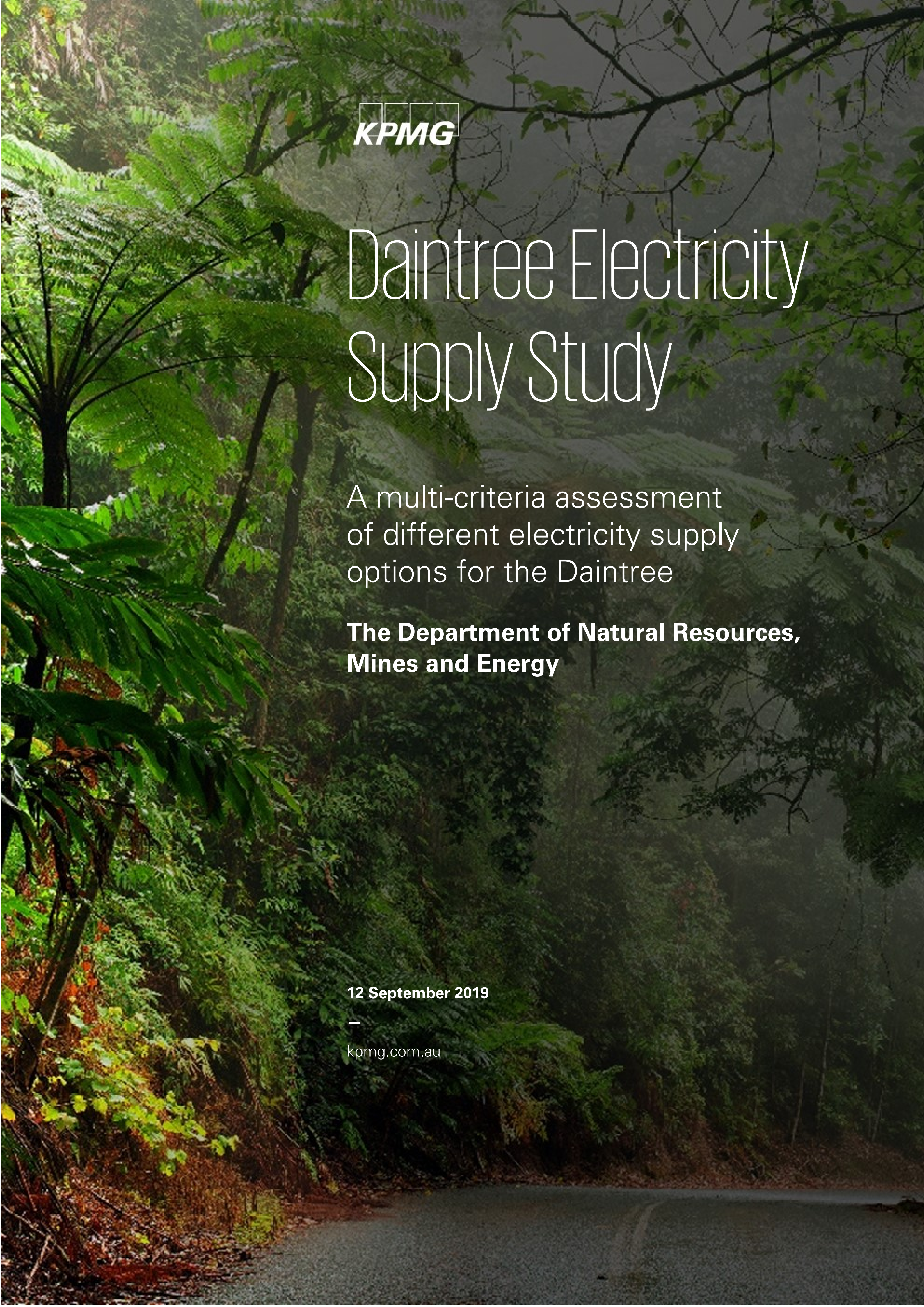

KPMG

Daintree Electricity Supply Study

A multi-criteria assessment of different electricity supply options for the Daintree

The Department of Natural Resources, Mines and Energy

12 September 2019

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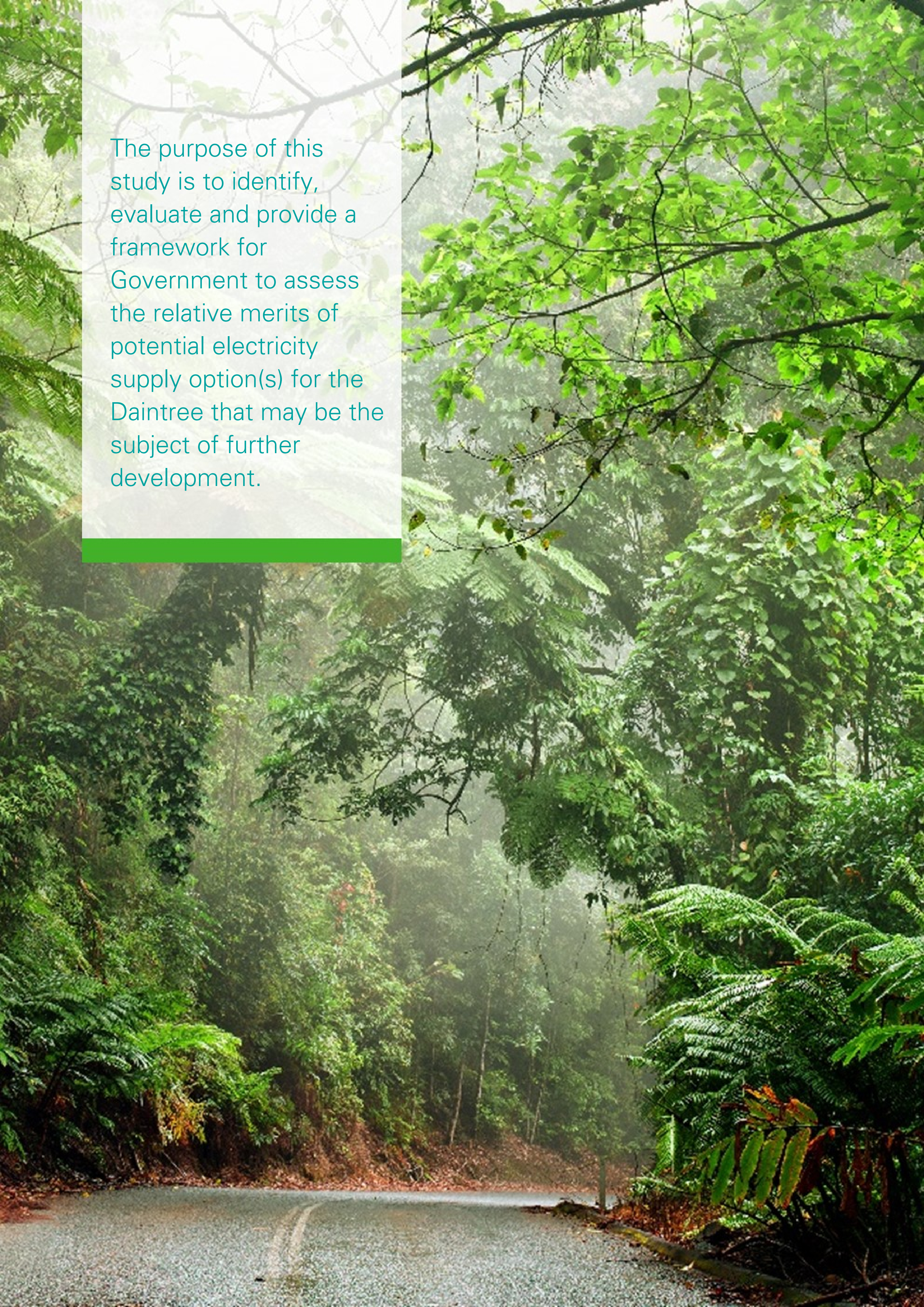
kpmg.com.au

The purpose of this study is to identify, evaluate and provide a framework for Government to assess the relative merits of potential electricity supply option(s) for the Daintree that may be the subject of further development.



KPMG

Limitations

This report has been prepared at the request of the Department of Natural Resources, Mines and Energy (DNRME) in accordance with the terms of KPMG's engagement contract executed 8 May 2019. The services provided under KPMG's engagement contract (the Services) have not been undertaken in accordance with any auditing, review or assurance standards. Any reference to 'audit' and 'review', throughout this report, is not intended to convey that the Services have been conducted in accordance with any auditing, review or assurance standards. Further, as KPMG's scope of work does not constitute an audit or review in accordance with any auditing, review or assurance standards, KPMG's work will not necessarily disclose all matters that may be of interest to DNRME or reveal errors and irregularities, if any, in the underlying information.

The responsibility for determining the adequacy or otherwise of our terms of reference is that of DNRME.

In preparing this report, KPMG and our subcontractor GHD have had access to information provided by DNRME, and publicly available information. We have relied upon the truth, accuracy and completeness of any information provided or made available to us in connection with the Services without independently verifying it. The publicly available information used in this report is current as of the date of this report. We do not take any responsibility for updating this information if it becomes out of date.

Any findings or recommendations contained within this report are based upon our reasonable professional judgement based on the information that is available from the sources indicated. Should the project elements, external factors and assumptions change then the findings and recommendations contained in this report may no longer be appropriate. Accordingly, we do not confirm, underwrite or guarantee that the outcomes referred to in this report will be achieved. We assume no obligation to update or otherwise revise this report unless requested by DNRME.

We do not make any statement as to whether any forecasts or projections will be achieved, or whether the assumptions and data underlying any such prospective financial information are accurate, complete or reasonable. We will not warrant or guarantee the achievement of any such forecasts or projections. There will usually be differences between forecast or projected and actual results, because events and circumstances frequently do not occur as expected or predicted, and those differences may be material.

Important Notice for Third Parties

This report is solely for the purpose set out in Section 1.2 of this report and for DNRME*'s* information and is not to be used for any other purpose.

If you are a party other than DNRME, KPMG and our subcontractor, GHD:

- owe you no duty (whether in contract or in tort or under statute or otherwise) with respect to or in connection with the attached report or any part thereof; and
- will have no liability to you for any loss or damage suffered or costs incurred by you or any other person arising out of or in connection with the provision to you of the attached report or any part thereof, however the loss or damage is caused, including, but not limited to, as a result of negligence.

If you are a party other than DNRME and you choose to rely upon the attached report or any part thereof, you do so entirely at your own risk. Other than our responsibility to DNRME, neither KPMG nor any member or employee of KPMG or their subcontractor, GHD, undertakes responsibility arising in any way from reliance placed by a third party on this report.

Summary of this Study

CONTEXT (SECTIONS 1-2)

Daintree forms part of the Wet Tropics World Heritage Area

- The Daintree region in Far North Queensland forms part of the Wet Tropics World Heritage Area.
- The region includes a coastal lowland area between the Daintree River and Cape Tribulation which comprises a small and unique local population that includes indigenous communities, tourist operators and a range of residents and business owners (this area is the subject of this study).
- Environmental constraints in the Daintree region include long wet seasons, shading, above average cloud cover and severe weather events. This means residents and businesses cannot solely rely on solar power, and instead have a heavy reliance on generators.
- The region is also geographically challenging with restricted access roads (e.g. access by river ferry crossing only), steep terrain and waterway crossings.

Daintree has been excluded from Ergon Energy's Distribution Authority and is off-grid

- Ergon Energy does not have a legal obligation, and is not authorised, to extend its existing network to the region. Consequently, electricity is supplied via individual standalone power systems (SPSs).
- A typical SPS comprises a combination of solar and diesel generation, complemented by battery storage and liquefied petroleum gas (LPG) for hot water and cooking. These systems are of varying sizes and age.
- Over many years numerous studies have been conducted in relation to electricity supply arrangements for the Daintree. While these studies have been valuable, there is currently insufficient information for Government to determine the most appropriate electricity supply option(s) for the region.

This study assesses the relative merits of different electricity supply options for the Daintree

- This study, prepared in response to a corresponding Queensland Government election commitment, assesses the relative merits of different electricity supply options for the Daintree.

ANALYSIS (SECTIONS 3-8)

A wide range of options are analysed including both microgrid and SPS based options

- The six options analysed as part of this study, comprising three microgrid based options and three individual SPS based options, include a combination of established (e.g. solar and diesel generators) and emerging technologies (e.g. hydrogen and lithium-ion battery storage).
- The options range from large scale investment in a single microgrid connecting all customers throughout the region to centralised electricity generation and storage through to incremental options such as fitting new batteries to existing installations to improve efficiencies.

Technical, planning and regulatory, financial, economic and risk factors are all considered

- This study analyses the technical, planning and regulatory, financial, economic and risk considerations associated with each option in order to inform their evaluation.

EVALUATION (SECTIONS 9-10)

The evaluation demonstrates that, at this time, no one option satisfies all of the Government's objectives

- The evaluation has been undertaken with reference to the Government's objectives including natural and cultural heritage, financial, reliability, economic, innovation and implementation considerations.
- At this time, no one option satisfies all of the Government's objectives. However, the evaluation suggests that some of the options have a relatively higher degree of alignment with the Government's objectives, and that these could be further considered and developed.

CONCLUSIONS (SECTION 11)

Microgrid based solutions do not appear to be the right long term solution for the Daintree

- A microgrid would supply residents with a reliable and secure energy network, however it presents numerous technical and commercial risks and is likely to be financially unviable without significant upfront and ongoing Government support. A microgrid would also take significant time to materialise, indicatively comprising a three year development and a further three year construction timeframe.
- A microgrid would require a large scale up front investment in long life infrastructure, which presents a risk to the natural and cultural heritage values of the region, when it appears that emerging technologies such as hydrogen may support improved SPS outcomes in the foreseeable future.
- For a typical household, the microgrid based solutions represent a significantly higher cost than current supply arrangements, costing around $11,000 to $15,000 more on an annual basis.
- If a microgrid based solution were to be pursued, separate community based microgrids appear preferable to a single whole-of-region microgrid. However, Government would need to consider equity issues around delivery of, and pricing for, separate microgrids.

SPS based solutions allow for incremental staged enhancement and replacement over time

- Relative to a microgrid, SPS based solutions preserve the existing natural and cultural heritage values of the Daintree and allow for incremental staged enhancement and upgrade/replacement of systems and technologies over time without necessarily requiring substantial financial support from the State.
- Opportunities to improve existing arrangements range from incremental enhancements (e.g. battery upgrade) to system upgrade and replacement (e.g. hydrogen based SPS, displacing diesel).
- For a typical household, the SPS based solutions cost around $700 and $6,000 more than current supply arrangements on an annual basis.

Opportunities exist to enhance existing systems in the short term

- In the short term, enhancements could be made to residents existing SPS systems by replacing lead acid battery storage with more advanced lithium-ion technology.
- This would provide a relatively low cost incremental enhancement to the current state, and could be seen as an interim solution for the region while other potential long term solutions are investigated and potentially relevant technologies mature.

A potential long term plan of action could initially involve staged investigations and testing of a hydrogen based SPS

- From a long term strategic energy future perspective, one option that may be worthy of further investigation is a hydrogen based SPS solution. This option would involve the installation of individual hydrogen fuel cells at customers' dwellings that replace their current SPS. Under this approach, compressed hydrogen, used by fuel cells to convert hydrogen into electricity, would be purchased and transported to customers from an established supplier outside of the Daintree area.
- Due to the current cost of hydrogen for domestic application, this approach does not currently represent a viable short term solution for the region but may be an example of the right long term solution as the hydrogen sector and technology continues to develop and mature over coming years.
- Importantly, further work and costs associated with advancing this option may be staged. For example, there may be merit in running a technology and logistics trial in the Daintree which seeks to demonstrate a representative hydrogen supply chain: sourcing hydrogen; transporting it into the Daintree; and power generation at the community level (through residential and commercial pilot units).

Guide to this Study

The figure opposite represents an upfront guide to the reader in terms of setting out the logical sequence and purpose of the various sections comprising this study.

The purpose of each section is reiterated at the beginning of each section throughout the study.

CONTEXT (SECTIONS 1-2)

- These sections overview the Government's objectives for this study and provides background information in relation to the Daintree region.
- They also outline estimated energy demand and supply in the region, breaking it down by area and customer type.

ANALYSIS (SECTIONS 3-8)

- These sections introduce six alternative energy supply options for the Daintree that are the subject of this study, including overviewing the technical characteristics of each option.
- Each option is then analysed from a planning and regulatory, economic, financial and risk perspective in order to inform their evaluation.

EVALUATION (SECTIONS 9-10)

- These sections introduce the seven evaluation criteria against which the energy supply options are to be evaluated and how these criteria cross-map to the Government's objectives.
- They outline KPMG and GHD’s collective assessment against these criteria, including each option being given a rating against each criterion informing an overall rating for each energy supply option.

CONCLUSIONS (Section 11)

- Drawing on the outcomes of the evaluation, this section provides high level conclusions for the Government's consideration in relation to where there may be merit in taking some options forward for further consideration and development.

Contents

1 BACKGROUND

PURPOSE OF THIS SECTION

- This section overviews the Government's objectives for this study and provides background information in relation to the Daintree region, including the complex planning and regulatory framework.
- Key references include: Section 1.3 - Objectives.

1.1 About the Daintree

The Daintree region, located north of Cairns in the Douglas Shire Council in Far North Queensland, is part of the Wet Tropics World Heritage Area. The Daintree rainforest is considered to be of outstanding natural value and includes flora representative of various stages of the evolution and radiation of the first flowering plants, and contains refugial areas that harbour examples of Australia's previous links to the Gondwanan supercontinent. The area is ecologically and scenically diverse and a major tourist attraction. The area is also located within Country of the Eastern Kuku Yalanji. Traditional Owners continue to use the area for cultural activities and have ongoing cultural obligations to be caring custodians of country, keeping culture strong for future generations.

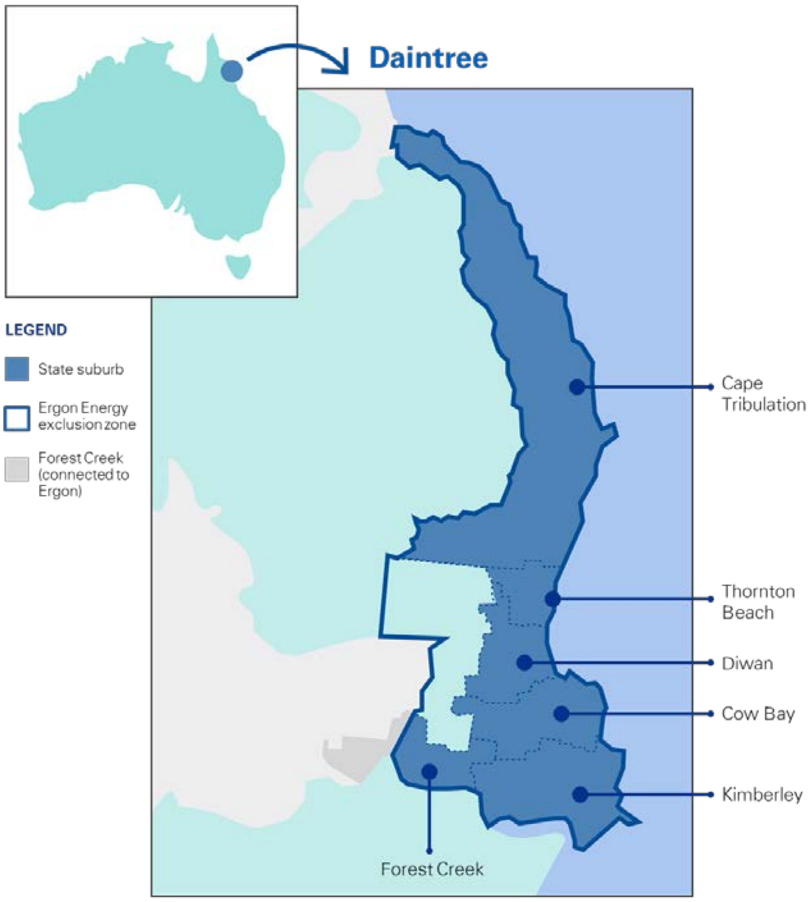
The Daintree region includes a coastal lowland area between the Daintree River and Cape Tribulation (the area subject of this study, "study area" or "Daintree region" or "Daintree") which comprises six state suburbs with a small and unique local population that includes indigenous communities, tourist operators and a range of residents and business owners.

Electricity Supply in the Daintree

The study area has been excluded from Ergon Energy's Distribution Authority, and Ergon Energy does not have a legal obligation, and is not authorised, to extend its existing supply network to provide electricity in the region[1]. Rather, electricity is principally supplied via individual standalone power systems (SPSs), typically comprising a combination of solar photovoltaic (PV) systems, diesel and/or petrol fuelled generators, liquefied petroleum gas (LPG) fuelled generators, battery storage and, for a limited number of properties, hydro-electric generators. These systems are of varying sizes and age. Environmental constraints in the Daintree region include long wet seasons, shading, above average cloud cover and severe weather events. This means residents and businesses cannot solely rely on solar power, and instead have a heavy reliance on generators.

[1] A small population of properties in the Forest Creek area are currently connected to the Ergon Energy distribution network. It is understood that these properties where already being supplied with electricity prior to the exclusion zone being implemented.

Figure 1-1: Daintree Region Study Area



Note: The above figure is for illustrative purposes only. The Wet Tropics of Queensland World Heritage Area extends to areas within the six state suburbs identified (refer Figure 5-1 for the Wet Tropics of Queensland World Heritage Area satellite map overlay).

1.2 Purpose and Scope

The purpose of this study is to inform the Queensland Government's 2017 election commitment to "*Partner with the Australian Renewable Energy Agency to develop a solution to deliver sustainable energy for the Daintree, to provide residents with a quality, clean, power supply to enhance their standard of living, reduce local pollution and support local businesses and jobs*".

To deliver on this purpose, this study involves a multi-criteria assessment of different electricity supply options for the Daintree, and identifies possible options that may be taken forward for further consideration and development.

In this way, the study will provide stakeholders and community members a clearer understanding of the practical considerations, including cost, associated with these electricity supply options, and provide Government the necessary information to make an informed decision on an appropriate path forward for the Daintree.

Purpose of this Study

The purpose of this study is to identify, evaluate and provide a framework for Government to assess the relative merits of potential electricity supply option(s) for the Daintree that may be the subject of further development.

1.3 Objectives

The Government's objectives for this study are to identify electricity supply options for the Daintree that:

- preserve the natural and cultural heritage values in the region
- are fiscally sustainable and/or present a commercial opportunity
- promote affordable electricity supply services and greater cost certainty
- promote improved environmental outcomes, including carbon and pollution reduction
- enhance the standard of living for electricity consumers and enhance associated economic outcomes in the region
- promote innovation and knowledge sharing amongst industry participants
- engage with and inform stakeholders regarding electricity supply in the region.

1.4 Work Completed to Date

A number of studies have been completed to date analysing electricity supply solutions for the Daintree. In developing this study, KPMG and GHD have given regard to these studies.

In particular, we have considered the findings and information in the following reports:

- Daintree/Cape Tribulation Electricity Survey, Compass Research (2016)
- Powering Daintree – A study of supply options for the Australian Renewable Energy Agency, Sunverge (2018)
- Daintree Electricity Supply Options – Natural Cultural Heritage Constraints Assessment, Wet Tropics Management Authority (WTMA) (2019)
- Daintree Electricity Supply Study Report – Aboriginal Cultural Heritage Constraints Assessment, Jabalbina Yalanji Aboriginal Corporation (JYAC) (2019)

Information gathered through members of the Stakeholder Reference Group established as part of the engagement process for the study has also been considered as part of this study.

The Stakeholder Reference Group comprises members from the follow groups and organisations:

- The Department of Natural Resources, Mines and Energy (DNRME)
- Douglas Shire Council
- Wet Tropics Management Authority
- Jabalbina Yalanji Aboriginal Corporation
- Daintree Renewable Energy Inc
- Daintree Marketing Cooperative
- Douglas Shire Sustainability Group
- Australian Tropical Research Foundation
- Australian Energy Market Commission
- Australian Renewable Energy Agency.

1.5 Regulatory and Planning Landscape

Environmental and Planning Considerations

The study area, defined as the coastal lowland Daintree between the Daintree River and Cape Tribulation, is subject to overlapping and complex regulatory jurisdictions. These include:

- National Park sections and some private properties within the study area that are within the Wet Tropics of Queensland World Heritage Area (WTWHA), and hence are bound by the policies and regulatory provisions of Commonwealth and international obligations under the *World Heritage Act 1993*, the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act) and the *Wet Tropics Management Plan 1998* (WTMP). This includes provisions for referral of the project to the Commonwealth for determination as to whether the project has significant impacts on Matters of National Environmental Significance and, if so, the level of assessment required.
- Some of the electricity supply options considered in this study include works within the Daintree National Park. The Department of Environment and Science (DES) is the primary custodian and has concurrent responsibilities in relation to assessment of State Development Applications where National Park is impacted.
- Similarly, the Daintree National Park sections are subject to an Indigenous Land Use Agreement (ILUA QI2006/026) under the provisions of the *Native Title Act 1993* and managed under the Daintree National Park Management Plan 2019.
- The locality is within a renowned area of high natural heritage and cultural values. These values are under the jurisdiction of multiple agencies, including DES, DNRME, Department of Agriculture and Fisheries (DAF), Wet Tropics Management Authority (WTMA) and Commonwealth Department of the Environment and Energy (DEE).
- Coordination of development approvals at a State level are undertaken through the State Assessment and Referral Agency (SARA), managed through the Department of State Development, Manufacturing, Infrastructure and Planning.
- Douglas Shire Council local laws and policies continue to apply in accordance with the provisions of the *Local Government Act 2009.*

To varying degrees, each of the electricity supply options considered in this study has the potential for wide ranging permitting and approval requirements depending on the jurisdiction of the tenure involved, site-specific locality details and level of disturbance proposed. Actions that trigger the Commonwealth EPBC Act and WTMA WTMP for example, may be determined to require an Environmental Impact Study (EIS) or Public Environment Report (PER) level of supporting information and may take up to three years to progress. State approvals are largely determined (but not exclusively) by the provisions of the Queensland *Planning Act 2016* and similarly the level of supporting information will vary significantly according to tenure, site specific location details and obligatory requirements of the regulatory agencies under their own legislation. Time frames for State approvals on their own, and supporting information requirements, subsequently may vary widely for different options.

Energy Regulatory Considerations

The Australian Energy Market Commission (AEMC) is presently undertaking a review into the regulatory arrangements frameworks for stand-alone power systems under the National Electricity Law (NEL), the National Energy Retail Law (NERL) and associated rules[2]. The Priority 2 area of this review will develop a national framework for the ongoing regulation of third party stand-alone power systems, that is, power systems not provided by the local distribution businesses which include microgrid systems and electricity supply systems for individual customers. This framework will apply to both the microgrid and individual options being considered to provide electricity supply to customers within the Daintree.

Regulation – Microgrid Options

It is considered likely that any Daintree microgrid options would be classified as Category 2 systems (which includes microgrids supplying smaller towns and more than a handful of customers) under the framework presently being developed by the AEMC[3].

The Australian Energy Market Operator (AEMO) is also currently undertaking work to allow for better integration of distributed energy resources, including large flexible loads such as electrolysers. The National Hydrogen Strategy, due to be published late 2019, is expected to include proposed legislative and regulatory reforms that will be required to remove barriers for development of hydrogen projects.

There are no regulations currently adopted in Australia that specifically relates to the centralised production of hydrogen via electrolysis. According to the National Hydrogen Roadmap[4], the existing safety regulations are broad enough to cover the use of hydrogen as a flammable gas. State regulation will determine if an electrolysis facility is to be classified as a Major Hazard facility, which may impose additional licensing and regulation.

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[2] https://www.aemc.gov.au/market-reviews-advice/review-regulatory-frameworks-stand-alone-power-systems
[3] Review of the regulatory frameworks for stand-alone power systems – Priority 2. AEMC 27 June 2019.
[4] National Hydrogen Roadmap, Pathways to an economically sustainable hydrogen industry, CSIRO, 2017.

Regulation – Individual Options

It is considered likely that any managed Daintree individual options (i.e. Option I2) would be classified as Category 3 systems (which includes Individual Power Systems with a sale of energy) under the framework presently being developed by the AEMC. The final framework is still under consideration by the AEMC but the broad guidelines provided in Section 5.1 will likely form the regulatory environment for supply to customers in the Daintree.

A detailed gap analysis is required to identify any potential revisions to existing standards or adoption of new standards needed to support the long term adoption of hydrogen in remote area power applications in Australia. Existing standards that may require review include *AS/NZS 5263.0: Gas appliances - General Requirements* and *AS/NZS 5601.1: Gas appliances - General Installations – Part 1: General Installations*. International standards that have been developed to ensure the safe use of hydrogen, but have not been adopted in Australia, include *ISO/TR 15916 – Basic considerations for the safety of hydrogen systems* and *ISO 26142 – Hydrogen detection apparatus – Stationary applications.*

1.6 Limitations

The analysis and conclusions contained within this study are limited in part by a number of factors, including:

- **Demographic/customer data:** The Daintree community is remote and, as such, there are inherent limitations in the demographic/customer data available. Available data that has been considered and analysed to estimate the number of potential customers accessing electricity supply has included:
  - Census data on the six State suburbs statistical areas
  - Desktop and stakeholder research of local businesses and structures
  - Demographic estimates included in previous studies and surveys.
- **Detailed information about resident's present energy systems:** Information from previous surveys has been used as a guide to the size, configuration and age of energy systems that are presently utilised by Daintree residents. However this information is limited and in some cases changes may have occurred since the survey was performed.
- **Predictions of uptake rates for new supply options by residents:** Uptake rates for new supply options by residents will depend on many factors including cost of energy, cost of connection, age of existing systems, the compatibility of the residences with being connected to the supply system, attitude of residents to the systems that will be available, reliability and security, and availability of support. As such, uptake rates may not match forecast or assumed levels.
- **Regulatory and approval requirements**: The level of regulatory approvals and permitting requirements will be largely dictated by options and site-specific factors that cannot be taken into account at this stage. The level of supporting information required for regulatory approvals and permits, and the assessment timeframe periods for these, vary widely. As outlined in the previous section, the regulatory framework for some options, e.g. microgrids, does not currently exist which introduces an additional level of uncertainty for delivery.

1.7 Project Team

A summary of the roles and responsibilities of the study's project team are outlined in the table below.

Table 1-1: Project Team

PROJECT TEAM		ROLE
SPONSOR	**The Department of Natural Resources, Mines and Energy**	DNRME is the Department charged with informing the Queensland Government's election commitment. DNRME have engaged KPMG (and its subcontractor GHD) to provide robust, independent analysis that enables Government decision making. DNRME has been responsible for setting the study's: • Purpose • Project Objectives • Evaluation Criteria
ADVISORS	**KPMG**	KPMG is one of Australia's leading providers of financial and commercial advice on infrastructure projects. KPMG is the lead coordinating advisor on the Daintree Electricity Study, including providing specialist advice on: • Options development • Financial analysis and modelling • Qualitative economic analysis • Commercial strategy
	GHD	GHD is one of the world's leading professional services companies operating in the global markets of water, energy and resources, environment, property and buildings, and transportation. GHD has provided specialist advice on: • Options development • Electricity demand and requirements • Infrastructure planning and costings • Operational costings • Regulatory and environmental considerations

2 DAINTREE ILLUSTRATIVE CUSTOMERS

PURPOSE OF THIS SECTION

- This section outlines estimated energy demand and supply in the Daintree, including breaking it down by area and customer type.
- Key references include: Table 2.4 - Total Estimated Annual Load by Community; and Table 2.6 - Illustrative Customer Estimated Costs.

2.1 Illustrative Customers

For the purposes of this study, and to provide a point of comparison between existing arrangements (Current State) and potential supply options, estimates of electricity loads and levelised annual costings have been developed for the following four Illustrative Customers.

Table 2-1: Illustrative Customers

ID#	ILLUSTRATIVE CUSTOMER	DESCRIPTION
IC1	Residential or equivalent	A typical residential household (or equivalent) in the Daintree region.
IC2	Residential BnB or equivalent	A typical residential household which is also offering a small BnB service (or equivalent) in the Daintree region.
IC3	Commercial shop or equivalent	A typical small sized business/commercial shop that does not offer an accommodation service (or equivalent) in the Daintree region.
IC4	Multi-room accommodation or equivalent.	A medium sized business/multi-room accommodation establishment (or equivalent) in the Daintree region.

Given the diverse range of residential and business circumstances, including each SPS being at a different stage in the replacement cycle, the four Illustrative Customers have been developed to represent the average of a range of electricity consumers within each Illustrative Customer category. Each Illustrative Customer has been developed using a detailed bottom-up approach that practically enables community stakeholders to review and interpret relative to their own circumstances. For example, giving regard to their SPSs composition, age, capacity, performance metrics, annual load etc. to assist them in considering the relative cost of an alternative electricity supply arrangement.

More broadly, the approach also enables an illustrative aggregation for the Daintree region as a whole, for selected communities or individual classifications to compare with the electricity supply options.

Estimated Number of Daintree Customers

The number of structures (customers) that could utilise an electricity supply in the Daintree region is estimated at 489 structures, comprising approximately:

- 385 Residential households[5]
- 87 Businesses
  - Accommodation businesses and BnBs (excluding AirBnB)
  - Other businesses with no accommodation (e.g. Shops, cafes, booking offices)
- 17 Low use structures
  - Small offices, buildings, sheds, Telstra structures, closed / vacant structures.

Each of these structures has been classified within each of the Illustrative Customer categories (note, 7 businesses and all 17 low use structures have been classified in the Residential Illustrative Customer category). As set out in Section 2.2, there are inherent limitations in developing this estimate, however, it is considered that this estimate is within an order of magnitude of what is present in the Daintree region. These limitations have also been taken into account in sizing the options, and other related assumptions such as usage growth and development growth.

In order to model energy systems in use by each of the Illustrative Customers, information from previous surveys and studies has been utilised and this has also been cross referenced to typical energy usage benchmarks for each classification of customer in northern Queensland.

The table below summarises the total estimated number of Illustrative Customers in the Daintree.

Table 2-2: Estimated Number of Daintree Customers

TOTAL ESTIMATED DAINTREE CUSTOMERS		CAPE TRIBULATION	THORNTON BEACH	DIWAN	COW BAY	FOREST CREEK	KIMBERLEY		
ILLUSTRATIVE CUSTOMER	ID#	NORTHERN	CENTRAL			SOUTHERN		TOTAL	% TOTAL
Residential^	IC1	67	10	98	145	66	23	409	84%
Residential BnB^	IC2	10	4	15	21	3	2	55	11%
Commercial shop^	IC3	3	1	1	3	-	-	8	2%
Multi-room accommodation^	IC4	8	-	6	3	-	-	17	3%
Total		88	15	120	172	69	25	489	100%
Community Total		88			307		94	489	
% Community Total		18%			63%		19%		100%

^Or equivalent

Note: The Residential (or Equivalent) Illustrative Customer (i.e. IC1) includes a limited number (less than 5%) of low use structures such as small offices, sheds and other structures that utilise electricity. As set out above, these structures are assumed to be offset by IC1 customers that have a higher annual load than assumed for IC1.

[5] Note: the average of a number of available estimates was used to determine the number of residential households

2.2 Illustrative Customer Loads

This section sets out the estimated annual load by each Illustrative Customer and for the Daintree region as a whole. Given metering data is not available due to the use of SPSs, the loads outlined in this section have been developed using information from various sources, including the Compass Research – Daintree/Cape Tribulation Electricity Survey, industry benchmarks (adjusted for the Daintree) and GHD experience.

Forecast Electricity Load Methodology – Individual Illustrative Customers

A bottom up approach has been used to develop the estimated annual load for each Illustrative Customer and characteristics of SPSs typically utilised, as set out in Table 2-3. To test their reasonableness, these estimates have been compared to industry benchmarks, including through making adjustments for Daintree conditions and likely electricity usage patterns.

Key assumptions underpinning annual load estimates include:

- **Cooking and water heating has been excluded from the load estimates:** Based on the Compass Research of a sample of 100 households and businesses, 99% used gas for cooking and 75% used gas for water heating. As a result, it has been assumed that all Illustrative Customers use gas (LPG) for cooking and water heating purposes. It has also been assumed that gas appliances and hot water systems will not be replaced by electric units under each of the electricity supply options. Gas consumption has however been separately estimated in Table 2-3.
- **Air-conditioning is not assumed for the two residential Illustrative Customers (i.e. IC1 and IC2):** The Compass Research also indicated only 14% of the sample used air-conditioning, and use of this appliance was limited by the capacity of their SPS.
- **All Illustrative Customers use diesel generators:** While the Compass Report indicated an even use of diesel and petrol generators, to avoid adding complexity to the analysis, only diesel generators have been assumed.
- **Only Residential Illustrative Customers (IC1 and IC2) use (lead-acid) batteries:** Given the load requirements of business Illustrative Customers, and Compass Report Research indicating that businesses operate diesel generators for 17.1 hours per day (compared with 3.5-4.5 hours a day for residential), no battery storage has been assumed for business Illustrative Customers. Based on the Compass Research, 80% of batteries were lead-acid.
- **Businesses rely heavily on generators:** Illustrative Customers IC3 and IC4 are assumed to rely heavily on generators for their electricity supply.
- **Back-up generators are primarily non-operational for residential Illustrative Customers:** While it is assumed that all Illustrative Customers own a back-up generator, it is assumed that the two residential Illustrative Customers (I1 and I2) use their back-up when their system has broken down (i.e. non-operational for the majority of the time), compared with the two business Illustrative Customers (I3 and I4) where it is assumed the back-up generator is used when the primary generator is undergoing maintenance or if additional load is required (i.e. is frequently operated).

- **Assumptions have been developed to account for the extensive Daintree wet season:** Given the extensive wet season in the Daintree, estimated at being 160 days or 44% of the year based on an analysis of Bureau of Meteorology rainfall averages between 2014 to 2018, the annual estimated loads take into account energy usage during both the wet and dry seasons. Hours of generation for solar PV and generators reflect these seasons and have been developed based on the Compass Research as well as analysis of average peak sun hours during these seasons.
- **The age of SPSs are based on Compass Research:** The age of each component of the SPSs is broadly based on Compass Research and an estimate of a likely replacement profile.
- **Performance metrics are based on GHD experience:** Capacity factors and load factors have been developed based on GHD experience of the likely performance of the SPS and relate to installations with high levels of shading.

Table 2-3: Illustrative Customer Annual Loads

IC#	STAND-ALONE POWER SYSTEM		CAPACITY	AGE	EXPOSURE / GENERATION	CAPACITY FACTOR	LOAD FACTOR	DAYS	ESTIMATED ANNUAL LOAD
	POWER SOURCE	TYPE	KW	YRS / HRS	HRS/DAY	%	%	DAYS	KWH P.A.
IC1	Solar PV - Dry season	Renewable	3.2 kW	11.0 yrs	5.5 hrs	22.9%	25.0%	205 days	908 kWh
	Solar PV - Wet Season	Renewable	3.2 kW		4.7 hrs	19.6%	25.0%	160 days	605 kWh
	Generator (diesel) - Dry season	Fossil Fuel	5.0 kW	10.0 yrs	3.5 hrs	95.0%	30.0%	205 days	1,022 kWh
	Generator (diesel) - Wet season	Fossil Fuel	5.0 kW		4.5 hrs	95.0%	30.0%	160 days	1,026 kWh
	Backup Generator (diesel) - Dry season	Fossil Fuel	2.0 kW	5.0 yrs	-	-	-	205 days	-
	Backup Generator (diesel) - Wet season	Fossil Fuel	2.0 kW		-	-	-	160 days	-
	Batteries (lead-acid)	Chemical	16.4 kWh	5.0 yrs	n/a	n/a	n/a	n/a	n/a
	TOTAL								3,561 kWh
	LPG	Fossil Fuel	45kg						5,525 Mj
IC2	Solar PV - Dry season	Renewable	5.0 kW	11.0 yrs	5.5 hrs	22.9%	25.0%	205 days	1,409 kWh
	Solar PV - Wet Season	Renewable	5.0 kW		4.7 hrs	19.6%	25.0%	160 days	940 kWh
	Generator (diesel) - Dry season	Fossil Fuel	7.5 kW	10.0 yrs	3.5 hrs	95.0%	35.0%	205 days	1,789 kWh
	Generator (diesel) - Wet season	Fossil Fuel	7.5 kW		4.5 hrs	95.0%	35.0%	160 days	1,796 kWh
	Backup Generator (diesel) - Dry season	Fossil Fuel	2.0 kW	5.0 yrs	-	-	-	205 days	-
	Backup Generator (diesel) - Wet season	Fossil Fuel	2.0 kW		-	-	-	160 days	-
	Batteries (lead-acid)	Chemical	31.3 kWh	5.0 yrs	n/a	n/a	n/a	n/a	n/a
	TOTAL								5,934 kWh
	LPG	Fossil Fuel	2x45kg						8,169 Mj
IC3	Solar PV - Dry season	Renewable	1.0 kW	11.0 yrs	5.5 hrs	22.9%	30.0%	205 days	338 kWh
	Solar PV - Wet Season	Renewable	1.0 kW		4.7 hrs	19.6%	30.0%	160 days	226 kWh
	Generator (diesel) - Dry season	Fossil Fuel	10.0 kW	10.0 yrs	17.1 hrs	95.0%	50.0%	205 days	16,651 kWh
	Generator (diesel) - Wet season	Fossil Fuel	10.0 kW		17.1 hrs	95.0%	50.0%	160 days	12,996 kWh
	Backup Generator (diesel) - Dry season	Fossil Fuel	10.0 kW	5.0 yrs	1.0 hrs	95.0%	50.0%	205 days	974 kWh
	Backup Generator (diesel) - Wet season	Fossil Fuel	10.0 kW		1.0 hrs	95.0%	50.0%	160 days	760 kWh
	Batteries (lead-acid)	Chemical	-	-	n/a	n/a	n/a	n/a	n/a
	TOTAL								31,945 kWh
	LPG	Fossil Fuel	-						-
IC4	Solar PV - Dry season	Renewable	5.0 kW	11.0 yrs	5.5 hrs	22.9%	30.0%	205 days	1,691 kWh
	Solar PV - Wet Season	Renewable	5.0 kW		4.7 hrs	19.6%	30.0%	160 days	1,128 kWh
	Generator (diesel) - Dry season	Fossil Fuel	30.0 kW	10.0 yrs	17.1 hrs	95.0%	60.0%	205 days	59,944 kWh
	Generator (diesel) - Wet season	Fossil Fuel	30.0 kW		17.1 hrs	95.0%	60.0%	160 days	46,786 kWh
	Backup Generator (diesel) - Dry season	Fossil Fuel	30.0 kW	5.0 yrs	1.0 hrs	95.0%	60.0%	205 days	3,506 kWh
	Backup Generator (diesel) - Wet season	Fossil Fuel	30.0 kW		1.0 hrs	95.0%	60.0%	160 days	2,736 kWh
	Batteries (lead-acid)	Chemical	-	-	n/a	n/a	n/a	n/a	n/a
	TOTAL								115,790 kWh
	LPG	Fossil Fuel	4x45kg						15,000 Mj

Forecast Electricity Load Methodology – Total Daintree Region

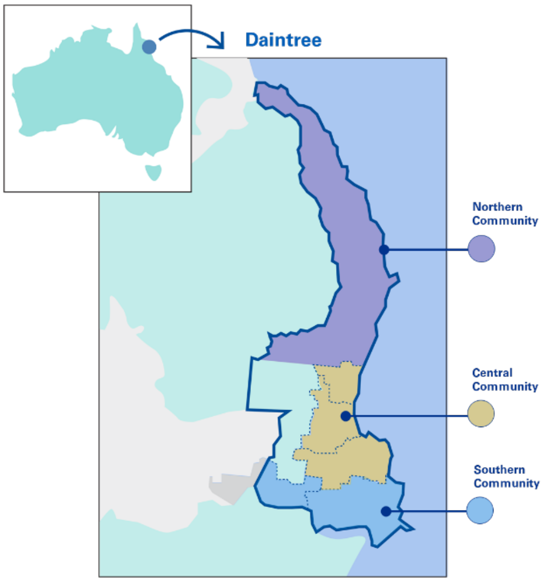
In order to determine the Daintree region's total estimated annual load, Illustrative Customers loads have been aggregated using the estimated number of Daintree customers set out in Table 2-2 above.

Due to population clustering and geographical reasons, community based supply options have been investigated as part of this study. The Daintree region has been divided up into the following three communities (as per the approach of previous studies):

- **Northern Community:** Cape Tribulation
- **Central Community:** Thornton Beach, Diwan and Cow Bay
- **Southern Community:** Forest Creek and Kimberley.

These communities are highlighted in Figure 2-1 and specific community based supply options will be evaluated as part of this study.

Figure 2-1: Daintree Communities



The tables and figure below set out the Daintree region's total estimated annual load, including by community (refer Table 2-4) and by generation source (refer Table 2-5).

Table 2-4: Total Estimated Annual Load by Community (MWh)

ILLUSTRATIVE CUSTOMER	NORTHERN COMMUNITY	CENTRAL COMMUNITY	SOUTHERN COMMUNITY	TOTAL REGION	TOTAL
	MWH				%
IC 1	239	901	317	1,457	36%
IC 2	59	237	30	326	8%
IC 3	96	160	-	256	6%
IC 4	926	1,042	-	1,968	49%
Total	**1,320**	**2,340**	**347**	**4,007**	**100%**

Figure 2-2: Illustrative Customer Annual Loads – Total Customer Load and Individual Customer Load

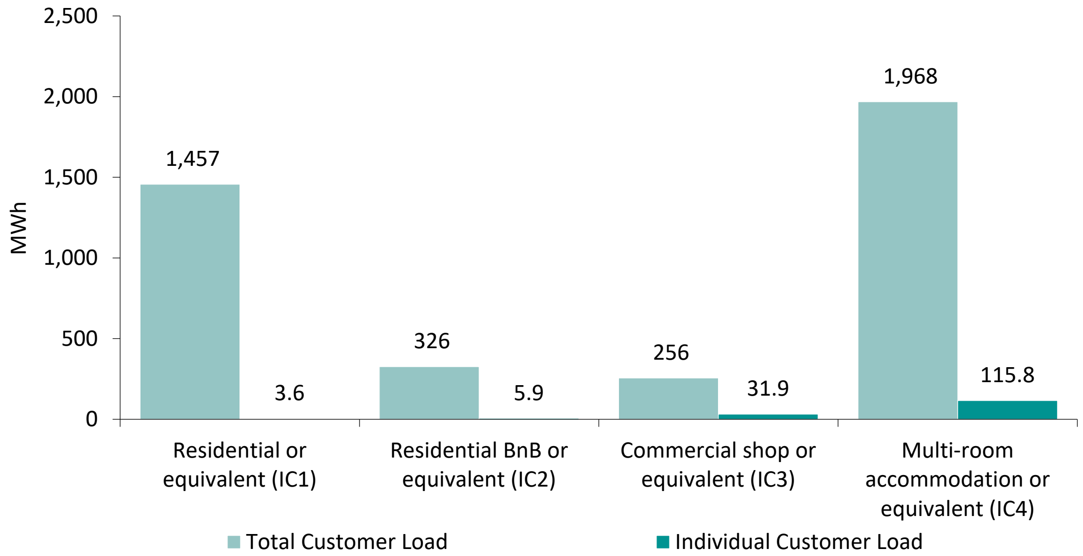


Table 2-5: Total Estimated Annual Load by Generation Source (MWh)

GENERATION SOURCE	IC1	IC2	IC3	IC4	TOTAL (MWH)
	IC TOTAL (MWH)				
Solar PV	619	129	5	48	800
Generator	838	197	237	1,814	3,087
Back-up Generator	-	-	14	106	120
Battery	-	-	-	-	-
Total	**1,457**	**326**	**256**	**1,968**	**4,007**
GENERATION SOURCE	**% IC TOTAL**				**% TOTAL**
Solar PV	42%	40%	2%	2%	20%
Generator	58%	60%	93%	92%	77%
Back-up Generator	-	-	5%	5%	3%
Battery	-	-	-	-	-
Total	**100%**	**100%**	**100%**	**100%**	**100%**

Illustrative Customer Loads over Time

In developing this study, it has been assumed that individual Illustrative Customer loads will not change over time. The overall total demand and energy used by customers in the Daintree area may increase as a result of additional development, however it has been assumed that any additional customers will, on average, have electricity usage patterns consistent with one of the four Illustrative Customer categories.

Key reasons for assuming individual Illustrative Customer demand and energy will remain at existing levels include:

- New appliances purchased by customers for use at their household or business will be at least as, and quite often more, energy efficient as existing appliances.
- The cost of energy and the cost of the components supplying that energy in the Daintree is sufficiently high that customers need to carefully consider the addition of any device that would result in an increase in energy usage.
- In general, energy efficiency and environmental considerations are important issues for residents of the Daintree.

An analysis of Illustrative Customer loads over time against each of the options has been undertaken as part of the technical analysis in Section 4.

2.3 Illustrative Customer Costs

This section sets out the estimated annual cost of electricity supply by each Illustrative Customer and for the Daintree region as a whole. The Illustrative Customer SPSs and load profiles developed in Table 2-3 have been used to calculate the estimated cost of electricity supply for each Illustrative Customer. The costings developed in this section have been developed using information from various sources, including industry benchmarks and GHD experience.

Forecast Electricity Cost Methodology – Individual Illustrative Customers

Consistent with the development of the Illustrative Customer loads, a bottom up approach has been used to develop the estimated costs for each Illustrative Customer, as set out in Table 2-6. Levelised costings (i.e. the average annual minimum price at which electricity must be sold in order to break-even over the lifetime of the project) of Illustrative Customers have been developed as part of the financial analysis in Section 7.

Key assumptions underpinning cost assumptions include:

- **Base date costs:** all base date cost inputs are in $2019.
- **Upfront costs are sunk costs:** Given SPSs are currently in place in the Daintree, no upfront costs have been included for Illustrative Customers.
- **Solar PV and batteries are assumed to have a lower cost of replacement than set out in Table** 2-6 **due to technological advancements:** Section 7.2 sets out the assumed downward trending cost curves of solar PV and batteries due to technological advancement. These cost curves show the costs assumed in Table 2-6 below (i.e. in $2019) are higher than assumed in the future.

- **Assumed lead-acid battery replacement cost allows replacement with lithium-ion:** As the uptake and production of lithium-ion batteries continues to increase over time, the cost to install is also expected to decline. As a result, it is expected that when lead-acid batteries that are presently in use for energy storage in the Daintree reach their end of life, it will be possible to replace the lead-acid batteries with lithium-ion cells for a similar cost or lower. This has no impact on the analysis as one form of energy storage is replaced with another at a similar cost.
- **Illustrative Customers replace SPS components at normal end of life:** When components of the SPSs reach end of life it has been assumed that the replacement cost of the item of plant will be incurred by the Illustrative Customer.
- **Illustrative Customers incur normal maintenance on SPS components:** It has been assumed that the Illustrative Customer performs recommended levels of maintenance on the components of their SPS.
- **Costings are adjusted for a potential ATO fuel tax credit:** For off-grid regions such as the Daintree, fuels such as petrol and diesel to power generators, and heating oil and LPG for heating and cooking are likely to fall under eligible fuels under the ATO fuel tax credit scheme (LPG may only do so when used for business purposes). It is unclear the extent that the fuel tax credit scheme is being accessed by Daintree residents, however it is likely that businesses in the region are claiming the credits due to the likelihood of their accountants claiming the credit in their business activity statements (regardless of whether the business has a made a profit). It is noted that individuals that do not have a taxable income (i.e. pensioners, veterans) are still able to claim tax fuel credits.

Table 2-6: Illustrative Customer Estimated Costs

IC#	STAND-ALONE POWER SYSTEM		UPFRONTCOSTS	ONGOING COSTS						
			CAPITAL	LIFECYCLE		MAINTENANCE	FUEL AND TRANSPORTATION			
			CAPITAL COST (REAL)	REPLACEMENT VALUE^ (REAL)	USEFUL LIFE	MAINTENANCE COST (REAL)	VOLUME	UNIT COST (REAL)	TRANSPORT-ATION COST (REAL)	POTENTIAL FUEL TAX CREDIT
	POWER SOURCE	TYPE	$	$	YRS / HRS	$/P.A.	L P.A.	$/UNIT	$ P.A.	$/UNIT
IC1	Solar PV	Renewable	-	$6,220	20.0 yrs	$100	n/a	n/a	n/a	n/a
	Generator (diesel)	Fossil Fuel	-	$6,250	20.0 yrs	$164	819.4 L	$1.40	$400	$0.416
	Backup Generator (diesel)	Fossil Fuel	-	$2,500	20.0 yrs	$164	-	-	-	-
	Batteries (lead-acid)	Chemical	-	$4,094	9.0 yrs	-	n/a	n/a	n/a	n/a
	TOTAL									
	LPG	Fossil Fuel	-	-	-	$221	5,524.5 Mj	$0.06	$400	$0.00
IC2	Solar PV	Renewable	-	$8,000	20.0 yrs	$100	n/a	n/a	n/a	n/a
	Generator (diesel)	Fossil Fuel	-	$6,250	20.0 yrs	$287	1,433.9 L	$1.40	$800	$0.416
	Backup Generator (diesel)	Fossil Fuel	-	$2,500	20.0 yrs	$164	-	-	-	-
	Batteries (lead-acid)	Chemical	-	$7,829	9.0 yrs	-	n/a	n/a	n/a	n/a
	TOTAL									
	LPG	Fossil Fuel	-	-	-	$327	8,169.0 Mj	$0.06	$600	$0.00
IC3	Solar PV	Renewable	-	$4,000	20.0 yrs	$50	n/a	n/a	n/a	n/a
	Generator (diesel)	Fossil Fuel	-	$12,500	20.0 yrs	$1,186	11,858.9 L	$1.40	$1,000	$0.416
	Backup Generator (diesel)	Fossil Fuel	-	$12,500	20.0 yrs	$69	693.5 L	$1.40		$0.416
	Batteries (lead-acid)	Chemical	-	-	-	-	n/a	n/a	n/a	n/a
	TOTAL									
	LPG	Fossil Fuel	-	-	-	-	-	-	-	-
IC4	Solar PV	Renewable	-	$8,000	20.0 yrs	$100	n/a	n/a	n/a	n/a
	Generator (diesel)	Fossil Fuel	-	$25,000	20.0 yrs	$4,269	42,691.9 L	$1.40	$3,000	$0.416
	Backup Generator (diesel)	Fossil Fuel	-	$25,000	20.0 yrs	$250	2,496.6 L	$1.40		$0.416
	Batteries (lead-acid)	Chemical	-	-	-	-	n/a	n/a	n/a	n/a
	TOTAL									
	LPG	Fossil Fuel	-	-	-	$600	15,000.0 Mj	$0.06	1,000	$0.136

^Replacement values are in 2019 dollars. As set out in the assumptions above, Solar PV and batteries are assumed to have a lower cost of replacement due to technological advancements.

3 OVERVIEW OF OPTIONS

PURPOSE OF THIS SECTION

- This section overviews the six electricity supply options that have been identified and assessed as part of this study.
- Key references include: Table 3.1 - Electricity Supply Options.

3.1 Options Identification

The table below summarises the six electricity supply options that have been assessed as part of this study, including a high level overview of the sources of generation. These options were discussed and agreed with DNRME at the commencement of this study and include previously identified and new options.

The options have been broken down into three categories.

- **Regional supply options:** Options that deliver a single electricity supply solution to the entire Daintree region.
- **Community supply options:** Options that deliver a single and bespoke electricity supply solution to each Daintree community. These options overcome the need to extend an electricity network between more populated communities, across sometimes difficult terrain as well as across areas of natural and cultural value.
- **Individual supply options:** Options that deliver an individual electricity supply solution to each individual Daintree customer.

A regional supply option that delivers a microgrid and utilises hydrogen fuel generation has been developed, refer Option R2, in order for DNRME to understand the potential cost and key considerations of this option, which is separately being pursued by a stakeholder group in the Daintree. Note that Option R2 has been developed based on a presumed technological solution as there is limited information available on the proposed solution at the time of this study.

As an alternative to Option R2 it may be possible to develop a microgrid solution that provides the same level of green energy by significantly increasing the size of the solar generation and battery energy storage that has been used in Option R1. Such a solution would have a higher levelised cost than Option R1, and is not as strategic as Option R2, however would likely have a lower levelised cost than Option R2. Similarly, a more cost effective version of Option R2 could be developed by scaling down the size of hydrogen generation and pairing it with diesel generation. This would reduce the level of green energy, however it would likely have a lower levelised cost than Option R2. These alternatives have not been developed in this study.

For the purposes of the assessment, it has been assumed that:

- **The 3 community microgrid options will be assessed as a single solution on the basis of equity:** While this study sets out the technical and financial requirement associated with each community, the overall evaluation has been undertaken on the basis of the implementation of each of the community microgrids as a single solution on the basis of equity. This assumption does preclude the community pursuing less than 3 community microgrids if they are minded to do so.
- **Options identified consider known constraints.** These constraints include:
  - Exclusion from Ergon Energy distribution network: No option contemplates a connection to the Ergon Energy distribution network within the Daintree Ergon Energy exclusion zone.
  - Option to use existing generation is likely to be impractical and costly: A microgrid using existing generation as the power source was contemplated but ultimately not evaluated as it was considered that this option would create a complex administrative overlay, it would not address the noise associated with generators and cost certainty and reliability would likely be significant issues. The microgrid options developed assume no reliance on existing generation however this generation could continue to be a secondary source of electricity if desired. This study does not consider commercial arrangements related to feed in tariffs.
- **As per Illustrative Customers, cooking and water heating has been excluded from the options' load estimates:** As set out in Section 2.2, it has also been assumed that gas appliances and hot water systems will not be replaced by electric units under each of the electricity supply options.
- **HOMER modelling has been used to size components:** HOMER modelling has been utilised to ensure the combination of diesel generation, renewable generation and battery storage in each option (excluding hydrogen based options R2 and I3) examined is optimally sized to minimise the cost of energy supplied to customers. As the size of the generation system decreases from a single microgrid, through three separate microgrids down to supply to individual customers the overall total amount of generation increases due to a lowering of diversity of loads. However, the amount of distribution network required to deliver the energy to customers will decrease. HOMER will provide appropriate analysis to determine the cost of delivered energy under each scenario.

Further Considerations of Microgrid Options

The options examined at this phase of the project are considered to be at the preliminary concept level stage. Should an option be the subject of further development and then subsequently proceed to detailed design, there are a number of refinements and optimisations that could be explored. While these refinements and optimisations may result in a lower levelised cost, there may be offsetting factors that increase the levelised cost, for example, resulting from the operating model and regulatory framework.

As set out in the financial analysis in Section 7, costings have been developed to facilitate the relative financial assessment of the options within this study. They do not represent detailed feasibility analysis and should not be used for budgeting purposes.

Potential refinements and optimisations to microgrid options could include:

- **Optimisation of the addition of generation assets to a microgrid:** As set out in Section 4.2, all generation assets are assumed to be built for day 1 operations. In practice, generation could be progressively added over time as demand increases, potentially resulting in a lower levelised cost.
- **Optimisation of the number of customers connecting to a microgrid:** Detailed design would investigate whether a mix of microgrid and SPS solutions may provide greater value for money (i.e. a lower levelised cost) than providing all customers with the same supply solution. This could include:
  - Assessment of the distance of the cabling required, for example, the Southern Community has the greatest cabling requirement however has the lowest demand for electricity.
  - A customer needs assessment, for example, customers may prefer to continue to be off-grid, their circumstances may lend themselves to be more suitable to SPS or nanogrid solution (e.g. those customers that currently access hydro, are located in difficult terrain, are farmland, are isolated etc.).
- **Nanogrids that utilise existing generation could be explored:** An option that explores the utilisation of existing generation, whether it be at the regional, community or nanogrid level is possible, however would present a number of challenges. As set out further above, an option to use existing generation is likely to face practical and cost challenges. The Government would likely need to provide a level of regulatory oversight for such systems as there is limited precedent for any rules that cover this at present. Jurisdictional responsibilities that flow from the Priority 2 framework being investigated by the AEMC could potentially be developed to suit such arrangements. Environmental and cultural heritage evaluations and impacts would also need to be addressed if it was necessary to provide a cable from one household to another (possibly through land owned by a third party) which would be challenging for small scale, incremental solutions.

Table 3-1: Electricity Supply Options

	#	OPTION	DESCRIPTION*	GRID**	SOLAR PV	DIESEL GENERATOR	HYDROGEN GAS TURBINE	LITHIUM-ION BATTERY	HYRDOGEN FUEL CELL	ELECTRO-LYSER	HYDROGEN STORAGE
					CENTRALISED GENERATION & STORAGE						
REGIONAL	R1	Optimised Microgrid	A single microgrid connecting all customers. Centralised generation and storage. This option is based on the most efficient and proven electricity supply technology.	✓							
REGIONAL	R2	Hydrogen based Microgrid	A single microgrid as per Option R1 but using hydrogen fuel generation to move away from fossil fuel generation.^	✓							
					CENTRALISED GENERATION & STORAGE						
COMMUNITY	C1-3	Northern (C1) Central (C2) and Southern (C3) Microgrids	C1 – A single microgrid connecting all customers in the Northern community of the Daintree. Centralised generation and storage.	✓							
COMMUNITY			C2 – A single microgrid connecting all customers in the Central community of the Daintree. Centralised generation and storage.	✓							
COMMUNITY			C3 – A single microgrid connecting all customers in the Southern area of the Daintree. Centralised generation and storage.	✓							
					SPS GENERATION & STORAGE						
INDIVIDUAL	I1	SPS Battery Retrofit	Fit lithium-ion batteries to customer's existing installations to improve efficiencies and reduce environmental impacts. Note: this option does not apply to IC3 and IC4 customers given it is assumed they do not have battery storage.		^^	^^					
INDIVIDUAL	I2	Standardised SPS	Provide standardised power systems to customers that are managed and maintained centrally. Customers pay standard charge for services.								
INDIVIDUAL	I3	Hydrogen SPS	Installation of individual hydrogen fuel cells at customer's dwellings that replace their current SPS. Compressed hydrogen, used by fuel cells to convert hydrogen into electricity, is purchased and transported to customers from an established supplier outside of the Daintree area.								

Excludes LPG used for cooking and water heating under all options.* * If compatible existing customers could connect their systems to the microgrid.*

^ A diesel generator has been included to act as a backup should a failure in the hydrogen production or generation system occur. ^^Existing SPS component.

4 TECHNICAL ANALYSIS

PURPOSE OF THIS SECTION

- This section overviews the technical characteristics associated with each of the identified energy supply options.
- Key references include: the Key Assumptions tables associated with each option set out in Sections 4.3 to 4.8.

4.1 Approach

This section of the study sets out the technical details of each of the options, including:

- Maximum demand and energy requirement
- Electricity supply solution
- Environmental considerations and impact
- Construction considerations, and
- Operating considerations.

Technical Constraints

For the purposes of options development, the following technical constraints have been taken into consideration:

- **While no overhead electricity distribution lines have been assumed for microgrid options, detailed assessments will be required if a microgrid option progresses to the project implementation stage:** Where distribution of electricity is required, underground cabling has been assumed to ensure minimal visual impact as well as providing appropriate levels of reliability and security in a rainforest environment. While this assumption has been used for this study, including to ensure compliance with natural and cultural heritage assessments, should a microgrid option progress to the project implementation stage, a detailed assessment will be required during route selection to determine the impact of underground cabling on surrounding vegetation. Previous works have shown that it is necessary to be selective with underground cabling. Underground cabling can require as much clearing as overhead wires as a tree root exclusion zone has to be established. That is, generally a 10m wide easement is grubbed clear of tree roots that would interfere with underground cables. This has proven to be a problem in other areas of the Wet Tropics however running the cable down the road or on the side with no existing tree root interference is considered to be acceptable. In an EIS performed previously for the Far North Queensland Electricity Board (prior to Ergon Energy) this issue was identified, and bundled aerial cabling was more environmentally friendly in many areas compared to underground cable due to the associated trenching and grubbing of root zones. Grubbing of roots also has the potential to impact vegetation, particularly larger trees that may be up to 20m from the underground cables. Allowances have been made when pricing the installation of underground cables to ensure that environmental issues can be addressed. Other possible options such as using armoured underground cable to reduce the need for grubbing are very expensive and unlikely to be cost competitive.

- **Utilise existing cleared access**: Where underground distribution of electricity is required it should (where possible) follow existing cleared access routes (i.e. roads) to minimise any additional impact on the environment. This will also be a requirement to ensure compliance with natural and cultural heritage assessments.
- **Energy supply systems will be designed to maximise utilisation of renewable energy and ensure any generation powered by fossil fuels is operated as efficiently as possible**: To ensure all generation is operated as efficiently as possible and to minimise waste, energy supply options include battery storage. This will ensure that when fossil fuelled generators operate they will operate for the shortest possible time and will be loaded to ensure efficiency of energy production. It will also ensure renewable energy inputs are not wasted should the amount being generated by renewables exceed the usage by customers at any particular time. The sizing of individual components of the energy system (e.g. diesel generators and battery storage) have been optimised by analysis using HOMER.
- **No reliance on existing generation assumed:** As set out in Section 3.1, the microgrid options developed assume no reliance on existing generation however this generation could continue to be a secondary source of electricity if desired and if compatible with standards that enable safe connection to the microgrid network. This study does not consider commercial arrangements related to feed in tariffs.
- **Connections to households:** It is noted that some customer's current SPS connections may not meet the required standards (voltage, safety compliance, etc.) to connect to a microgrid network, or potentially to standardised SPSs (option I2) or fuel cell technology (Option I3). This may require some additional time to resolve for customers that wish to connect to an energy system. This risk is assessed qualitatively in the risk analysis in Section 7.1 as a technical implementation risk and commercial implementation risk.

HOMER Modelling

A HOMER Energy model for each option has been developed by GHD in order to optimise the use of the solar, gas, diesel and energy storage capacity incorporated in each option. HOMER is the global standard software package for optimising microgrid design. The technical/cost modelling uses site specific load, solar irradiance and ambient temperature data and system cost calculations to account for capital, replacement, operation and maintenance, and fuel costs.

HOMER simulates the operation of a system by making energy balance calculations in each time step (interval) of the year. For each time step, HOMER compares the electric demand in that time step to the energy that the system can supply in that time step, and calculates the flow of energy to and from each component of the system.

The HOMER modelling has allowed an optimal concept level design for each option, which includes optimal sizing of generation system components, and has allowed options to be compared using a consistent approach to calculating the levelised cost and the required annual capital and operating expenditure.

4.2 Demand and Energy

This section sets out the demand and energy estimates and key assumptions that underpin the technical electricity supply solution set out in this Section 4, and levelised cost set out in Section 7.3, developed for each option.

For regional and community supply options, which are all based on a microgrid solution ("microgrid options"), demand and energy assumptions have been developed at both the Daintree region level and the individual level. For individual based options, which do not rely on centralised assets, these assumptions have been developed at the individual level only[6].

Key assumptions underpinning demand and energy estimates include:

- **Estimates have been developed with reference to Illustrative Customers:** Demand and energy estimates are based on Illustrative Customer loads developed in Section 2.2. For the microgrid options, uptake and growth assumptions, including through increased usage and development, have been assumed (refer Table 4-1). No growth has been assumed for individual supply options (or Illustrative Customers) over the 25 year project term.
- **Microgrid options have been sized for the year 25 maximum demand at year 0:** To reduce the complexity of electricity supply solutions at this options evaluation stage of the project, it has been assumed that all generation assets are procured during the construction period (i.e. no additional generation assets added over time). In practice, generation would be progressively added over time as demand increases.
- **Diversity factors:** As the size of the generation system decreases from a single microgrid, through three separate microgrids down to supply to individual customers, the overall total amount of generation increases due to a lowering of diversity of loads. For all microgrid options, a diversity factor of 40% has been applied given each microgrid will service more than 50 customers (a higher diversity factor will apply if the number of customers were to fall below 50). For all individual options there is no diversity of supply given each customer has their own individual SPS, and a diversity factor of 100% has been applied.
- **Increase in energy usage through development**: Increase in energy usage as a result of increased development has only been developed at the regional level given the low quality of information at the sub-regional level. To the extent those regions contain freehold land, the increase in energy usage would be similar to that of the regional level. Growth in development has been assumed to occur at a rate of 1% per annum. This equates to approximately 122 blocks over the life of the project[7]. This increase has been assumed to relate to energy requirements equivalent to an IC1 customer.
- **25 year operations and maintenance period:** As set out in the financial analysis, a 25 year operations and maintenance period has been assumed for the study.

[6] If required, these individual levels can be aggregated up on a linear basis.
[7] Note: it is unclear the number of vacant freehold lots that would be available for potential development in the Daintree region, excluding lots that have been bought back for conservation purposes. However, the limited evidence available suggests this number may be in the order of 200 lots, including native title, farmland, and vacant lots with development rights.

As set out above, Table 4-1 below provides the microgrid options uptake and growth assumptions. The uptake assumptions in particular have been developed with consideration of the inherent demand and uptake risk.

Table 4-1: Microgrid Options – Uptake and Growth Assumptions

UPTAKE AND GROWTH CATEGORY	ASSUMPTION
Base uptake (connections as % of total customers)	50%
Maximum uptake (connections as % of total customers)	80%
Year max uptake is reached	10 years
Growth through increased usage^^	0.25% p.a. (IC1 and IC2)
Growth through increased development (R1 & R2 only, assuming IC1 demand and energy)	1% p.a.

Note: These demand and energy profiles are simple linear profiles that illustrate the materiality of different uptake scenarios.

^^It is assumed there is no increase in IC3 and IC4 customers from current levels

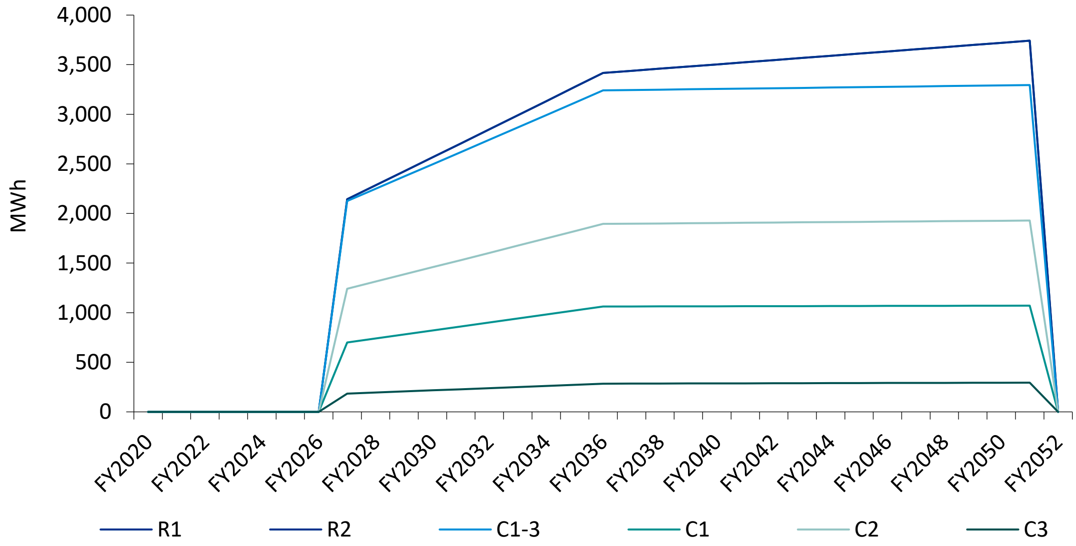
Microgrid options

The table below sets out the demand and energy assumptions that underpin the microgrid options on a whole of Daintree region basis.

Table 4-2: Microgrid Options Demand and Energy Assumptions

ITEM	OPTIONS				
	R1	R2	C1	C2	C3
After Diversity Maximum Demand (MVA)					
Year 0	0.81	0.81	0.17	0.50	0.13
Year 25	1.72	1.72	0.29	0.85	0.23
Energy (MWh p.a.)					
Year 0	2,003	2,003	660	1,170	173
Year 25	3,742	3,742	1,071	1,929	295

Figure 4-1: Energy Profiles Daintree Region – Microgrid options



Note: Option C1, C2 and C3 have been presented on an aggregate and stand-alone basis for comparison to the full microgrid options. The principal difference in energy between the options is the full microgrid options R1 and R2 include a development assumption.

Individual options

The table below sets out the demand and energy assumptions that underpin all individual options on an individual basis.

Table 4-3: Individual Options Demand and Energy Assumptions

ITEM	ALL INDIVIDUAL OPTIONS AND ILLUSTRATIVE CUSTOMERS	
	DEMAND (KVA)	ENERGY (KWH P.A.)
IC1	7.00	3,561
IC2	10.00	5,934
IC3	15.00	31,945
IC4	30.00	115,790

4.3 R1 - Optimised Microgrid

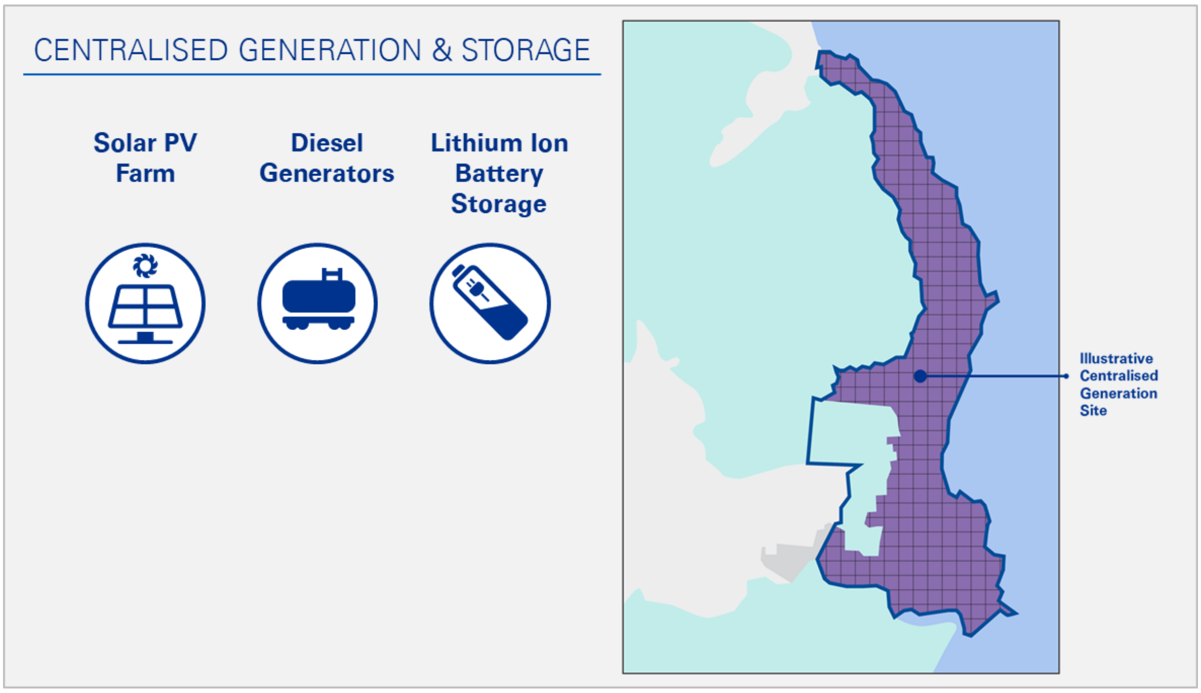
This option involves the construction of an underground electricity microgrid that would service the entire Daintree region. The microgrid would be powered by a centralised generation site that would involve a combination of solar PV and diesel generation paired with lithium-ion battery storage.

Table 4-4: Option R1 Key Assumptions

TYPE	ITEM	ASSUMPTION
INFRASTRUCTURE	Cabling (Total HV and LV)	160 kM
SYSTEM ARCHITECTURE	Solar PV	2,000 kW
	Diesel Generators	3 x 500 kW
	Lithium-ion Battery Storage	3,000 kWh
	System converter	1,000 kW
	Total Capacity	2,000 kW
OTHER	Land requirement	20,000 m^2
	Project Development	3 years
	Construction	3 years
	Operating	25 years
	Carbon intensity	0.219 kgCO2e/kWh supplied

The following figure is an illustrative example of the option's generation and storage components.

Figure 4-2: Option R1 – Optimised Microgrid



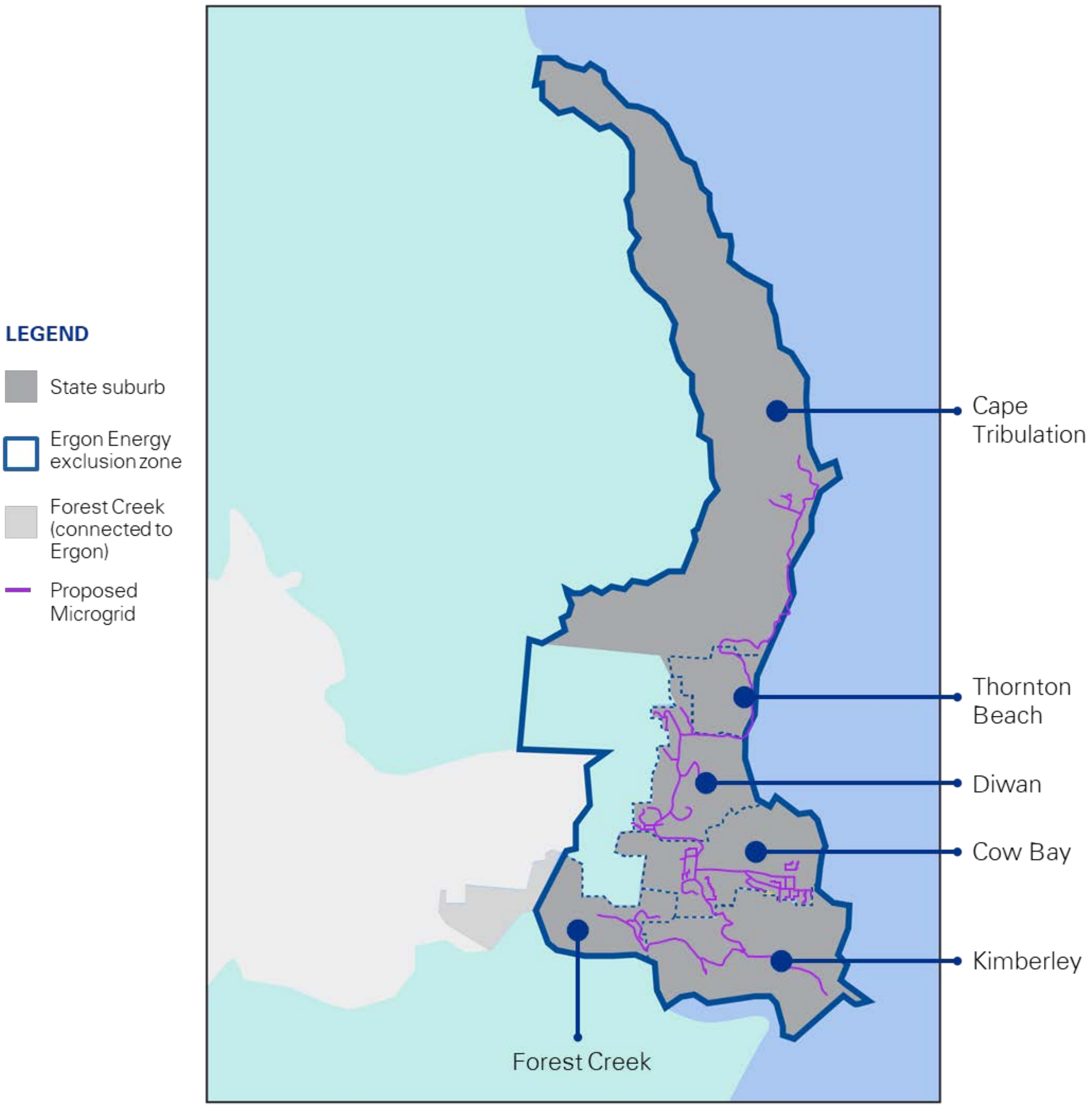
Note: The grid overlay in the above figure is for illustrative purposes only. Refer to Figure 4-3 for Option R1's indicative microgrid.

Electricity Supply Solution

The microgrid system for Option R1 will consist of a centralised generation facility containing 2,000 kW of solar, 3 x 500 kW of diesel generators, 1,000 kW DC to AC inverter, and 3,000 kWh of lithium-ion battery storage. The central generation facility will connect to a high voltage underground network to distribute electricity to the population centres where it will be transformed to low voltage as required. A low voltage underground supply network will then be used to make supply available to all customers that want to connect. The generation and supply systems will be remotely monitored and controlled to assist with fault diagnosis and repair as well as determining maintenance needs. Customer's energy usage will be metered at their point of supply.

The figure below provides the indicative microgrid for this option that follows the existing cleared access routes (i.e. road network) to minimise any additional impact on the environment.

Figure 4-3: Option R1 Microgrid – Indicative Microgrid



Environmental Considerations and Impact

Option R1 emits a total of 242 tCO_2e per annum (based on 25 year levels) to supply the anticipated loads. This equates to a carbon intensity of 0.219 $kgCO_2e/kWh$ (refer Section 7.5 for further carbon production analysis).

The carbon dioxide emissions in this option are produced by the diesel generators. To mitigate carbon dioxide emissions the generation system contains 2,000kW of solar as well as a large battery to ensure excess solar generation is not wasted and to improve the efficiency of the diesel generators when they operate.

It is expected that a combination of sound proofing in the diesel generator enclosure as well as locating the generator away from residents will ensure that any noise pollution is minimised.

There will be good ability to control any fuel spills at a central generation facility and all fuel supplies will come to this single central point.

Construction Considerations

There will be a requirement to obtain environmental and cultural heritage approvals to install the necessary cabling to provide supply to the customer base in the Daintree area. It is anticipated that these approvals will take at least three years prior to construction commencing. Once the necessary approvals are obtained construction may be hampered by the need to install the cables within the road reserve because of the need to block at least part of the roadway while this work is completed. Some areas in between population centres have extensive rock or swamp to traverse which may provide additional difficulty for the construction of microgrid systems.

Operating Considerations

Sufficient diesel generators have been included in the design to allow for a single unit to be out of service for maintenance (or due to failure) and still have sufficient capacity to supply all of the customers during those periods. The generation and distribution system can be remotely monitored to identify faults or emerging issues and arrange for appropriate service personnel to attend.

4.4 R2 - Hydrogen Based Microgrid

This option involves construction of an underground electricity microgrid that would service the entire Daintree region. The microgrid would be powered by a centralised hydrogen generation site. This generation site would contain a large scale solar PV farm whose electricity would be harnessed for the electrolysis of water to produce hydrogen and to provide energy directly to customers during daylight hours. The hydrogen produced by the electrolysers would be contained within storage and fed into a centralised hydrogen fuelled gas turbine to generate electricity which would be distributed through the underground microgrid network.

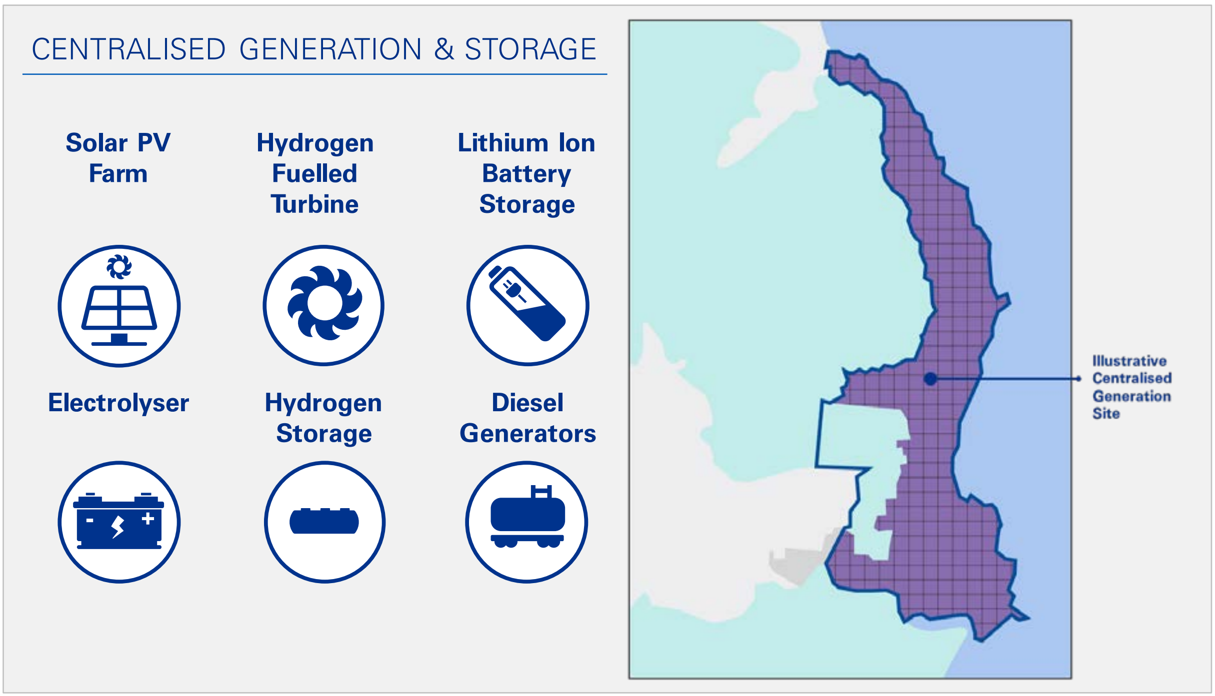
As an alternative to Option R2 it may be possible to develop a microgrid solution that provides the same level of green energy by significantly increasing the size of the solar generation and battery energy storage that has been used in Option R1. Such a solution would have a higher levelised cost than Option R1, and is not as strategic as Option R2, however would likely have a lower levelised cost than Option R2. This alternative has not been developed in this study.

Table 4-5: Option R2 Key Assumptions

TYPE	ITEM	ASSUMPTION
INFRASTRUCTURE	Cabling	160 kM
SYSTEM ARCHITECTURE	Solar PV	7,000kW
	Electrolyser	5 x 1,250 kW
	Hydrogen Storage	1,530 kg (3 days)
	Lithium-ion Battery Storage	333 kWh
	System converter	1,000 kW
	Hydrogen Gas Turbine	1,000 kW
	Diesel Generator	2,000 kW
	Total Capacity	2,000 kW
OTHER	Land requirement	70,000 m^2
	Project Development	3 yrs
	Construction	3 yrs
	Operating	25 yrs
	Carbon intensity	0 kgCO2e/kWh supplied

The following figure is an illustrative example of the option's generation and storage components.

Figure 4-4: R2 – Hydrogen based Microgrid



Note: The grid overlay in the above figure is for illustrative purposes only. Refer to Figure 4-5 for the Option R2's indicative microgrid.

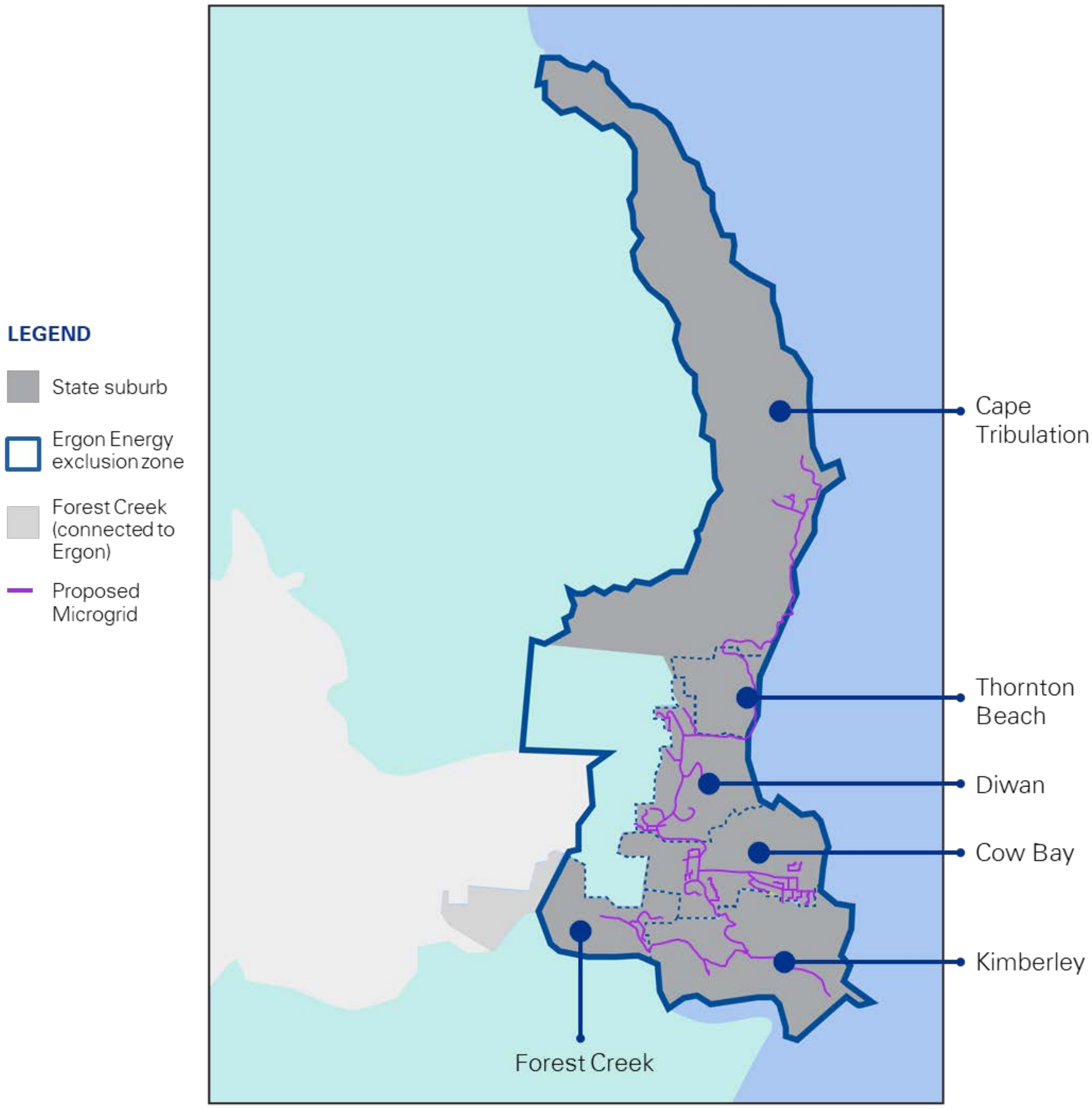
Electricity Supply Solution

The microgrid system for Option R2 will consist of a centralised generation facility consisting of 7,000 kW of solar, a 1,000 kW hydrogen fuelled turbine, 1,000 kW DC to AC inverter, and 333 kWh of lithium-ion battery storage (the battery/inverter is used for grid forming without the need to operate generators inefficiently at low load). The central generation facility will connect to a high voltage underground network to distribute electricity to the population centres where it will be transformed to low voltage as required. A low voltage underground supply network will then be used to make supply available to all customers that want to connect. The generation and supply systems will be remotely monitored and controlled to assist with fault diagnosis and repair as well as determining maintenance needs. Customer's energy usage will be metered at their point of supply.

To supply the central generation system with hydrogen, a solar generator (7,000 kW) will provide supply to an electrolyser as well providing supply directly to customers during daylight hours. A diesel generator will be available and will only operate if the hydrogen production, storage and generation system has a failure and cannot provide sufficient supply to customers.

The figure below provides the indicative microgrid for this option that follows the existing cleared access routes (i.e. road network) to minimise any additional impact on the environment (as per Option R1).

Figure 4-5: Option R2 Microgrid – Indicative Microgrid



Environmental Considerations and Impact

This option is designed to provide supply to the Daintree with minimal carbon emissions. Emissions will only occur should there be an extended period of cloud cover which would result in a shortage of hydrogen for the generation system as the electrolyser operates from solar energy. In this event a diesel generator will start to operate the electrolyser. It is expected that this will occur rarely. Modelling has indicated that the diesel generator would not normally be required other than for a component failure (refer Section 7.5 for further carbon production analysis).

The hydrogen generators should emit minimal noise pollution. Any noise from the operation will be minimised by locating the generation system away from residents and ensuring any enclosure provides sufficient noise shielding.

A small amount of diesel will be required for the backup diesel generator, delivery will be infrequent and any spills for that purpose will be easily managed.

Construction considerations

There will be a requirement to obtain environmental and cultural heritage approvals to install the necessary cabling to provide supply to the customer base in the Daintree area. It is anticipated that these approvals will take at least three years prior to construction commencing. Once the necessary approvals are obtained construction may be hampered by the need to install the cables within the road reserve because of the need to block at least part of the roadway while this work is completed. Some areas have extensive rock or swamp to traverse which may provide additional difficulty in construction of microgrid systems.

There will need to be a supply of water for the electrolyser which will need to be considered when siting the generation system. Water supply options may have additional regulatory requirements.

There will be a need to establish a facility for the safe storage of hydrogen near the generation system.

Operating considerations

Sufficient hydrogen electrolysers and hydrogen storage have been included in the design to allow for likely periods of high levels of cloud cover which will reduce, or prevent, production of sufficient hydrogen, and still be able to supply all of the customers during those periods. A diesel generator has been included to act as a backup should a failure in the hydrogen production or generation system occur. It is expected that the amount of time that the diesel generation is required would be minimal as it would only be started as a result of an abnormal event. The generation and distribution system can be remotely monitored to identify faults or emerging issues and arrange for appropriate service personnel to attend.

4.5 C1-3 - Community Microgrids

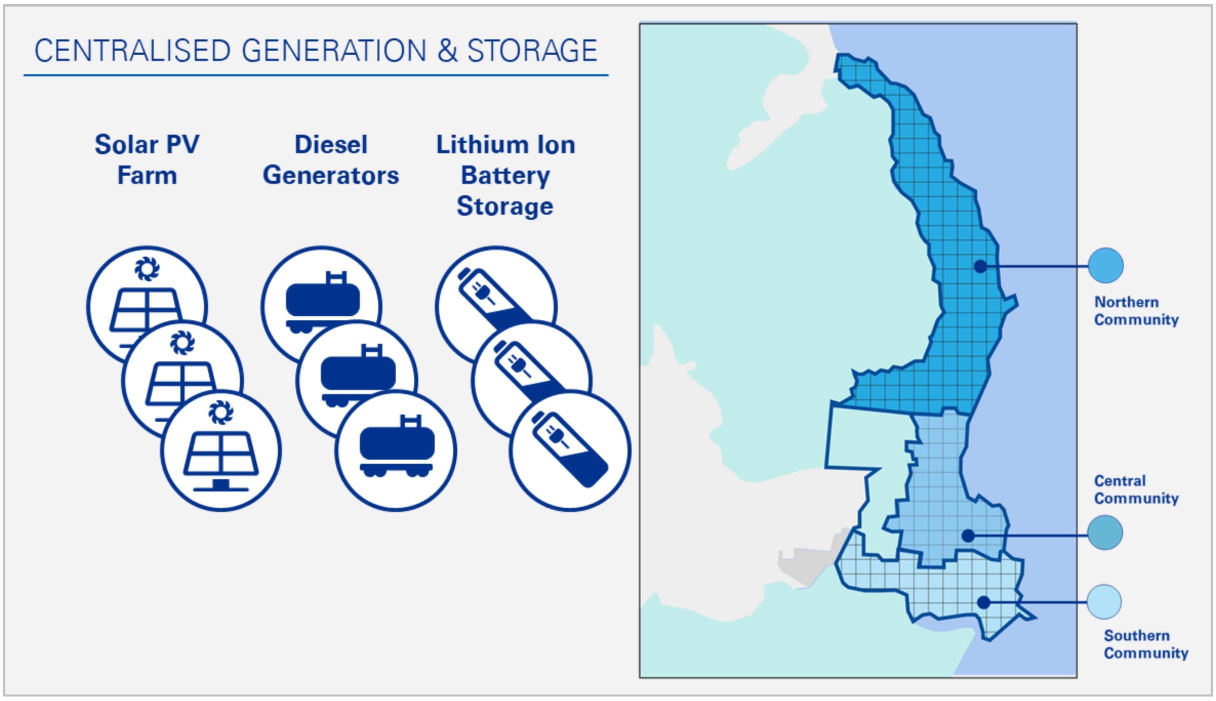
This option involves construction of three underground electricity microgrids that would service the northern, central and southern areas of the Daintree. The microgrids would be powered by three individual centralised generation sites that would involve a combination of solar and diesel generation paired with lithium-ion battery storage.

Table 4-6: Option C1-3 Key Assumptions

TYPE	ITEM	ASSUMPTION BY COMMUNITY		
		C1 - NORTHERN	C2 - CENTRAL	C3 - SOUTHERN
INFRASTRUCTURE	Cabling	30 km	40 km	60 km
SYSTEM ARCHITECTURE	Solar PV	800 kW	1,000 kW	100 kW
	Diesel Generators	3 x 135 kW	3 x 230 kW	3 x 40 kW
	Lithium-ion Battery Storage	1,000 kWh	2,500 kWh	300 kWh
	System converter	400 kW	800 kW	100 kW
	Total Capacity	670 kW	1,260 kW	180 kW
OTHER	Land requirement	10,000 m^2	10,000 m^2	5,000 m^2
	Project Development	1.5 yrs	1.5 yrs	1.5 yrs
	Construction	2.5 yrs	2.5 yrs	2.5 yrs
	Operating	25 yrs	25 yrs	25 yrs
	Carbon intensity (kg CO2e/kWh supplied)	0.178	0.150	0.442

The following figure is an illustrative example of the option's generation and storage components.

Figure 4-6: C1-3 – Community Microgrids



Note: The grid overlay in the above figure is for illustrative purposes only. Refer to Figure 4-7 for the Option C1-3's indicative microgrids.

Electricity Supply Solution

This option utilises three separate microgrids to provide supply to each of the main population centres in the Daintree, C1 (northern), C2 (central) and C3 (southern).

The microgrid system for Option C1 will consist of a generation facility comprising of 800 kW of solar, 3 x 135kW of diesel generators, 400 kW DC to AC inverter, and 1,000 kWh of lithium-ion battery storage.

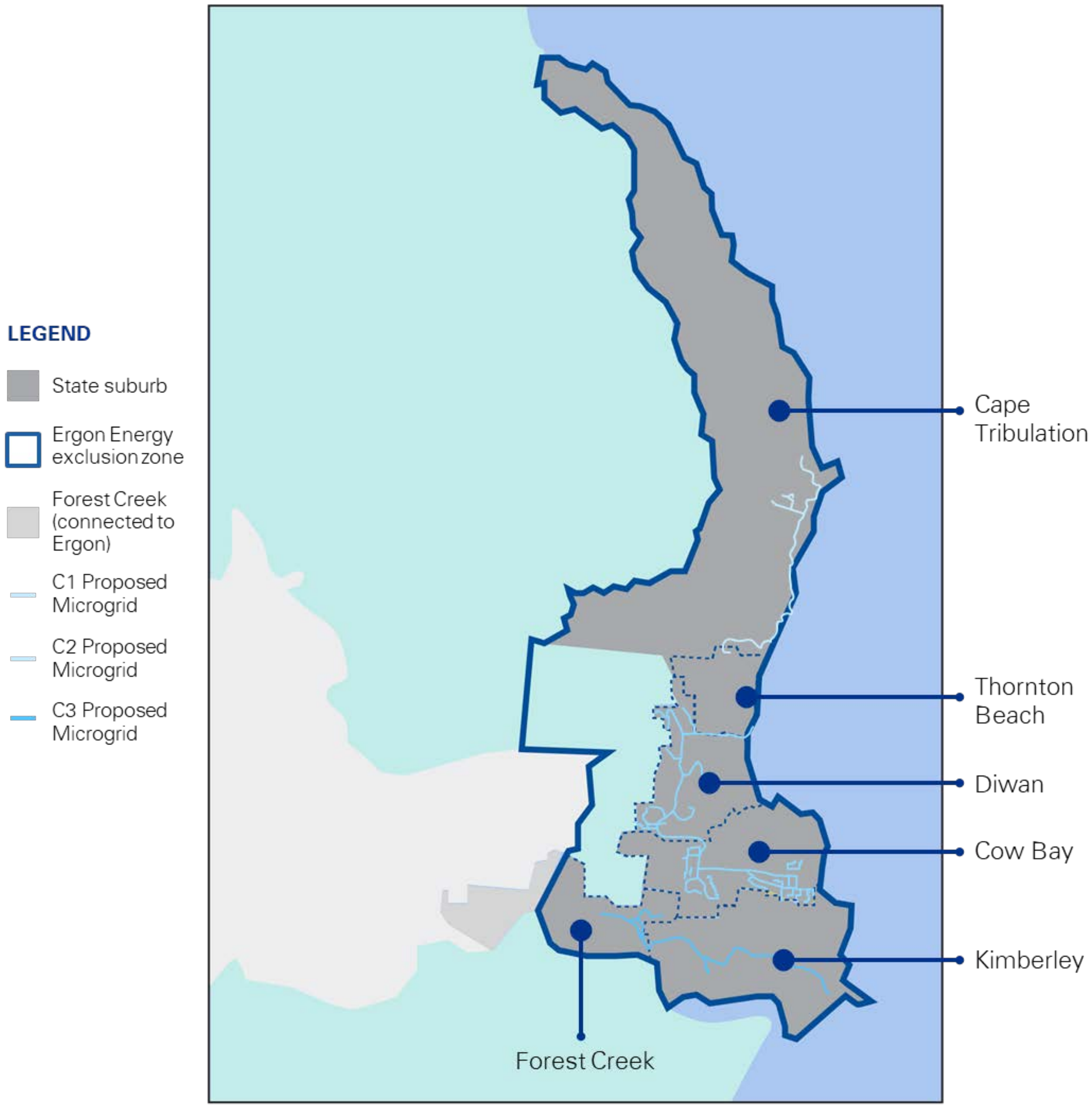
The microgrid system for Option C2 will consist of a generation facility comprising of 1,000 kW of solar, 3 x 230kW of diesel generators, 800 kW DC to AC inverter, and 2,500 kWh of lithium-ion battery storage.

The microgrid system for Option C3 will consist of a generation facility comprising of 100 kW of solar, 3 x 40 kW of diesel generators, 100 kW DC to AC inverter, and 300 kWh of lithium-on battery storage.

Each of the three generation facilities will connect to a high voltage underground network to distribute electricity where it will be transformed to low voltage as required. A low voltage underground supply network will then be used to make supply available to all customers that want to connect. The generation and supply systems will be remotely monitored and controlled to assist with fault diagnosis and repair as well as determining maintenance needs. Customer's energy usage will be metered at their point of supply.

The figure below provides the indicative microgrid for this option that follows the existing cleared access routes (i.e. road network) to minimise any additional impact on the environment (as per Options R1 and R2, however excludes connections between population centres).

Figure 4-7: Option C1-3 Microgrids – Indicative Microgrids



Environmental Considerations and Impact

Option C1-3 emit a total of 149 tCO_2e per annum (based on year 25 levels) to supply the anticipated loads. This equates to a carbon intensity of 0.204 $kgCO_2e/kWh$ when averaged across the total energy produced by all three microgrids (refer Section 7.5 for further carbon production analysis).

The carbon dioxide emissions in this option come from the diesel generators at each of the three generation sites. To mitigate carbon dioxide emissions each generation system contains solar panels as well as a large battery to ensure excess solar generation is not wasted and to improve the efficiency of the diesel generators when they operate.

It is expected that a combination of sound proofing in the diesel generators enclosure as well as locating the generators away from residents will ensure that any noise pollution is minimised.

There will be good ability to control any diesel fuel spills at each central generation facility, however fuel supplies will be delivered to three separate points.

Construction Considerations

There will be a requirement to obtain environmental and cultural heritage approvals to install the necessary cabling to provide supply to the customer base in the Daintree area. It is anticipated that this may be somewhat easier than Options R1 and R2 as the WTWHA between population centres does not need to be traversed by cabling.

Operating Considerations

Sufficient diesel generators have been provided in each microgrid to allow for a single unit to be out of service for maintenance (or due to failure) and still have sufficient capacity to supply all of the customers during those periods.

4.6 I1 - SPS Battery Retrofit

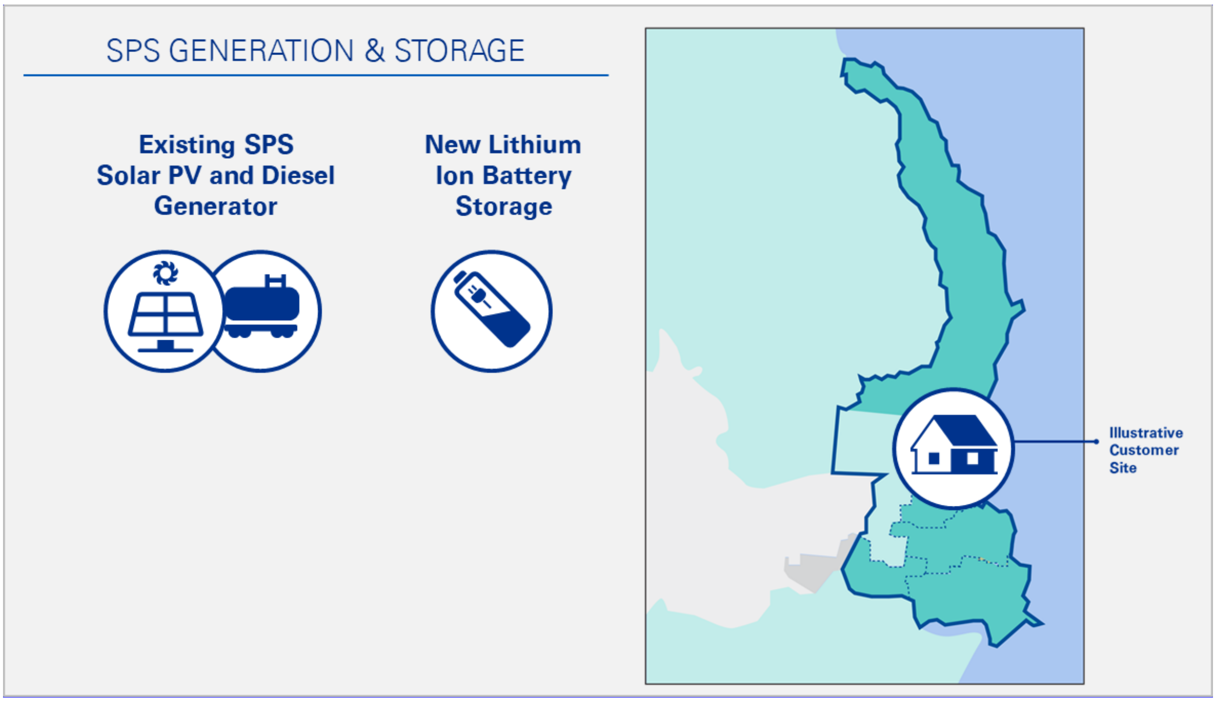
This option involves the installation of individual lithium-ion batteries at customer's dwellings that would be an addition to their current SPSs. This option is intended to improve the efficiency of customer's current solutions. It is noted that this option currently only applies to IC1 and IC2 as it is assumed that IC3 and IC4 do not have battery storage, however in reality, Option I1 does not preclude these customers from accessing the option.

Table 4-7: Option I1 Key Assumptions

TYPE	ITEM	ASSUMPTION			
		IC1	IC2	IC3	IC4
INFRASTRUCTURE	Enclosure	n/a	n/a	n/a	n/a
SYSTEM ARCHITECTURE – NEW AND EXISTING	Existing: Solar PV	3.2 kW	5 kW	1 kW	5 kW
	Existing: Diesel Generators	5 kW	7.5 kW	2x10 kW	2x30 kW
	New: Lithium-ion Battery Storage	16 kWh	31 kWh	0 kWh	0 kWh
	Existing: System converter	5 kW	5 kW	5 kW	5 kW
	Total Capacity	10 kW	12.5 kW	20 kW	60 kW
OTHER	Land requirement	n/a (existing premises)			
	Project Development	1 yrs			
	Construction	1 yrs			
	Operating	25 yrs			
	Carbon intensity (kgCO2e/kWh supplied)	0.567	0.530	0.925	0.883

The following figure is an illustrative example of the option's generation and storage components.

Figure 4-8: I1 – SPS Battery Retrofit



Electricity Supply Solution

This option consists of replacing residents' existing lead-acid battery banks with an equivalent lithium-ion bank. It has been assumed that battery sizes are the same as the illustrative customer example cases. All other components of the existing generation systems will remain unchanged.

Environmental Considerations and Impact

This option will emit between 1.2 – 99.8 tCO2e per customer per annum, or 2,006 tCO2e assuming 80% uptake. This is based on a carbon intensity between 0.530 – 0.925 kgCO2e/kWh for the four Illustrative Customer categories. The environmental outcomes for the existing SPSs used in the Daintree will largely remain unchanged with only new battery technology introduced (i.e. no change in diesel generator usage). As such, emissions for Option I1 are equivalent to the Current State (refer Section 7.5 for further carbon production analysis).

This option is designed to reduce the usage of lead-acid battery cells within the Daintree. This will minimise any dumping of end of life cells in the environment by replacing existing lead-acid cells with lithium-ion cells.

Construction considerations

The construction will consist of replacing existing lead-acid battery banks with equivalent sized lithium-ion cells. It will be necessary to ensure the cells are safely installed and that the cells being removed are transported away from the Daintree and disposed of in an acceptable manner.

Operating considerations

There is a need to ensure that the battery is operated within its specifications (voltage, charge and discharge rates, etc.).

4.7 I2 - Standardised SPS

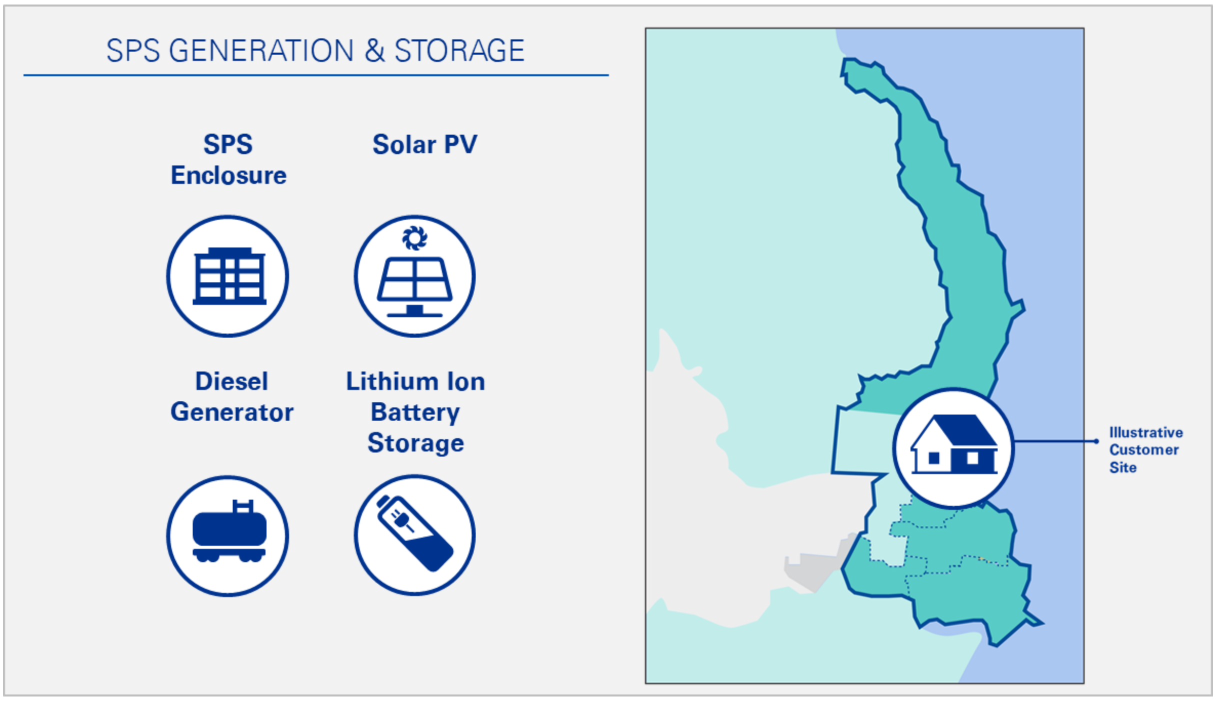
This option involves the development of standardised SPSs that are managed and maintained by a central organisation/authority. Customers would pay a standard charge for services and electricity. Each SPS would involve a level of solar PV and diesel generation paired with lithium-ion battery storage.

Table 4-8: Option I2 Key Assumptions

TYPE	ITEM	ASSUMPTION			
		IC1	IC2	IC3	IC4
INFRASTRUCTURE	Enclosure	✓	✓	✓	✓
SYSTEM ARCHITECTURE	Solar PV	2.5 kW	5 kW	5 kW	10 kW
	Generators (diesel)	1x7 kW	1x10 kW	1x15 kW	1x30 kW
	Battery Storage (lithium-ion)	25 kWh	40 kWh	225 kWh	750 kWh
	System converter	2.5 kW	5 kW	50 kW	50 kW
	Total Capacity	7 kW	10 kW	15 kW	30 kW
OTHER	Land requirement	50 m^2 (existing premises)			
	Project Development	1.5 yrs			
	Construction	2 yrs			
	Operating	25 yrs			
	Carbon intensity (kgCO2e/kWh supplied)	0.630	0.564	0.856	0.853

The following figure is an illustrative example of the option's generation and storage components.

Figure 4-9: I2 – Standardised SPS



Electricity Supply Solution

This option provides each customer with an individual energy supply system. The sizing of the power system will be dependent on the customer's needs. Four base power systems have been developed that can be deployed as needed. The generation system for each customer category is assumed to consist of the following:

- IC1 will consist of 2.5kW of solar, 1 x 7kW diesel generator, 2.5kW DC to AC inverter, and 25kWh of lithium-ion battery storage.
- IC2 will consist of 5kW of solar, 1 x 10kW diesel generator, 5kW DC to AC inverter, and 40kWh of lithium-ion battery storage.
- IC3 will consist of 5kW of solar, 1 x 15kW diesel generator, 50kW DC to AC inverter, and 225kWh of lithium-ion battery storage.
- IC4 will consist of 10kW of solar, 1 x 30kW diesel generator, 50kW DC to AC inverter, and 750kWh of lithium-ion battery storage.

Environmental Considerations and Impact

Option I2 emits a total of 1.7 – 96.4 tCO2e per customer per annum, or 2,156 tCO2e assuming 80% uptake. This is based on a carbon intensity between 0.564 – 0.856 kgCO2e/kWh for the four Illustrative Customer categories (refer Section 7.5 for further carbon production analysis).

The carbon dioxide emissions for each of these options comes from the diesel generators. To mitigate carbon dioxide emissions the generation system contains a solar power system as well as a battery to ensure excess solar generation is not wasted and to improve the efficiency of the diesel generators when they operate.

It is expected that enclosures for the diesel generators will be sufficiently sound proofed to minimise noise pollution for residents.

Care will be required in the management of diesel fuel spills as every customer will have a separate power system that needs to be fuelled at regular intervals. This increases the risk of a fuel spill occurring over the microgrid solutions.

Construction Considerations

Environmental issues during construction will be minimised compared to other options as the systems can be manufactured off site and then delivered to, and operated from, a suitable area within the customer's property.

Operating Considerations

The power system can be remotely monitored to identify faults or emerging issues and appropriate service personnel can rectify any issues.

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4.8 I3 - Hydrogen SPS

This option involves the installation of individual hydrogen fuel cells at customer's dwellings that would replace their current SPSs. The hydrogen fuel could be sourced the following ways:

- **Green hydrogen:** Produced via electrolysis at a site outside the Daintree area (assumed to either be a smaller scale facility near Cairns, Option I3.1, or a larger hydrogen hub in Townsville, Option I3.2). It is assumed that electrolysis facilities would be connected to an adjacent solar farm behind the meter supplying low cost solar energy for 8 hours a day, and supplemented with grid imported electricity at a transmission level connection to maximise the electrolyser utilisation.
- **Brown hydrogen:** Purchased through the established chemicals industry, which would likely be sourced from the nearest steam methane reforming facility in Newcastle, Option I3.3.

Compressed hydrogen would then be transported by a gas transportation truck suitably designed to transport as cylinders, and distributed to a nearby fuel station as a central distribution point, or directly delivered to households. Fuel cells installed at each household would then convert hydrogen into electricity.

Table 4-9: Option I3 Key Assumptions

TYPE	ITEM	ASSUMPTION			
INFRASTRUCTURE	Enclosure	×			
SYSTEM ARCHITECTURE	Hydrogen fuel cell - unit size per customer	IC1	IC2	IC3	IC4
		6.3 kW	9.0 kW	13.5 kW	27.0 kW
	Hydrogen fuel	Option I3.1	1.25 MW electrolyser located in Cairns		
		Option I3.2	10 MW electrolyser located in Townsville		
		Option I3.3	Brown hydrogen sourced from Newcastle		
	Hydrogen transportation	Transportation of compressed hydrogen via truck			
OTHER	Land requirement	25 m^2 (existing premises)			
	Project Development	3 yrs			
	Construction	2 yrs			
	Operating	25 yrs			
	Carbon intensity	0 kgCO2e/kWh supplied ^			

^ Fuel cell power generation; fuel carbon footprint depends on source

For the green hydrogen Options I3.1 and I3.2, the hydrogen fuel and transportation unit costs that have been assumed for these options have been developed with reference to, and are contingent on, an electrolysis facility being developed and located in Cairns (Option I3.1) or Townsville (Option I3.2). In relation to:

- **Hydrogen fuel unit costs:** These are the levelised costs of hydrogen, based on Daintree demand for electricity, required to support the investment in the electrolysis facility at each of the assumed locations (i.e. the unit cost is derived from the development and operation of the electrolysis facility). As demonstrated in the table below, the Townsville facility, which is assumed to have a larger production volume and broader offtake than just the Daintree, has a lower cost of hydrogen.
- **Transportation unit costs:** These are the logistics costs to transport the hydrogen to the Daintree from the assumed electrolysis facility locations, with the unit cost being lower the closer the facility is to the Daintree (i.e. the electrolysis facility located in Cairns has the lowest cost of transportation).

The table below provides the indicative costs to develop and operate these potential electrolysis facilities in these locations and the resulting hydrogen fuel and transportation unit costs. The key purpose of providing these costs compared with other options is due to the absence of an established market for hydrogen fuel supply in Australia at the residential level. Key assumptions underpinning these costs include:

- Construction commencement in 2024
- Utilisation of 14h per day in Cairns and 20h per day in Townsville
- Behind the meter solar for 8 hours per day
- Price of behind the meter solar estimated to be $50/MWh in Cairns and $40/MWh in Townsville (it is assumed that the electrolysis facilities would be connected to an adjacent solar farm behind the meter supplying low cost solar energy for 8 hours a day, and supplemented with grid imported electricity at a transmission level connection to maximise the electrolyser utilisation)
- Low pressure compression
- Water price of $1,000/ML
- Site acquisition costs and grid connection costs have been excluded at this concept stage as these costs will vary considerably, ranging from being not a material cost to being a material cost, depending on the precise location of the production facility.

Further to these costs, all versions of Option I3 require a material investment in fuel cells to be located at each customers dwelling. The upfront and replacement cost of these fuel cells is the most material cost item underpinning the levelised cost provided in the financial analysis in Section 7.

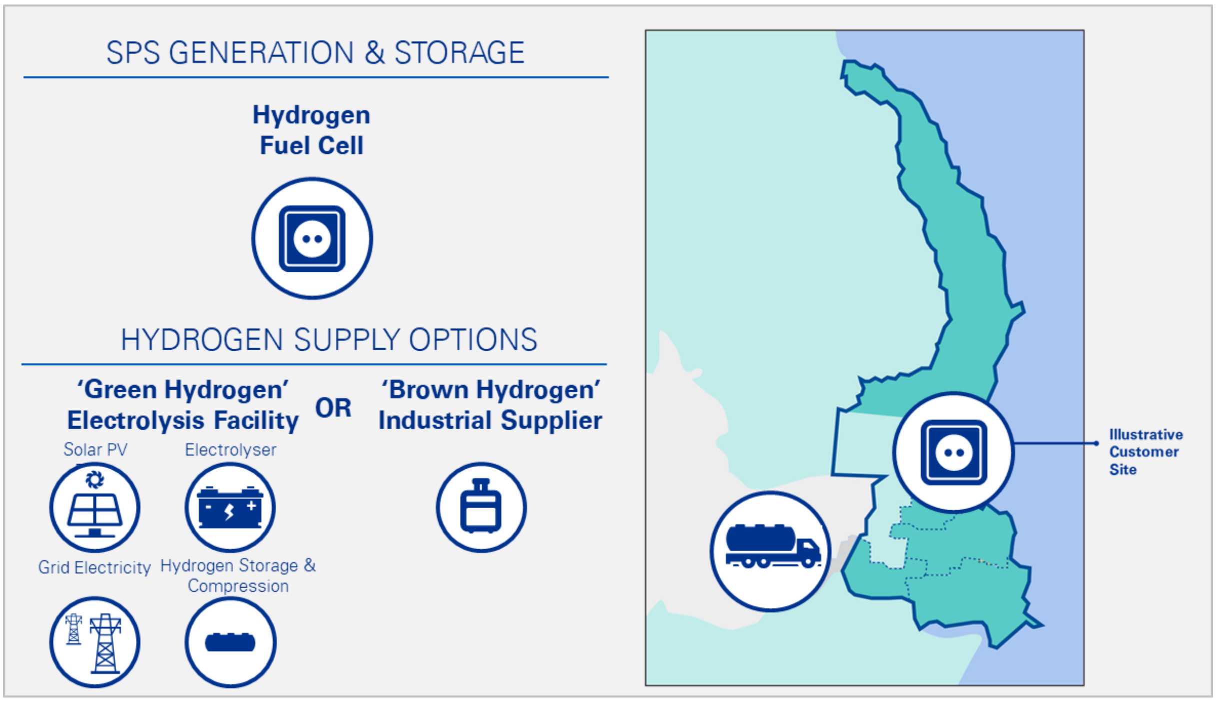
Table 4-10: Indicative Electrolysis Facility Costs and Option Unit Costs for Green Hydrogen Production

COST CATEGORY		1.25 MW electrolyser – Cairns (Option I3.1)	10 MW electrolyser – Townsville (Option I3.2)
Indicative Electrolysis Facility Costs ($nominal)			
Capital*	Electrolyser	$2,500,000	$19,200,000
	Storage and Compression	$480,000	$6,300,000
Operating	Electrolyser	$420,000 p.a.	$5,500,000 p.a.
	Storage and Compression	$10,000 p.a.	$126,000 p.a.
Option I3.1 and I3.2 Hydrogen Fuel and Transportation Unit Costs ($2019)			
Hydrogen Fuel Cost^		$5.80/kg	$4.90/kg
Hydrogen Transportation Cost^		$0.30/kg	$1.15/kg

** It should be noted that the purchase of at the home fuel cells is a separate and material cost item. Refer to Table 7-4 for a breakdown of the upfront costs for fuel cells by customer type.*
^The hydrogen fuel and transportation unit costs for the brown hydrogen Option I3.3 are $2.20/kg and $5.90/kg respectively.

The following figure is an illustrative example of the option's generation and storage components.

Figure 4-10: I3 – Hydrogen SPS



Note: Hydrogen Fuel Cells will be installed at individual dwellings

Electricity Supply Solution

Each of the generation systems will be similar to those specified in Option I2 with the diesel generators, batteries and solar generation replaced with hydrogen fuel cell generators. For IC1 a 6.3 kW fuel cell will be used. For IC2 a 9.0 kW fuel cell will be used. For IC3 a 13.5 kW fuel cell will be used. For IC4 a 27.0 kW fuel cell will be used.

Environmental Considerations and Impact

The generation of electricity from hydrogen is free of carbon emissions as well as pollution, since water is the only by-product of hydrogen fuel cells, however, the underlying production method for the hydrogen that is delivered to the Daintree would influence the net carbon emissions attributable to this hydrogen option.

Given electrolysis requires electricity and water to produce hydrogen, the carbon emissions for each electrolysis option would vary to the extent grid electricity is imported to meet utilisation requirements. For the two electrolysis options (Options I3.1 and I3.2), we have assumed that behind the meter solar would be available for an average of 8 hours during the day (equating to 58% and 40% for these options, respectively). The remainder of electricity is assumed to be imported from the grid and the carbon emissions associated with this energy would be dependent on the grid emissions factor at the time.

Nevertheless, it is reasonable to refer to these options as 'green hydrogen' options, as a significant percentage of energy used to produce the hydrogen would be renewable, and this is expected to increase with the further uptake of renewables and emerging forms of renewable energy storage in the grid.

As part of the production process, brown hydrogen (i.e. produced through Steam Methane Reforming) results in carbon emissions similar to the emissions associated with production of other refined fuel products such as diesel and petrol.

Construction considerations

Residential fuel cell technology is in its infancy although several technology types are currently considered mature from a technological perspective – including Polymer Electrolyte Membrane (PEM), alkaline fuel cells which are suitable for back up and portable power applications at small scale[8]. It would be expected that a preferred supplier would have to be identified to develop prototypes for the fuel cells that would meet the requisite design specifications for this particular application. This would most likely be an adaptation of existing models in the market and so we would expect this process to take approximately 6 months, to test and trial these prototypes. To the extent that there is an overrun for the design process period, this could delay project delivery. However since the technology is already mature and significant research and development has been undertaken in these applications, we would expect the most important challenge to overcome would be finding a suitable and interested supplier able to work on a bespoke design.

[8] National Hydrogen Roadmap, Pathways to an economically sustainable hydrogen industry, CSIRO, 2017.

Additionally, existing household/business wiring may not be compatible with the specifications of the fuel cells and this may require customers to incur additional costs to upgrade their wiring to accommodate the installation of fuel cells.

Safety guidelines and regulatory obligations should also be considered as part of this project option. This may include:

- Standards and codes of practice associated with the transportation of hydrogen
- Restrictions and safety considerations with respect to the storage and use of hydrogen within residential and business use zones, and
- Safety requirements for delivery and storage at a central distribution hub (if required).

Operating considerations

Consideration should be given to the possible execution of contracts to fix the hydrogen fuel supply cost to Daintree customers during the contract term. An up-front agreement to procure a large volume over the extended contract term may result in a lower average $/kg fuel cost and protect Daintree customers against hydrogen price fluctuations.

User interface for the fuel cells may need to be developed alongside the preferred supplier. Standard fuel cells may not facilitate the dynamic energy management system required by customers in the Daintree and would need to be considered in the design and testing process.

The approach to fuel cell maintenance should also be considered. An agreement with a preferred fuel cell maintenance contractor may be an optimal solution to provide customers with a direct supplier and fixed cost for the provision of fuel cell inspections and maintenance.

5 PLANNING AND REGULATORY ANALYSIS

PURPOSE OF THIS SECTION

- This section analyses the Commonwealth and State regulatory and planning considerations associated with each of the electricity supply options.
- Key references include: Table 5.1 - Relevant State Development Assessment Provisions; and Table 5.2 - Planning and regulatory requirements.

5.1 Overview

The study area encompasses multiple tenures where development is subject to a wide variety of regulatory aspects. The various suburbs in the study area are separated by significant areas of conservation reserves, with the majority of this being the WTWHA which includes the Daintree National Park (refer Figure 5-1 below). Outside of the Daintree National Park, some freehold land has been voluntarily included within the boundaries of the WTWHA, however the majority of the potential household/business connections are on private, freehold land outside of the WTWHA. World Heritage values are found both within private freehold land and the WTWHA. These values include habitats that support endemic, rare or otherwise conservation significant fauna and flora species and communities. Thus, while the majority of the freehold areas are not within conservation reserves, they do include World Heritage values that would be addressed as part of any regulatory permit/approval assessment process. A summary of each option's potential impact on the WTWHA (including the Daintree National Park) is as follows:

- Options R1 and R2 are for single microgrids that would service the entire area between the Daintree River and Cape Tribulation. These options will require connections through the intervening sections of the WTWHA. That is, cabling, trenching and road works will be required through these areas of the WTWHA to enable connections between suburb localities.
- Options C1, C2, C3, are for suburb/locality based networks, entirely contained within freehold areas outside of the WTWHA. These options do not require connections through the WTWHA. No cables, trenches or road works are required in the WTWHA.
- Options I1, I2 and I3 are based on an individual household/business property site level and do not require connections through, or disturbance of, the WTWHA for cables, trenches and associated road works.

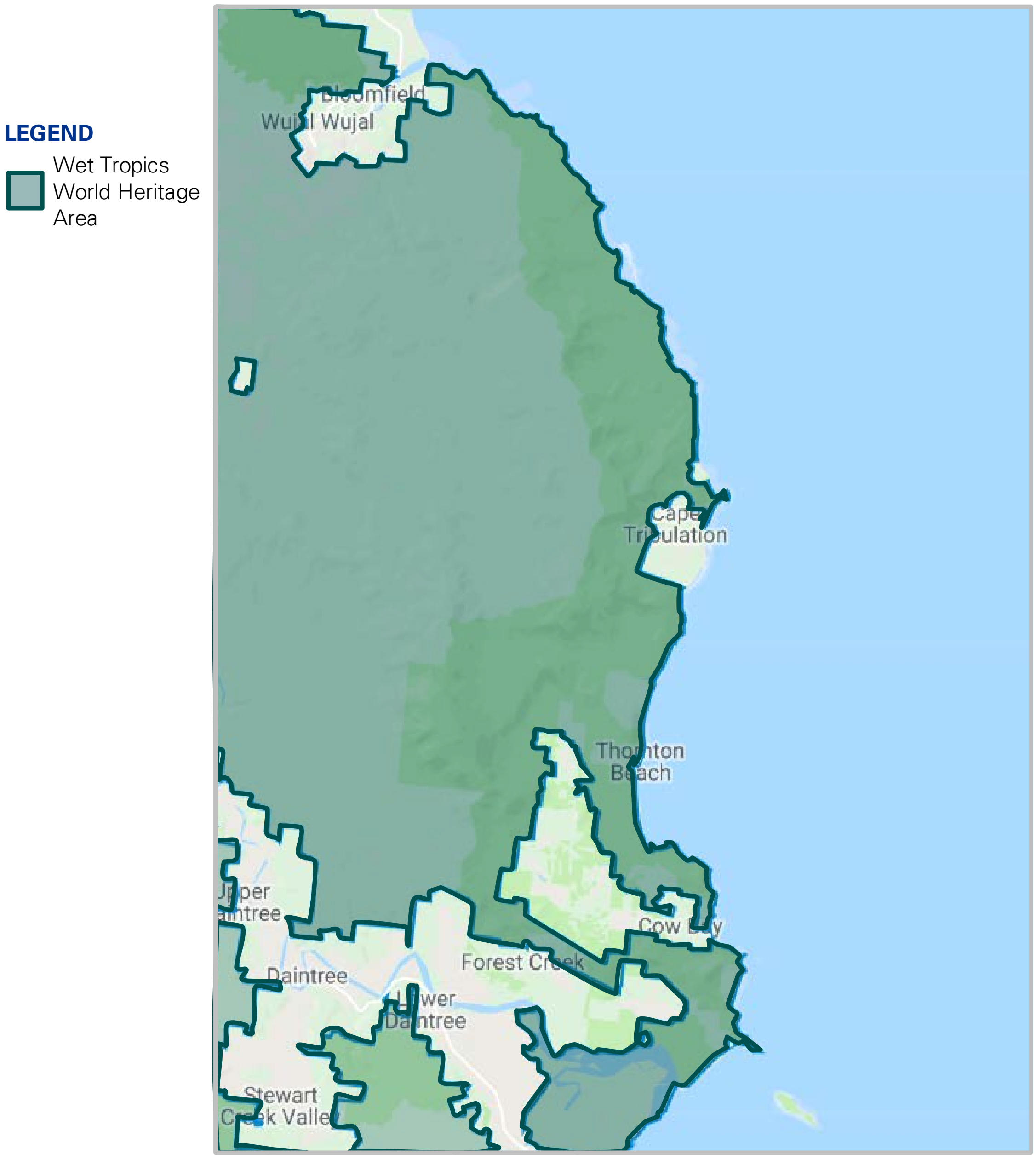
This juxtaposition of freehold land with World Heritage values in proximity and adjacent to the WTWHA, results in complex government agency jurisdictions and legislative responsibilities in relation to the regulatory and approval process for development projects in the study area. An overview of the jurisdiction and interests of the various agencies involved (Commonwealth, State, Local), their legislative responsibilities and regulatory requirements is set out in the sections below.

WTWHA – Study Area Boundary Overlay

The map below provides the boundary of the WTWHA overlayed on the study area. It shows:

- **WTWHA:** This includes all of the Daintree National Park, and some private properties who voluntarily offered their properties for inclusion with the WHA.
- **Area outside of the WTWHA:** The majority of Cow Bay, Diwan, Cape Tribulation, Forest Creek, Cape Kimberley and a small section of Thornton Beach are not within the World Heritage Area, but do have World Heritage values. Even though the freehold properties within these suburbs are not in the WTWHA, they still have vegetation/communities on these properties that support endemic, rare, threatened fauna/flora and their habitats.

Figure 5-1: Wet Tropics of Queensland World Heritage Area – Study Area Boundary Overlay



Energy Regulatory Considerations – Microgrid Options

AEMC Category 2 Systems

It is considered likely that any Daintree microgrid implementation would be classified as a Category 2 system under the Priority 2 framework presently being developed by the AEMC[9].

Category 2 systems will encompass those supplying smaller towns and as such would match the size of the system that would be required to provide supply to the Daintree. Effective retail competition is unrealistic in this category as any network tariffs would be specific to each microgrid and retailers generally require many thousands of customers for it to be cost effective to develop specific retail tariffs and therefore support retail competition. In any event, the costs associated with the Australian Energy Regulator revenue determination process to set network tariffs would be disproportionately burdensome. Consequently, microgrids under Category 2 will generally be vertically integrated. The flexibility and proportionality in a regulatory framework necessary to accommodate the potential breadth of circumstances is likely to be most effectively supported through regulation being undertaken at a jurisdictional level. However, the development of frameworks along nationally consistent principles would minimise additional compliance costs for operators seeking to operate on a national basis.

AEMC Category 2 Systems – Reliability, Security and Technical Standards

Reliability, security and technical standards for Category 2 systems will be set by the jurisdictional regulator and will likely reference relevant Australian standards for quality of supply, metering, service and installation rules and asset management plans. Targets for reliability may not be the same as those set for distribution network service providers (DNSPs). Reporting on performance against targets and any rectification for poor performance would be included in jurisdictional license conditions.

AEMC Category 2 Systems – Licensing

Licensing for Category 2 systems would be performed on a jurisdictional basis with combined licenses for network, generation and retail activities. License conditions would be determined on a risk basis. No form of registration with AEMO would be required.

The AEMC has considered the risks of a failure of an operator of the power systems covered by the Priority 2 framework. It is generally very important, if not critical, to consumers that an uninterrupted supply of electricity is maintained. Consequently, if the system of checks put in place prior to the registration and/or licensing of a service provider proves ineffective or circumstances change, and the provider fails, pre-existing arrangements must already be in place to provide for supply continuity.

The AEMC's initial view is that there would likely be value in including the appointment of a nominated Operator of Last Resort (OoLR) in the jurisdictional licensing framework for third party power system operators, with the OoLR for a third-party power system appointed upfront, and with DNSPs and other parties such as other third-party power system providers being able to compete for provision of OoLR services.

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[9] Review of the regulatory frameworks for stand-alone power systems – Priority 2. AEMC 27 June 2019.

For Category 2 systems, the OoLR would need to be capable of covering the full supply chain of operations including generation, distribution and retailing of energy. In order to limit the risk that the third party provided energy supply system is not prudently managed and to limit the costs which may be passed onto an OoLR it may be necessary to introduce a requirement that the system operator be covered by an appropriate insurance scheme. If the only realistic provider of the OoLR service is the local DNSP it may be a licensing requirement that the service provider consult with the DNSP when designing their system to align standards where prudent.

It is likely that an obligation to supply will be placed on microgrid operators and implemented through the licensing conditions. It would oblige operators to provide supply to users, including micro generators, but would not apply to the connection of generators greater than 5MW. There would be no obligation on customers to take supply if available.

AEMC Category 2 Systems – Jurisdictional Regulation

Jurisdictional regulation would apply some form of light-handed economic regulation such as price monitoring or a negotiate/arbitrate regime. Consumer protection will be provided via license conditions, which would likely contain the same protections as in the NECF applied in a more proportionate way, as well as access to the jurisdictional energy ombudsman and concession, rebate and emergency payment assistance schemes.

The final framework is still under consideration by the AEMC but the broad guidelines provided above will likely form the regulatory environment that would apply for supply to customers in the Daintree supplied by microgrid systems.

Hydrogen

There are currently no Australian regulations or standards in place to govern the production of hydrogen. International standards include *ISO/DIS 22734 - Hydrogen generators using water electrolysis process – Industrial, commercial, and residential applications* (under development) and *ISO 22734-1:2008 Hydrogen generators using water electrolysis process – Part 1: Industrial and commercial applications*. With the development of the National Hydrogen Strategy, it is anticipated that similar standards would need to be implemented. In addition, the classification of an electrolysis facility as a Major Hazard Facility would currently be subject to state safety regulations and will require further review[10].

Energy Regulatory Considerations – Individual Options

AEMC Category 3 Systems

It is considered likely that any managed electricity supply systems for individual customers (i.e. Option I2) would be classified as a Category 3 system under the Priority 2 framework presently being developed by the AEMC[11]. Category 3 applies to individual supply systems with the sale of energy and it is proposed that a light-touch regulation regime will be utilised (i.e. this is at least expected to be relevant to option I2).

[10] National Hydrogen Roadmap, Pathways to an economically sustainable hydrogen industry, CSIRO, 2017.
[11] Review of the regulatory frameworks for stand-alone power systems – Priority 2. AEMC 27 June 2019.

AEMC Category 3 Systems – Reliability, Security and Technical Standards

There would be no reliability obligations on the system provider, but customers would be able to negotiate reliability needs. System security and technical standards would be set by the jurisdictional regulator and would adopt relevant Australian standards for quality of supply, service and installation rules and asset management plans. Operators would be required to use pattern approved meters. Safety requirements would also need to comply with Australian standards such as AS3000 and AS4509.

AEMC Category 3 Systems – Licensing

Licensing, or exemptions, for Category 3 systems will be done on a jurisdictional basis using either a risk based licencing regime with proportionate license conditions or an exemptions framework with exemption conditions. Presently the AEMC considers that it is likely that there would be no requirement to appoint an OoLR for Category 3 systems. There would be no obligations placed on SPS providers to offer to connect and supply customers. There would be no economic regulation obligations for these systems. A set of minimum consumer protection conditions would be imposed in licensing/exemption conditions covering areas such as billing information, minimum payment requirements and disconnection/reconnection obligations.

AEMC Category 3 Systems – Jurisdictional Regulation

As for microgrids, the final framework for individual power systems is still under consideration by the AEMC but the broad guidelines provided above will likely form the regulatory environment that would apply for supply to customers in the Daintree supplied by any of the individual options described in this study.

Hydrogen

Similar to the discussion on the production of hydrogen for microgrid options, the hydrogen production facility for individual options would be subject to similar safety and functional regulations and standards. The Australian hydrogen market is still in its infancy, and the regulatory framework is uncertain and likely to be complex, although the development of a National Hydrogen Strategy may accelerate the development of the industry and assist in overcoming barriers associated with sourcing and establishment of a fuel supply chain, regulatory approvals and development of the technical solution.

An international standard for stationary and portable storage of hydrogen (*ISO19884 - Gaseous hydrogen – Cylinders and tubes for stationary storage)* is currently under development. The transport, storage and use of hydrogen in residential fuel cells would require further detailed analysis of the applicable regulatory environment which is currently based on the natural gas and LPG industry[12].

[12] National Hydrogen Roadmap, Pathways to an economically sustainable hydrogen industry, CSIRO, 2017.

5.2 Commonwealth Interests

The Commonwealth will have overarching interests based on a number of factors including:

- Options that include infrastructure (cabling) within World Heritage listed areas (R1 and R2).
- The potential for options C1, C2 and C3 to have cumulative or indirect impacts on land adjoining to or adjacent the WTWHA.
- The potential for listed species and communities under the EPBC Act to be impacted by construction works.
- The future cumulative impact of further uptake of available land and development that will adversely impact on World Heritage values.

There are two key Commonwealth and Commonwealth/State regulatory requirements:

- The Commonwealth *Environment and Protection Biodiversity Conservation Act 1999* (EPBC Act)
- Commonwealth/State *World Heritage Act 1993* and *Wet Tropics Management Plan 1998.*

Environment and Protection Biodiversity Conservation Act 1999

A referral of the project to the Commonwealth is required under the provisions of the EPBC Act for determination as to whether or not the project is deemed a controlled action for Options R1, R2 and C1, C2 and C3. The Minister has 20 business days to determine whether the proposed works requires further assessment and approval. This includes a public comment period of 10 days. The level of assessment will vary between Options R1 and R2, and Option C1-3. Options R1 and R2 are compulsory referrals as they involve works within the WTWHA, i.e. cabling within the Daintree National Park to connections within the various suburb locations, in addition to the considerations listed below for Options C1, C2, and C3. For Options R1 and R2, the level of assessment will be very high. It is highly anticipated that the level of assessment may extend to requiring an EIS or PER level of investigation. Either of these may take up to three years.

For options C1, C2 and C3, referral assessment may be less stringent as no direct impacts on the WTWHA are anticipated for these options. Notwithstanding, a referral assessment will consider the following:

- Substantial capital works adjacent to the WTWHA and National Heritage Estate areas may have indirect and cumulative impacts on these areas.
- The project has the potential to have adverse impacts on protected fauna and flora species and their habitats listed as Matters of National Environmental Significance (MNES).
- The project has the potential to impact on the adjacent coastal sections of the Great Barrier Reef Marine Park through sediment and hazardous spills impacting on key waterways.

The EPBC Act has significant implications for the project in the following areas:

- **Time factors:** Decision periods, including requests for information, may take 12 to 36 months.
- **Onerous conditions:** The Commonwealth has powers to compel conditions on the issuance of any approval under the EBPC Act. These conditions may impact on design and construction elements of the project.

- **Biodiversity offsets:** The Commonwealth may insist on biodiversity offsets for any MNES affected by the project. This could take a number of forms including land acquisition, or rehabilitation. The purpose of biodiversity offsets is to achieve equivalency (or better) i.e. no net loss of World Heritage values.
- **Financial:** As part of the assessment process the Commonwealth may request further information which may include, for example:
  - Erosion and sediment modelling studies
  - Detailed studies on likely affected MNES species/habitats, including population studies (e.g. Cassowaries)
  - Population modelling, forecasting of future land sales, development potential based on provision of grid electricity, and potential development related impacts on World Heritage values and landscapes
  - Land acquisition for biodiversity offsetting
  - Any other aspect they deem necessary to assess the potential impacts of the project.
- **Cultural heritage:** Detailed cultural heritage assessment and engagement.

The EPBC Act will have limited to no application for Options I1, I2 and potentially I3 as these are based on upgrades/maintenance of existing SPS. Option I3 may rely on an external electrolysis facility being developed to underpin the supply of hydrogen to fuel cells. The applicability of the EPBC Act to this facility will depend on the location and tenure of this electrolysis facility with respect to MNES and WTWHA.

World Heritage Act 1983 and Wet Tropics Plan 1998

WTMA have identified that the project will be regarded as having the potential for significant impacts on World Heritage values, and that approval under the *Wet Tropics Plan 1998* (as per the controlling provisions of the WH Act 1983) is required for Options R1 and R2 as these options directly impact on the WTWHA.

A permit application will be required that addresses a number of key requirements:

- Identification of World Heritage values in the affected area (fauna/flora, cultural heritage)
- Identification of management actions to mitigate potential impacts via an Environmental Management Plan (EMP)
- Engagement with the Eastern Kuku Yalanji Native Title holders as per the requirements of the ILUA and the Daintree National Park Management Plan 2019.

The WTMA assessment will be concurrent and complementary with the EPBC Referral assessment and will reflect similar assessment requirements, including requests for information, including up to an EIS level of investigation. The WTMA may also request an EIS level of assessment in order to provide the necessary information. In accordance with the MOU between the Queensland and Federal agencies, it should be noted that a single EIS (if required) undertaken in accordance with either EPBC Act or WTMP provision will satisfy conditions for both agencies. Similarly, any conditions on an EPBC approval will reflect those issued under the Queensland *Planning Act 2016* via a Development Application approval.

A permit under the WTMP 1998 is not anticipated for the community and individual options (i.e. C1-3 and I1, I2, and I3), provided that these options do not include works (including on private freehold) within the WTWHA. However, the WTMA still has obligations under their legislation to ensure that development adjacent to the WTWHA does not have an indirect or cumulative adverse impact on World Heritage values. Subsequently while the WTMA may not have a direct regulatory function for these options, they may be a referral agency for any Development Application undertaken through the State Assessment and Referral Agency (SARA) managed through the Department of State Development, Manufacturing, Infrastructure and Planning. Subsequently the WTMA may still have inputs into conditions on Development Application approvals by various agencies.

5.3 State Interests

Planning Act 2016

State Interests are primarily addressed through the State Assessment Referral Agency (SARA) process under the *Planning Act 2016*. Development Applications made under this Act must address the relevant State Development Assessment Provisions (SDAP) that represent the interests of the various State Government agencies and the legislation they are responsible for.

Options R1, R2 and C1-3 will require a Development Application. Options I1, I2 and I3 do not need Development Applications to be made for the project components within the study area. The requirements for a Development Application for a possible electrolysis facility that supports the supply of hydrogen for Option I3 will depend on the tenure and town planning scheme of the local government involved. As the possible electrolysis facility is external to the study area and site location unknown, regulatory/planning aspects for this facility are not included in the following.

A summary of the various SDAP required to be addressed are presented in Table 5-1 below.

Other Legislative Approvals

Approvals will be required additional to the Development Approvals obtained under the *Planning Act 2016*. These primarily relate to the provisions of the *Nature Conservation Act 1992* with specific reference to the following:

- The study area includes significant areas mapped as High Risk Protected Flora Survey Trigger Area, and as such the protected plants framework under the NC Act will apply and a permit to remove protected plants will be required, accompanied by the relevant survey report.
- The works are within essential mapped habitat for a number of species listed under the Schedules of the *Nature Conservation (Wildlife) Regulation 2006*. Interference with faunal breeding areas will require a Damage Mitigation Permit and/or accompanied by a Species Management Program that must be approved by the Director, DES.

Note: Vegetation clearing approved under SARA and the Development Application does not allow clearing where protected flora species are present. Clearing applications are considered and approved in this instance under a clearing permit authorisation from DES (Permitting and Licence Management, PALM) made under a separate application.

These regulatory requirements will be mandatory of Options R1, R2 and C1-3, but will not apply to Options I1, I2 and I3.

The *Aboriginal Cultural Heritage Act 1993* (ACH Act) will also have implications for the project, but may not necessarily be a compulsory regulatory approval for any of the Options. The ACH Act requires all proponents to observe Duty of Care guidelines in relation to the design, construction and maintenance of any project where there is a risk of Aboriginal cultural heritage being present. The Duty of Care guidelines will primarily apply to any option where there is clearing required of mature forest (i.e. a greenfield site), or disturbance to the bed and banks of waterways, e.g. for cable crossings. Aboriginal Cultural Heritage is also intrinsically addressed in the Commonwealth EPBC process and directly addressed in the WTMA Permit application and assessment process.

Regulation of Energy Supply

To comply with the Electricity Act 1994 all microgrid options would need to be licenced by DNRME under a Special Approval arrangement. Special Approvals may be issued by the Regulator under the Act to authorise the holder to do anything stated in the Special Approval that a generation entity, transmission entity or distribution entity may do under the Act. For example, in special circumstances, a Special Approval may authorise a person to connect specified generating plant to a supply network and/or supply electricity using a supply network to specified persons.

The jurisdictional regulator will likely have oversight of the Priority 2 framework being established by the AEMC for Category 2 and Category 3 systems. Under this framework the jurisdictional regulator will:

- Set and monitor licencing or exemption conditions for energy providers
- Set the performance and technical standards that will apply to the energy systems deployed, and
- Set the conditions to be met for retailing electricity to customers in the Daintree.

Table 5-1: Relevant State Development Assessment Provisions

INTEREST	LEGISLATION	AGENCY	ASPECT/TRIGGER	APPROVAL	SUPPORTING INFORMATION
Approvals Triggered by State Interests and Coordinated under *Planning Act 2016* Development Application for Options R1, R2 and C1-3					
State Planning Interests *Planning Act 2016*	*Land Act 1994*	DNRME	Owners consent for work undertaken within state land. This includes road reserves, esplanades, and other reserves. Does not include National Parks or protected area estates.	Application for owner consent, in this instance, DNRME.	Requires Application forms (A & B), Development Application Form 1 and relevant attachments (maps, plans etc.).
	Planning Act 2016	Local Government	Material Change of Use. Primarily will apply to the location of solar farms and generating/storage areas where the proposed infrastructure is consistent with the current zoning of the land, or there is a change in the intensity of existing land uses.	Local Government assessment, in this case Douglas Shire Council.	Requires MCU application forms as part of Development Application to be submitted along with appropriate plans and design drawings.
	Vegetation Management Act 1999	DNRME	Vegetation to be cleared is mapped as remnant regulated vegetation and project does not meet the exemption qualifications as identified under the Act.	A relevant purpose determination is required from DNRME prior to lodging the Development Application. Development Application needs to address SDAP State Code 16, native vegetation clearing.	Detailed report on vegetation structure, floristic structure and integrity and presence/absence protected species. Possible requirements for identification of offsets.
	Coastal Protection and Management Act 1995	DES	Operational works that are prescribed tidal works. Parts of the study area are located within the coastal management district and likely to impact on Matters of State Environmental Significance (MSES).	Full response against SDAP State Code 8: Coastal development and tidal works.	Supporting Development Approval Planning Report, relevant plans and EMP. Also must address all matters related to MSES. Requires detailed environment report.
	Planning Regulation 2017	GBRMPA, DES	Operational works that are undertaken in a Great Barrier Reef wetland protection area. A number of significant waterways in the Project area are declared protection areas.	Full response against SDAP State Code 9: Great Barrier Reef wetland protection areas.	To be addressed as per supporting information above.

INTEREST	LEGISLATION	AGENCY	ASPECT/TRIGGER	APPROVAL	SUPPORTING INFORMATION
	Fisheries Act 1994	DAFF	Waterway barrier works. Any project works involving creek/waterway crossings/disturbance and infrastructure construction may require waterway barrier works.	Development application must include a full response against SDAP State Code 18, constructing or raising waterway barrier works in fish habitats.	Specifically the SDAP response must address Performance Outcomes PO1 to PO18, and PO36, and PO32 to PO35. Requires detailed plans, instream habitat report. Should a residual impact to fish passage be identified an environmental offset may apply
Other State Agency Approvals and Triggers outside the Planning Act 2016 (i.e. not covered under a Development Application)					
State Interest: Protected flora	*Nature Conservation Act 1992*	DES (PALM)	The majority of the study area is within a high risk protected flora survey trigger area. Construction for Options R1 and R2 and Options C1-3 will require removal of protected flora species.	Protected plant clearing application and approval. A relevant offset will be required as part of the application.	A survey report in accordance with the Flora Survey Guidelines – Protected Plans (EHP 2016) must be supplied together with clearing permit application and an Impact Management Plan approved.
State Interest: Fauna	*Nature Conservation (Wildlife Management Regulation 2006*	DES	Clearing of mapped essential habitat will be required for Options R1 and R2 and Options C1-3. Disturbance of breeding places for fauna of conservation significance and special least concern animals may occur.	Application for a damage mitigation permit to interfere with an animal breeding place for colonial species, threatened species, or special least concern.	Species Management Program must be lodged and approved by the Executive, DES, prior to any disturbance of faunal breeding place.
State Interest: National parks	*Lands Act 1994* *Acquisition of Land Act 1967* *Nature Conservation Act 1992*	DNRME, DNPSR	Sections of the road reserve proposed to be used for cabling may actually be within the National Park as cadastre boundaries in the study area are known to be very inaccurate in some areas.	Application by Deed of Grant under the Lands Act for expansion of road reserve to incorporate works area. Alternatively, minor road realignments on exchange of land basis under s22 of ALA 1967	Daintree NP is jointly managed with the Eastern Kuku Yalanji under the Daintree National Park Draft Plan of Management and ILUA. Engagement with traditional owners must be demonstrated. Survey plans of cadastre boundaries and indicated amendments to road reserve as required.
State Interest: Cultural Heritage	*Aboriginal Cultural Heritage Act 1993*	DES	Clearing of mature vegetation, and disturbance of waterways and riparian areas have the potential to disturb or encounter Aboriginal cultural heritage.	The Act obligates all aspects of design, construction and maintenance to consider the Duty of Care requirements under the Act. Where cultural heritage may be encountered then protocols must be in place to identify, assess and manage the find.	Will vary according to site location. Generally any green site clearing or waterways works will involve a high level of Duty of Care and engagement with the JYAC may be required for further guidance.

5.4 Local Government Interests

The Douglas Shire Council will be extensively involved in the assessment and application of conditions on the project for Options R1, R2 and C1-3, and is responsible for the application of local planning laws and building codes for Options I1, I2 and I3. The road reserve network is maintained and managed in trust by the Douglas Shire Council (i.e. the roads are all Council roads) although land ownership is still vested with the State. The use of road reserves for the Project will require approval by Douglas Shire Council as part of the Development Application process for which Douglas Shire Council will be a concurrence agency. Agreements and approvals to use the road reserve may be sought through meeting a combination of requirements under the *Transport (Road Use Management) Act 1995, Local Government Act 2009* and the *Planning Act 2016.*

In addition to regulatory requirements for the above, Douglas Shire Council also has numerous responsibilities that may be applicable in relation to building codes and compliance for infrastructure on private properties. Douglas Shire Council are also responsible for the implementation and management of the application of Local Laws and Planning statutes for development north of the Daintree River that may apply to all options.

5.5 Summary of Requirements and Anticipated Timeframes

Table 5-2 below provides a summary of the planning and regulatory requirements for each of the options, including an assessment of the likely timeframes and complexity of the assessments required to be undertaken.

In summary, the timing will depend on the option progressed. Options R1 and R2 are likely impact assessable for EPBC and WTMA permits. Option C1-3 will be dependent on level of supporting information requirements and level of assessment required, which may be up to 18 months. Options I1, I2 and I3 must address local government planning and building codes (where required).

These timeframes have been taken into account as part of the options financial analysis "Project Development Periods" and have resulted in an assumed operational commencement date of 1 July 2026 for all options (refer Section 7.2).

KPMG

Table 5-2: Planning and regulatory requirements

LEGEND	
	Long timeframe for assessments and requires high level of supporting information/studies, e.g. EIS level of assessment
	Complex integrated assessment for Development Applications with multiple agencies and specialised requirements
	State assessment timeframes. May require some specialised studies e.g. Protected Flora Surveys and Clearing permits
	No regulatory permits required, may require Council development and building approvals and/or referral to WTMA for conditions on Development Application

PLANNING/ REGULATORY REQUIREMENT	STAKEHOLDER ENTITY	STATE / FEDERAL / OTHER	EST. TIMING (APPLICATION & APPROVAL)	OPTION						
				R1	R2	C1-3	I1	I2	I3	COMMENTS
Environment Protection and Biodiversity Conservation Act 1999 Referral	Department of the Environment and Energy (DEE)	Federal	12 to 36 months							The length of assessment will depend on actual location of infrastructure (including cabling). Various sites, e.g. sections through National Parks, may require extensive studies and a likely EIS or PER (Public Environment Report) level of assessment.
Wet Tropics Management Plan 1998 permit	Wet Tropics Management Authority (WTMA)	State/Federal partnership agreement between DES and DEE	Concurrent with EPBC Referral							Will only need a permit when there are direct impacts on World Heritage Areas, otherwise the WTMA will be a referral agency to most Development Applications (but not require a permit). Will likely require an EIS level of assessment for R1 and R2 options. Rezoning under the Wet Tropics Management Plan may be required for some sections of the WTWHA.
Fisheries Act 1994	Department of Agriculture and Fisheries (DAF)	State	6 to 18 months Concurrent with Development Application							A Development Application will require assessment by DAF whenever a declared waterway is crossed or marine plants will be disturbed.

PLANNING/ REGULATORY REQUIREMENT	STAKEHOLDER ENTITY	STATE / FEDERAL / OTHER	EST. TIMING (APPLICATION & APPROVAL)	OPTION						COMMENTS
				R1	R2	C1-3	I1	I2	I3	
Vegetation Management Act 1999	Department of Natural Resources, Mines and Energy (DNRME)	State	6 to 18 months concurrent with Development Application							A Development Application will require assessment by DMRME whenever mapped regulated vegetation is to be cleared.
Nature Conservation Act 1992	Department of Environment and Science (DES)	State	12 to 18 weeks							Multiple aspects required external and separate to Development Application. Includes Protected Flora Clearing permits and faunal habitat assessments. May require damage mitigation permits. Agreements to utilising land within the national estate (if required) are considered below.
Nature Conservation Act 1992	Department of Environment and Science (DES) and Queensland Parks and Wildlife Service (QPWS)	State	18 to 36 months							Any works within the National Park boundaries will require agreement with DES/QPWS and possible s35 agreements. Note that this may also impact on permits from the WTMA as WTMA may require rezoning of the World Heritage Area depending on location of infrastructure.
Planning Act 2016	Department of State Development, Manufacturing, Infrastructure and Planning	State	9 to 18 months Up to 36 months if WTWHA and EPBC requirements to be integrated.							Complex Development Application with requirements for MCU, possibly reconfiguration of a lot, multiple referrals to various agencies. Level of assessment (i.e. information request, specialised studies or impact assessable, e.g. EIS) will determine length of approval process

PLANNING/ REGULATORY REQUIREMENT	STAKEHOLDER ENTITY	STATE / FEDERAL / OTHER	EST. TIMING (APPLICATION & APPROVAL)	OPTION						
				R1	R2	C1-3	I1	I2	I3	COMMENTS
Land Act 1994	Department of Natural Resources, Mines and Energy (DNRME)	State	6 to 12 months concurrent with Development Application							Landholder consent for state land occupation, e.g. occupation of road reserve, and other state land by infrastructure.
Douglas Shire Council *Planning Scheme, Local Planning Laws and Regulations*	Douglas Shire Council	Local government	6 to 12 months							Douglas Shire Council will be integral to any development application assessment. Douglas Shire Council is also responsible for the road network north of the Daintree River. As a landholder, Douglas Shire Council will also have inputs into land occupation, compliance with local planning laws and building regulations where applicable.
Electricity Act 1994	Department of Natural Resources, Mines and Energy (DNRME)	State	6 to 12 months							All microgrid options need to be licenced by DNRME under a Special Approval arrangement.
Total Anticipated Timing			Up to 3 years	Up to 3 years	Up to 3 years	To 18 months	To 12 months	To 12 months	To 12 months	Refer below
Timing will depend on the option progressed. Options R1 and R2 are likely impact assessable for EPBC and WTMA permits. Option C1-3 will be dependent on level of supporting information requirements and level of assessment required, which may be up to 18 months. Options I1 to I3 are subject to local government planning laws and building codes (where applicable).										

6 QUALITATIVE ECONOMIC ANALYSIS

PURPOSE OF THIS SECTION

- This section provides a high level qualitative economic analysis of the electricity supply options.
- Key references include: Table 6 2: Qualitative Economic Assessment.

6.1 Approach

A qualitative high level economic analysis has been undertaken to identify the relative opportunity (if any) to generate an incremental economic return associated with each option. Figure 6-1 provides a summary of the approach taken to assess the relative economic benefits of the options.

Figure 6-1: Economic analysis approach

STEP 1. CURRENT STATE DEFINITION	STEP 2. DEMAND ANALYSIS	STEP 3. OPTION DEFINTIONS	STEP 4. IDENTIFICATION OF ECONOMIC IMPACTS	STEP 5. EVALUATION OF ECONOMIC IMPACTS
A description of the current state of the study area, and establishment of the Base Case.	Analysis of the existing and expected demand in the study area for electricity.	A statement on the options being assessed to achieve the study objectives.	Identification of the relevant economic impacts in terms of benefits and costs to the study area.	An evaluation of each options' relative economic impacts in increment to the Base Case.

Key Assumptions

The key assumptions underpinning the economic analysis are as follows and in Table 6-1.

- **Impacts are equally weighted:** All impacts assessed were weighted equally when determining relative rankings for options.
- **Current state generation mix:** It is assumed that the current state utilises an 80:20 mix of generator power (diesel and petrol) and renewable energy. This is based on the average estimated load of all customers in the study area. It should be noted that this mix will vary depending on the type of customer, seasonal weather patterns and individual set-ups. As such, each property is likely to experience varied amounts of benefit from any one impact identified.
- **Electricity demand:** It has been assumed that demand for electricity remains constant into the future without taking into consideration changes in technology which may improve the energy efficiency of appliances and other plug-ins or the possibility that energy demand may increase if one of the options is taken forward due to increased usage and development.

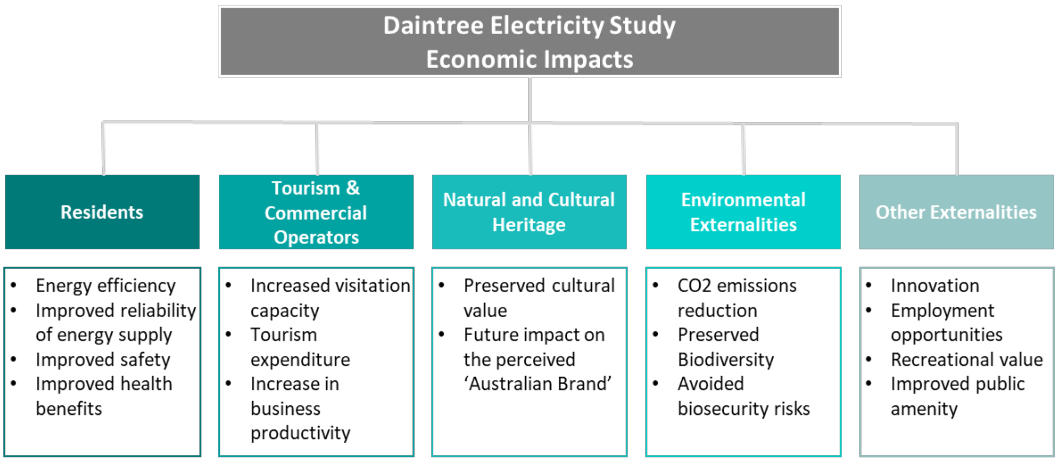
Table 6-1: Economic Analysis Options Assumptions

DESCRIPTION	BASE CASE	OPTIONS					
		R1	R2	C1-3	I1	I2	I3
Grid	Individual	Region wide	Region wide	Community wide	Individual	Individual	Individual
Centralised Generation	No	Yes	Yes	Yes	No	No	No
Primary Generation	Diesel Generator	Solar	Hydrogen	Solar	Generator	Generator	Hydrogen Fuel Cell
Secondary Generation	Solar	Diesel Generator	Diesel Generator	Diesel Generator	Solar	Solar	n/a
Battery Storage	Battery (Lead- acid)	Battery (Lithium-ion)	Battery (Lithium-ion)	Battery (Lithium-ion)	Battery (Lithium-ion)	Battery (Lithium-ion)	n/a
Standardised Service	No	Yes	Yes	Yes	No	Yes	Yes

6.2 Identification of Economic Impacts

There are a number of potential economic impacts associated with the introduction of new energy supply arrangements in the study area. The following impact groups have been identified as part of the economic assessment, and are considered to have the potential to experience an economic change as a result of the Project.

Figure 6-2: Economic Impacts



Notwithstanding this range of potential impact groups, the assessment of the economics evaluation criterion, as set out in Section 9 and 10 in this study, has been undertaken with an emphasis on the impact an option has on **tourism and commercial operators only**, noting that the impacts on residents, natural and cultural heritage, environment and other externalities are considered through other dedicated criteria.

6.3 Economic Assessment

Each option has been assessed against the current state for the impact groups identified and provided a rating between high benefit and high dis-benefit (an economic cost). It has been concluded that the regional options provide have the potential to generate low dis-benefit, whereas Options I1 and I2 have no overall expected incremental economic benefit, and Option I3 provides a low expected incremental economic benefit.

Table 6-2: Qualitative Economic Assessment

IMPACT GROUP	OPTIONS					
	R1	R2	C1-3	I1	I2	I3
Residents	Moderate benefit	High benefit	Moderate benefit	No change	Low benefit	Low benefit
Tourism and Commercial Operators	Low benefit	Low benefit	Low benefit	No change	No change	No change
Preserved Natural and Cultural Heritage	High dis-benefit	High dis-benefit	High dis-benefit	No change	No change	No change
Environmental Externalities	Moderate dis-benefit	Moderate dis-benefit	Moderate dis-benefit	No change	No change	Low benefit
Other Externalities	Moderate dis-benefit	Low dis-benefit	Moderate dis-benefit	No change	No change	Low benefit
Expected Incremental Economic Benefit	**Low dis-benefit**	**Low dis-benefit**	**Low dis-benefit**	**No change**	**No change**	**Low benefit**
Rating used for Options Assessment^	**Low benefit**	**Low benefit**	**Low benefit**	**No change**	**No change**	**No change**

^As set out above, this is based on the rating of Tourism and Commercial Operators

6.4 Economic Assessment - Key Considerations

The table below outlines at a high level the key considerations and differentiation between the impact groups for each supply option.

Table 6-3: Qualitative Economic Assessment – Key Considerations

IMPACT GROUP	KEY CONSIDERATIONS
Residents	• **Option R1 and C1-3:** Moderate Benefit – The anticipated benefits to existing residents are likely to be most prominent in the gains associated with efficiency improvements, and reduced health risks from moving from individual power supply configurations to microgrid systems. This is on the basis that grid systems and the centralised generation provide economies of scale in the supply of power to the study area's customers. • **Option R2:** High Benefit – As per Option R1 and C1-3 with increased health benefits associated with moving to hydrogen fuelled power. • **Option I1:** No Change – Option I1 provides no incremental economic benefit as it provides a low increase to energy efficiency and increase of comfort, with no safety, health or reliability and security benefits. • **Option I2 and I3:** Low Benefit – The low benefit to residents from options I2 and I3 is due to marginal energy efficiency improvements.
Tourism and Commercial Operators	• **Microgrid options:** Low Benefit – The anticipated economic benefits from tourism and commercial operators are most likely to occur under cases where the option provides more reliable and efficient access to power generation through economies of scale. These benefits are most likely to be greater in microgrid options where centralised generation is introduced, relative to options that retain individual power systems. • **Individual options:** No Change – Individual options are not expected to provide any incremental benefit on the basis that power generation capacity is not necessarily enhanced. A change in capacity could impact on operator's ability to expand.
Preserved Natural and Cultural Heritage	• **Microgrid options:** High Dis-Benefit – Options that require the installation of a microgrid and centralised generation are likely to have the most significant adverse impact on natural and cultural heritage values. Although construction methodologies employed may seek to preserve the natural and cultural heritage of the region, the development of freehold land is likely to have a higher impact. • **Individual options:** No Change – Individual options do not require disturbance to land outside of current properties and therefore do not change the current state of impacts on natural and cultural heritage.

IMPACT GROUP	KEY CONSIDERATIONS
Environmental Externalities	• **Microgrid options:** Moderate Dis-Benefit – Regional and community microgrids pose a threat to the preservation of the Daintree as they require disturbance to a comparatively large amount of land to install all necessary grid infrastructure. • **Option I1 and I2:** No Change – Options provide no change to the current state in terms of environmental externalities. • **Option I3:** Low Benefit – Option provides CO_2 emissions reduction benefit.
Other Externalities	• **Option R1 and C1-3:** Moderate Dis-Benefit – The regional and centralised grid options have the potential to impact on the Daintree's recreational sites. In addition, public amenity within the study area could be impacted negatively by grid infrastructure. • **Option R2:** Low Dis-Benefit – Dis-benefits are partly offset as increased demand for hydrogen technology has the potential to grow expected profits in the industry creating an innovation benefit. • **Option I1 and I2:** No Change – No change is expected to recreational value or public amenity from the current state. • **Option I3:** Low Benefit – Individual supply systems which use hydrogen are expected to generate some innovation benefit.

7 FINANCIAL ANALYSIS

PURPOSE OF THIS SECTION

- This section provides a financial analysis of the electricity supply options by customer type, including analysing upfront, ongoing and total costs on a levelised basis.

Key references include: The table below weights the levelised cost of each option by the assumed load of each Illustrative Customer.

7.1 Approach

This section of the study sets out for each of the options, the:

- Key timing, general and cost assumptions
- Levelised cost analysis over the assumed project term
- An indicative break-even analysis, and
- Carbon production by option.

7.2 Key Assumptions

Timing Assumptions

Overall, to ensure a comparable financial analysis, all options pivot off a common operations and maintenance start date of 1 July 2026.

This date is based on the estimated start date for the full microgrid options, Options R1 and R2, which have extensive project development and construction periods (i.e. indicatively 6 years in total). It is noted that Option I3 may involve a similarly lengthy development timetable in any event, due to the regulatory and commercial complexity associated with developing the underlying electrolysis facility. Options I1 and I2 could however be implemented much earlier as they involve established technologies and are compatible with existing SPS arrangements. The table below provides the key timing assumptions for each of the options.

Table 7-1: Timing Assumptions

PROJECT STAGE	OPTIONS					
	R1	R2	C1-3	I1	I2	I3
Project Development	3 years		1.5 years	1 years	1.5 years	3 years
Construction	3 years		2.5 years	1 year	2 years	2 years
Operations and	25 years					

General (Discounting and Indexation) Assumptions

The following table provides a summary of the key discounting and indexation assumptions that have been used in the financial analysis. Sources are based on GHD and KPMG analysis of a range of relevant reference data, including project precedents, publicly available information and CSIRO data.

Table 7-2: Discounting and Indexation Assumptions

ITEM	ASSUMPTION	SOURCE
Base Date for Costs	30 June 2019	GHD and KPMG
Discounting Assumptions		
Discount Date	30 June 2019	KPMG
Discount rate (WACC)^	10.0%	KPMG
Indexation and cost curves^^		
Owners Costs	2.5% p.a. (CPI)	KPMG
Capital and Lifecycle		
Cables	1.00% p.a.	GHD
Primary Plant	1.00% p.a.	GHD
Secondary Systems	1.50% p.a.	GHD
Solar Panels	(1.5%) to (1.0%) p.a.	GHD
Batteries - Li-ion	(12.0%) to (1.0%) p.a.	GHD
Batteries - Lead Acid	0.0% to 1.0% p.a.	GHD
Diesel Generators	1.0% p.a.	GHD
Fuel Cell	(5.0%) to (0.7%) p.a.	KPMG
Maintenance		
Option R2 Electrolysis Facility, Storage, Turbine	Nominal (levelised cost)	KPMG
Option I3 Fuel Cells	(1.1%) to 0.0% p.a.	KPMG
All other maintenance costs	2.3% p.a.	GHD
Fuel		
Diesel	(1.0%) to 1.0% p.a.	GHD
*Hydrogen (Green)^^^*	0.0%	KPMG
*Hydrogen (Brown)^^^*	0.0%	KPMG
Fuel – Transportation	2.5% (CPI)	KPMG & GHD

^ The commercial framework will be critical to determining the relevant WACC for any option, in particular options involving commercial investment in assets. Demand risk for example is a very material consideration and could in itself ultimately make options unviable (e.g. investors would not take material uptake risk and therefore could not finance the project).

The WACC that has been used is based on empirical evidence for greenfield privately funded energy projects and has been applied to all options. In reality, a different WACC would apply to each option to reflect its' associated risks, however to ensure a relative assessment at this options stage of the project, the same WACC has been used for all options.

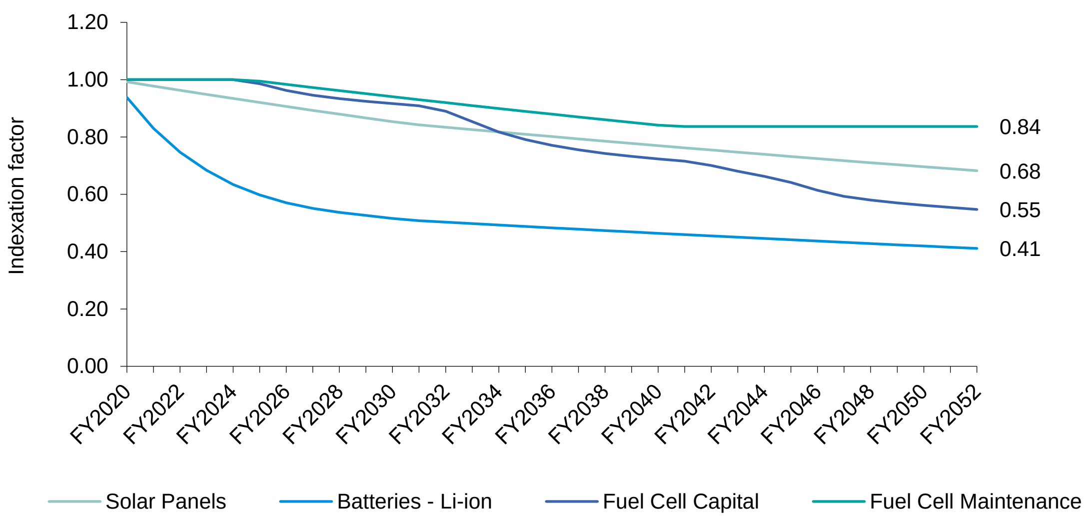
Given this approach, assessment of demand risk is included in the risk analysis in Section 8 through the commercial implementation risk, and then subsequently in each option's evaluation in Section 10, rather than in this financial analysis section through the WACC.

^^ *Refer Figure 7-1 for costs that are expected to reduce over time due to advancements in technology / increased production due to increased uptake.*

^^^ *The cost of Green Hydrogen assumed is a levelised cost over the assumed life of the project that has been calculated with reference to the development of the broader electrolysis facility, while the cost of Brown Hydrogen is assumed to be relatively flat over time, based on industry analysis.*

As set out above, a number of costs are expected to reduce over time due to advancements in technology and/or increased production due to increased uptake. The figure below provides the declining cost curves for these costs, which indicates that the components with declining cost curves will reduce in cost by between 20% (Fuel Cell Maintenance) and 59% (Fuel Cell Capital and Lithium-ion Batteries) over the life of the project (i.e. 1 minus the indexation factor).

Figure 7-1: Indexation for costs with declining cost curves



Cost Assumptions

Upfront and ongoing costs have been developed by GHD and, in relation to hydrogen components, KPMG.

Key assumptions underpinning cost estimates include:

- **Benchmarked concept level costings:** Upfront and ongoing costings have been developed at a concept level using industry, GHD and KPMG benchmarks with allowances made to ensure costings are prudent and reasonable, including taking into consideration natural and cultural heritage constraints. As a result of this approach, no dedicated risk or contingency amount has been added to cost estimates, however, cost certainty has been qualitatively assessed for each option as part of this financial analysis and broader options evaluation.

  The costings have been developed to facilitate the relative financial assessment of the options within this study. They do not represent detailed feasibility analysis and should not be used for budgeting purposes.

- **Costs are presented in aggregate for microgrid options (i.e. total customers) and at the individual level for individual options (i.e. an incremental customer):** As set out in Section 4.2, microgrid options have been developed at the Daintree region level and for individual based options, which do not rely on centralised assets, these assumptions have been developed at the individual level only (Note: as part of the indicative break-even analysis, individual option costs have been aggregated on a linear basis).
- **Electricity supply solutions have been sized for the year 25 maximum demand at year 1:** As set out in Section 4.2, to reduce the complexity of electricity supply solutions at this options stage, it has been assumed that all generation assets are procured during the construction period.
- **Cost certainty risk has been assessed as part of the risk analysis in Section 8 however is ultimately evaluated as part of the Financial criterion in Section 10:** The tables below provide the cost certainty risk rating that has been assessed in the risk analysis in Section 8 and in turn evaluated as part of the Financial criterion in Section 10. Affordability and cost certainty are the primary considerations in assessing the Financial criterion.
- **Three versions of Option I3 are presented to enable financial analysis of potential options for hydrogen fuel supply:** As set out in Section 4.8, given a market for hydrogen fuel supply has not been established in Australia at the residential level, three versions of Option I3 have been developed to enable comparison of potential supply options, and their resultant fuel and transportation costs. These options are as follows:
  - Option I3.1: Green hydrogen sourced from a 1.25 MW electrolyser located in Cairns to be separately developed and constructed by Government or the private sector.
  - Option I3.2: Green hydrogen sourced from a 10 MW electrolyser located in Townsville to be separately developed and constructed by Government or the private sector.
  - Option I3.3: Brown hydrogen sourced from the nearest steam methane reforming facility in Newcastle.
- **Gas usage, through cooking and water heating, has been excluded from the cost estimates:** As set out in Section 2.2, it has been assumed that gas appliances and hot water systems will not be replaced by electric units under each of the electricity supply options.

The tables below provide the whole of life costs under each of the microgrid and individual options on a nominal basis. As set out above, the microgrid options are presented in aggregate and the individual options are presented on an incremental cost/individual level basis.

Key cost categories, as required under the option, include:

- **Owners Costs – Project Development:** Project development / procurement, site acquisition, advisor costs
- **Owners Costs – Construction:** Project management and advisor costs
- **Microgrid Infrastructure:** Civil works, cabling (installed, including civil works), distribution transformers/switch gear, protection and control equipment, communications, service connections
- **Individual Option Infrastructure (Option I2 only):** Enclosure and communications

- **Components:** Solar PV, diesel generator, diesel generator auxiliaries, battery storage, system converter, converter auxiliaries, hydrogen electrolyser, hydrogen storage and compression, H2 gas turbine, hydrogen fuel cell
- **Fuel:** Diesel and, for Option I3, hydrogen
- **Transportation:** Diesel and hydrogen fuel transportation costs, and
- **Diesel Fuel Tax Credit:** Diesel fuel tax credits (Options I1 and I2 only).

Table 7-3: Whole of Life Costs – Microgrid Options ($million Nominal)

WHOLE OF LIFE COSTS ($MILLIONS NOMINAL)	OPTION					
	R1	R2	C1	C2	C3	C1-3
UPFRONT COSTS						
Owners Costs – Project Development	11.4	16.7	3.9	3.9	3.9	11.8
Owners Costs – Construction	5.6	7.0	1.9	1.9	1.9	5.6
Microgrid Infrastructure	75.2	75.2	13.8	19.5	26.2	59.4
Microgrid Components	6.3	27.5	2.1	3.9	0.5	6.5
TOTAL	**98.5**	**126.5**	**21.7**	**29.1**	**32.4**	**83.3**
OPERATING COSTS						
Owners Costs - Operations	82.5	82.5	27.5	27.5	27.5	82.5
TOTAL	**82.5**	**82.5**	**27.5**	**27.5**	**27.5**	**82.5**
LIFECYCLE COSTS						
Microgrid Infrastructure	0.8	0.8	0.7	0.7	0.7	2.0
Microgrid Components	9.7	16.1	3.4	6.2	0.8	10.3
TOTAL	**10.6**	**17.0**	**4.1**	**6.8**	**1.4**	**12.4**
MAINTENANCE COSTS						
Microgrid Infrastructure	1.4	1.4	0.7	0.7	0.7	2.1
Microgrid Components	3.7	19.7	0.9	1.3	0.5	2.6
TOTAL	**5.1**	**21.1**	**1.6**	**2.0**	**1.1**	**4.7**
FUEL AND TRANSPORTAION COSTS						
Fuel (Diesel)	11.8	-	2.9	4.4	1.9	9.2
Transportation	1.2	-	0.3	0.4	0.2	0.9
Fuel Tax Credit	-	-	-	-	-	-
TOTAL	**13.0**	**-**	**3.2**	**4.8**	**2.1**	**10.1**
TOTAL NOMINAL COSTS	**209.7**	**247.0**	**58.1**	**70.2**	**64.6**	**192.9**

COST CERTAINTY RISK	Medium-High	High	Medium	Medium	Medium	Medium

Compared with the table above which relates to the larger scale microgrid options, and is presented in millions of dollars, the table below relates to the smaller scale individual options and is simply presented in whole dollars.

Table 7-4: Whole of Life Costs – Individual Options – Base Case ($Nominal)

WHOLE OF LIFE COSTS ($NOMINAL)	OPTION					CURRENT STATE
	I1	I2	I3.1	I3.2	I3.3	
IC1						
Upfront	9,474	34,504	52,533	52,533	52,533	-
Operating	-	-	-	-	-	-
Lifecycle	30,155	46,545	70,885	70,885	70,885	28,490
Maintenance	16,934	69,937	39,765	39,765	39,765	16,934
Fuel (Diesel/Hydrogen)	33,919	35,849	25,820	21,814	9,794	33,919
Transport	16,494	3,571	2,203	8,444	43,323	16,494
Diesel Fuel Tax Credit	(14,055)	(14,947)	-	-	-	(14,055)
TOTAL NOMINAL COSTS	**92,921**	**175,459**	**191,205**	**193,440**	**216,299**	**81,782**
IC2						
Upfront	20,801	51,682	75,933	75,933	75,933	-
Operating	-	-	-	-	-	-
Lifecycle	45,298	73,649	101,264	101,264	101,264	41,743
Maintenance	21,800	74,121	56,807	56,807	56,807	21,800
Fuel	59,359	53,112	43,023	36,347	16,319	59,359
Transport	32,988	5,290	3,670	14,070	72,185	32,988
Diesel Fuel Tax Credit	(24,597)	(22,145)	-	-	-	(24,597)
TOTAL NOMINAL COSTS	**155,649**	**235,709**	**280,696**	**284,420**	**322,507**	**131,293**
IC3						
Upfront	-	207,765	122,919	122,919	122,919	-
Operating	-	-	-	-	-	-
Lifecycle	33,618	320,413	151,896	151,896	151,896	33,618
Maintenance	51,674	186,974	85,210	85,210	85,210	51,674
Fuel	519,625	433,091	231,599	195,661	87,848	519,625
Transport	41,235	43,140	19,759	75,742	388,589	41,235
Diesel Fuel Tax Credit	(215,322)	(180,575)	-	-	-	(215,322)
TOTAL NOMINAL COSTS	**430,830**	**1,010,809**	**611,382**	**631,428**	**836,461**	**430,830**

WHOLE OF LIFE COSTS ($NOMINAL)	OPTION					CURRENT STATE
	I1	I2	I3.1	I3.2	I3.3	
IC4						
Upfront	-	547,398	234,661	234,661	234,661	-
Operating	-	-	-	-	-	-
Lifecycle	67,236	835,683	303,792	303,792	303,792	67,236
Maintenance	182,858	467,018	170,420	170,420	170,420	182,858
Fuel	1,870,649	1,717,132	839,480	709,216	318,424	1,870,649
Transport	123,706	171,044	71,620	274,543	1,408,523	123,706
Diesel Fuel Tax Credit	(775,158)	(715,949)	-	-	-	(775,158)
TOTAL NOMINAL COSTS	**1,469,292**	**3,022,326**	**1,619,973**	**1,692,631**	**2,435,819**	**1,469,292**
COST CERTAINTY RISK	Medium	Low-Medium	Medium-High	Medium-High	Medium-High	Medium

7.3 Levelised Cost Analysis

This section sets out the annual levelised cost for each of the options and compares it to the Current State and a regional Queensland benchmark[13]. The levelised cost is used to assess and compare the alternative options, and takes into account all upfront and ongoing costs through a unitised "levelised" cost. It can be thought of as the average annual cost of all costs over the life of the project.

The table below provides the $/kWh total and ongoing levelised cost for each of the options. Even after accounting for the Current State not including upfront capital costs, the table demonstrates that all options have a higher ongoing levelised cost than the Current State, with the exception of Option I1 which is marginally lower.

[13] A regional Queensland benchmark has been provided for comparison purposes using the regulated electricity prices that apply to customers supplied by Ergon Energy in regional Queensland (Tariff 11 for residents and Tariff 20 for businesses). The fixed nature of these prices (i.e. variable supply tariff plus a fixed daily supply charge) allows for a direct comparison of costs to the options on a kWh basis.

Table 7-5: Levelised Cost of Options ($/kWh) – Total and Ongoing

ILLUSTRATIVE CUSTOMER	IC1	IC2	IC3	IC4
Total Levelised Cost ($/kWh) – Upfront and Ongoing				
Current State	0.58	0.56	0.35	0.33
Regional Benchmark	0.36	0.32	0.28	0.27
Option R1	3.65	3.65	3.65	3.65
Option R2	4.54	4.54	4.54	4.54
Option C1-3	4.69	3.22	2.32	2.40
Option C1	2.85	2.85	2.85	2.85
Option C2	2.01	2.01	2.01	2.01
Option C3	13.72	13.72	-	-
Option I1	0.77	0.81	0.35	0.33
Option I2	1.64	1.36	1.08	0.87
Option I3.1	2.07	1.82	0.68	0.46
Option I3.2	2.08	1.83	0.69	0.48
Option I3.3	2.23	1.97	0.84	0.62
Ongoing Levelised Cost ($/kWh)				
Current State	0.58	0.56	0.35	0.33
Regional Benchmark	0.36	0.32	0.28	0.27
Option R1	0.86	0.86	0.86	0.86
Option R2	0.94	0.94	0.94	0.94
Option C1-3	1.16	0.85	0.69	0.73
Option C1	0.91	0.91	0.91	0.91
Option C2	0.57	0.57	0.57	0.57
Option C3	3.06	3.06	-	-
Option I1	0.57	0.55	0.35	0.33
Option I2	0.87	0.67	0.57	0.50
Option I3.1	0.91	0.81	0.38	0.30
Option I3.2	0.92	0.82	0.39	0.32
Option I3.3	1.07	0.97	0.54	0.46

The table below weights the levelised cost of each option by the assumed load of each Illustrative Customer.

Table 7-6: Weighted Levelised Cost of Options ($ p.a.)

ILLUSTRATIVE CUSTOMER	IC1	IC2	IC3	IC4
ASSUMED LOAD (KWH P.A.)	**3,561**	**5,934**	**31,945**	**115,790**
Total Weighted Levelised Cost ($ p.a.)				
Current State	**2,064**	**3,321**	**11,290**	**38,787**
Regional Benchmark	**1,290**	**1,908**	**9,087**	**31,621**
Option R1	12,983	21,633	116,453	422,109
Option R2	16,166	26,937	145,007	525,608
Option C1-3	16,717	19,135	74,157	278,075
Option C1	10,133	16,884	90,891	329,454
Option C2	7,148	11,911	64,117	232,405
Option C3	48,875	81,436	-	-
Option I1	2,728	4,799	-	-
Option I2	5,832	8,053	34,418	100,907
Option I3.1	7,372	10,781	21,774	53,690
Option I3.2	7,415	10,852	22,154	55,065
Option I3.3	7,933	11,716	26,806	71,928

Based on the table above, for an individual IC1 customer as an example:

- **Regional microgrid options:** The annual levelised cost of a microgrid option broadly ranges between $13,000 and $16,000 per annum, which is significantly higher than the Current State.
- **Community microgrid options:** The annual levelised cost of the three community based microgrid options, assuming this cost is levelised across all three regions based on equity grounds, is around $17,000 per annum. This cost varies materially across the communities with Option C2 – Central being around $7,000 per annum and Option C3 – Southern being as high as $49,000 per annum. The cost in the Southern Area is the highest due to a combination of this area requiring the longest length of cabling (60km) compared with the Northern (30km) and Central (40km) Areas and also having the lowest electricity requirement, in part due to no IC3 or IC4 customers assumed to be located in this area.
- **Individual options:** Option I1 is the lowest cost option, being around $700 per annum higher than the Current State on an annual levelised cost basis. Options I2 to I3, although approximately half the cost of the microgrid options, still represent a material increase to the Current State with an annual levelised cost ranging between around $6,000 and $8,000 per annum.

- **Option I2:** Although this option is a similar concept to the Current State, this option has a higher levelised cost, including when considering ongoing costs only. Key factors resulting in the higher levelised cost on an ongoing basis include the provision of a managed service, remote monitoring, and higher maintenance and lifecycle replacement costs (e.g. lithium-ion battery) when compared to the Current State.
- **Option I3:** Under the three versions of this option, the two green hydrogen options have the lowest annual levelised cost primarily due to the transportation being materially lower than the brown hydrogen Option I3.3 (i.e. the cost of brown hydrogen is the lowest however, given the limited market and need to be transported from Newcastle, this is the highest cost version of this Option).

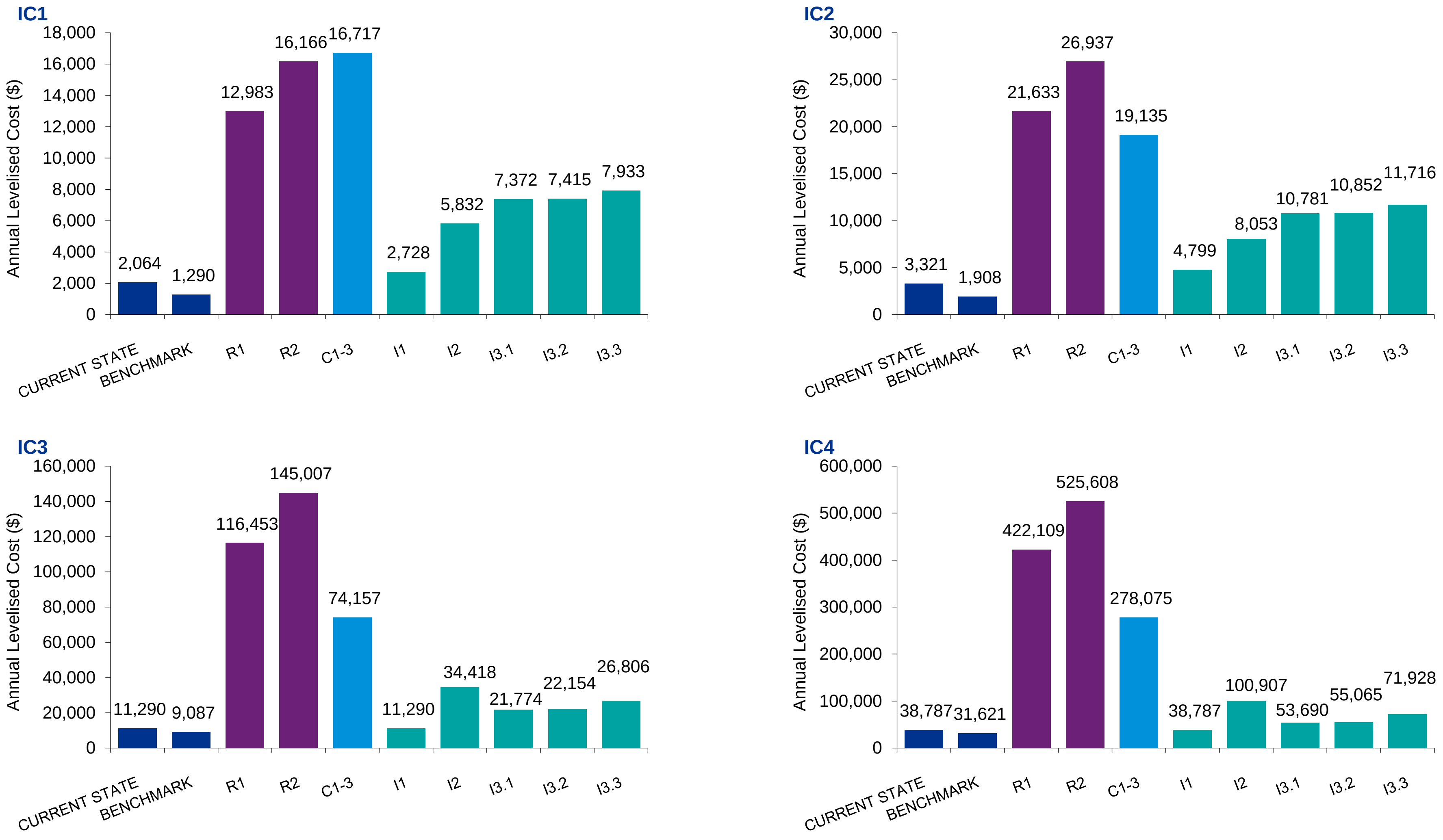
The table below provides the variance of each option to the Current State to provide further context of the change in cost an option potentially represents to existing arrangements.

Table 7-7: Weighted Levelised Cost of Options – Variance to the Current State ($millions NPC)

ILLUSTRATIVE CUSTOMER	IC1	IC2	IC3	IC4
ASSUMED LOAD (KWH P.A.)	3,561	5,934	31,945	115,790
Variance to Current State ($ p.a.)				
Current State	**-**	**-**	**-**	**-**
Regional Benchmark	**(774)**	**(1,414)**	**(2,203)**	**(7,166)**
Option R1	10,919	18,312	105,163	383,322
Option R2	14,102	23,616	133,717	486,822
Option C1-3	14,653	15,814	62,868	239,288
Option C1	8,069	13,563	79,601	290,667
Option C2	5,084	8,589	52,827	193,618
Option C3	46,811	78,115	-	-
Option I1	664	1,478	-	-
Option I2	3,768	4,732	23,128	62,120
Option I3.1	5,308	7,460	10,484	14,903
Option I3.2	5,350	7,531	10,864	16,278
Option I3.3	5,869	8,395	15,516	33,142

The figures below graphically illustrate the levelised cost for each of the options, by Illustrative Customer category, to enable a clear relative analysis.

Figure 7-2: IC1-IC4 Weighted Levelised Cost Comparison ($ p.a.)



7.4 Indicative Break-even Analysis

This section provides an indicative whole of life break-even analysis, on a net present cost (NPC) basis, relative to the extent that an option exceeds the cost of the Current State.

This analysis is useful from the following two perspectives:

- **Customers:** For potential customers in the region, it assists them to gain an understanding of the additional costs they would incur under an option in the absence of Government subsidisation.
- **Government:** For Government, it provides an order of magnitude of the level of Government subsidisation that would be required to preserve the customers' current level of electricity costs under an option (i.e. not paying more for electricity than what they are already paying).

Caveats of Analysis

Whole of life NPC analysis

Consistent with the levelised analysis, the analysis in this section is based on a theoretical whole of life NPC analysis, and it should not be used to directly inform a potential Government subsidy or scheme.

It is however useful in that it provides an order of magnitude for any potential subsidy and the relativity of the potential level of required subsidisation between the options. In practice, the amount would likely need to be higher when considered in nominal terms (or at least closer to the higher end of the range presented in NPC terms below).

This analysis should also not be taken to suggest that such a subsidy would in and of itself make an option commercially viable and bankable.

Sensitivity to the Discount Rate

The analysis in this section is also very sensitive to the discount rate used and, as a result, the range is wide. In reality, the level of subsidy required would also depend on the investors assumed return on capital and the relative timing of the subsidy.

For the microgrid options, given the common user nature of the assets developed and the unique circumstances surrounding the Daintree (including high demand risk and credit risk), it is likely that the assets would need to be regulated to be commercially viable. Depending on the final details of the applicable regulatory framework (e.g. treatment of stranded assets), this could potentially defray risk and result in a materially lower applicable discount rate than assumed in this study.

The discount rate used in this study seeks to provide an indication of the return hurdle that may be applied in the absence of Government subsidisation and regulation de-risking the investment. Conversely, the discount rate applied in this study may be lower than what is required in the absence of Government support which could simply show the investment to be too risky and not viable.

Alternative Approaches to a Break-even Analysis

While the break-even analysis presented is focussed on the amount the Government (or the customer) would need to contribute, an alternative purely hypothetical analysis could involve determining the additional total load the Daintree would need to "break-even" with the Current State level of cost (i.e. a higher load assists to spread the cost).

For example, for Option C1-3, which is the lowest overall cost microgrid option, the total load of the Daintree would need to be in the order of 7 times higher than the assumed current load in the region. Of course this level of consumption is completely unrealistic for the isolated Daintree region, however this metric is useful in that it assists to demonstrate the extent to which the potential investment in a microgrid is disproportionate to the current load.

Key Assumptions

Key assumptions underpinning the break-even analysis include:

- **Microgrid options – Uptake and growth assumptions are assumed to be met:** If these were not achieved the subsidy would need to be higher (refer Section 4.2 for these assumptions, including an assumed maximum uptake of 80% of customers).
- **Individual options – The total region amounts are based on 80% uptake (as per the maximum uptake assumed for microgrid options):** In order to keep the analysis of individual options consistent with microgrid options, the aggregated total customers for each individual option is based on a simple extrapolation of customers over the life of the analysis (i.e. multiplied by 80% uptake). For example, for Option I1, it assumes 80% of customers migrate to a new battery. In reality, this is an optimistic assumption and this level of penetration may not be achieved (which would result in assumed total region break-even costs being lower). In relation to Option I2 and I3, the assumed uptake rate is also optimistic due to the solution being a replacement of existing systems (compared with Option I1 which is an enhancement).

Indicative Break-even Analysis

The table below provides the break-even analysis of the options.

Table 7-8: Indicative Whole of Life Break-even Analysis ($millions NPC)

	DISCOUNT RATE 10%	DISCOUNT RATE 2.5%
Microgrid Options		
Option R1	68.7	117.6
Option R2	88.0	148.2
Options C1-3	58.2	106.0
Option C1	16.3	31.6
Option C2	18.5	30.5
Option C3	23.4	43.9
Individual Options		
Option I1	2.0	3.7
Option I2	17.3	40.5
Option I3.1	16.6	33.4
Option I3.2	16.8	34.5
Option I3.3	20.1	46.8

The indicative break-even analysis demonstrates that, in NPC terms, a potential subsidy or total customer contribution in the order of approximately:

- $70 - $150 million would be required to support the **Regional microgrid options (R1 and R2)**
- $60 - $110 million would be required to support the **Community based microgrid options (C1-C3)**
- $2 - $50 million would be required to support the **Individual options (I1, I2 and I3)**

For Options I1 and I2, in practice the required subsidy would be expected to be at the lower end of the range in nominal terms as Government would practically run a scheme over a set period of time (likely materially less than the 25 years) and any subsidy would unlikely extend to lifecycle replacement costs. For Option I3, further analysis would be required as to whether any subsidy would extend beyond an upfront contribution given the use of the emerging hydrogen fuel cell technology.

7.5 Carbon Production

This section provides an analysis of carbon production for each of the options which will be used to inform the quantitative aspect of the Environmental criterion. The technical analysis in Section 4 provides further technical overview of the environmental considerations for each of the options.

It is noted that carbon production has not been explicitly priced and is based on volume produced.

Key Assumptions

Key assumptions underpinning the carbon production analysis include:

- **Carbon emissions are as at year 25:** In order to account for growth in uptake and increased energy usage in all microgrid options, and growth in development for Options R1 and R2, as well as the subsequent decline in existing SPSs, the table below simply presents the carbon emissions as at year 25 of an option.
- **The total emissions amounts are based on 80% uptake of options:** As per the indicative break-even analysis above, the analysis presents all options at year 25 assuming an 80% uptake of the option (as per the maximum uptake assumed for microgrid options). The remaining 20% of customers are assumed to remain using their current SPSs and produce carbon at current levels.

Carbon Production Analysis

The table below provides the carbon intensity of each option as well as total emissions produced region wide in year 25.

Table 7-9: Carbon Production Analysis

	CARBON INTENSITY (KGCO2E/KWH)	YEAR 25 EMISSIONS (KGCO2E)		
		UPTAKE OF OPTION (80%)	CUSTOMERS REMAINING ON EXISTING SPS (20%)	TOTAL REGION
Microgrid Options				
Option R1	0.219	242,439	501,521	743,960
Option R2	-	-	501,521	501,521
Options C1-3	0.204	148,676	501,521	650,197
Option C1	0.178	43,374	196,407	239,781
Option C2	0.150	55,394	282,556	337,950
Option C3	0.442	49,908	22,558	72,466
Individual Options				
Option I1	0.530-0.925	2,006,085	501,521	2,507,606
Option I2	0.564-0.856	2,155,990	501,521	2,657,511
Option I3.1	-	-	501,521	501,521
Option I3.2	-	-	501,521	501,521
Option I3.3	-	-	501,521	501,521
Current State				
Current State	0.530-0.925	2,006,085	501,521	2,507,606

The carbon production analysis demonstrates that:

- **Option R1**: Option R1 will emit 242,439 kgCO2 in year 25 based off a carbon intensity factor of 0.219 kgCO2e/kWh. Under this option region wide emissions would be 743,960 kgCO2 in year 25. Microgrid options are generally more efficient than individual SPSs because the diversity that exists between multiple customer loads reduces the overall total peak demand and provides a much more constant load for the generators compared with the variations in the load of a single customer supplied from an individual SPS.
- **Option R2:** Option R2 will produce 0 kgCO2 in year 25. This option is designed to provide 100% green electricity supply to the Daintree and will only emit carbon emissions should the backup diesel generator be used. It is assumed this will rarely happen and the emissions from this are negligible. As uptake of this option is not assumed to be 100%, total region wide emissions will be 501,521 kgCO2 in year 25, which is based on the remaining 20% of customers remaining on their existing SPSs.
- **Option C1-3:** Option C1-3 will cumulatively produce 148,676 kgCO2 in year 25 based off an average carbon intensity factor of 0.204 kgCO2/kWh. Under this option region wide emissions would be 650,197 kgCO2 in year 25 across the four Illustrative Customer categories. This option has a lower carbon intensity and emissions when compared to Option R1 as a result of there being a higher overall proportion of solar and battery systems in the three generation facilities. This provides a greater proportion of renewable energy across all three sites.
- **Option I1**: Option I1 will produce 2,006,085 kgCO2 in year 25 based off a carbon intensity factor between 0.530 – 0.925 kgCO2e/kWh. Under this option region wide emissions would be 2,507,606 kgCO2 in year 25. The environmental outcomes for the existing SPSs used in the Daintree will largely remain unchanged with only new battery technology introduced (i.e. no change in diesel generator usage). As such, emissions for Option I1 are equivalent to the Current State.
- **Option I2**: Option I2 will produce 2,155,990 kgCO2 in year 25 based off a carbon intensity factor between 0.564 – 0.856 kgCO2e/kWh across the four Illustrative Customer categories. Under this option region wide emissions would be 2,657,511 kgCO2 in year 25. The carbon intensity of Option I2 will not be as low as the microgrid options as no efficiency can be gained by diversification of loads.
- **Option I3:** Option I3 will produce 0 kgCO2 in year 25. Hydrogen fuel cells only produce water, electricity and heat, and zero carbon emissions or pollution. As uptake of this option is not assumed to be 100%, total region wide emissions will be 501,521 kgCO2 in year 25, which is based on the remaining 20% of customers remaining on their existing SPSs.

8 RISK ANALYSIS

PURPOSE OF THIS SECTION

- This section provides a high level risk analysis of the electricity supply options.
- Key references include: Table 8.2 - Assessed Risks.

8.1 Approach

This section provides a high level qualitative analysis of key technical and commercial risks associated with the proposed supply options, including:

- Key risks and impacts, and
- A risk assessment which includes ratings and key considerations.

The risk analysis is preliminary and reflects a range of assumptions regarding the various supply options.

8.2 Risk Identification and Assessment

Twelve key risks were identified as part of this high level analysis. These risks are not considered an exhaustive list and there may be other risks associated with the various supply options. Risks have been assessed from a natural and culture heritage, financial, reliability and security of supply, and technical and commercial implementation risk perspective, aligning with key evaluation criteria, as set out in Section 9.1. A description of these risks and their impact are outlined in Table 8-1.

Table 8-1: Key Risks

RISK CATEGORY	DESCRIPTION	IMPACT
Natural and Cultural Heritage		
Construction – Natural Heritage	The risk that the construction of the option has an impact on natural heritage in the region.	Adverse impacts to natural heritage values.
Construction – Cultural Heritage	The risk that the construction of the option has an impact on cultural heritage in the region.	Adverse impacts to cultural heritage values.
Development – Natural Heritage	The risk that the option leads to increased development that has an impact on natural heritage in the region.	Adverse impacts to natural heritage values.
Development – Cultural Heritage	The risk that the option leads to increased development that has an impact on cultural heritage in the region.	Adverse impacts to cultural heritage values.

RISK CATEGORY	DESCRIPTION	IMPACT
Financial		
Cost Certainty	The risk that the option will operate above estimated costs over time.	Increased levelised cost and/or increased likelihood of stranded asset.
Reliability and Security of Supply		
Reliability	The risk that the option does not have the capacity to meet peak demand over the assumed life of the project.	Option cannot supply customer demand and could require load limiting.
Security	The risk that the option has uncertainty in supply security / cannot withstand a single credible contingency event.	Option is not secure and leads to loss of supply during a contingency event.
Technical and Commercial Implementation		
Planning and Regulatory Implementation	The risk of delay to project delivery due to: • Planning and approvals • Regulatory approvals • External public notification and commentary responses.	Regulatory and planning approvals are either not forthcoming and/or a high level of supporting information is required (e.g. project deemed impact assessable and requires a formal EIS) resulting in delays to the project.
Commercial Implementation	The risk that the option would not be able to establish a viable commercial framework, for example due to uncertainty surrounding regulatory framework or bankability (demand risk, counterparty risk etc.).	Option is not viable and will not progress or, if implemented, increased levelised cost and/or increased likelihood of stranded asset.
Delivery	The risk of delay to project delivery due to: • Site conditions • Design and construction • Transport and construction difficulty during wet season.	Construction is delayed due to site conditions, leading to additional time and cost.
Connection/ Integration	The risk that customers are unable to connect to the network.	Customer's installation may not be suitable (voltage, safety compliant, compliant with Australian Standards) to safely connect to the network.
Generation Technology	The risk that generation technology cannot be operated and/or maintained.	Newer technology may be more difficult to manage in remote areas as there will be little local expertise and spare parts. Proven technology would tend to be more reliable and easier to repair following failure.

8.3 Risk Assessment

Each risk has been assessed against each option and assigned a risk rating. Naturally, if options are further progressed in the future, the risks identified will require further evaluation to determine whether they pose a substantial threat to the viability of the option and whether their impacts can be mitigated or limited to an acceptable level.

Table 8-2: Assessed Risks

RISK	R1	R2	C1-3	I1	I2	I3
	MICROGRID OPTIONS			INDIVIDUAL OPTIONS		
Natural and Cultural Heritage – *A higher rating indicates the option poses a greater risk to the natural and cultural heritage values of the region*						
Construction – Natural Heritage	Medium	Medium	Medium	Low	Low	Low
Construction – Cultural Heritage	Low-Medium	Low-Medium	Low - Medium	Low	Low	Low
Development – Natural Heritage	Medium - High	Medium - High	Medium - High	Low	Low	Low
Development – Cultural Heritage	Low - Medium	Low - Medium	Low - Medium	Low	Low	Low
Overall rating[14]	**Medium - High**	**Medium - High**	**Medium - High**	**Low**	**Low**	**Low**
Financial – *a higher rating indicates the option poses a greater financial risk to consumers*						
Cost Certainty	**Medium - High**	**High**	**Medium**	**Medium**	**Low - Medium**	**Medium - High**
Reliability and Security of Supply – *a higher rating indicates the option has a lower reliability and security of supply*						
Reliability	Low - Medium	Low - Medium	Low - Medium	Medium	Medium	Low - Medium
Security	Low - Medium	Low - Medium	Low - Medium	Medium	Medium	High
Overall rating	**Low - Medium**	**Low - Medium**	**Low - Medium**	**Medium**	**Medium**	**Medium**

[14] The ratings associated with "Development – Natural Heritage" have been adopted for all options' overall ratings (noting individual options rated low for all risks) as it is considered that the most significant impacts on natural and cultural heritage values will not come from construction, but from the accelerated development and clearing associated with provision of a grid system (including this being a key stand of the WTMA and the Commonwealth).

RISK	R1	R2	C1-3	I1	I2	I3
	MICROGRID OPTIONS			INDIVIDUAL OPTIONS		
Technical and Commercial Implementation – *a higher rating indicates the option presents a greater risk to technical and commercial implementation*						
Planning and Regulatory Implementation	High	High	Medium - High	Low	Low	Medium
Delivery	High	High	Medium - High	Low - Medium	Low - Medium	Low - Medium
Connection/Integration	Medium - High	Medium - High	Medium - High	Low - Medium	Medium	Medium
Generation Technology	Low	Medium-High	Low	Low	Low	Medium - High
Commercial Implementation	High	High	High	Low	Low - Medium	High
Overall rating	**High**	**High**	**Medium High**	**Low**	**Low - Medium**	**Medium - High**

8.4 Risk Assessment - Key Considerations

The table below outlines at a high level the key considerations and differentiation between the risks for each supply option.

Table 8-3: Risk Matrix – Key Considerations of Risk Ratings

RISK	KEY CONSIDERATIONS OF RISK RATINGS
Natural and Cultural Heritage	
Construction – Natural Heritage	• **Microgrid options:** Medium – All options have similar immediate impacts on the natural environment (i.e. all will require waterway crossings, vegetation clearance, soil disturbance etc. and similar such construction risks). • **Individual options:** Low – Options involve impacts site specific to immediate properties concerned and generally involve already existing SPSs or minimal impacts on private lands.
Construction – Cultural Heritage	• **Microgrid options:** Low-Medium – Generally as per above, where the impacts will be highest where vegetation is removed, earth works and/or disturbance of waterways and riparian areas are required. • **Individual options:** Low – Regarded as low risk as impacts with these options are restricted to existing/upgrading current SPSs.
Development – Natural Heritage	• **Microgrid options:** Medium-High – Options are seen as encouraging and accelerating uptake of available land and subsequent further development that involves vegetation/habitat clearances and ongoing cumulative impacts on World Heritage values including edge effects, loss of landscape connectivity and introduction/spread of invasive species. • **Individual options:** Low – Regarded as low risk to further development on natural heritage as impacts with these options are restricted to individual properties, and already impacted systems.
Development – Cultural Heritage	• **Microgrid options:** Low-Medium – Further development of vegetated properties encouraged by the availability of a microgrid may have impacts on cultural heritage as vegetation is cleared and/or waterways impacted. • **Individual options:** Low – Regarded as low risk as impacts with these options are restricted to individual properties.

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RISK	KEY CONSIDERATIONS OF RISK RATINGS
Financial	
Cost Certainty	• **Option R1:** Medium-High – Natural and cultural constraints within the Daintree may result in construction cost overruns due to technical constraints and regulatory uncertainty (i.e. causing delays that result in further costs). The need to use existing roads would provide uncertainty around the costs of burying the cable within the road reserve given the needs for traffic management and restoration to an acceptable level. Ongoing operational management costs also have a level of uncertainty for this option. • **Option R2:** High – Option is rated high risk in particular due to the electrolysis facility being located within the Daintree, potential for diesel generators to be deployed if hydrogen storage/supply is not sufficient, and general uncertainty of the cost of hydrogen technology due to it being emerging, unproven and non-commercial at this time. Ongoing operational management costs also have a level of uncertainty for this option. • **Option C1-C3:** Medium – Option has a lower risk than Options R1 and R2 due to not having to install cable in the sensitive WTWHAs between the population centres. Ongoing operational management costs also have a level of uncertainty for this option. • **Option I1:** Medium – Although the new battery storage is based on fairly well established technology and low cost base compared with other options, there is continued uncertainty around fluctuating fuel prices and ongoing maintenance requirements for the SPS as a whole (as per the Current State). • **Option I2:** Low-Medium – Fairly well established technology. Can be manufactured off site. Transport and installation costs are more difficult to estimate. The solution can be externally managed and provide a greater level of consistency and standardisation relative to Current State. The lumpy nature of maintenance/replacement is also removed for customers (which can be unpredictable). • **Option I3:** Medium-High – There is price uncertainty due to the emerging nature of the technology, however the consensus from current literature and observed trends in fuel cell cost is that the cost of this technology is expected to decrease substantially over the coming decade. Notwithstanding, this option retains a relatively high level of cost uncertainty at this time.
Reliability and Security of Supply	
Reliability	• **Microgrid options:** Low-Medium – Options use an established supply technique with redundancy in the generation facility, including for the newer technology associated with hydrogen production and storage in Option R2. Finding faults on the distribution network may take some time given the remote area and rainforest surroundings. Single feeder to customers (no redundancy). • **Option I1:** Medium – Reliability will remain at or marginally better than existing levels which are rated as medium risk. • **Option I2:** Medium – Fairly well established technology. Remote monitoring of status. Remote area increases time to repair faults. Partial redundancy. May be expected to be better than Current State although scored as Medium. • **Option I3:** Low-Medium – Fuel cells are more reliable (and quieter) than generators. The ancillary systems such as fans, pumps, etc. are also based on mature technology resulting in a high degree of reliability.

RISK	KEY CONSIDERATIONS OF RISK RATINGS
Security	• **Microgrid options:** Low-Medium – Redundancy in generation. Single feeder to customers (no redundancy). • **Option I1:** Medium – Security will remain at or be better than existing levels which are rated as medium risk. • **Option I2:** Medium – Partial redundancy. Remote monitoring. • **Option I3:** High – Short term uncertainty over supply security as hydrogen market develops. Potentially prohibitive cost of brown hydrogen at low supply levels and no operational electrolysers in the region at present although several projects under development. This may be mitigated however if residents retain existing generators for back-up.
Technical and Commercial Implementation	
Planning and Regulatory Implementation	• **Options R1 and R2:** High – These options have the highest regulatory risk ratings as they invoke Commonwealth obligations under the EPBC Act and WTMA permit requirements that are concurrent with EPBC Act referrals. They may require external public notification and comment and require a level of assessment that may include EIS or Public Environment Report (PER). Up to 3 years may be required to obtain a determination from DEE and WTMA and approvals may be refused. These options also require Development Applications under the Qld *Planning Act 2016* and a high level of supporting information, up to and including an EIS level of investigation if the works are deemed impact assessable. An EIS would be compliant with Terms of Reference required for any Commonwealth EPBC requirement (i.e. be the one document). Technical regulation of the distribution network is a relatively new area for microgrids. The jurisdictional regulator will be largely responsible for developing the rules that will apply to these networks. • **Option C1-3:** Medium-High – Option will require EPBC referral and Development Application where a high level of supporting information may be required for multiple regulatory requirements. Should the project be classed as impact assessable development, both the DA and EPBC referral may require an EIS level of information support. Technical regulation of the distribution network is a relatively new area for microgrids. The jurisdictional regulator will be largely responsible for developing the rules that will apply to these networks. • **Option I1 and I2:** Low – These options have the lowest risk ratings as approvals are primarily under local government ordinances in relation to building codes, and local laws (if relevant to the individual property). The main technical risk is with the customer's installation complying with Australian standards in order to take supply from the SPS. • **Option I3:** Medium – There are no regulations currently adopted in Australia that specifically relate to the centralised production of hydrogen via electrolysis. The National Hydrogen Strategy, due to be published late 2019, is expected to include proposed legislative and regulatory reforms that will be required to remove barriers for development of hydrogen projects.

RISK	KEY CONSIDERATIONS OF RISK RATINGS
Delivery	• **Option R1 and R2:** High – Delivery of a microgrid network in the WTWHA will be complex (e.g. underground cables are common however construction of underground cables in WHAs is rare). Cables will need to be installed within the road reserve which involves disturbing the road, installing the cable and then restoration of the road. This can be costly for a well trafficked road. There will be difficulty in traversing rocky areas and swamp areas in between population centres for this option. Connection of cables from the road reserve to customers' premises may be difficult if tree roots will be disturbed. • **Option C1-3:** Medium-High – There is a slightly lower risk than the single microgrid options as these networks do not have to traverse more difficult terrain and sensitive WTWHA between population centres. • **Option I1:** Low-Medium – Easy to deliver into the same application as the batteries that are presently in service. Connection to existing systems and suitable sheltering may be more variable. • **Option I2 and I3:** Low-Medium – May be manufactured off site and delivered as a package. Establishing a suitable area to install at the customer's premises may pose a higher risk.
Connection/ Integration	• **Microgrid options:** Medium-High – Establishing a service connection from the backbone line to the customer may pose some risk and uncertainly around the ability to use underground cabling. The ability to connect to the customer's installation will depend on the standard of wiring that is in place. • **Option I1:** Low-Medium – Difficulty of connection will be dependent on customer's present installation which may be variable. Once suitable conditions can be ensured the connection process is relatively simple as it will replace existing equipment. • **Option I2 and I3:** Medium – The ability to connect to the customer's installation will depend on the standard of wiring that is in place.
Generation Technology	• **Option R1 and C1-3:** Low – The technology has been proven and is in use at many other locations. • **Option R2:** Medium-High – Although the risk is high given new technology being used for the hydrogen fuelled generation and hydrogen production, the risk is reduced by this option including diesel redundancy (noting that it is intended that this option primarily rely on the hydrogen technology). • **Option I1:** Low – From a technical perspective this option is easy to implement and risks are quite low. • **Option I2:** Low – The energy systems use well proven technology that has been utilised in many areas worldwide to provide supply. • **Option I3:** Medium-High – The prototype development and testing phase may result in a delay in project delivery.

RISK	KEY CONSIDERATIONS OF RISK RATINGS
Commercial Implementation	• **Microgrid options:** High – In particular due to the relatively high demand and counterparty risk of the customer base, and complex regulatory and approval requirements. This may impact an acceptable commercial framework and the bankability of these options, particularly without upfront and ongoing government support. Banks will also be hesitant to get involved in financing, especially for Option R2, due to deployment of new generation technology. A high percentage of the total investment for construction of the generation systems and network will need to be made upfront prior to the connection of any customers. • **Option I1:** Low – Successful frameworks have been established for options such as this by the Queensland Government previously, and could be utilised for this option (e.g. Interest Free Loans for Solar and Storage Scheme) to the extent Government has a preference to provide support for this option. • **Option I2:** Low-Medium – Established technology however demand and counterparty risk may impact the bankability of this option for an operator without Government support. Investment may be more easily staged over time (compared to the microgrid options) as each individual power system will only need to be delivered as customers choose to be connected. • **Option I3:** High – Due to this option relying on either brown hydrogen (where the price is very sensitive to economies of scale, which is low in the Daintree), or green hydrogen (which may rely on the establishment of an electrolysis facility that is likely to need additional offtake than the Daintree). There are limited electrolysis facilities of this nature in Australia. In addition, the regulatory framework is uncertain and likely to be complex. The complexity associated with commercial implementation may result in delays, although the development of a National Hydrogen Strategy may accelerate the development of the industry and assist in overcoming barriers associated with sourcing and establishment of a fuel supply chain, regulatory approvals and development of the technical solution.

9 EVALUATION - METHODOLOGY

PURPOSE OF THIS SECTION

- This section overviews the evaluation criteria and methodology that are applied to the electricity supply options, including the key considerations associated with each criterion.
- Key references include: Table 9.2 - Evaluation Criteria Matrix – Project Objectives.

9.1 Evaluation Criteria

The table below sets out the evaluation criteria, as agreed with DNRME, used for the evaluation of the options. Formal, fixed weightings have not been applied to the Evaluation Criteria. Rather, evaluation criteria have been individually assessed and scored, and then KPMG and GHD have reached an informed, consensus view of the overall score and relative merits of each option against the evaluation criteria as a guide to DNRME for its further consideration of the options.

Table 9-1: Evaluation Criteria

NO	CRITERION	DESCRIPTION	ASSESSMENT
1	Natural and Cultural Heritage	The ability of the option to preserve the natural and cultural heritage values in the region and limit cumulative/indirect impacts on these values into the future.	Qualitative
2	Financial	The estimated levelised cost of the option and the ability of the option to provide cost certainty for consumers.	Quantitative + Qualitative
3	Environmental	The ability of the option to reduce carbon emissions and pollution.	Qualitative + Quantitative
4	Reliability and Security of Supply	The ability of the option to provide ongoing reliability of supply (capacity to meet peak demand) and security of supply (operating within the range of acceptable limits and ability to withstand faults) that will meet or exceed the status quo.	Qualitative
5	Economic	The ability of the option to deliver incremental economic benefits to the region.	Qualitative
6	Learning and Innovation	The ability of the option to provide a level of innovation to support Queensland's transition to a low carbon economy, including facilitating skills development for new technology.	Qualitative
7	Technical and Commercial Implementation Risk	The certainty of the option in terms of technical implementation risk (delivering the upgraded services in the anticipated timeframes and managing disruption and integration risk) and commercial implementation risk (the complexity, flexibility and certainty of the commercial framework).	Qualitative

The evaluation criteria were developed with reference to the Government's Project Objectives outlined in Section 1.3 and as follows:

- preserve the natural and cultural heritage values in the region (1)
- are fiscally sustainable and/or present a commercial opportunity (2)
- promote affordable electricity supply services and greater cost certainty (3)
- promote improved environmental outcomes, including carbon and pollution reduction (4)
- enhance the standard of living for electricity consumers and enhance associated economic outcomes in the region (5)
- promote innovation and knowledge sharing amongst industry participants (6)
- engage with and inform stakeholders regarding electricity supply in the region (7).

For completeness, the table below maps the evaluation criteria to each of these Project Objectives.

Table 9-2: Evaluation Criteria Matrix – Project Objectives

	PROJECT OBJECTIVES						
EVALUATION CRITERIA	1	2	3	4	5	6	7
Natural and Cultural Heritage	✓						✓
Financial		✓	✓				✓
Environmental				✓			✓
Reliability and Security of Supply					✓		✓
Economic					✓		✓
Learning and Innovation						✓	✓
Technical and Commercial Implementation Risk							✓

9.2 Evaluation Ratings

The table below sets out the ratings scale that was used to evaluate each electricity supply option. These ratings are used to inform a relative assessment of the options and are not intended to rule an option in or out.

Table 9-3: Evaluation Ratings

RATING SCALE	DESCRIPTION
High	High – High expectation that the option meets or exceeds the requirements of the evaluation criteria.
Medium/High	Medium/High – Medium to high expectation that the option meets or exceeds the requirements of the evaluation criteria.
Medium	Medium – Medium expectation that the option meets the requirements of the evaluation criteria.
Low/Medium	Low/Medium – Low to medium expectation that the option meets the requirements of the evaluation criteria.
Low	Low – Low expectation that the option meets the requirements of the evaluation criteria.

9.3 Evaluation Criteria - Key Considerations

1 Natural and Cultural Heritage

Key considerations in the evaluation of this criterion will include the direct and indirect impacts the options will have on the natural and cultural heritage values in the region as well as any natural and cultural constraints that may impact on the deliverability of the options.

- **Direct impacts:** the construction of any option will need to take into account the significant natural and cultural heritage values in the region. Options will be assessed against the following potential direct impacts:
  - Temporary displacement of fauna species, and permanent displacement where remnant vegetation is removed
  - Damage to vegetation including regulated vegetation and impacts on protected flora species
  - Biosecurity risks, particularly the introduction of various non-native ant species including fire ants and yellow crazy ants, introduction of soil pathogens and invasive plant species. Works may also result in the spread of existing weed infestations.
  - Disturbance to soil, erosion and sedimentation issues on steep and unstable slopes or adjacent sensitive waterways.
  - Disturbance to beds, banks and riparian areas of watercourses and aquatic ecosystems

- **Indirect impacts:** the implementation of some options may have indirect impacts to natural and cultural heritage through:
  - Increased uptake and development of available residential land, leading to further habitat fragmentation, loss of biodiversity and potential for further introduction and spread of non-native species.
  - Increased tourism pressures, e.g. cars/buses, on local resources (such as National Park trails and infrastructure, beaches) and tourism developments in the region.
  - The likelihood that an option encourages development in the region, increases the residential and tourist population, and the impact this has on natural and cultural heritage will be assessed.
- **Natural and cultural constraints:** assessments have been undertaken by the WTMA and JYAC on the impacts and constraints supply options would encounter. Furthermore, there are numerous legislative, planning and regulatory requirements at a Local, State and Federal level that must be taken into consideration when evaluating each option.

2 Financial

Key considerations in the evaluation of this criterion will include:

- **Affordability:** A key objective of this study is to ensure that any option considered promotes affordable electricity supply services. The levelised cost for each option has been developed and will be used as the key metric in determining the affordability for customers. The affordability of the option will also be considered from a State perspective and whether any upfront or ongoing financial commitment is required by the State in order for the option to be viable.
- **Cost Certainty:** The cost certainty of each option will be evaluated both from a construction and operational standpoint. This will involve the evaluation of the likelihood of cost overruns and delays in construction, as well as the possibility of increased costs during the operations and maintenance phase.

As part of the financial evaluation of each option, the trade-off between reliability and cost will be evaluated in determining an overall rating for this criterion for each option.

3 Environmental

A significant criticism of residents current SPSs is the amount of diesel that is required. Promoting improved environmental outcomes and a reduction in carbon and pollution is an objective of this study. Key considerations in this evaluation criterion will include:

- **Carbon emissions:** Carbon emissions produced by each option have been calculated by HOMER. These will be compared against current carbon emissions, which have been estimated by modelling in HOMER software, of the current systems that customers use to provide supply. The emissions are based on the diesel generation component of the system only.
- **Noise pollution:** A qualitative assessment of the noise that will be generated by the relevant option and how adjacent it is to the customers being supplied.
- **Other pollution:** Dumping of batteries. Oil and/or fuel leakage.
- **Renewable technology utilised:** The proportion of energy that will be supplied by renewable technology.

4 Reliability and Security of Supply

As defined by the AEMC, a reliable power system has enough generation, demand response and network capacity to supply customers with the energy that they demand with a very high degree of confidence. Key considerations in this evaluation of this criterion will include:

Reliability of supply

- **Option sizing:** the generation capacity of each option as well as the trade-off between capacity, reliability and cost.
- **Distribution:** the reliability and performance of each options transmission and distribution along with the network capacity of any proposed microgrid solution.

Security of supply

- **System security:** the ability of each option to operate in a secure state, that is, the ability of the option to withstand shocks to its technical equilibrium such as a large load being connected or removed from the network.
- **Contingency events:** the ability of the option to withstand a single credible contingency event. A contingency event is an event that affects the power system in a way which would likely involve the failure or sudden and unexpected removal from operational service of a generating unit or transmission/distribution element. Credible contingency events are events that AEMO considers to:
  - Be reasonably possible to occur, or
  - Have the potential for a significant impact on the power system.
- **Environment:** Geographic and climatic conditions of the Daintree (e.g. thermal and humidity impacts on physical infrastructure).

5 Economic

Notwithstanding the range of potential impact groups, the assessment of the economics evaluation criterion has been undertaken with an emphasis on the impact an option has on tourism and commercial operators, noting that the impacts on residents, natural and cultural heritage, environment and other externalities, and costs, are considered through other dedicated criteria.

6 Learning and Innovation

Key considerations in the evaluation of this criterion will include:

- **Relevant Government policies:** the ability of each option to support the uptake of renewable technology to reduce emissions in line with government priorities and initiatives.
- **Research opportunity:** the ability of each option to provide opportunities for research or innovation through the approach or technology employed.
- **Regulatory opportunity:** the ability of each option to provide opportunities for regulatory learning.
- **Future transition:** the immediate and/or future ability of the option to transition to renewable energy.

7 Technical and Commercial Implementation Risk

Technical

Key considerations in the evaluation of the Technical Implementation Risk include:

- **Planning and regulatory:** the intensity of impact on natural and cultural heritage values for each option, and subsequent timeframes and level of supporting information required by agencies for assessing approval/development applications.
- **Construction**:
  - Timing and difficulty of construction, giving regard to physical constraints, particularly through the WTWHA.
  - Reliability of deliverability and likelihood and consequences of delay.
  - Issues associated with household connections from the system providing supply.
  - Location of generation facilities or SPSs with respect to customers, sensitive areas and vegetation.
- **Generation Technology:**
  - The extent to which generation technology is proven.

Commercial

Key considerations in the evaluation of the Commercial Implementation Risk include:

- **Bankability:** the ability of an option to establish a viable commercial framework without a substantial upfront and / or ongoing financial commitment from the State. Key risks that will impact project viability and bankability include demand risk and counterparty risk of the customer base and the complexity and certainty of the regulatory and operating framework.

10 EVALUATION - ASSESSMENT

PURPOSE OF THIS SECTION

- This section outline KPMG and GHD's collective assessment of each electricity supply option against the evaluation criteria, including each option being given a rating against each criterion informing an overall rating for each energy supply option.
- Key references include: Table 10.1 - Option Assessment Rating Summary.

10.1 Overall Options Assessment

The following section provides a summary of KPMG and GHD's assessment against each evaluation criterion. These assessments give regard to the detailed considerations outlined in Section 9.3 and the key points of difference between each proposed option. Each option has been given a rating against each criterion which has informed an overall rating.

Table 10-1 below provides a summary of the criterion and overall rating for each option.

Table 10-1: Option Assessment Rating Summary

NO	CRITERION	R1	R2	C1-3	I1	I2	I3	CURRENT STATE
1	Natural and Cultural Heritage	Low/Medium	Low/Medium	Medium	High	High	High	High
2	Financial	Low/Medium	Low	Low/Medium	Medium	Medium	Low/Medium	Medium
3	Environmental	Medium	High	Medium/High	Low/Medium	Low/Medium	High	Low
4	Reliability and Security of Supply	Medium/High	Medium/High	Medium/High	Medium	High	Medium/High	Medium
5	Economic^	Low/Medium	Low/Medium	Low/Medium	Low	Low	Low	Low
6	Learning and Innovation	Medium	Medium/High	Medium	Low	Low/Medium	High	Low
7	Technical and Commercial Implementation Risk	Low	Low	Low/Medium	High	Medium/High	Low/Medium	High
Assessment Summary		**Low**	**Low**	**Low/Medium**	**Medium/High**	**Medium**	**Medium/High**	**Medium**

^ Note: The evaluation of the Economics criterion has been undertaken with an emphasis on the impact an option has on tourism and commercial operators (refer Sections 6.2 and 9.3).

10.2 Individual Option Assessments

This section provides detailed assessments for the Current State and for each option. In relation to risk and assessment ratings provided in the these assessments, it is noted that they inverse denotations, with a higher assessment rating indicating that the option is expected to perform well against the requirements of an evaluation criterion (i.e. meet / exceed), and a higher risk rating indicating that the option has a higher level of risk (and therefore impacts negatively on the assessment rating, taking into consideration other elements of the relevant evaluation criterion).

10.2.1 Current State

The table below provides an assessment of the Current State against each evaluation criterion to provide a reference point for the evaluation of Options.

Table 10-2: Current State Assessment

NO	CRITERION	CURRENT STATE - ASSESSMENT COMMENTS	CURRENT STATE RATING
1	Natural and Cultural Heritage	• SPS within existing residential/business/commercial footprints. • Existing arrangements can continue to be managed through normal Douglas Shire Council building codes, planning requirements, local laws and regulations. • **Natural and Cultural Heritage Risk:** Low	High
2	Financial	• This current state has a lower levelised cost than any option, ranging from $2,064 to $38,787 per annum for IC1 to IC4. • **Cost Certainty Risk:** Medium – there are no cost risks in relation to construction. Continued risk around fluctuating fuel prices and ongoing maintenance requirements.	Medium

NO	CRITERION	CURRENT STATE - ASSESSMENT COMMENTS	CURRENT STATE RATING
3	Environmental	• These systems have not been optimised in any way to ensure the most efficient use of each component. • Noise of generation is a significant issue and is not maintained. • Fuel being delivered over a large number of customer sites increases the risk of a diesel spill. • **Carbon Emissions (based on year 25 levels):** 2,508 tCO_2 per annum based on a carbon intensity of 0.530 – 0.925 $kgCO_2e/kWh$.	Low
4	Reliability and Security of Supply	• Given there are a range of different energy systems in use it is expected that reliability and security of supply is presently quite variable across all customers. • **Reliability and Security of Supply Risk:** Medium	Medium
5	Economic	• No change – continuation of the Current State will not result in incremental economic benefits to the region.	Low
6	Learning and Innovation	• No change – continuation of the Current State does not provide learning and innovation.	Low
7	Technical and Commercial Implementation Risk	• No change – continuation of the Current State has no associated implementation risk.	High

Assessment Summary	*The Current State arrangements preserve (but do not improve) the natural and cultural heritage values of the region. They do not impose any additional costs on the State but neither are they expected to improve the affordability of electricity for residents in the region. The Current State arrangements do however represent an established solution in the short to medium term if emerging potential technology applications, such as hydrogen, prove viable in a SPS application in the longer term.*	**Medium**

10.2.2 Option R1

The table below provides an assessment of Option R1 against each evaluation criterion, including key differentiating factors associated with this option.

Table 10-3: Option R1 Assessment

NO	CRITERION	OPTION R1 - ASSESSMENT COMMENTS	OPTION R1 RATING	CURRENT STATE RATING
1	Natural and Cultural Heritage	• High level of regulatory approvals necessary with referral to the Commonwealth and WTMA permit required owing to works including sections within National Park and the WTWHA. A complex Development Application integrated with the Commonwealth and WTMA inputs will be required with subsequent high level of supporting information including vegetation, protected fauna/flora, WHA values assessment and waterways assessment. Project may be deemed impact assessable under Commonwealth and State and an EIS or PER may be required. • Construction methodologies employed are likely to preserve the natural and cultural heritage of the region (rating likely to be a medium in relation to construction) however the development of freehold land is likely to have a much higher impact on natural and cultural heritage and is seen as a much higher risk when compared with construction. This option is also likely to see an increase in tourism, visitation, vehicles etc. which increases the risk of the option and brings the overall rating for this criterion down to a Low-Medium. • **Natural and Cultural Heritage Risk:** Medium-High – Option is seen as encouraging and accelerating uptake of available land and subsequent further development that involves vegetation/habitat clearances and ongoing cumulative impacts on World Heritage values including edge effects, loss of landscape connectivity and introduction/spread of invasive species.	Low/Medium	High

NO	CRITERION	OPTION R1 - ASSESSMENT COMMENTS	OPTION R1 RATING	CURRENT STATE RATING
2	Financial	• This option has the second highest levelised cost, ranging from $12,983 to $422,109 per annum for IC1 to IC4. • **Cost Certainty Risk:** Medium-High Risk – Natural and cultural constraints within the Daintree may result in construction cost overruns due to technical constraints and regulatory uncertainty (i.e. causing delays that result in further costs). The need to use existing roads would provide uncertainty around the costs of burying the cable within the road reserve given the needs for traffic management and restoration to an acceptable level. Ongoing operational management costs also have a level of uncertainty for this option.	Low/Medium	Medium
3	Environmental	• A 2,000kW solar system provides renewable energy to the system and a battery storage system ensure that excess energy from the solar generation can be stored to offset diesel usage. • Microgrid options are generally more efficient than individual stand-alone power systems because the diversity that exists between multiple customer loads reduces the overall total peak demand and provides a much more constant load for the generators compared with the variations in the load of a single customer supplied from an individual stand-alone power system. • There will be improved ability to control any spills at a central generation facility and all fuel supplies will come to a single point. Noise of generation can be managed by placing the facility away from population as much as possible and providing good noise insulation in the generation housing. • **Carbon Emissions (based on year 25 levels):** 744 tCO2 per annum based on a carbon intensity of 0.219 kgCO2e/kWh.	Medium	Low

NO	CRITERION	OPTION R1 - ASSESSMENT COMMENTS	OPTION R1 RATING	CURRENT STATE RATING
4	Reliability and Security of Supply	• The generation system provides N-1 security, so one generator can be out of service for maintenance or due to a fault without any impact on supply to customers. The distribution system provides N security so a fault in one component would result in some customers losing supply until a repair can be made. The generation and distribution system will have remote monitoring to quickly identify faults. • Given there are no large disturbing loads in the supply area security of supply will be high. • **Reliability and Security of Supply Risk:** Low-Medium – Option uses an established supply technique with redundancy in the generation facility. Finding faults on the distribution network may take some time given the remote area and rainforest surroundings. Single feeder to customers (no redundancy).	Medium/High	Medium
5	Economic	• No anticipated material incremental net economic benefit. It may result in a marginal benefit to tourism and commercial operators. • Note: Other potential economic impacts, including in relation to existing residents, natural and cultural heritage, environment and cost are already generally otherwise scored through other dedicated criteria.	Low/Medium	Low
6	Learning and Innovation	• Provides an opportunity to develop a microgrid that could provide substantial industry learnings. A microgrid of this type would be used as a case study, including in relation to the AEMC's Priority 2 review of SPSs, specifically Category 2 systems. • Presents an opportunity to transition to greener fuel sources (e.g. renewable/green biofuels in the short-medium term).	Medium	Low

NO	CRITERION	OPTION R1 - ASSESSMENT COMMENTS	OPTION R1 RATING	CURRENT STATE RATING
7	Technical and Commercial Implementation Risk	• **Technical Implementation Risk – Planning and Regulatory:** High – This option, and Option R2, have the highest regulatory risk ratings as they invoke Commonwealth obligations under the EPBC Act and WTMA permit requirements that are concurrent with EPBC Act referrals. They may require external public notification and comment and require a level of assessment that may include EIS or Public Environment Report (PER). Up to 3 years may be required to obtain a determination from DEE and WTMA and approvals may be refused. These options also require Development Applications under the Qld *Planning Act 2016* and a high level of supporting information, up to and including an EIS level of investigation if the works are deemed impact assessable. An EIS would be compliant with Terms of Reference required for any Commonwealth EPBC requirement (i.e. be the one document). Technical regulation of the distribution network is a relatively new area for microgrids. The jurisdictional regulator will be largely responsible for developing the rules that will apply to these networks. • **Technical Implementation Risk – Delivery:** High – Delivery of a microgrid network in the WTWHA will be complex (e.g. underground cables are common however construction of underground cables in WHAs is rare). Cables will need to be installed within the road reserve which involves disturbing the road, installing the cable and then restoration of the road. This can be costly for a well trafficked road. There will be difficulty in traversing rocky areas and swamp areas in between population centres for this option. Connection of cables from the road reserve to customers' premises may be difficult if tree roots will be disturbed. • **Technical Implementation Risk – Connection/Integration:** Medium-High – Establishing a service connection from the backbone line to the customer may pose some risk and uncertainly around the ability to use underground cabling. The ability to connect to the customer's installation will depend on the standard of wiring that is in place.	Low	High

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NO	CRITERION	OPTION R1 - ASSESSMENT COMMENTS	OPTION R1 RATING	CURRENT STATE RATING
		• **Technical Implementation Risk – Generation Technology:** Low – The technology has been proven and is in use at many other locations. • **Commercial Implementation Risk:** High – In particular due to the relatively high demand and counterparty risk of the customer base, and complex regulatory and approval requirements. This may impact an acceptable commercial framework and the bankability of these options, particularly without upfront and ongoing government support. A high percentage of the total investment for construction of the generation systems and network will need to be made upfront prior to the connection of any customers.		

Assessment Summary	*This option requires a high level of regulatory approvals and design work as well as a substantial upfront capital contribution. The option also presents a risk to the natural and cultural heritage values of the region. The option would supply residents with a reliable and secure energy network, however, it presents numerous technical and commercial risks and is likely to be financially unviable without significant and ongoing Government support.*	**Low**	**Medium**

10.2.3 Option R2

The table below provides an assessment of Option R2 against each evaluation criterion, including key differentiating factors associated with this option.

Table 10-4: Option R2 Assessment

NO	CRITERION	OPTION R2 - ASSESSMENT COMMENTS	OPTION R2 RATING	CURRENT STATE RATING
1	Natural and Cultural Heritage	• As per Option R1. • **Natural and Cultural Heritage Risk:** Medium-High – As per Option R1.	Low/Medium	High
2	Financial	• This option has the highest levelised cost, ranging from $16,166 to $525,608 per annum for IC1 to IC4. • Given this option is a strategic 'green option', assumed to be based on 100% renewable technology with diesel generator redundancy for contingency events, the costs are inherently higher due to the need to oversize solar PV and storage and also provide for the diesel generator back-up. To the extent that more efficient fossil fuel technology is incorporated into the option, the costs for this option would go down. • **Cost Certainty Risk:** High – Option is rated high risk in particular due to the electrolysis facility being located within the Daintree, potential for diesel generators to be deployed if hydrogen storage/supply is not sufficient, and general uncertainty of the cost of hydrogen technology due to it being emerging, unproven and non-commercial at this time. Ongoing operational management costs also have a level of uncertainty for this option.	Low	Medium

NO	CRITERION	OPTION R2 - ASSESSMENT COMMENTS	OPTION R2 RATING	CURRENT STATE RATING
3	Environmental	• This option is designed to provide supply to the Daintree with minimal carbon emissions. Emissions will only occur should there be an extended period of cloud cover which would result in a shortage of hydrogen for the generation system as the electrolyser operates from solar energy. In this event a diesel generator will start to operate the electrolyser. It is expected that this will occur rarely. The hydrogen used to fuel the generation system will utilise green energy to produce the hydrogen so the carbon emission will be very low. • **Carbon Emissions (based on year 25 levels):** 0 tCO2 per annum.	High	Low
4	Reliability and Security of Supply	• This option has essentially the same level of reliability and security risks as Option R1 because the electricity distribution network is exactly the same and the same level of redundancy (any one component can fail or be removed for maintenance without loss of supply) is provided in the central generation facility. • The distribution network will be identical to Option R1. • **Reliability and Security of Supply Risk:** Low-Medium – As per Option R1. This option uses an established supply technique with redundancy in the generation facility, including for the newer technology associated with hydrogen production and storage. Finding faults on the distribution network may take some time given the remote area and rainforest surroundings. Single feeder to customers (no redundancy).	Medium/High	Medium
5	Economic	• As per Option R1.	Low/Medium	Low
6	Learning and Innovation	• Option scores slightly higher than Option R1 due to the deployment of hydrogen electrolysis technology however scores slightly lower than Option I3 due to Option I3 incorporating fuel cell technology at the home and opportunity for regulatory and supply chain learnings.	Medium/High	Low

NO	CRITERION	OPTION R2 - ASSESSMENT COMMENTS	OPTION R2 RATING	CURRENT STATE RATING
7	Technical and Commercial Implementation Risk	• **Technical Implementation Risk – Planning and Regulatory:** High – As per Option R1. • **Technical Implementation Risk – Delivery:** High – As per Option R1. • **Technical Implementation Risk – Connection/Integration:** Medium-High – As per Option R1. • **Technical Implementation Risk – Generation Technology:** Medium-High – Although the risk is high given new technology being used for the hydrogen fuelled generation and hydrogen production, the risk is reduced by this option including diesel redundancy (noting that it is intended that this option primarily rely on the hydrogen technology). • **Commercial Implementation Risk:** High – As per Option R1. Banks will also be hesitant to get involved in financing especially due to deployment of new generation technology.	Low	High

Assessment Summary	*As per Option R1 – however, due to the use of hydrogen generation, this option would be substantially more expensive but may offer more strategic value in terms of the demonstration as an emerging technology.*	**Low**	**Medium**

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10.2.4 Option C1-3

The table below provides an aggregated assessment of Options C1-3 against each evaluation criterion, including key differentiating factors associated with this option.

Table 10-5: Option C1-3 Assessment

NO	CRITERION	OPTION C1-3 - ASSESSMENT COMMENTS	OPTION C1-3 RATING	CURRENT STATE RATING
1	Natural and Cultural Heritage	• As per Option R1 however assessed as relatively better given construction is not required in the sensitive WTWHA between population centres. • **Natural and Cultural Heritage Risk:** Medium-High – As per Option R1.	Medium	High
2	Financial	• This option has the third highest levelised cost, ranging from $16,717 to $278,075 per annum for IC1 to IC4. • Option has lower network costs as cabling between communities goes through difficult terrain however this is somewhat offset by multiple generation sites and slightly smaller scale equipment increases the cost of generation hardware. • The key difference between this option and Option R1 is that some of the highest risk elements, from a cost perspective, are not included. • This option is rated Low/Medium, as per Option R1, however has a slightly lower level of risk. • **Cost Certainty Risk:** Medium Risk – Option has a lower risk than Options R1 and R2 due to not having to install cable in the sensitive WTWHAs between the population centres. Ongoing operational management costs also have a level of uncertainty for this option.	Low/Medium	Medium

NO	CRITERION	OPTION C1-3 - ASSESSMENT COMMENTS	OPTION C1-3 RATING	CURRENT STATE RATING
3	Environmental	• The generation system will be spread over three separate centres having a smaller size than Option R1. Each generator contains a solar system to provide renewable energy to the system and a battery storage system to ensure that excess energy from the solar generation can be stored to offset diesel usage. • There will be good ability to control any spills at each central generation facility, however fuel supplies will be delivered to three separate points. • Noise of generation can be managed by placing each facility away from population as much as possible and providing good noise insulation in the generation housing • This option has a lower carbon intensity compared to Option R1 as a result of there being a higher overall proportion of solar and battery systems in the generation facilities. This provides a greater proportion of renewable energy across all three sites. • **Carbon Emissions (based on year 25 levels):** 650 tCO_2 per annum based on a carbon intensity of 0.204 $kgCO_2e/kWh$.	Medium/High	Low
4	Reliability and Security of Supply	• The reliability and security of supply will be largely the same as for Option R1. • The reliability of generation would be slightly higher as it is spread over three separate sites. • **Reliability and Security of Supply Risk:** Low-Medium – As per Option R1.	Medium/High	Medium
5	Economic	• As per Option R1.	Low/Medium	Low
6	Learning and Innovation	• As per Option R1.	Medium	Low

NO	CRITERION	OPTION C1-3 - ASSESSMENT COMMENTS	OPTION C1-3 RATING	CURRENT STATE RATING
7	Technical and Commercial Implementation Risk	• **Technical Implementation Risk – Planning and Regulatory:** Medium-High – Option will require EPBC referral and Development Application where a high level of supporting information may be required for multiple regulatory requirements. Should the project be classed as impact assessable development, both the DA and EPBC referral may require an EIS level of information support. • **Technical Implementation Risk – Delivery:** Medium-High – There is a slightly lower risk than the single microgrid options as these networks do not have to traverse more difficult terrain and sensitive WTWHA between population centres. • **Technical Implementation Risk – Connection/Integration:** Medium-High – As per Option R1. • **Technical Implementation Risk – Generation Technology:** Low – As per Option R1. • **Commercial Implementation Risk:** High Risk – As per Option I1.	Low/Medium	High
	Assessment Summary	*As per Option R1 – however this option comes with lower technical delivery risk as these networks do not have to traverse more difficult terrain and sensitive WTWHA between population centres*.	**Low/Medium**	**Medium**

10.2.5 Option I1

The table below provides an assessment of Option I1 against each evaluation criterion, including key differentiating factors associated with this option.

Table 10-6: Option I1 Assessment

NO	CRITERION	OPTION I1 - ASSESSMENT COMMENTS	OPTION I1 RATING	CURRENT STATE RATING
1	Natural and Cultural Heritage	• All works are centred on upgrades of SPS within existing residential/business/commercial footprints. • Impacts are primarily site and property specific and can be managed through normal Douglas Shire Council building codes, planning requirements, local laws and regulations. • This option is not regarded as encouraging/accelerating development which is considered to have the most significant impacts on natural and cultural heritage. • **Natural and Cultural Heritage Risk:** Low – Regarded as low risk to further development on natural heritage as impacts with these options are restricted to individual properties, and already impacted systems.	High	High
2	Financial	• This option has the lowest levelised cost, ranging from $2,728 to $4,799 per annum for IC1 to IC2 (IC3 and IC4 are not applicable for this option). • This is a low cost option to improve the operation of existing SPSs. • **Cost Certainty Risk:** Medium – Although the new battery storage is based on fairly well established technology and low cost base compared with other options, there is continued uncertainty around fluctuating fuel prices and ongoing maintenance requirements for the SPS as a whole (as per the Current State).	Medium	Medium

NO	CRITERION	OPTION I1 - ASSESSMENT COMMENTS	OPTION I1 RATING	CURRENT STATE RATING
3	Environmental	• The environmental outcomes for the existing SPSs used in the Daintree will largely remain unchanged. These systems have not been optimised in any way to ensure the most efficient use of each component. • There will be an environmental benefit resulting from a reduction in risk associated with dumping end of life lead-acid batteries in the Daintree environment, however it is unclear the extent that this is currently occurring. • **Carbon Emissions (based on year 25 levels):** 2,508 tCO_2 per annum based on a carbon intensity of 0.530 – 0.925 $kgCO_2e/kWh$.	Low/Medium	Low
4	Reliability and Security of Supply	• This will remain at present levels. Given there are a range of different energy systems in use it is expected that reliability and security of supply is presently quite variable across all customers. • **Reliability and Security of Supply Risk:** Medium – Reliability will remain at or marginally better than existing levels which are rated as medium risk.	Medium	Medium
5	Economic	• No anticipated incremental net economic benefit for tourism and commercial operators. • Note: Other potential economic impacts, including in relation to existing residents, natural and cultural heritage, environment and cost are already generally otherwise scored through other dedicated criteria.	Low	Low
6	Learning and Innovation	• Limited learning and innovation opportunities given technology is widely used and similar schemes have already been put in place in Queensland (e.g. Interest Free Loans for Solar and Storage Scheme).	Low	Low

NO	CRITERION	OPTION I1 - ASSESSMENT COMMENTS	OPTION I1 RATING	CURRENT STATE RATING
7	Technical and Commercial Implementation Risk	• **Technical Implementation Risk – Planning and Regulatory:** Low – Approvals are primarily under local government ordinances in relation to building codes, and local laws (if relevant to the individual property). • **Technical Implementation Risk – Delivery:** Low-Medium – Easy to deliver into the same application as batteries are presently in service. Connection to existing systems and suitable sheltering may be more variable. • **Technical Implementation Risk – Connection/Integration:** Low-Medium – Difficulty of connection will be dependent on customer's present installation which may be variable. Once suitable conditions can be ensured the connection process is relatively simple as it will replace existing equipment. • **Technical Implementation Risk – Generation Technology:** Low – From a technical perspective this option is easy to implement and risks are quite low. • **Commercial Implementation Risk:** Low – Successful frameworks have been established for options such as this by the Queensland Government previously, and could be utilised for this option (e.g. Interest Free Loans for Solar and Storage Scheme) to the extent Government has a preference to provide support for this option.	High	High
	Assessment Summary	*While not substantially changing the Current State, this option provides a low cost modest enhancement to existing arrangements but would only likely be perceived as favourable if supported by a corresponding Government scheme of financial support.*	**Medium/High**	**Medium**

10.2.6 Option I2

The table below provides an assessment of Option I2 against each evaluation criterion, including key differentiating factors associated with this option.

Table 10-7: Option I2 Assessment

NO	CRITERION	OPTION I2 - ASSESSMENT COMMENTS	OPTION I2 RATING	CURRENT STATE RATING
1	Natural and Cultural Heritage	• As per Option I1 • **Natural and Cultural Heritage Risk:** Low	High	High
2	Financial	• This option has a levelised cost that is materially lower than the microgrid options, but is still materially higher than Option I1, ranging from \$5,832 to \$100,907 per annum for IC1 to IC4. • **Cost Certainty Risk:** Low-Medium Risk – Fairly well established technology. Can be manufactured off site. Transport and installation costs are more difficult to estimate. The solution can be externally managed and provide a greater level of consistency and standardisation relative to Current State. The lumpy nature of maintenance/replacement is also removed for customers (which can be unpredictable).	Medium	Medium

NO	CRITERION	OPTION I2 - ASSESSMENT COMMENTS	OPTION I2 RATING	CURRENT STATE RATING
3	Environmental	• Each customer will have an individual generation system. The carbon intensity of the Option I2 will not be as low as the microgrids options as no efficiency can be gained by diversification of loads. Each generator will contain a solar system to provide renewable energy to the system and a battery storage system ensure that excess energy from the solar generation can be stored to offset diesel usage. • Fuel being delivered over a large number of customer sites increases the risk of a diesel spill. • Noise of generation can be managed by placing each energy system in a suitable location on the customer site and providing good noise insulation in the generation housing. • **Carbon Emissions (based on year 25 levels):** 2,658 tCO_2 per annum based on a carbon intensity of 0.564 – 0.856 $kgCO_2e/kWh$.	Low/Medium	Low
4	Reliability and Security of Supply	• Across all of the Daintree customers this will provide a very high level of reliability and security as each customer will have a separate energy system to provide supply. Any failure will impact only one customer whereas a failure in a microgrid will likely impact a group of customers. At the individual customer level reliability and security of supply will be quite high with partial redundancy in the generation system and very short service from the energy system to the customer premises. The systems will be remotely monitored so that any issues can be identified and resolved quickly. • **Reliability and Security of Supply Risk:** Medium – Fairly well established technology. Remote monitoring of status. Remote area increases time to repair faults. Partial redundancy. May be expected to be better than Current State although scored as Medium.	High	Medium
5	Economic	• As per Option I1.	Low	Low

NO	CRITERION	OPTION I2 - ASSESSMENT COMMENTS	OPTION I2 RATING	CURRENT STATE RATING
6	Learning and Innovation	• Option would be used as a case study in relation to the AEMC's Priority 2 review of SPSs, specifically Category 3 systems. • Limited technical learnings as this technology is widely used and is currently status quo.	Low/Medium	Low
7	Technical and Commercial Implementation Risk	• **Technical Implementation Risk – Planning and Regulatory:** Low – As per Option I1. • **Technical Implementation Risk – Delivery:** Low-Medium – May be manufactured off site and delivered as a package. Establishing a suitable area to install at the customer's premises may pose a higher risk. • **Technical Implementation Risk – Connection/Integration:** Medium – The ability to connect to the customer's installation will depend on the standard of wiring that is in place. • **Technical Implementation Risk – Generation Technology:** Low – The energy systems use well proven technology that has been utilised in many areas worldwide to provide supply. • **Commercial Implementation Risk:** Low-Medium Risk – Established technology however demand and counterparty risk may impact the bankability of this option for an operator without Government support. Investment may be more easily staged over time (compared to the microgrid options) as each individual power system will only need to be delivered as customers choose to be connected.	Medium/High	High
	Assessment Summary	*The managed service arrangement mitigates a lot of the risks that are currently faced by customers. However, this option is materially more expensive than what customers currently pay for electricity and, in the absence of material Government financial support, is unlikely to have a high penetration in the region.*	**Medium**	**Medium**

10.2.7 Option I3

The table below provides an assessment of Option I3 against each evaluation criterion, including key differentiating factors associated with this option.

Table 10-8: Option I3 Assessment

NO	CRITERION	OPTION I3 - ASSESSMENT COMMENTS	OPTION I3 RATING	CURRENT STATE RATING
1	Natural and Cultural Heritage	• As per Option I1 • **Natural and Cultural Heritage Risk:** Low	High	High
2	Financial	• This option has a levelised cost that is materially lower than the microgrid options, but is still materially higher than Option I1, ranging from $7,372 to $53,690 per annum for IC1 to IC4 (based on Option I3.1). • The Australian hydrogen market is still in its infancy, and fuel cell technologies are currently considered to be more expensive compared to least cost alternatives. In the short to medium terms, these fuel cells would require a significant upfront investment by the end consumers. • However, the value associated with high reliability compared to, for example, batteries, which rely on sufficient solar power to charge, may prove to be attractive for some customers in the Daintree. • Lease to buy financing options could be explored to overcome the initial barrier to entry. • In addition, as a longer term option this is expected to become much more competitive, and the consensus from current literature and observed trends in fuel cell cost curves to date suggests that capital and operating costs of hydrogen technologies will decrease substantially over the coming decade. • **Cost Certainty Risk:** Medium-High – There is price uncertainty due to the emerging nature of the technology, however the consensus from current literature and observed trends in fuel cell cost is that the cost of this technology is expected to decrease substantially over	Low/Medium	Medium

NO	CRITERION	OPTION I3 - ASSESSMENT COMMENTS	OPTION I3 RATING	CURRENT STATE RATING
		the coming decade. Notwithstanding, this option retains a relatively high level of cost uncertainty at this time.		
3	Environmental	• Hydrogen fuel cells only produce water, electricity and heat, and zero carbon emissions or pollution. • Hydrogen fuel cells are not associated with the issue of disposal that accompanies batteries as the chemicals do not degrade over time. • Depending on where and how the hydrogen is sourced, the hydrogen fuel itself also has the potential to be carbon free. • **Carbon Emissions (based on year 25 levels):** 0 tCO2 per annum.	High	Low
4	Reliability and Security of Supply	• The absence of moving parts in fuel cells makes them more reliable and quieter than generators. The ancillary systems such as fans, pumps, etc. are also based on mature technology resulting in a high overall degree of reliability. • Security of supply for hydrogen fuel would need to be carefully considered. Although it is possible to purchase hydrogen fuel from existing producers of brown hydrogen, the costs may be prohibitive depending on transport distance and volume of demand. • Should a dedicated electrolyser facility be constructed in Cairns or Townsville, Daintree customers could offer a steady source of demand for these facilities and if this were coordinated well, this could result in a high degree of fuel security. • This option is considered to be better than the status quo due to external maintenance required for fuel cell. • **Reliability and Security of Supply Risk:** Medium – Fuel cells are more reliable (and quieter) than generators however there is a short term uncertainty over supply security as hydrogen market develops. This may be mitigated however is residents retain existing generators for back-up.	Medium/High	Medium

NO	CRITERION	OPTION I3 - ASSESSMENT COMMENTS	OPTION I3 RATING	CURRENT STATE RATING
5	Economic	• As per Option I1.	Low	Low
6	Learning and Innovation	• Uptake of cutting edge technology in a unique location – this would be one of the first of its kind in the world and a first for Australia. • Provides technical innovation, functional application, regulatory and supply chain learning opportunities. • Opportunity to test viability of remote area application of hydrogen for power generation at a domestic level. • Advances Australia's hydrogen ambitions.	High	Low
7	Technical and Commercial Implementation Risk	• **Technical Implementation Risk – Planning and Regulatory:** Medium – There are no regulations currently adopted in Australia that specifically relate to the centralised production of hydrogen via electrolysis. The National Hydrogen Strategy, due to be published late 2019, is expected to include proposed legislative and regulatory reforms that will be required to remove barriers for development of hydrogen projects. • **Technical Implementation Risk – Delivery:** Low to Medium – As per Option I2. • **Technical Implementation Risk – Connection/Integration:** Medium – As per Option I2. • **Technical Implementation Risk – Generation Technology:** Medium-High – The prototype development and testing phase may result in a delay in project delivery.	Low/Medium	High

NO	CRITERION	OPTION I3 - ASSESSMENT COMMENTS	OPTION I3 RATING	CURRENT STATE RATING
		• **Commercial Implementation Risk:** High – Due to this option relying on either brown hydrogen (where the price is very sensitive to economies of scale, which is low in the Daintree), or green hydrogen (which may rely on the establishment of an electrolysis facility that is likely to need additional offtake than the Daintree). There are limited electrolysis facilities of this nature in Australia. In addition, the regulatory framework is uncertain and likely to be complex. The complexity associated with commercial implementation may result in delays, although the development of a National Hydrogen Strategy may accelerate the development of the industry and assist in overcoming barriers associated with sourcing and establishment of a fuel supply chain, regulatory approvals and development of the technical solution.		
	Assessment Summary	*This option is conceptual and requires significant development, both technical and commercially, and is not expected to be financially viable in the short term. However, it may be an example of the right long term strategic solution for the region, potentially enabling a gradual transition from diesel to hydrogen in an SPS application, thereby preserving the natural and cultural heritage values of the region and improving environmental outcomes. To some extent, the Government may be able to accelerate the potential commercialisation of this option through supporting technology trials and other potential support.*	**Medium/High**	**Medium**

11 CONCLUSIONS

PURPOSE OF THIS SECTION

- Drawing on the outcomes of the evaluation, this section provides high level conclusions for the Government's consideration in relation to where there may be merit in taking some options forward for further consideration and development.

The evaluation set out in Section 10 demonstrates that, at this time, no one option satisfies all of the Government's objectives. However, the evaluation suggests that some of the options have a relatively higher degree of alignment with the Government's objectives, and that these could be further considered and developed.

Microgrid based solutions do not appear to be the right long term solution for the Daintree

A microgrid would supply residents with a reliable and secure energy network, however it presents numerous technical and commercial risks and is likely to be financially unviable without significant upfront and ongoing Government support. A microgrid would also take significant time to materialise, indicatively comprising a three year development and a further three year construction timeframe.

A microgrid would require a large scale up front investment in long life infrastructure, which presents a risk to the natural and cultural heritage values of the region, when it appears that emerging technologies such as hydrogen may support improved SPS outcomes in the foreseeable future.

For a typical household, the microgrid based solutions represent a significantly higher cost than current supply arrangements, costing around $11,000 to $15,000 more on an annual basis.

If a microgrid based solution were to be pursued, separate community based microgrids appear preferable to a single whole-of-region microgrid. However, Government would need to consider equity issues around delivery of, and pricing for, separate microgrids.

SPS based solutions allow for incremental staged enhancement and replacement over time

Relative to a microgrid, SPS based solutions preserve the existing natural and cultural heritage values of the Daintree and allow for incremental staged enhancement and upgrade/replacement of systems and technologies over time without necessarily requiring substantial financial support from the State.

Opportunities to improve existing arrangements range from incremental enhancements (e.g. battery upgrade) to system upgrade and replacement (e.g. hydrogen based SPS, displacing diesel).

For a typical household, the SPS based solutions cost around $700 and $6,000 more than current supply arrangements on an annual basis.

Opportunities exist to enhance existing systems in the short term

In the short term, enhancements could be made to residents existing SPS systems by replacing lead acid battery storage with more advanced lithium-ion technology.

This would provide a relatively low cost incremental enhancement to the current state, and could be seen as an interim solution for the region while other potential long term solutions are investigated and potentially relevant technologies mature.

A potential long term plan of action could initially involve staged investigations and testing of a hydrogen based SPS

From a long term strategic energy future perspective, one option that may be worthy of further investigation is a hydrogen based SPS solution. This option involves the installation of individual hydrogen fuel cells at customers' dwellings that replace their current SPS. Compressed hydrogen, used by fuel cells to convert hydrogen into electricity, would be purchased and transported to customers from an established supplier outside of the Daintree area.

Due to the current cost of hydrogen for domestic application, currently this does not represent a viable short term solution to the region but may be an example of the right long term solution as the hydrogen sector and technology continues to develop and mature over coming years.

Importantly, further work and costs associated with advancing this option may be staged. For example, there may be merit in running a technology and logistics trial in the Daintree which seeks to demonstrate a representative hydrogen supply chain: sourcing hydrogen; transporting it into the Daintree; and power generation at the community level (through residential and commercial pilot units).