advantages and disadvantages of the Grid CST scenario are discussed further in Section 6.1.5.

4.9 References

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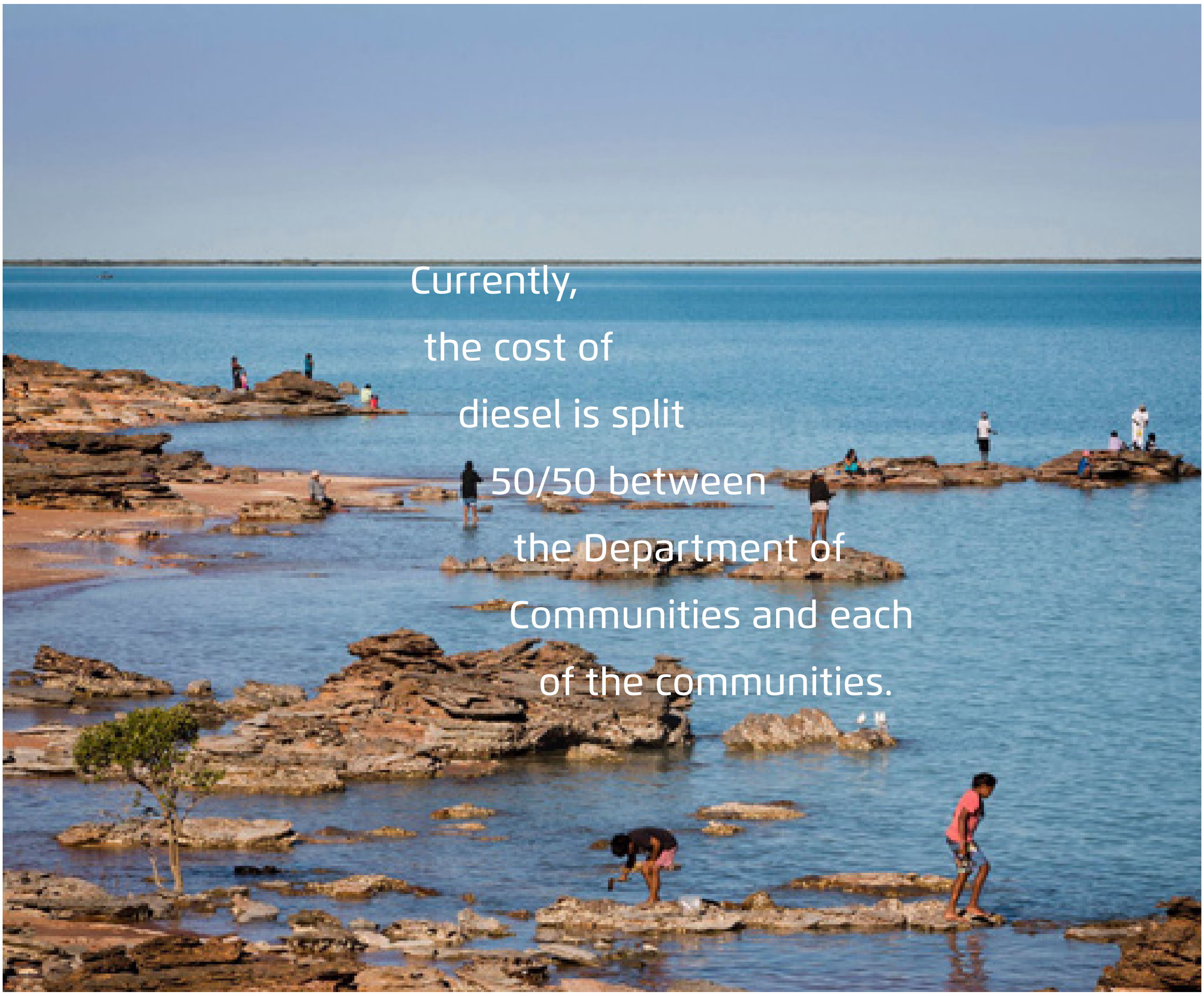


Image: Damian Kelly, Damian Kelly Photography

Section 5

Discussion

5.1 Limitations and Basis of This Study

The results presented in the previous Section and summarised in the following Section indicate a positive outlook for the uptake of renewable electricity in the Kimberley. However, care must be taken not to make extravagant claims about these results. The following points should be considered.

The results are based on mathematical modelling based on a series of assumptions, and hourly load, solar and wind data for 2017. While the high level modelling conducted using these assumptions is robust, it must be taken for what it is – a pre-feasibility study. In-depth engineering and financial feasibility studies will need to be conducted by project proponents before they submit tenders for projects. These would be 'due diligence' studies, including costing of actual components and installation, on-site investigations of actual wind strengths, and suitability of the sub-soil for foundations, etc., at each location

Modelled costs will vary according to the weather data for the year modelled. In this case, it was for 2017, when the Wet season was significantly wetter and less sunny than average. This means that the LCOE values derived for 2017 may be slightly higher (less favourable) than would be expected in an average year.

As actual costs of running power plants in the Kimberley are not available, costs from recent reliable sources have been used in this Report. Modelling and costing of control and monitoring systems for the RE scenarios are not included in this study and would need to be costed separately. They are likely to be negligible compared to the LCOEs calculated in this Report.

An assumption has been made in the modelling that each scenario will have at least enough IC generation capacity to supply maximum power demand plus 10% in reserve in the absence of renewables. Currently, fuelled generation in Broome and Derby far exceeds this amount.

Some of the costs involved in providing wholesale electricity (e.g. administration, profit, distribution cost, etc.) are required with both fossil fuel and RE scenarios, so any comparison of the modelled costs to actual costs needs to allow for this. However, comparison between modelled fossil fuel and RE scenarios is appropriate.

For these reasons, the margin of error in the LCOE costings is in the order of 30% to 50%.

All figures are NPV (net Present Value) except where specifically specified otherwise.

5.2 Summary of Results

A detailed summary of the modelling results is shown in *Table 5.2.4*. The key points are summarised below.

5.2.1 Model 1: Cost-minimised

The model optimised for minimum cost results in only around 50% RE, but, compared to the modelled fuelled scenario, LCOE values are significantly less expensive, as follows:

Broome: $53/MWh less than the modelled fuelled scenario

Fitzroy Crossing: $58/MWh less than the modelled fuelled scenario

Beagle Bay: $40/MWh less than the modelled fuelled scenario

The Broome-Derby Grid scenario is $70/MWh less expensive than its fuelled equivalent, but ~$20/MWh more expensive than the stand-alone alternatives, mainly due to the cost of the transmission lines.

The use of piped FNG in both Grid and Stand-alone scenarios is cost equivalent to the renewable options. See Section 5.3.2 for further discussion on this issue.

5.2.2 Model 2: $30/MWh Lower Cost Than Fuelled Generation

Optimising the renewable mix to be $30/MWh less than the modelled fuelled generation results in 74-88% RE generation in larger centres and 60-71% RE in communities, saving 153,000 tonnes of CO_2 emissions per annum.

An investment of $489 m in RE ($600 m total investment), amortised over 25 years, would save more than $45 million in fuel costs per year. When loan repayments (from higher CAPEX for renewables) and operating costs are accounted for, overall annual savings are estimated at $10.7 m.

Table 5.2 provides details of the physical size of the renewable installations at each location. In Broome, the largest centre, less than 12 sq. km is required for the 19 wind turbines and 41MW of solar panels. Most of this land can also be used for other purposes, because only a fraction of the available surface area is taken up by wind turbines and associated infrastructure. There is much flexibility in where RE generation facilities can be sited. A mutually-agreed location on Indigenous-managed land could be a win-win proposition.

Modelled results were scaled for the 57 smaller communities with populations of less than 200. As with all other load centres, wind turbines are an important part of the generation mix, to reduce battery requirements and fuelled generation at night. In the case of smaller communities, smaller wind turbines are required. These are typically less efficient and more expensive than larger ones, but still provide a valuable contribution. A summary is shown in *Table 4.5.2*.

5.2.3 Model 3: Lower Cost Assumptions

A third round of modelling was performed with the most recent AEMO price predictions[1], which predict 25% lower prices for utility solar PV and CST by 2021/22, and a lower cost of capital. The use of a Grid between Broome and Derby makes it practical to install aero-derivative OCGT gas turbines at a single larger power station in Broome. Savings on CAPEX, fixed annual costs, higher efficiency and fuel transport could reduce the LCOE of the grid scenarios by a further $10-20/MWh.

Under these new assumptions, the Grid CST scenario becomes $65/MWh less than the LNG Grid equivalent. Furthermore, the Grid CST scenario now becomes around the same price as the stand-alone WPVB scenario, making it a feasible option.

The use of the lower cost assumptions also increases the annual savings of the CST option by more than 100%.

5.2.4 Overall Summary

This study has demonstrated that it is possible to transition to 60-90% RE in the Kimberley while creating savings of a minimum of $30/MWh in the wholesale price of electricity. The generation mix modelled is for solar, wind and batteries to be rolled out across every town and community in the West Kimberley region. In total, a total 117 MW of Wind and 97 MW of utility-scale solar PV generation can be installed, with battery storage of 132 MWh, whilst retaining some fossil-fuelled backup.

Table 5.2.4 expands on this summary. It combines the results of Models 2 & 3 for stand-alone population centres. For most population centres, ***Table 5.2.4*** displays Model 2 results, with price predictions for 2019, optimised to be $30/MWh less than modelled fuelled generation. For Broome, Derby and the Thunderbird Mine, Model 3 results are presented, using AEMO price predictions for solar PV for 2021-22[1]. This results in a cost $40-44/MWh less than the equivalent fuelled cost. Results for the Grid scenarios are provided in ***Table 5.3.1***.

An investment of $449 m in RE ($560 m total investment), amortised over 25 years, would save more than $45 million in fuel costs per year. When loan repayments (from higher capital expenditure for renewables) and operating costs are accounted for, overall annual savings are estimated at $14.8 m per year.

5.2.5 Subsidies and Incentives

Further calculations were carried out on Model 2, to ascertain the effects of subsidies and incentives: the existing RET LGC mechanism; and a hypothetical 'carbon price' of $20 per tonne of carbon emissions.

When both subsidies are applied at the same time, renewables become between $52 and $56/MWh (~5.5c/kWh) less expensive than the modelled LNG generation. See ***Table 5.3.1*** below. This is equivalent to a wholesale price reduction of 20%.

5.2.6 Hourly Analysis

An analysis was performed of the hourly generation mix across the year for the two Grid scenarios. In the WPVB scenario (82% RE WPVB), fuelled generation is needed throughout the year, but less so in the Dry season. The CST Grid scenario (88% RE) has less need for fuelled backup, because the molten salt storage can meet night time demand on many occasions. In fact, during the Dry season, molten salt from CST, and some battery drawdown, can meet all modelled demand. However, fuelled backup will still be needed on cloudy days during the Wet season. Of the two grid scenarios (CST and WPVB), the CST option provides the greater proportion of RE and requires less fuelled backup. The CST scenario is therefore preferred in the following discussion.

5.3 Discussion

Substantial amounts of RE (50% to 80% depending on specific locations) can be justified now on purely financial grounds. When non-financial aspects are also considered (e.g. carbon pollution reduction; increased employment), the rollout of substantial RE in the Kimberley has a strong justification.

It is important to note that 100% renewable electricity cannot currently be justified on purely financial grounds. However, if, as is likely, battery costs decrease and technologies such as hydrogen and biogas generation, tidal turbines and geothermal steam generation mature, 100% renewables in the Kimberley may become cost effective at a future date.

There is significant flexibility in the comparative capacities of wind and PV in the modelling. In other words, approximately 10% of wind and PV generation could be interchanged for very little difference in LCOE and percentage of RE generation.

Nevertheless, wind generation is an important part of the Kimberley Clean Energy Roadmap, because it offers night time generation for much of the year, reducing fossil-fuelled backup generation.

However, in the past, Horizon Power has apparently done little work with wind generation in the tropics, and may need to build expertise in this area. Research will be needed into the availability of cyclone-rated wind turbines of various sizes. For smaller

	City/Town/ Community	Population	RE as portion of Gen. (%)	Savings $p.a.	Total RE Invest-ment ($)	LCOE ($/MWh)	Wind (MW)	Wind Farm Area (ha)	Turbine size (MW)	Number of Wind Turbines	PV (MW)	PV Farm Area (ha)	Number of Panels	Battery Capacity (MWh)	Fossil-fuelled Capacity (MW)	CO_2-e saved (kilo-Tonnes)
Towns and Industry	Broome*	14,000	80%	$5.8 m	$168 m	$197	37	962	2.0	19	41	172	132,000	45	27	54.0
	Thunderbird*	N/A	85%	$6.0 m	$203 m	$204	49	1456	2.0	28	45	198	152,000	61	18	61.5
	Derby*	3,300	82%	$1.3 m	$46 m	$225	9.5	247	2.0	5	12	58	44,400	13	6.0	13.5
	Fitzroy Crossing	1,140	74%	$419 k	$17 m	$223	4.2	109	0.5	9	3.9	20	15,600	1.8	2.8	5.5
	Halls Creek	1,550	74%	$380 k	$16 m	$223	3.8	99	0.5	8	3.5	18	14,179	1.6	2.5	5.0
	Abattoir	N/A	77%	$353 k	$15 m	$218	3.0	78	0.5	6	3.0	16	12,000	5.5	1.8	4.5
Medium Sized Communities	Beagle Bay	350	60%	$49 k	$2.0 m	$247	0.30	7.8	0.23	2	0.39	2	1,560	0.36	0.40	0.7
	Kalumburu	400	69%	$62 k	$3.1 m	$278	0.54	14.0	0.23	3	0.58	3	2,320	0.44	0.38	1.0
	Ardyaloon	350	62%	$56 k	$2.3 m	$247	0.34	8.9	0.23	2	0.45	2	1,783	0.41	0.46	1.0
	Bidyadanga	600	62%	$92 k	$3.7 m	$247	0.56	14.5	0.23	3	0.72	4	2,898	0.67	0.74	1.5
	Camballin	550	62%	$73 k	$3.0 m	$247	0.45	11.6	0.23	2	0.58	3	2,318	0.53	0.59	1.0
	Djarindjin	450	62%	$49 k	$2.0 m	$247	0.30	7.8	0.23	2	0.39	2	1,560	0.36	0.40	0.7
	Warmun	200	71%	$90 k	$3.7 m	$278	0.56	14.5	0.23	3	0.72	4	2,898	0.67	0.74	2.0
	Yungngora	400	62%	$99 k	$4.0 m	$247	0.60	15.6	0.23	3	0.78	4	3,120	0.72	0.80	1.5
	Total	**23,290**	**N/A**	**$14.8 m**	**$449 m**	**N/A**	**117**	**3046**	**N/A**	**95**	**97**	**505**	**388,636**	**132**	**62**	**153**

Table 5.2.4 Full details of the stand-alone scenarios, for all towns and communities supplied by Horizon Power (plus industrial sites), using AEMO price predictions for 2019, and optimised to be $30/MWh less than the equivalent fuelled cost. The figures provided here result from evidence-based assumptions. RE generation is not subsidised.
*** Modelled on the latest, lower AEMO price predictions for solar PV for 2021-22. This results in a cost $40-44/MWh less than the equivalent fuelled cost.**

If the Federal Government's RET subsidy was added, further savings of approximately $4.7 m p.a. are achievable.
If a hypothetical $20 /Tonne Carbon Price on fossil-fuelled generation is also included, savings of approximately $2.6 m p.a. are also possible.
Electricity generation capacity is measured in Kilowatts (kW) or Megawatts (MW). Electricity energy use is measured in kilowatt hours (kWh) or Megawatt hours (MWh) – the amount of electrical energy consumed.

turbines, towers which can be lowered to the ground when storms approach may be appropriate.

Table 3.4.2 shows that the CAPEX for utility solar PV is $1.74 m/MW installed for the base-case, falling to $1.3 m/MW installed for the 2021/2022 low-cost situation. This indicates that it is feasible to build utility solar PV farms for $2-2.5 m/MW, a price equivalent to that which Horizon Power[1] states is needed for solar PV to be competitive with fuelled generation, and in line with smaller scale installation costs quoted by local installers.

However, for these costs to be realised in the Kimberley, economies of scale need to be achieved and mechanisms put in place to encourage a mature RE industry in the region, e.g. by letting tenders for numerous installations, concurrently.

Some legislative and regulatory barriers might need to be resolved to allow Horizon Power to realise these economies of scale and roll out renewables across the Kimberley. Some legislative and regulatory barriers might need to be resolved to allow Horizon Power to realise these economies of scale and roll out renewables across the Kimberley. Their submission to the Legislative Assembly Microgrid Inquiry[3] identified a need:

- For coherent regulation encompassing all owners of microgrids – generators, distributors, and retailers
- To address the inconsistencies in information that exist between Horizon Power and the Government
- To update generation rules to reflect current and emerging market requirements and become more flexible
- For more flexible tariff structures to support current and emerging market requirements

5.3.1 Best-case Costings

Both the addition of subsidies and incentives, and the use of lower cost assumptions, have a significant impact on the outcome of the modelling for Broome, Derby and the Thunderbird mine. ***Table 5.3.1*** displays the base-case scenario ('$30 less than fuelled'; column 2) and the fuelled scenario with a carbon price (column 3). The best-case scenario (column 6) combines the cost benefits of the low-cost scenario (column 4) with those from the subsidised scenario with LGCs (column 5).

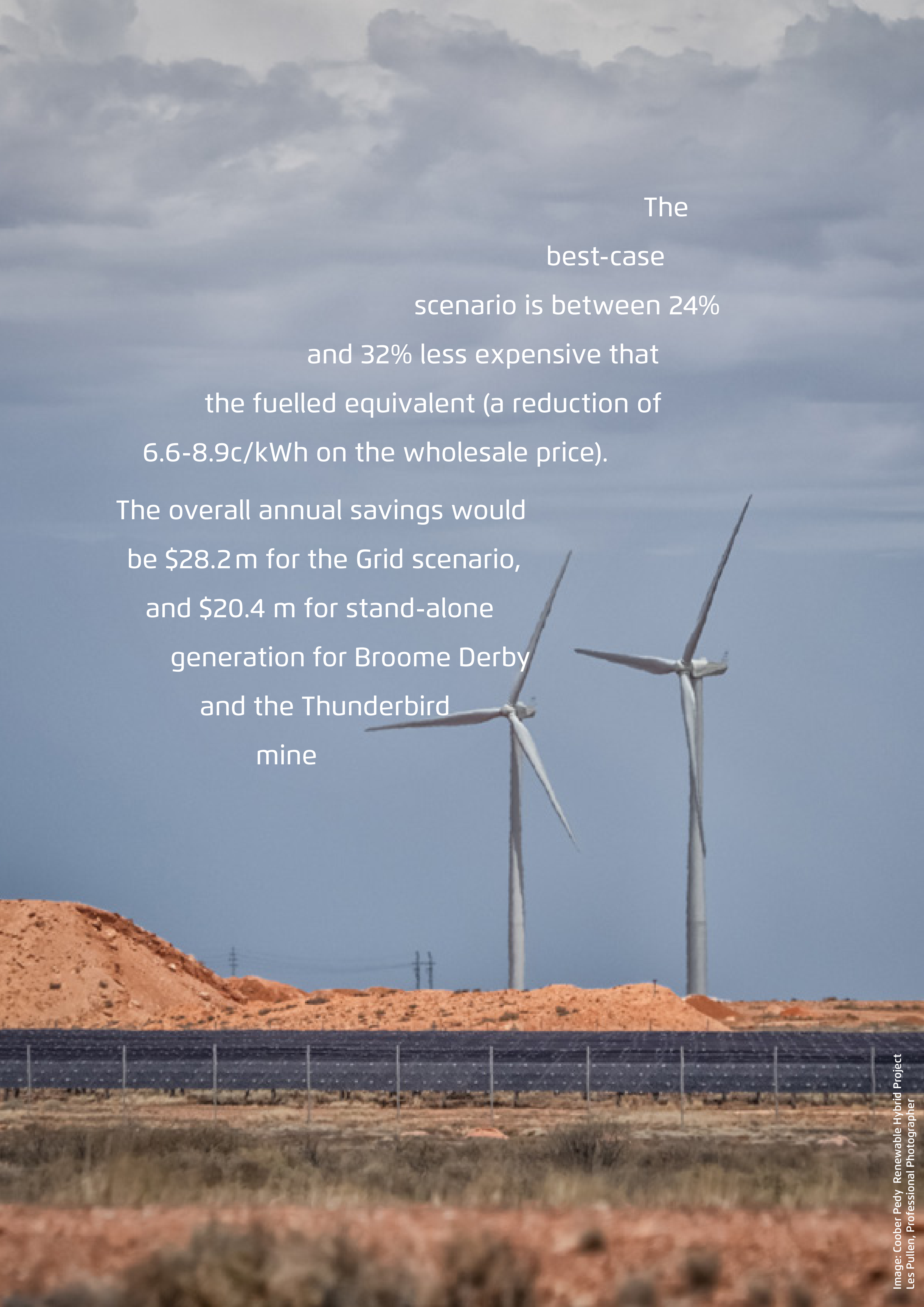
Columns 7-9 compare the best-case situation and the LNG-fuelled equivalent with a carbon price.

This shows that the best-case scenario is between 24 and 32% less expensive that the fuelled equivalent (a reduction of 6.6-8.9c/kWh on the wholesale price). The overall annual savings would be $28.2 m for the Grid scenario, and $20.4 m for stand-alone generation for Broome Derby and the Thunderbird mine.

Scenario	Base-case[1]	LNG with carbon price [2]	Low cost	Base-case with LGCs	Best case [3]	LCOE Savings*; best-case[4]	%[4]	Total Savings[4]; best-case
Grid CST	$240	$281	$205	$226	$192	$89	32%	$28.2 m
Broome WPVB	$211	$251	$197	$197	$185	$66	26%	$8.6 m
Thunderbird WPVB	$217	$257	$204	$200	$188	$69	27%	$9.7 m
Derby WPVB	$217	$276	$225	$219	$210	$66	24%	$2.1 m

Table 5.3.1 Comparison of the low-cost scenario with subsidies (LGC's and a Carbon Price) with the LNG-fuelled equivalent. LCOE in $/MWh.

1 Base case scenario – optimised for $30/MWh less than the unsubsidised LNG equivalent
2 Modelled LNG scenario with a $20 per tonne Carbon price
3 Best case scenario, with low cost assumptions, LGCs and a Carbon Price.
4 Compared to LNG with a Carbon Price



The best-case scenario is between 24% and 32% less expensive that the fuelled equivalent (a reduction of 6.6-8.9c/kWh on the wholesale price).

The overall annual savings would be $28.2 m for the Grid scenario, and $20.4 m for stand-alone generation for Broome Derby and the Thunderbird mine

Image: Coober Pedy Renewable Hybrid Project
Les Pullen, Professional Photographer

5.3.2 Comparison with Piped FNG

The previous Section shows that the best-case renewables options are clearly superior to the modelled results for existing LNG-fuelled generation. This Section examines the viability of FNG from the Canning Basin, initially through a pipeline. The modelling assumes gas would be supplied via spur-lines from a future large pipeline from Kimberley gas fields to a large liquefaction / export plant.

Section 4.2 outlines how powering fuelled generation with piped FNG from the Canning Basin would be cost equivalent to the cost-minimised RE scenario for the Broome-Derby region.

Table 5.3.2 compares the most cost-effective renewable options with existing generators fuelled by a FNG pipeline. The costing trends are shown graphically in *Figure 5.3.2*. The cost-minimised (52-74% RE) scenario is more cost-effective than fuelled generation with piped FNG. The cost-minimised solution would gain a further $9/MWh if LGCs are rebated.

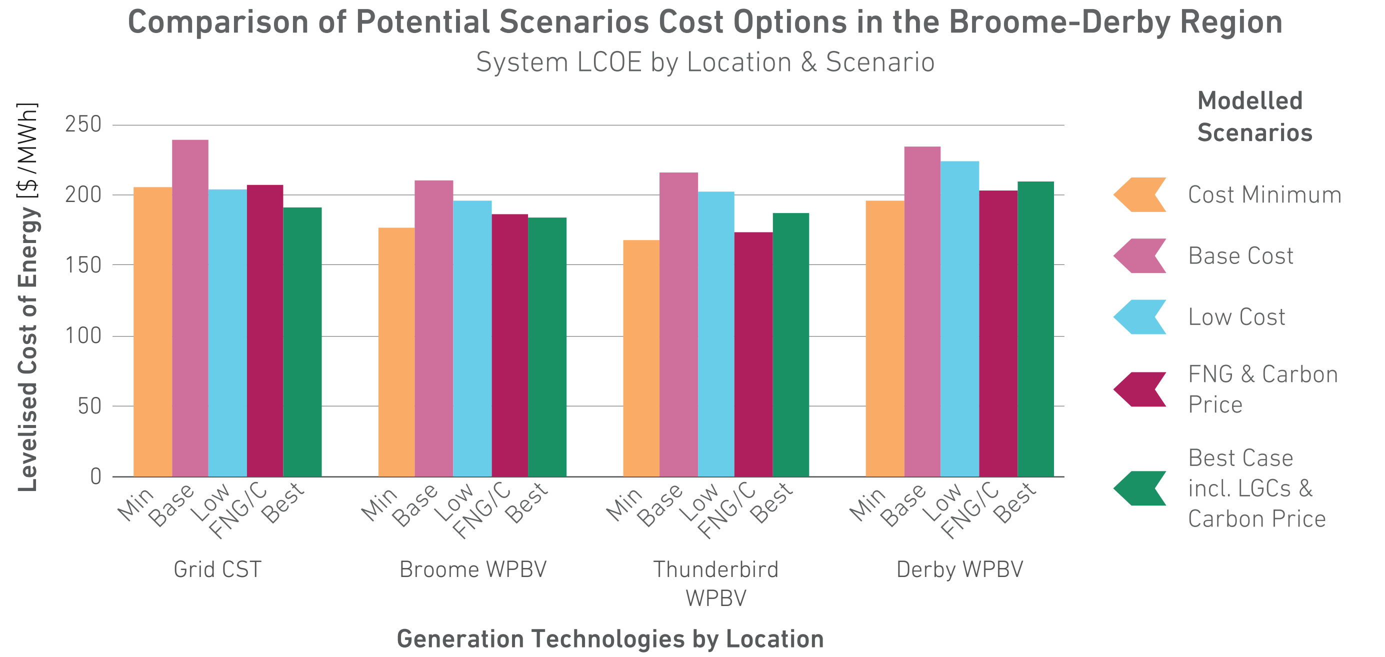


Figure 5.3.2. Comparison of cost options across the four potential scenarios in the Broome-Derby region

Scenario	Cost-minimised	Base case	Low cost†	Best case *	LNFG^	Best case vs LNFG
Grid CST	$207 74% RE	$240 88% RE	$205	$192	$208	8%
Broome WPVB	$178 54% RE	$211 80% RE	$197	$185	$187	1%
Thunderbird WPVB	$169 57% RE	$217 85% RE	$204	$188	$174	-8%
Derby WPVB	$197 52% RE	$235 82% RE	$225	$210	$204	-3%

Table 5.3.2 Comparison of the most cost-effective renewable options with existing generators fuelled by a pipeline of FNG from the Canning Basin.

† Same RE% as the Base case
* Based on the low-cost case, with LGCs and a Carbon price. Same RE% as the Base case.
^ With a Carbon Price of $20 per tonne

The best-case (80-88% RE) scenario provides LCOE values that are similar to the cost of fuelled generation with piped FNG. The last column of ***Table 5.3.2*** shows that the differences are between -8% and 8%.

In other words, electricity supply in the Broome-Derby region can be supplied by Canning Basin FNG via a pipeline for around the same LCOE as a stand-alone RE WPVB scenario, or a Grid CST scenario.

5.3.3 Viability of FNG

Other factors, building on information in Sections 2.4.7.1 and 3.4.4, impact on the feasibility of FNG fuelled electricity generation in the Kimberley.

The modelling assumes that gas supply will be on spur lines from a larger pipeline to existing or new facilities. However, the proposed James Price Point gas hub was terminated in 2013, and an agreement to support a pipeline from the Canning Basin to Dampier was terminated by the WA Labor Government in August 2018.

A second option is to build a smaller pipeline from the Canning Basin to the major Kimberley load centres. A relatively small amount of gas is required for these centres (i.e. 10MMscf/d). SEN's calculations indicate that it will not be viable to run such a pipeline, for several reasons:

- The already sunk costs of the existing trucked LNG infrastructure will need to be offset
- At least three to four times this volumetric flowrate will be required to provide a reasonable return on investment for such a pipeline, but there are no other obvious customers in the Kimberley
- The State Government's 15% Domestic Gas Policy covers domestic gas volumes, and, as existing contracts are far in excess of the demand in this context, there is no need to have further developments to cater for demand
- there is little or no redundancy (duplication) on a single pipeline purely for local supply, and to build it in would be cost-prohibitive.

Informal advice from Horizon Power also indicated that demand in the Broome-Derby region is too low to make a local pipeline viable.

In the absence of a pipeline, delivery of FNG can only be by truck. There are two options: LNG and CNG. LNG takes up less volume but costs more to process (because it requires a regasification facility), while CNG takes up more volume but is cheaper to process. The extra trucking cost of transporting CNG is offset by the extra production costs of LNG, making the two options similar in cost.

Appendix G demonstrates that road delivery of both LNG and/or CNG is likely to be only slightly less expensive (up to $2/GJ from the shorter transport distances) than the current method of transporting gas from the Pilbara by truck.

In summary, this research demonstrates the only way that FNG generation can compete with RE, under the present and future likely energy demand, is if it is provided by spur lines from a new major pipeline, but this seems an unlikely outcome. Further, given the uncertainty about a potential pipeline, renewables can be installed and commissioned in a shorter timeline.

Should unconventional gas fracking be permitted by the State Government, other factors are likely to make FNG extraction more expensive than the modelled cost assumptions, due to the costs of monitoring and offsetting the risks of methane leakage and pollution of fresh water aquifers. This may make Canning Basin FNG uneconomic to extract.

5.3.4 Asia Renewable Energy Hub

Funding has been committed for a $22 billion proposal for an 'Asia Renewable Energy Hub' in the Pilbara[4]. This is proposed to generate large amounts of RE for use in Pilbara resource industries, with a second phase to export electricity to Indonesia and Singapore through an undersea cable. Up to 11 GW of electricity would be generated by large wind and solar PV plants in the Pilbara, with another solar farm near Broome, from where the cable will go undersea.

However, the relatively low demand for electricity in Broome or on a potential Broome-Derby grid means that a connection from the Asia Renewable Energy Hub is unlikely to be economical to build in the context of the large scale of this proposal.

Other factors related to the project unknowns are:

- It is not certain that the project will proceed
- The implementation time scale is uncertain, but mooted to be 6 or 7 years from 2021
- It not clear how the infrastructure will be made cyclone-proof in a high intensity cyclone area

However, if this solar export project does proceed, the workforce assembled for the Kimberley Clean Energy Roadmap would be in place to assist in the construction phase.

5.3.5 Battery Advances

Technology advances and price decreases are an integral part of the RE landscape. This also applies to battery technologies.

In our modelling, we assume that the lifetime/amortisation period of a lithium ion large battery will be 15 years, and we estimate that a large system will cost $717,000/MWh (see Section 2.5.7), based on recent reports of the costs of the Hornsdale Tesla battery.

The cost of large-scale grid battery systems is predicted to fall below $500,000/MWh by 2028-29[1]. However, others have predicted much larger falls in battery prices, especially at the consumer level. For example, Professor Ray Wills' analysis[5] shows that battery prices have had an annual 28% price reduction since 2013, and prices are predicted to continue on this trajectory as electric vehicles penetrate the vehicle market.

Even if the costs of battery cells continue to fall, switching and inverter costs are a significant component of overall battery system costs. These are relatively mature technologies, so prices of these components are more stable. In other words, overall battery system prices will not drop as quickly as the battery technology itself. Nevertheless, as large battery installations increase across Australia, the increasing effective lifetimes and reducing CAPEX will bring LCOE down quickly.

Vanadium flow batteries are potentially suitable for remote locations. This battery chemistry has a rated lifetime of 20 years and may be an excellent alternative to lithium batteries in many situations. A trial of vanadium batteries is recommended.

5.4 References

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Image: Ben Little, Little Duo Photography

Section 6

Implementation

Image: Damian Kelly, Damian Kelly Photography

Previous Sections have shown that RE is cost effective for the Kimberley now. However, based on price trends, the optimum time to commence construction would be 2021 – 22.

Maximizing economies of scale is essential to achieving the savings outlined in this Report. Tenders should be let concurrently for groups of installations in order that installers can set up operations in the Kimberley and operate with maximum cost effectiveness.

An appropriate way to minimise tender prices is to run State-backed reverse auctions for PPAs so that developers can obtain cheaper finance and be confident in bidding on what otherwise might be considered higher risk projects. Government PPAs around the world have shown that very competitive pricing will emerge if they attract interest from global players in the renewables industry[1].

6.1 Implementation Timelines

There are too many unknowns at the current stage of development of the Kimberley Clean Energy Roadmap to develop a comprehensive timeline. However, some of the steps are listed below in logical order:

1. Develop a Kimberley Electricity Transition plan from this Roadmap
2. Update policy settings to enable Horizon Power to facilitate a RE transition in the Kimberley; for example, update generation rules, adopt microgrid standards
3. Conduct an in-depth feasibility study into the viability of a Broome-Derby Grid including a CST-MS power station
4. Research and cost optimal wind turbine models and PV array technologies for Kimberley weather conditions
5. Develop plans and support for a Kimberley RE construction industry
6. Develop tender requirements, reverse auction conditions and PPA criteria
7. Develop staged plans of works for the Towns and Industry, medium communities and small communities –each discussed separately below
8. Identify areas of preferred RE developments and work toward pre-approval for development of these sites and transmission corridors as applicable.

6.1.1 Plans of Works

Existing PPAs for fossil fuelled generation could potentially hinder timely implementation of RE in the Kimberley. For towns and industry and medium communities, PPAs may not expire until 2027 (some possibly in 2023). While this is a relatively distant time horizon, it need not mean that RE installation could not commence in 2021 or 2022:

- There is ample time for careful planning. Careful planning, funded by approximately 10% of budget up front, can significantly reduce total implementation costs.
- PPAs are able to be renegotiated. Existing generation assets will still be required as backup, meaning that there will be an ongoing, but reduced, source of income from those assets.
- Alternatively, PPAs can be bought out, especially as they are already well advanced. A case can be built that savings from new generation capacity can offset costs of buying out PPAs.

Nevertheless, a sensible starting point for a RE roll-out would be with the 57 smaller communities.

6.1.2 Smaller Communities

In the smaller communities, Government should support the Department of Communities and Horizon Power to develop a staged roll-out plan across the 57 smaller communities:

- Utilising best practice standards, enabling remote fleet management of the range of technologies involved
- Refining Horizon Power's new utility asset class of 'micro power systems' for the remote community context
- Maximising logistical efficiencies, by installing each subsequent system at the next nearest community, and starting in the most remote/ expensive regions
- Renegotiating PPAs for existing fuelled generation

Such a roll-out would also establish a regional work force, with associated Indigenous employment opportunities, some of which could be deployed to the large developments described below.

6.1.3 Medium Communities

In the eight medium communities, a staged approach can lead ultimately to 60% RE at a LCOE of $247/MWh. Three potentially-unrelated installation stages are envisaged, in this suggested order:

- Solar PV installation (to reduce daytime fuelled generation, and because Horizon Power is familiar with this technology)
- Battery installation (to balance supply from intermittent renewable sources)
- Wind Installation (to give Horizon Power more time to become familiar with this technology and to reduce night time fuelled generation)
- Renegotiating PPAs for existing fuelled generation

6.1.4 Small Towns

In the small towns of Fitzroy Crossing and Halls Creek, a two-stage installation could be appropriate. A sensible first stage would be to aim for the minimum cost scenario. For Fitzroy Crossing, this involves 48% RE, for an LCOE of $209/MWh (see ***Table 4.2***). The second stage would be to expand RE to 74%, aiming for an LCOE of $223/MWh, $30 less than the modelled, fuelled equivalent (***Table 4.3.1***a).

As per the approach for medium communities, this could commence with a staged roll-out of solar PV, followed by battery installation, wind turbines, and renegotiation of PPAs for existing fuelled generation. However, an over-build of the switching and control technologies (battery management, etc.) would be prudent at the outset. Extra storage and renewable capacity can then be added incrementally at relatively low cost, at appropriate times, without the need to replace core infrastructure (and associated 'regret' costs).

6.1.5 Broome-Derby Region

Two scenarios need to be considered here, both stand-alone and grid-connected. Stand-alone options for the Broome-Derby region do not carry the cost and construction time required for a HV (high voltage) grid. However, of all the modelled options, CST and a grid maximises RE use, reduces CO_2 emissions by the largest extent, and requires the least amount of fuelled generation. This option also provides a nation-building opportunity to open up parts of the Kimberley.

Careful work will be required on both technical and political grounds to determine whether the grid or stand-alone option is preferable. The following sub-sections outline a possible set of activities and timelines for each option.

6.1.5.1 Stand-alone Option

In this option, Broome, Derby and the proposed Thunderbird mine are assumed to continue as isolated centres. A sensible first stage would be to install the minimum cost RE capacities. For Broome, this corresponds to 54% RE, with an LCOE of $178/MWh ($63/MWh less than fuelled generation (see ***Table 4.2***). The second stage would be to expand RE to 80%, aiming for an LCOE of $211/MWh, $30/MWh less than the modelled, fuelled equivalent (***Table 4.3.1***a).

Once again, it is suggested that an initial over-build of the switching and control technologies (battery management, etc.) be carried out at the outset. Battery, wind and solar PV capacity can then be added in a staged way, at appropriate times.

6.1.5.2 Grid Option

Implementing the Grid scenario is a longer-term proposition. Building 200+ kms of high-voltage transmission lines through relatively untouched country will require time and careful planning. Similarly, gaining approval for a CST plant, and subsequent construction, may take several years.

Construction of the solar PV farms need not commence until this other infrastructure is largely in place. By this time, existing PPAs might be approaching their end-of-life, facilitating a simpler transition. However, delaying the roll-out of the Grid scenario is not recommended because, for each year of delay, over $20million of cost savings will be foregone , and 100,000 tonnes of CO_2 emissions will be released.

However, achieving a grid that is cost-equivalent to the stand-alone scenario requires that the existing fuelled generators in Broome be replaced by aero-derivative OCGTs (see Section 2.5.8). The appropriate time to do this is when the current PPAs expire in 2027.

The grid CST option is only viable if it includes the Thunderbird mine, for which environmental approval has already been given. The mine may well be up and running by 2022. This is a further strong reason for the grid option (if selected) to also be up and running as soon as possible. Initially, some OCGTs and PV could be located at the mine until the full grid-linked system is in place, after which it may be preferable to relocate the OCGTs to Broome.

The mine could be connected to the grid well before its expansion to 32MW of electrical load.

However, if the State Government or the Northern Australia Infrastructure Fund saw the nation-building opportunity of a West Kimberley CST plant and grid, Sheffield Resources may be persuaded to become part of it from the outset, and to benefit from ongoing savings.

6.2 Training

Numerous courses and training opportunities in various aspects of renewable technology are available Australia-wide. The organisation Renew regularly publishes an updated guide to most available courses (the latest in 2018)[2]. Courses can be undertaken on-campus or online, and range in length from multi-day short courses to multi-year courses for trades qualifications.

In WA, the North Regional TAFE, based in the Pilbara and Kimberley, offers a range of courses[3] relevant to RE installation.

These include:

- Certificate II in Electronic Assembly. This is a 12 - 18 months course, offered in Karratha, Pundulmurra (Port Hedland) and Broome to become an Electrotechnology equipment installer/servicer or to move into a subsequent apprenticeship/traineeship.
- Certificate III in Electrotechnology Electrician. A four-year Electrician apprenticeship (with three years at TAFE) offered at Karratha, Pundulmurra and Broome (first and second year only).

A subsequent Certificate IV in Electrotechnology (Systems Electrician) is available, but does not seem to be offered in WA. However, the Perth-based College of Electrical Training offers an eight-day short course[4] for registered electricians: 'Stand-alone Power Systems Design and Installation'.

Certificates I, II and III in Remote Area Essential Service are offered by the Centre for Appropriate Technology Limited in the Northern Territory and Queensland. The Certificate II in Remote Area Essential Service is offered in WA by the Kimberley Remote Service Providers[5]. This company also claims that they "***continue to support and employ Aboriginal graduates from previous intakes***".

Horizon Power has been developing and trialling an apprenticeship for Remote Community Utilities Workers, who are responsible for all utilities in their community. The first four graduates[6] have recently completed the program and live and work in their communities, maintaining electrical networks and, in Kalumburu and Yungngora, maintaining the power stations.

There is scope to extend training opportunities in Remote Services and Utilities Maintenance in the Kimberley and other remote areas of WA. The Kimberley Clean Energy Roadmap can act as a catalyst for this Indigenous training and employment initiative.

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6.3 Employment

This Section explores the potential employment opportunities for a roll out of RE across the West Kimberley. A nominal period of 10 years was assumed to complete the roll out. Ten years provides effective long-term employment and would likely be extended as further RE is installed in a second round due to lower prices. If the rollout duration was shortened, the job numbers would increase but only for the shorter duration.

6.3.1 Assumptions and Methodology

Reputable studies about RE job figures were reviewed. These figures vary depending on the countries and processes they apply to and when they were produced, but they have reduced significantly over the last decade.

Generally, conservative estimates are used, that sit towards the lower end of the documented ranges. Job year coefficients (job years per MW installed) were derived and applied in the calculations.

The data sources were compiled for SEN's 2017 modelling for the RE transition for the SWIS[7]. The estimates derived here differ slightly to those used in the SWIS jobs analysis, to reflect the different conditions in the Kimberley; namely:

- Higher job ratios on the smaller projects, and overall, as all projects will be smaller and therefore less efficient (and more expensive, as reflected in the costings) than for the SWIS.
- Few manufacturing jobs for the Kimberley, as it is considered that any local manufacturing jobs would be in the larger centres.

Approximate job estimates are presented in ***Table 6.3.1***. These job estimates do not include any component for utility-scale batteries, as reliable published figures were not available. Jobs generated by a potential increase in rooftop PV/battery installations were not estimated, because the amount of rooftop PV modelled was very small.

Job Division	Job Division	RE Generation Type	
		Wind	Utility SolarPV
Construction & Installation	Job.years/MW	3	3
Manufacturing	Job.years/MW	5.1	6.7
Components manufactured in WA	Percentage	20%	20%
Components manufactured in the Kimberley	Percentage	0%	5%
Operations & Maintenance	Jobs/MW	0.24	0.4
Transmission (Construction & Installation)	Job.years/km		3.2

Table 6.3.1 Employment 'job coefficient' costs per megawatt for Utility wind and solar PV.

Jobs for battery installations may be added in the future, when data is available. Less employment would be expected for battery installations than for PV and wind jobs.

Table 6.3.1 breaks down the jobs components of building and operating a power station into Construction and Installation for plant and transmission, Manufacturing, and Operations and Maintenance.

Long-term jobs are determined by multiplying projected installed capacity (MW) by the Operations and Maintenance jobs coefficient contained in ***Table 6.3.1***. All other jobs in construction, installation and manufacturing are calculated in terms of job-years. Subsequently, these figures for job-years are converted by dividing by the number of years of the proposed RE transition to determine an employment estimate for each year.

It is important to note the difference between expressing potential employment in job-years and as long-term jobs. For example, in ***Table 6.3.2***, Kimberley manufacturing, construction and installation jobs are estimated as 915 job years. This is equivalent to 91 people working for 10 years.

Not all renewable electricity components can be manufactured in WA, e.g. wind turbine motors and solar panels. However, wind turbine pylons and solar PV framing can be manufactured in WA, or even in the West Kimberley. ***Table 6.3.1*** assumes that 20% of components can be manufactured in WA, including 5% in the West Kimberley.

This might include footing reinforcement, ground mount fixings, and assembly of transmission towers.

Job numbers used as the basis for these calculations are for utility-scale projects. These are applicable to towns and industries, but less so for the communities. In smaller population centres, efficiencies and economies of scale are reduced, with a consequent increase in costs and job-years.

A system size multiplier is used for the medium and small communities, on the basis that materials, transport and labour will all increase in inverse proportion to the size of the community. A multiplier of 125% has been used for the medium communities, and 150% for the small communities. An analogous system size multiplier has been used in Section 4.5.1 to calculate the LCOE of very small and very remote communities.

The scaling of job numbers for communities is predicated on assumed average values, and it is understood there is likely to be a variation in cost and job-years multipliers between different communities, dependent on remoteness, terrain, transport logistics and other factors.

The system size multiplier has only been applied to Operations and Construction activities. Manufacturing is typically performed in larger, central locations where economies of scale apply, as grouped with the other projects.

6.3.2 Jobs Modelling Results

The results of the jobs modelling are shown in ***Table 6.3.2***. The total number of jobs over the entire region is shown in column 2, while individual numbers are given for the towns and industry, the eight medium communities, and the 57 smaller communities.

In the Kimberley, there are potentially 879 construction job years and 36 potential manufacturing job years, for a total of 915 job years. Over a ten year roll out, this equates to 91 jobs, which could be matched by 71 ongoing operations and maintenance jobs.

In addition, there are potentially 221 more manufacturing job-years in the larger southern centres to support these projects. The total number of long-term jobs within the State for a Kimberley RE rollout is 184.

Renewable technologies are known to be more labour intensive than fossil-fuelled generators. In its SWIS analysis, SEN estimated that there were three times as many Operations and Maintenance jobs than with coal generators[7].

Construction jobs have been listed as 'long-term' in ***Table 6.3.2***, as they cover a 10-year period. However, as renewable technologies advance further and prices continue to drop within the 10-year period, it will become economically viable to return to each site and increase the amount of renewables with a further round of ongoing jobs. Beyond this, replacements and upgrades will begin to be required, so truly permanent jobs can be expected. There will also be the core of a trained workforce should the proposed Pilbara/ Kimberley renewable electricity export proposal go ahead.

6.3.3 Indigenous Employment

There is potential for Kimberley Indigenous Corporations to set up 'sitework' and transportation businesses to prepare the ground for renewable electricity projects, and build foundations.

The major providers of electricity supply services in the West Kimberley (Horizon Power, Department of Communities, Kimberley Remote Service Providers and EMC Kimberley) have committed

	Total Jobs No grid	Towns & Industry	Medium Communities	Small Communities
System Size Multiplier		100%	125%	150%
Wind Capacity (MW)		107	3.6	1.8
Utility solar PV Capacity (MW)		100	4.6	2.4
Operations Jobs (Kimberley)				
Jobs in wind (long-term jobs)	27	26	1.1	0.7
Utility solar Jobs (long-term jobs)	44	40	2.3	1.4
Construction Jobs (Kimberley)				
Wind (job-years)	341	320	13.7	8.3
Utility solar Jobs (job-years)	327	299	17.3	10.7
Jobs in Transmission (Kimberley)				
Kilometres	63	55	4.0	4.0
Transmission Construction jobs (job-years)	211	176	16.0	19.2
Jobs in Manufacturing				
Total jobs in wind (job-years)	571	543	18.6	9.4
WA jobs in wind (job-years)	114	109	3.7	1.9
Kimberley jobs in wind (job-years)	0	0	0.0	0.0
Total utility solar jobs (job-years)	714	667	30.9	15.9
WA jobs in solar (job-years)	143	133	6.2	3.2
Kimberley jobs in solar (job-years)	36	33	1.5	0.8
Local jobs (Kimberley)	36	33	1.5	0.8
Local jobs (WA)	257	242	9.9	5.1
Local jobs (rest of WA)	221	209	8.4	4.3
Total Jobs Summary				
Construction jobs (job-years)	879	794	47.0	38.1
Manufacturing jobs Kimberley (job-years)	36	33	1.5	0.8
Kimberley manufacturing, construction and installation jobs (job-years)	915	828	48.5	38.9
Manufacturing jobs (rest of WA) (job-years)	221	209	8.4	4.3
Construction phase length (years)	10	10	10.0	10.0
Long-term manufacturing, construction and installation jobs (Kimberley)	91	83	4.9	3.9
Long-term manufacturing jobs (rest of WA)	22	21	0.8	0.4
Long-term operations jobs (Kimberley)	70	65	3.4	2.1
Total long-term jobs (Kimberley)	162	148	8.3	6.0
Total long-term jobs	184	169	9.1	6.4

Table 6.3.2 Jobs modelling results for the stand-alone (non-grid) scenarios in the Kimberley.

to training and employing Indigenous workers as part of their activities. See also Section 6.2.

However, the jobs modelling only predicts 5.5 Operations and Maintenance jobs in the 66 medium and small communities. Each community is unlikely to able to support a full-time electricity maintenance job. An alternative, which has been developed by Horizon Power, is to train and employ Remote Community Utilities Workers, who are responsible for all utilities in their community[6].

6.3.4 Other Employment-Related Information

Horizon Power has also done work in this area. Their Microgrid Inquiry submission[13] stated: "***Based on the experiences of California and plans from other nations, at the scale of WA, a strategic thrust into clean energy would translate to a bold goal of creating 50,000 jobs by 2030 in the industry***."

While this claim is across the entire state, much of it is related to microgrids in regional WA:

"To maximise the multiplier effect on its public investments ($300m estimated annual capital investment in advanced microgrid infrastructure and technologies), Western Australia would need to make strategic choices about areas of focus for job creation." [13, p. 29]

6.4 Investment Options

Section 5.2.4 indicates that an investment of $449 m in RE ($560 m total investment), is required to fully implement the Kimberley Clean Energy Roadmap. While this will be amortised over 25 years, it is a relatively large investment for a cash-strapped State Government to make.

However, a majority of the investment required to implement this roadmap could come from the private sector. RE investment projects with long-term PPAs are attractive 'fortress investments' for superannuation funds and other investors, because most of the costs are known up-front and are predictable. Such investments are also not subject to cost fluctuations, for example in fuel prices.

On the other hand, it may be appropriate for the State to retain control of balancing generation to prevent excess profit-taking by 'gaming' the system, as has occurred in the National Energy Market in the Eastern States.

Investment options could also include grant funding from national sources like the Australian Renewable Energy Agency (ARENA), the Northern Australian Infrastructure Fund (NAIF), and the newly formed Business Renewables Centre – Australia (BRC-A); whose purpose is to support the uptake by big business of long term and large scale RE Power Purchase Agreements (PPAs).

6.5 References

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Section 7

Conclusion

Image: Damian Kelly Photography

This study provides a comprehensive, fully-costed Renewable Energy roadmap for the Kimberley. Wind, solar PV, CST and battery storage are all currently viable electricity technologies for the Kimberley, and will provide substantial cost savings over the current LNG and diesel generation.

7.1 Economics

When the scenarios are modelled for minimum cost, the results show that approximately 50% RE generation can be achieved for $40-60/MWh less than fuelled generation. When modelling is optimised for savings of $30/MWh over fuelled generation, the results show 60-90% RE generation can be achieved, depending on the location.

More recent cost assumptions for 2021-22, and the use of subsidies, makes RE $65/MWh cheaper than existing fossil fuel generation. Solar PV and, to a lesser extent, battery prices are predicted to fall significantly over the next five years, making the RE option even more favourable.

The proposed generation mix is for 117 MW of wind and 97 MW of utility-scale solar PV generation, with battery storage (132 MWh) and some fossil-fuelled backup.

An investment of $449 m in RE ($560 m total investment), amortised over 25 years, will save more than $45m in fuel costs per year. When loan repayments (from higher CAPEX for renewables) and operating costs are accounted for, overall annual savings are estimated at $14.8m per year.

Combustion emissions of CO_2 in the West Kimberley would be reduced by at least 150,000 tonnes per annum, the equivalent of taking 25,000 petrol-powered cars off the roads each year.

The Kimberley Clean Energy Roadmap, if implemented, will potentially result in numerous long-term jobs within WA:

- 88 long-term jobs in Construction and Installation
- 26 long-term jobs in Manufacturing across WA
- 70 ongoing Operations and Maintenance jobs
- 162 long-term jobs in the Kimberley
- 184 long-term jobs across WA

This Roadmap is clearly an opportunity for the WA Labor Government to deliver on its Jobs Plan, which focusses on:

- Local jobs and content
- Creating jobs in regions
- An innovation economy
- Integrated, coordinated infrastructure planning
- Supporting a Renewables Industry

In summary, substantial amounts of RE (from 50% to 80%, depending on specific locations) can be justified on purely financial grounds. When non-financial aspects are also considered (e.g. carbon pollution reduction; increased employment), there is strong justification for RE in the Kimberley.

The majority of the investment required for the Kimberley Clean Energy Roadmap need not come from the Government. RE investment projects with long-term PPAs are attractive 'fortress investments' for superannuation funds and other investors.

On the other hand, it may be appropriate for the State to retain control of balancing generation to prevent excess profit-taking by 'gaming' the system, as has occurred in the National Energy Market in the Eastern States.

7.1.1 Opportunities

This research shows that significant amounts of surplus RE will be generated. This energy could be used for new industry opportunities, such as to produce liquefied hydrogen fuel, which could be used to fuel IC generators or other engines.

There is an opportunity for a government-funded trial of vanadium flow batteries, and tidal turbines, to explore future RE generation options.

7.1.2 Prospects for Fracking

There is no economic benefit in using FNG generation for electricity in the Kimberley. While supply from spur lines from a new major export pipeline is competitive with two of the RE scenarios presented, this option is unlikely in the medium term, given that the current State Government has terminated an agreement to support a pipeline from the Canning Basin to Dampier, and the proposed James Price Point gas hub was terminated in 2013. Furthermore, renewables can be installed and commissioned in a shorter timeline than gas pipelines and processing plants.

The alternative of using road trains to deliver either LNG or CNG from local FNG wells to Kimberley load centres is not significantly cheaper than the existing LNG and diesel solutions.

Should unconventional gas fracking be permitted by the State Government, other factors are likely to ensure fracked gas extraction is more expensive than the modelled cost assumptions. This is due to the high costs of stringent regulations, monitoring and offsetting methane fugitive emissions, as well as the potentially significant costs of remediating any contamination of freshwater sources.

7.2 Implementation

The implementation of the Kimberley Clean Energy Roadmap will need to include agreements and partnerships with Native Title groups and Indigenous communities, based on the principles of free-prior and informed consent. The involvement of other local stakeholders, and the State Government and Horizon Power, will also be crucial.

Implementation of the Kimberley Clean Energy Roadmap will be easier to achieve if there is political direction for a broad transition across the Kimberley. A long-term plan for a staged rollout of renewables across the Kimberley will enable economies of scale to be realised. Mechanisms need to be put in place to provide investment certainty for businesses, and local long-term employment. A mature RE industry in the Kimberley can be encouraged, for example, by letting tenders for numerous installations concurrently.

Some legislative and regulatory barriers might need to be resolved to allow Horizon Power to realise these economies of scale and roll out renewables across the Kimberley. Achieving these changes requires clear political direction from the WA Government.

Horizon Power's submission to the Legislative Assembly Microgrid Inquiry identified a need:

- For coherent regulation encompassing all owners of microgrids – generators, distributors, and retailers
- To address the inconsistencies in information that exist between Horizon Power and the Government
- To update generation rules to reflect current and emerging market requirements and become more flexible
- For more flexible tariff structures to support current and emerging market requirements

Once regulatory barriers are resolved, a managed transition plan is key to maximising the benefits from implementing this RE roadmap. Such a plan would:

- Build upon the groundwork already begun by Horizon Power
- Put appropriate control and monitoring structures in place, to enable a secure and stable supply of electricity to consumers
- Provide investment certainty and economies of scale to reduce installation costs
- Have the potential for co-investment by Indigenous communities or Native Title groups
- Map out the creation of a new sustainable regional workforce, providing training opportunities and boosting local indigenous employment opportunities
- Create a sustainable regional workforce
- Reduce reliance on fossil fuels, such as gas and diesel

Some RE training opportunities are available in the Kimberley, but there is scope to extend training opportunities in Remote Services and Utilities Maintenance. The Kimberley Clean Energy Roadmap can act as a catalyst for this Indigenous training and employment initiative.

7.3 Recommendations

That the WA Government:

- Adopts a West Kimberley Clean Energy Roadmap
- Supports implementation of Horizon Power's advanced microgrid roadmap
- Develops a Kimberley Electricity Transition plan from this Roadmap
- Updates policy settings to enable Horizon Power to facilitate a RE transition in the Kimberley (update generation rules, adopt microgrid standards, and enable an ongoing pipeline of RE installation, enabling economies of scale)
- Conducts in-depth feasibility studies for the uptake of renewable electricity in the Kimberley as soon as possible
- Conducts a feasibility study into the viability of a Broome-Derby Grid
- Conducts a feasibility study into suitable wind turbine models (of different sizes) for Kimberley weather conditions
- Allocates funding in the forward estimates to develop the managed transition plan and implement a Kimberley Clean Energy Roadmap
- Pre-approves RE development zones and transmission corridors to enable rapid implementation
- Develops plans/ support for a Kimberley RE construction industry
- Develops tender requirements, reverse auction conditions and PPA criteria
- Develops staged plans of works for the towns and industry, medium communities and small communities.

This Report demonstrates that the commitment to a RE future for the Kimberley will create a reliable, economically-favourable source of electricity for the future, reduce electricity costs for consumers, and create ongoing jobs.

If adopted by the WA Government, this visionary model could be rolled-out to other parts of regional and remote WA. It can also provide case experience and an incentive for wider adoption of RE across the south-west corner of the State.

Appendices


Image: Damian Kelly Photography

Appendix A
LCOE Methodology

Costs are calculated on a Levelized Cost of Electricity (LCOE) basis. Technology capital cost (CAPEX) per MW installed is used to calculate annualized capital cost and other fixed costs are added to give fixed annual costs per MWh generated per year. Variable costs per MWh are the sum of fuel consumed times fuel cost and operating costs per MWh of electricity sent out. Cost of electricity generated by a particular technology is calculated by:

$$C_{ed} = (P \times C_{fa}) + (E_g \times C_v)$$

Where:

C_{ed} = *Cost of electricity generated*
P = *Rated power capacity*
C_{fa} = *Fixed annual cost per unit of capacity*
E_g = *Electricity generated*
C_v = *Variable costs*

Weighted annual average LCOE for a scenario for a particular year is calculated for a particular year by:

$$LCoE_{wa} \text{ for scenario} = \left(\frac{C_{Gr} + C_{Gb}}{\text{total annual energy consumed on grid}} \right)$$

Where:

$LCoE_{wa}$ = *Weighted average LCoE*
C_{Gr} = *Cost of renewable energy generated per year*
C_{Gb} = *Cost of balancing (fuelled & storage) generated per year*

As the LCOE is calculated based on the energy actually consumed, not the nameplate capacity of the generation units, it accounts for the cost of unused (spilled) energy when generators operate at lower than their theoretical maximum capacity factor.

LCOE of a RE technology is directly related to regional wind or solar energy intensity. For example the LCOE of a wind turbine in the Kimberley, operating with a capacity factor of 24% would be double that of the same turbine located in a high wind area, operating with a capacity factor of 48%.

Appendix B

Details of the 57 Kimberley Communities with populations greater than or equal to 10 and less than 200

Site name	Longitude	Latitude	Corporation	Population	Nearest Town	Known Capacity and notes
Balginjirr	123.78708	-17.90476	Balginjirr Aboriginal Corporation	21	Derby	
Bawoorrooga	126.11790	-18.75652	Bawoorrooga Community Inc.	11	Fitzroy Crossing	
Bidan	123.16822	-17.64478	Bidan Aboriginal Corporation	12	Broome	48.1 kWh/day solar/diesel power
Bidijul	125.12634	-18.60993	Bidijul Aboriginal Corporation	15	Fitzroy Crossing	
Billard	122.67326	-16.97203	Billard Aboriginal Corporation	72	Broome	
Biridu	125.62271	-17.88783	Biridu Association Incorporated	30	Fitzroy Crossing	
Bobieding	122.63467	-16.97480	Bobieding Aboriginal Corporation	16	Broome	
Budgarjook	122.52102	-17.01770	Budgarjook Aboriginal Corporation	20	Broome	
Dodnun	126.21204	-16.43924	Dodnun Aboriginal Corporation	43	Derby	
Embalgun	122.62760	-16.80055	Embalgun Aboriginal Corporation	29	Broome	
Galamanda	125.40032	-17.75819	Galmarringarri Aboriginal Corporation	20	Fitzroy Crossing	
Galeru Gorge	126.07492	-18.60777	Galeru Gorge Aboriginal Corporation	28	Fitzroy Crossing	
Ganinyi	126.71481	-18.71102	Ganinyi Aboriginal Corporation	25	Halls Creek	See Yiyili
Gilaroong	125.60027	-18.29464	Gilaroong Aboriginal Corp	40	Fitzroy Crossing	On Fitzroy Crossing grid
Girriyoowa	126.76767	-18.72112	Girriyoowa Aboriginal Corporation	42	Halls Creek	See Yiyili
Gnylmarung	122.55087	-16.86039	Gnylmarung Aboriginal Corporation	15	Broome	
Goolarabooloo	122.21766	-17.83709	Goolarabooloo-Millibinyarri Aboriginal Corporation	27	Broome	
Gullaweed	123.02269	-16.39790	Gullaweed Aboriginal Corporation	15	Broome	
Gulumonon	122.90419	-16.46064	Gulumonon Aboriginal Corporation	20	Broome	
Gumbarnun	123.03215	-16.42280	Gumbarnun Aboriginal Group Incorporated	15	Broome	
Gurrbalgun	122.78715	-16.73208	Gurrbalgun Aboriginal Corporation	17	Broome	
Honeymoon Beach	126.68010	-14.10425	French Family Aboriginal Corporation	17	Kununurra	
Imintji	125.46143	-17.15052	Imintji Aboriginal Corporation	45	Derby	215kW. 45 kW; 70 kW and 100 kW.
Jarlmadangah Burru	124.01150	-18.01424	Jarlmadangah Burru Aboriginal Corporation	87	Derby	70kVA generator plus standby
Jimbalakudunj	124.64471	-17.89242	Jimbalakudunj Aboriginal Corporation	31	Fitzroy Crossing	
Joy Springs	125.69203	-18.33239	Eight Mile (Aboriginal Corporation)	60	Fitzroy Crossing	On Fitzroy Crossing grid. Solar/ Battery upgrade underway
Kandiwal	125.84197	-14.82067	Kandiwal Aboriginal Corporation	25	Kununurra	New system installed in 2010?
Koorabye	124.75418	-18.58425	Koorrabay Aboriginal Corporation	45	Fitzroy Crossing	

Appendix B [continued]

Details of the 57 Kimberley Communities with populations greater than or equal to 10 and less than 200

Site name	Longitude	Latitude	Corporation	Population	Nearest Town	Known Capacity and notes
Kupungarri	125.93025	-16.71994	Kupungarri Aboriginal Corporation	92	Derby	3 variable speed generators
La Djardarr Bay	123.14959	-16.88262	La Djardarr Bay Aboriginal Corporation	27	Broome	
Larinyuwar	123.66187	-16.48527	Larinyuwar Aboriginal Corporation	30	Derby	
Loongabid	122.54489	-16.97343	Loongabid Aboriginal Inc	15	Broome	
Maddarr	123.15742	-16.81912	Maddarr Aboriginal Corporation	12	Broome	
Mimbi	126.05813	-18.72639	Mimbi Aboriginal Corp	17	Fitzroy Crossing	
Mingalkala	126.16155	-18.69446	Mingalkala Aboriginal Corporation	47	Fitzroy Crossing	
Monbon	122.33111	-17.05842	Monbon Aboriginal Corporation	28	Broome	
Moongardie	126.44806	-18.78049	Moongardie Aboriginal Corporation	26	Halls Creek	32.5kW. 22.5kW and 10kW generators
Muludja	125.76164	-18.15971	Muludja Aboriginal Corporation	163	Fitzroy Crossing	100kW, 70kW and 40kW gensets
Munget	122.62228	-16.79913	Munget Aboriginal Corporation	10	Broome	
Munmarul	125.75067	-17.45577	Munmarul Aboriginal Corporation	14	Derby	
Neem	122.58054	-16.79016	Neem Aboriginal Corporation	10	Broome	
Ngalingkadji	125.70816	-18.65792	Ngalingkadji Aboriginal Corporation	42	Fitzroy Crossing	110kW. Two gensets 4kW; 70kW
Ngallagunda	126.43252	-16.42689	Ngalingkadji Aboriginal Corporation	75	Derby	3 diesel generators
Ngamakoon	122.91700	-16.44704	Ngamakoon Aboriginal Corporation	30	Broome	
Ngumpan	126.03583	-18.76916	Ngumpan Aboriginal Corporation	40	Fitzroy Crossing	
Ngurtuwarta	125.51968	-18.27826	Ngurtuwarta Aboriginal Corporation	40	Fitzroy Crossing	60kW. Two gensets
Nillygan	122.55250	-16.88039	Nillygan Aboriginal Corporation	14	Broome	
Nyumwah	122.98248	-16.55721	Nyumwah Aboriginal Corporation	10	Broome	No layout plan
Pandanus Park	123.65916	-17.73697	Yurmulun Aboriginal Corporation	135	Derby	Three generators 60-80 kW.
Rarrdjali	122.63146	-17.82595	Rarrdjali Aboriginal Corporation	12	Broome	
Tappers Inlet	122.55705	-16.81101	Tappers Inlet Community Aboriginal Corporation	12	Broome	
Tirralintji	126.43552	-17.19575	Tirralintji (Aboriginal Corporation)	13	Derby	
Wanamulnyundong	121.88795	-18.74509	Wanamulnyundong Aboriginal Corporation	20	Broome	
Windjingayr	124.61947	-17.17181	Windjingayr Aboriginal Corporation	30	Derby	
Yakanarra	125.29882	-18.67164	Yakanarra Aboriginal Corporation	134	Fitzroy Crossing	Solar/ Battery upgrade underway
Yiyili	126.75421	-18.71887	Yiyili Community Aboriginal Corporation	101	Halls Creek	370kW via 3 diesel generators. .
Yulmbu	126.90106	-17.27829	Yulmbu Aboriginal Corporation	15	Halls Creek	

Appendix C
Weather considerations

Solar radiation is high in the Kimberley region, as it lies in the hot tropics between 14 to 19 degrees south. Sunny days are generally constant during the long winter Dry season, but there are cloudy periods during the four-month summer Wet season.

Maximum recorded wind gusts in the Kimberley are summarised in ***Table C.1***, derived from the Australian Government Bureau of Meteorology (BoM) Online Climate database[1]. The highest wind gust recorded in Broome in 75 years of records was 160 kph, which storm rated wind turbines are built to withstand. However, Cyclone Rosita passed 45 km south of Broome in the 1980s with very destructive winds in excess of 200 kph[2]. For that reason, moving wind farms inland and/ or north of Broome, further from destructive cyclone paths, would be a good risk mitigation strategy. High land identified 34 km inland and 55 km NNE of Broome would be one such location. The proposed Thunderbird Mine is 75 km inland from open ocean, and Curtin air base is 150 km from open ocean, and cyclone risk would be no more than category 2 (160 kph) winds[3]. Both storm-rated wind turbines and the CST-MS technology are built to withstand these wind speeds.

Wind and solar generation vary from year to year by up to a few percent, depending on weather conditions. Solar CST and PV generation from a given investment in plant will be lower in a year with lower solar radiation (global solar exposure). This translates to a higher LCOE in such years. The LCOE will therefore vary by up to several dollars per MWh depending on the weather conditions for the year modelled.

Rainfall and global solar exposure during the cyclone season months of December and January to March are good indicators of solar generation in a year. The figures in ***Table C.2***, derived from the BoM Online Climate database[1], show that the cyclone season in 2017 (the year modelled) was significantly wetter and less sunny than average. This means that the LCOEs modelled in this study are likely to be a few dollars higher than would be expected in an average year.

BoM station	Duration of data	Maximum recorded wind gust (kph)
Broome Airport	1939 -2018	161
Broome	n/a (anecdotal)	175
Derby	1972 -2018	124
Halls Creek	1962 - 2017	143
Cape Villaret (40 km south of Broome)	n/a (estimated)	290
Mandora	1987 - 2017	217
Curtin Aero	2003 - 2018	98

Table C.1 Maximum recorded wind gusts at Kimberley locations

	Global solar exposure (MJ/m2) - Dec, Jan- Apr average of monthly means	Rainfall (mm) Dec, Jan-Apr
2017	22.32	769
1939 - 2018 average	22.9	769

Table C.2 Solar radiation and rainfall for 2017 and average cyclone seasons.

Appendix D

Fugitive Methane emissions

Implementation of the 82-88% RE scenarios recommended in this study would reduce CO_2 combustion emissions by 140-155,000 tonnes per annum – a large Cape Class ship load of CO_2e – compared to using generators fuelled by LNG.

However, gas combustion (Scope 1) emissions are only part of the issue. 'Scope 3' emissions from the extraction, liquefaction, transport and storage of LNG must be added to fully account for emissions from LNG used. The 'full cycle' (Scope 1, 2 & 3) emission factor for LNG used in heavy vehicles is 65 kgCO2-e/GJ (this would be similar to transported LNG used in Kimberley power stations) compared to 51.3 kgCO2-e/GJ for WA natural gas from the NW Shelf gas pipeline. In other words, total full cycle emissions from LNG are 27% higher than the scope 1 emissions from the combustion of NW Shelf gas[4].

Scope 3 emissions from FNG are certain to be significantly higher, due to ongoing leakage from hundreds of capped wells after production is finished. This risk is much higher with FNG because of the large number of short-lived wells and the possibility that the fractures will enable methane leakage to the surface via natural fracture zones and water wells. Methane is 25 times more potent than CO2 as a greenhouse gas, so this is a serious problem with FNG that must not be overlooked.

It is impossible to predict how much higher FNG scope 3 emissions will be but, if total methane leakage reaches 3.2% of the volume extracted, the full cycle emission factor will double to near that of burning coal. Further, the leakage from hundreds of wells may continue for decades after the company has closed the field and the cost of monitoring will continue for long after the wells are capped. There is a high risk of leakage becoming a significant ongoing problem, the cost of which will have to be borne by future generations of Australian taxpayers, either through a future carbon price or remediation.

Appendix E

STC's and LGC's

Under the current Renewable Energy Target (RET) scheme, small-scale technology certificates (STCs) can be claimed immediately on installation of small residential and commercial projects less than 100 kW solar PV and less than 10 kW for wind and hydro.

Large-scale generation certificates (LGCs) can be claimed annually at the market price. Calculation of the renewable energy certificate rebates that may accrue to the projects modelled are summarized below.

STC Calculation – small PV <100 kW	Conservative calculated NPV of STC's	References
Average STCs per kW, Broome (10years)	15.4	Refs: Green Energy Markets[14]
Assumed Average STC price	$38	REC Registry[5]
Assumed STC rebate per kW installed	$585	

Table E.1 STC calculation[5]

LGC Calculation, large wind and PV capacity factor 23-24%	Conservative calculated NPV of LGC's	References
Average LGCs per kW installed, NT (9 years)	15.36	Green Energy Markets[14]
Assumed Average LGC price	$25	Energetics[6]
NPV of LGCs (per kW installed)	$297	

Table E.2 LGC calculation for wind and solar PV[6]

LGC Calculation for solar thermal, capacity factor 0.42	Conservative calculated NPV of LGC's	References
Average LGCs per kW installed, NT (9 years)	26.88	Green Energy Markets[14]
Assumed Average LGC price	$25	Energetics[6]
Assumed Average LGC price	$25	Energetics[6]
NPV of LGCs (per kW installed)	$520	

Table E.3 LGC calculation for Solar thermal[6]

The base case scenarios do not include these rebates but a sensitivity analysis of their effect and that of a carbon price and future higher fuel prices can be found in Section 4.6.

The LGC calculation assumes an initial price of $35, declining linearly to $15/MWh over a period of nine years from 2022 to 2030, and aggregates these to a lump sum. The STC and LGC calculations are summarized in Tables E.1 – E.3. Note that the LGCs payable for solar thermal are higher than for PV, in proportion to the higher capacity factor.

Appendix F Assumptions

Base-case and low-cost RE technology CAPEX and LCOEs are summarized in ***Table F.1***, with the data sources in ***Table F.2***.

Capacity Factors

The existing IC capacity installed at Broome is running at a capacity factor (CF) of 0.38, and for Derby 0.29. For the 'IC only' scenarios, IC capacity modelled at Thunderbird has a CF of 40% and the capacity modelled for the Grid, a CF of 42%. These figures are low for 'base load' fuelled generators, as large coal fired units often run at CF of >80%. The smaller IC installed capacities modelled for the >80% RE had CF of 9-12%, meaning that the generators run much less and at lower load when operating as backup for RE.

Cost of capital

For the base case, weighted average cost of capital (WACC) figures from Finkel, 2018 and where appropriate Government finance rates were used. The low-cost scenario uses a WACC of 6% for RE technologies[11]. WACC averages the rate of return required by the investor and the borrowing rate. For example, a project 50% financed by an investor requiring a rate of return of 10% and 50% financed by banks at 5.5% would have a WACC of 7.75%.

The amortization period is set at the expected minimum working life of the project – 25 years for wind and PV, 30 years for transmission and CST and 15 years for batteries.

The modelled WACCs are summarized in ***Table F.3***.

Technology	Base case CAPEX (2018-19, installed)	Low-cost CAPEX forecast (2022, installed)	FOC - annualised capital costs + fixed O&M ($/MW/ year)	VOC - fuel, operation and maintenance ($/MWh)	Tech. LCOE ($/MWh)	Comments
Rooftop Solar PV	$2.1 m /MW	n/a	$143,699	0	$78	Lower WACC (3%)
Fixed utility PV - large scale	$1.74 m /MW	$1.3 m /MW	$173,758	0	$83	
Fixed utility PV - small scale	$2.25 m /MW	n/a	$217,916	0	$104	
Onshore wind farms large scale	$1.86 m /MW	n/a	$193,548	$13	$105-115	
Onshore wind farms small scale (<0.5 MW)	$2.5 m /MW	n/a	$248,962	$13	$164	
CST large scale	$4.32 m /MW	$3.3 m /MW	$422,611	$6	$142	
Internal Combustion LNG gensets - base load ; backup	$1.4 m /MW	n/a	$293,656; $235,227	$219	$165-276	Varies with fuel costs & run mode
Internal Combustion diesel gensets – remote base load; backup	$1.47 m /MW	n/a	$301,594; $241,191	$219	$292-$412*	Dependent on fuel costs & run mode
Molten salt storage	$0.064 m / MWh	n/a	$5,173	0	$20	$ per MWh storage capacity
Battery storage large scale > 5 MWh	$0.7254 m / MWh	n/a	$79,242	$3	$270 - $370	$ per MWh storage capacity
Battery storage small scale <5 MWh	$1.00 m /MWh	n/a	$143,036	$3	$460 -610*	$ per MWh storage capacity
Transmission 132 kV AC a/g single	$0.75 m / km	n/a	n/a	0	n/a	$ per km; above ground
Transmission b/g 33 kV	$0.40 m / km	n/a	n/a	0	n/a	$/km; below ground
Transmission a/g low voltage	$0.013m / km	n/a	n/a	$1	n/a	$/km; above ground

Table F.1 Kimberley RE installations – base-case and low-cost data assumptions and LCOE by technology

Technology	Technology CAPEX $/kW installed	Source 1	Source 2	Source 3
Onshore wind – large scale 1–3 MW turbines	$1,859 - $1,944	Lazards[7] average 2017 wind AUD/kW	AETA 2013[8] (2020 estimate for Pilbara, 2025)	Salt Creek 54 MW wind farm[9]
Onshore wind – small < 1 MW turbines remote	$2500	Increase large scale estimate of $1860 by 1/3 for smaller size turbines and remote installation		
Rooftop PV	$2100	Horizon Power, 2018 estimate for existing rooftop PV installations to 2017[10]		
Fixed utility PV- large scale	$1300- $1740	AEMO, 2018[11]	BREE[8] estimate for Pilbara, 2025	Bloomberg, 2015[12] (estimate for 2019)
Fixed utility PV – small scale remote	$2,000 – $2,500	Kimberley- based installer – John Davidson[13].		Clean Energy Regulator, 2017[14]
Concentrated solar thermal (CST)	$3,300 – $4,316	AEMO, 2018[11]	SEN, adapted from NREL, 2016[15]	
IC gensets – towns	$1,400	Parsons Brinkerhoff, 2009 (AUD)[16]	Cummins Perth industry sources, 2018	
IC gensets - remote	$1470	As above; add 5% for remote installation	N/A	N/A
Battery storage – 5 -100 MWh	$554 per MWh	Tesla Hornsdale 123 MWh battery in SA, 2018[17]		N/A
Battery storage, < 5 MWh	$1,000 - $1,500/MWh	John Davidson; Kimberley installer, 2018[13]	Clean Energy Regulator, 2018[14]	N/A
Molten Salt Storage	$64/MWh	NREL, 2013[15]	Solar Reserve, 2018[18]	N/A

Table F.2 Technology CAPEX data sources

Appendix G
Fuel Cost Assumptions

The modelling in this report assumes a rounded cost of $18/GJ for LNG and $20/GJ for diesel delivered to Broome. Estimates of the breakdown of costs for LNG and diesel can be found in *Table G.1*. Column 2 shows the LNG price ex-Karratha, and column 5 shows the assumed diesel price, for different locations. The components contributing to these price calculations are broken down in *Table G.2*.

Columns 3 & 4 of *Table G.1* show assumed prices for FNG from different sources, described in more detail below. The extra transport costs for LNG in *Table G.1* are expanded on in *Table G.3*, where base case and high case costs are considered ($4 /GJ increase for LNG and $3 /GJ increase for diesel)

Technology	WACC % base case estimate	WACC% low estimate	Amortization period years	WACC reference
Wind	7.1%	6%	25	Finkel,[19]; AEMO[11]
Fixed utility PV	7.1%	6%	25	
Rooftop PV	3%	n/a	25	Based on 2018 term deposit rates
Concentrating Solar Thermal	7.1%	6%	30	Finkel,[19]; AEMO[11]
IC Genset backup for RE	8.1%	n/a	25	
IC Genset baseload	8.1%	n/a	20	
Battery (Utility)	7.1%	6%	10	
Molten salt storage	7.1%	6%	30	
Transmission AC a/g 132 kV and all other types including transformers and end stations	5%	n/a	30	Estimate based on Government finance rates

Table F.3 Cost of capital

Existing LNG

LNG supplied to Broome is liquefied in a small plant at Karratha. The cost of the natural gas supplied from the pipeline is a minor part of the total LNG cost, which also includes liquefaction, transport by road train and receival (refrigerated storage) costs. Receival costs are additional to the cost delivered to Broome and are paid by the independent power providers.

FNG via pipeline

The lowest cost option of FNG would be supplied via spur-lines from a future large pipeline from the Kimberley gas fields to Dampier, where the gas would be liquefied for export. As a past attempt to establish a LNG plant near Broome was ruled invalid by the EPA in 2013, it is assumed that this would not be an option. There are no forecast prices for possible future Kimberley FNG from a pipeline. For the purpose of this modelling, the base case estimate of $11 /GJ (column 3 of ***Table G.1***) for FNG is the forecast new NW Shelf ex-plant gas contract price for

	LNG	Fracked - from spur pipeline	Fracked gas liquefied / compressed	Diesel
Base case - current estimate ($/GJ)	$18 (Broome) $19 (Derby, Thunderbird) $21 (Halls Creek)	$11.00	$15	$20 (Broome), $23 (Beagle Bay, Yungngora), $27 (Kalumburu)
High case - 2027 estimate ($/GJ)	$22 (Broome) $23 (Derby/Thunderbird) $25 (Halls Creek)	$11.00	N/A	$23 (Broome), $26 (Beagle Bay, Yungngora), $30 (Kalumburu)

Table G.1 Fuel cost assumptions ($/GJ)

	LNG base case (2018)	LNG base case (2018)	Diesel current		Diesel High – (2027)	Notes
	($/GJ)	($/GJ)	($/L)	($/GJ)	($/GJ)	
W/sale contract price at port (Karratha – LNG; Broome - diesel)	$4.50	$8.00	$1.30	$33.68		AEMO[22]
Assumed pipeline cost Dampier Karratha	0.3	0.3				
Estimate based on above (take away GST and excise for diesel)	$4.80	$8.30	$0.76	$19.69		Note that no GST or fuel excise is paid
Assumed liquefaction cost LNG	$6.70	$6.70				Liquefaction cost 30-40% of total [23]
LNG Transport–quad road train tanker 834 km Karratha -Broome	$3.33	$3.33				
TOTAL PRICE delivered to Broome	$14.83	$18.33		$19.69	$23.00	
Receiving costs- storage, regasification, distribution	$3.56	$3.56	$0.00	$0.00	$0.00	Receiving costs 15-25% of total[23]
TOTAL FUEL COST to power station at Broome	$18.39	$21.89		$19.69		
Total modelled Fuel Cost as above, rounded	$18.00	$22.00		$20.00	$23.00	

Table G.2 Break-down of fuel costs

	Km/days travel	Transport cost	Unit	Cost delivered	Base case rounded	High case rounded
LNG, Karratha to Broome	834	$3.29	$/GJ	$18.39	$18.00	$22.00
LNG, Broome to Derby	220	$0.88	$/GJ	$18.88	$19.00	$23.00
LNG, Broome to Fitzroy Crossing	398	$1.59	$/GJ	$19.59	$19.60	$23.60
LNG, Broome to Halls Creek	686	$2.74	$/GJ	$20.74	$21.00	$25.00
Diesel off ship at Broome	n/a	n/a	$/GJ	$19.69	$20.00	$23.00
Diesel, Broome to Aboriginal communities (10 t rigid truck)	500 k 1.5 day	$3.57	$/GJ	$23.57	$23.00	$26.00
Diesel, Broome to remote communities (10 t rigid truck)	1200 2.5 days	$7.15	$/GJ	$27.15	$27.00	$30.00

Table G.3 Fuel cost by destination, including road transport

Excluding excise and GST and assuming the CAPEX and OPEX recovery prices in the tables below and local transmission (transport) costs estimates in this study and that these are equal for CNG and LNG.

	LNG ($/DLE)	LNG ($/GJ)	CNG ($/DLE)	CNG ($/GJ)	Ref
W/sale contract price		$5.50		$5.50	CORE Energy Group[24]
Transport road train 400 km		$1.59		$1.59	Freightmetrics,[20]
CAPEX and OPEX recovery	$0.51	$14.13	$0.54	$14.96	CORE Energy Group[24]
TOTAL Cost (/$GJ)	LNG $21.22		CNG $22.05		

Table G.4 Relative costs of LNG and CNG delivered by truck.

	Grid CST	Grid LNG	Broome WPVB	Broome LNG	Thunderbird WPVB.	Thunderbird LNG	Thunderbird LNG	Derby LNG
LCOE base case fuel	$240	$270	$211	$241	$217	$247	$235	$265
Additional high case fuel	$4.23	$36.00	$7.17	$36.00	$5.50	$36.90	$6.78	$36.90

Table G.5 Effect on recommended base case scenarios of $4/GJ increase in fuel cost

natural gas in 2027 of $9 /GJ[22], plus pipeline cost of $2 per GJ. No low cost pipeline gas option has been modelled because we believe that a Kimberley FNG development would require this price to be viable and local pipelines would not be viable with the small volumes involved.

Liquefied or compressed FNG

The alternatives for FNG are much more expensive than the $11 /GJ piped cost (column 4 of ***Table G.1***). It could be liquefied or compressed near the wells then trucked to Kimberley power stations. Liquefied FNG would cost at least $16 /GJ and CNG $17 / GJ, only $1-2 /GJ less than the ex-Karratha LNG prices used in this modelling. The saving would be on trucking costs. Compressed FNG would cost more than LNG as CAPEX and OPEX costs are higher (***Table G.4***). The cost of compressing the gas would likely be lower than liquefying it, but this would likely be more than offset by the high cost of transporting many more truckloads. These two scenarios were not modelled.

Diesel

Diesel is also purchased by Horizon Power at low cost in contracts struck several years ago. The diesel price ex-Broome is assumed to be 76c per litre (19.70 /GJ), with fuel excise and GST not payable. For details, see ***Table G.3***. Transport to communities was costed at $3.58 /GJ to $7 / GJ based on the charge for a 10,000 litre rigid tanker truck with a journey time of one to two days[20]. Total rounded current cost of diesel including transport was assumed to be $23 /GJ for communities within 100-500 km of Broome mainly accessible by good roads, such as Beagle Bay and Yungngora, and $27 /MWh for more remote communities such as Kalumburu (see ***Table G.1***). As diesel prices are also trending up with oil prices[21], the current price is considered to be the low estimate in this study, with higher (2027) estimates being $3 /GJ higher. The effect of higher diesel prices is modelled in Section G.1 – Sensitivity.

The relative cost estimates are shown in ***Table G.4***.

These costs are higher than the estimates in the study for the price paid by Horizon Power in the Kimberley. However, the point to be noted is that CNG is estimated to cost about 80 c /GJ more than LNG, due to slightly higher CAPEX and OPEX recovery

Appendix G.1 Sensitivity of LCOE to fuel price

Fuel prices have a significant direct impact on LCOE and Large Generation Certificates (LGC's) are likely to exert downward pressure on PPAs struck before 2021, with the effect diminishing until 2030 when the existing RET scheme expires.

The fuel price increases considered likely by 2027 (***Table G.5***) have a significant direct effect on LCOEs by increasing variable costs, in particular for the IC scenarios, which consume most fuel.

The high fuel cost case for the major load centres – a $4 increase in the delivered cost of LPG - increases the cost gap between the recommended RE and the fuelled scenarios by over $30 (See ***Table G.5***).

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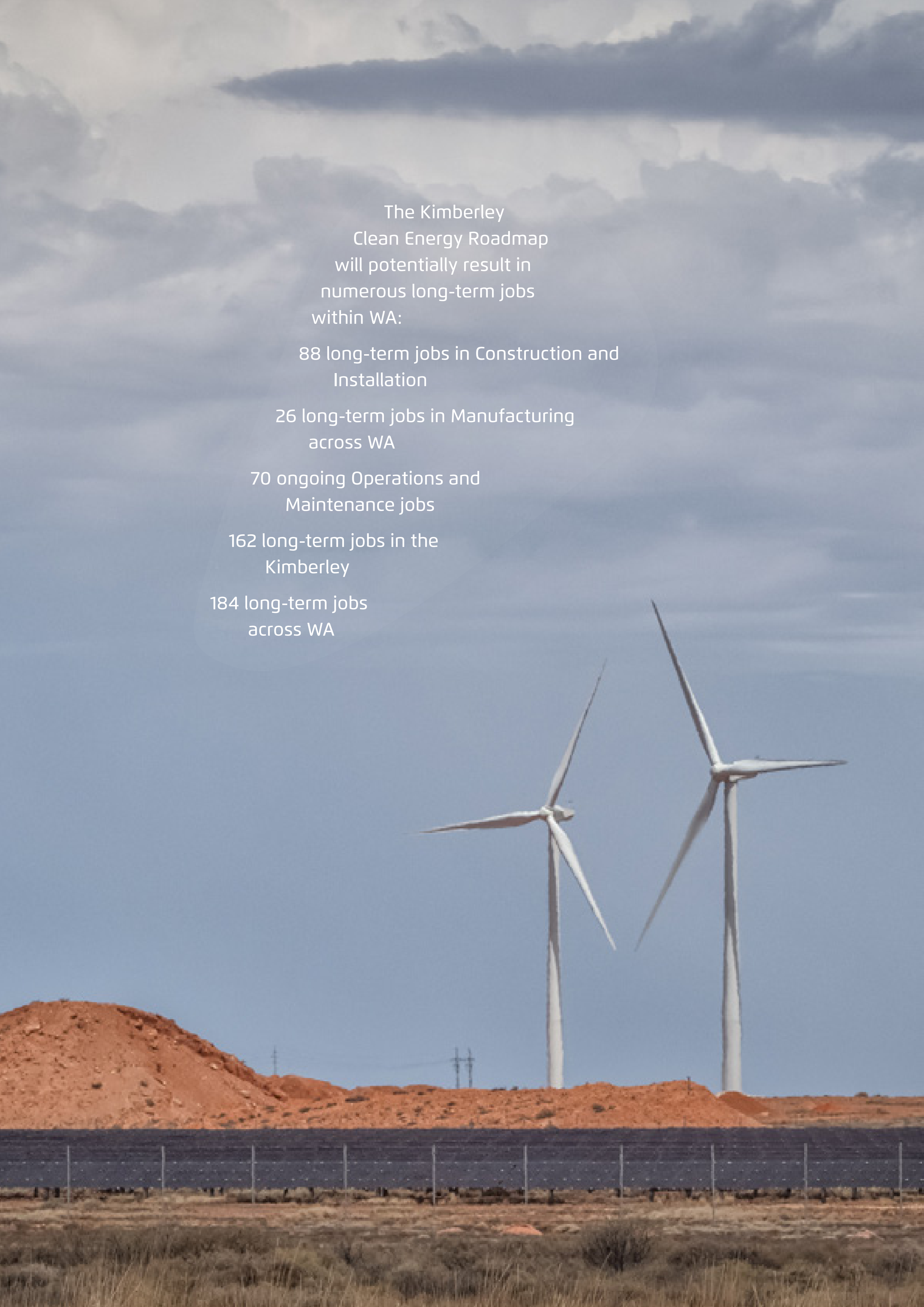
Image: Les Pullen, Professional Photographer



The Kimberley Clean Energy Roadmap will potentially result in numerous long-term jobs within WA:

88 long-term jobs in Construction and Installation

26 long-term jobs in Manufacturing across WA

70 ongoing Operations and Maintenance jobs

162 long-term jobs in the Kimberley

184 long-term jobs across WA

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Image: Damian Kelly Photography

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Sustainable Energy NOW

Kimberley Clean Energy Roadmap: Key Findings

Kimberley Clean Energy Roadmap

Currently 94% of Kimberley power is fossil-fuelled generation.

The Kimberley Clean Energy Roadmap shows that transitioning to 60-90% Renewable Energy will result in:

- savings of $30-$45 per Megawatt-hour on the wholesale price of electricity
- a saving of more than $14.8 million per year
- a reduction of 153,000 tonnes of CO2 emissions per year

The Renewable Energy build could include:

- wind (117 MW)
- utility-scale solar PV (97 MW)
- battery storage (132 MWh)

And make significantly reduced use of existing fossil-fuelled generation for backup.

The Kimberley Clean Energy Roadmap will produce 184 direct long-term jobs for the Kimberley region and State of WA, including local indigenous employment opportunities.

Renewables are simply cheaper, provide more jobs, and are better for the environment.

Sustainable Energy NOW