Updated Definitive Feasibility Study sees major reduction in capital costs of Waroona Renewable Energy Project

Frontier Energy Limited (ASX: FHE; OTCQB: FRHYF) (**Frontier** or the **Company**) is pleased to announce an updated Definitive Feasibility Study (**DFS** or **Study**) for Stage One of its Waroona Renewable Energy Project, comprising a 120MWdc solar facility and an integrated 80MW 4.75-hour (380MWh) battery (**Waroona Project** or the **Project**). The update follows material changes to a number of key areas including capital costs and energy market forecasts.

Highlights from the Study include a significant reduction in capital costs of **$21m (7%) to $283m**, a rapid **payback of 6.1 years** and strong EBITDA generation averaging **$57m per annum over the first decade**.

HIGHLIGHTS

- **DFS confirms the Project as a highly profitable renewable energy project with long life (30 years) and low operating costs**
- **Over the first decade of production, the Project generates average annual revenue of $65m and average annual EBITDA[1] of $57m, based on independent price forecasts**
- **Post-tax payback[1] of 6.1 years based on initial $283m total capital cost. The lower capital cost is due to a reduction in the cost of key equipment, namely solar panels and batteries, and a reduction in the cost of the switchyard which is sized for Stage One**
- **Post-tax IRR of 15.4% (pre-tax IRR is 18.7%)[1] and Project NPV$_{7\%}$ of $244m**
    - *All key financial outputs were in line with the February 2024 DFS*
- **Further upside to Stage One economics – DFS assumes nil value for Frequency Control Essential System Services (FCESS), highly conservative large-scale generation certificate (LGC) pricing and no account for recent positive changes to the Reserve Capacity structure, all of which are expected to positively impact financial returns**
- **A longer duration 80MW 4.75hr battery (380MWh) selected to allow for more energy to be sold into the peak market and extend the maximum Reserve Capacity payment to 8 years**
- **Annual solar energy generation is 258GWh[2], with 134GWh discharged/sold through the battery in the daily peak period, and solar energy not required for charging the battery sold into the Wholesale Electricity Market (WEM)**

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[1] *Nominal – Base Case Scenario. Independent expert energy market consultancy Aurora Energy Research provided price forecasts for the Project. Unless otherwise stated, in this announcement, $ means Australian dollars.*

[2] *Year one forecast P50 production*

- **Stage One is development ready with all major approvals and an access contract executed with Western Power for connection onto the South West Interconnected System (SWIS), WA's main electricity grid**

- **Major expansion potential as Stage One utilises only a third of Frontier's 868ha landholding and is a fraction of total long-term potential energy production**

- **Project funding for Stage One to consist of both debt financing and equity solutions – the Company is considering multiple options to minimise shareholder dilution**

- **The Company had $14.5m cash as at November 2024 (unaudited, nil debt)**

CEO Adam Kiley commented: *"Our updated DFS reconfirms strong economics for the Waroona Project and again highlights the unique opportunity Frontier presents for investors, as the only pureplay renewable energy developer on the ASX, with near-term exposure to the rapidly growing electricity market in Western Australia.*

The Waroona Project remains one of the most advanced renewable energy projects in WA, with an approved connection onto the SWIS and other key development approvals and permits in place.

We updated the DFS to re-position the Project prior to advancing funding discussions for its development. Pleasingly, we have benefited from cost reductions for key equipment, decreasing capex by $21 million or 7% compared to the original DFS. Importantly, our capital cost estimate was based on pricing received from vendors and contractors ready for construction, thereby providing a high degree of confidence in these estimates.

In addition, we enhanced the Project with a larger 4.75-hour duration battery (4 hours previously) to allow more energy to be sold in the peak energy market conditions, therefore providing greater flexibility and also ensuring the Company maintains maximum Reserve Capacity benefits for longer.

Whilst the Study applied a conservative approach regarding revenue assumptions, the Project continues to produce strong financial returns for a renewable energy project under all key metrics, including $65m average annual revenue and $57m average annual EBITDA over the first decade of production. This results in an attractive payback of six years, or 20% of the operational life, and strong IRR of more than 15%.[3]

We are now focused firmly on project financing. The Company will be running multiple funding strategies in parallel, to ensure the optimal solution is available for development."

[3] *All financial assumptions were based on independent forecasts for energy prices in WA, detailed in Section 9 of this Report.*

Cautionary Statement

The DFS has been undertaken to assess the economic feasibility of a 120MWdc Solar Farm with an 80MW (380MWh) battery (Stage One of the Project). The DFS provides engineering studies and estimates for costs and rates of return that support the technical and financial viability of Stage One of the Project thus enabling the Company to move to develop a debt and equity funding solution, update key approvals and thereafter a final investment decision can be made.

Investors should note that there is no certainty that the Company will be able to raise funding when needed. It is also possible that such funding may only be available on terms that are dilutive or otherwise affect the value of the Company's existing shares.

The Company has concluded that, based on the results of the Study and supportive market fundamentals, there is a sufficient degree of confidence to progress Stage One of the Project further. However, given the uncertainties involved, investors should not make any investment decisions based solely on the results of the Study.

Forward-Looking Statements

This release contains 'forward-looking statements' that are based on the Company's expectations, estimates and projections as at the date of the statements. All statements, trend analysis and other information contained in this announcement relative to markets for the Company, trends in energy markets, production quantities and anticipated expense levels, as well as other statements about anticipated future events or results constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "believe", "plan", "estimate", "expect" and "intend" and statements that an event or result "may", "will", "should", "could" or "might" occur or be achieved and other similar expressions.

Forward-looking statements and information are subject to known and unknown risks, uncertainties and other factors that could cause actual results to differ materially from those contained in the forward-looking statements. This includes factors such as: general business, economic, competitive, political and social uncertainties; outcome of further economic valuations; regulatory and political changes on energy production and consumption, decarbonisation and climate change related matters both at federal and state level; the cost to procure and build plant and equipment including the impact of inflation and the availability of contractors to do; supply chain disruption, delay and cost increases; delays in government approvals or other government steps needed to support renewable energy projects; the ability of the Company to secure financing and the cost and terms of such financing.

Forward-looking statements are based on estimates and opinions of management at the date the statements are made. The Company does not undertake any obligation to update forward-looking statements even if circumstances or management's estimates or opinions should change. Investors should not place undue reliance on forward-looking statements.

Executive Summary

The Waroona Project is located in the South West region of Western Australia, approximately 120km from Perth and 8km from the town of Waroona. A key strategic advantage is its proximity to the Landwehr Terminal, which is less than 0.5km from the Project. The Company has executed an access contract with Western Power for connection onto the SWIS, enabling the sale of electricity into the SWIS, on one of the least constrained portions of the electricity transmission network.

The Company updated the previous DFS completed in February 2024[4] to include cost reductions of key capital items, a longer duration battery and current independent electricity price forecasts.

Table 1 shows key Project metrics used in the Study and changes from the February 2024 DFS.

		Year 1		
Key Assumptions	**Unit**	**DFS Update**	**Feb DFS**	**Change**
Life of operation	Years	30	30	-
Solar				
Energy production (Yr 1)	GWh	258	258	-
Annual degradation (Solar)	%	0.45	0.45	-
Availability	%	98	98	-
Battery				
Nominal power capacity	MW	80	80	-
Storage capacity	MWh	380	320	60
Annual degradation (average over first 20 years, varies by year)	%	1.3	1.6	(0.3)
Energy sold (pa) - battery	GWh	134	120	14
Energy sold - Solar	GWh	99	116	(17)
Costs – Operating[1]				
Total (real)	$m pa	6.8	5.0	1.8
Capital				
Integrated solar and battery	$m	283	304	21

Table 1: Key project assumptions

1 – Excludes financing, depreciation and corporate costs

The Study forecasts annual renewable electricity generation of approximately 258GWh (Year One). Of this, 134GWh (Year One) is stored in integrated DC coupled batteries and sold in the WEM at peak demand times, with a charging and discharging efficiency loss of 13% on average over a 20-year battery life (declining from 87.6% initially to 86.3% in Year 20). This sees excess solar generation of 99GWh (Year One), from energy produced but not stored in the battery. Importantly, this solar energy will be sold during "shoulder periods", which significantly reduces the risk of curtailment (<1%) and low prices, during mid-day periods.

The key advantage of integrating the battery with the solar array is it enables solar electricity, typically generated during the time of day when there is an oversupply of electricity and

[4] *See ASX announcement 28 February 2024*

prices are low or negative, to be stored and sold during the time of day when there is peak demand and prices are highest. This strategy ensures the battery can continuously supply 100% renewable energy generation during peak energy periods, year-round.

This differs from standalone batteries that rely on low energy price periods to charge and then discharge during higher price periods (arbitrage), and do not differentiate between energy sources. With a lack of new generation forecast in WA over coming years, and the requirement for load bearing prior to discharging, there is a risk that during peak period conditions, these standalone batteries could put further strain on the grid, given their reserve capacity obligations.

In the Base Case price forecast scenario, with energy sold into the merchant market, the Study shows capacity to generate on average, revenue of $65.1m per year over the first 10 years, as illustrated in Table 2 below. A Stress Test scenario, containing a more optimistic view on future supply of new energy in the SWIS and lower electricity price forecasts, was also assessed and resulted in revenue of $57.0m per year over the first 10 years.

		10-year Average	
Revenue Breakdown – Base Case		**Base Case**	**Stress Test**
Energy Sales - Battery	$m	25.8	21.7
Energy Sales - Solar	$m	13.8	10.8
Reserve Capacity – Battery	$m	19.5	19.5
Reserve Capacity – Solar	$m	1.8	1.8
LGCs	$m	4.2	3.3
FCESS	$m	-	-
Total Revenue	**$m**	**65.1**	**57.0**

Table 2: Project Revenue – Base Case Scenario

Operating costs average ~$8.0m per annum over the first 10 years of production (nominal costs). The increase in operating costs was primarily due to ~$1m per year of Western Power fees, battery warranty costs and inverter maintenance costs.

This results in the forecast average annual EBITDA of $57.1m over the first 10 years of operation. Figure 1 below shows the key revenue and cost drivers.

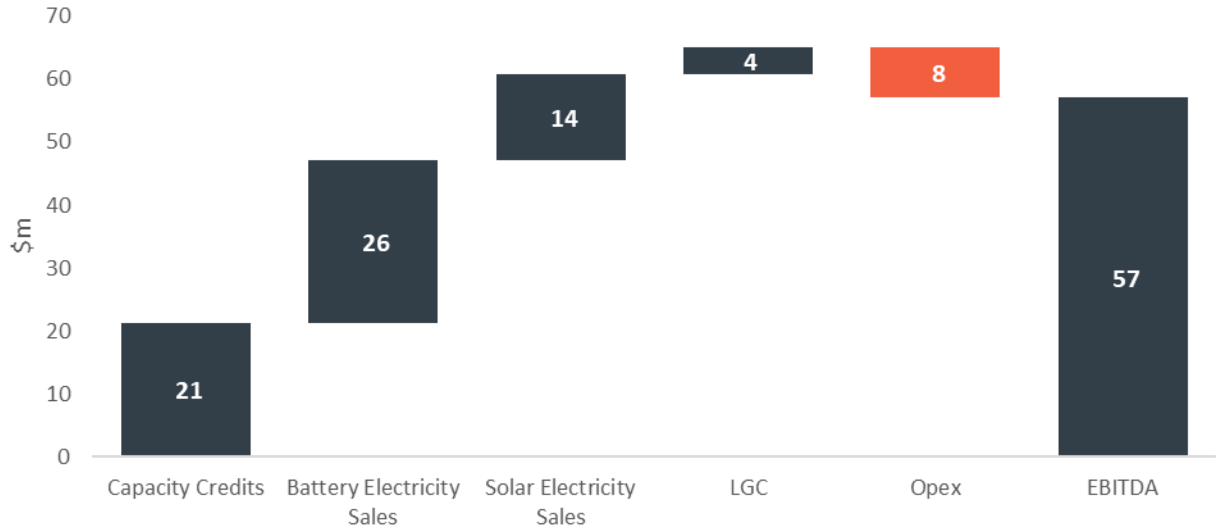

Figure 1: EBITDA waterfall

This robust profitability of $57.1m EBITDA per year over the first 10 years generates a payback period of 6.1 years and post-tax unleveraged IRR of 15.4%. Even under the more pessimistic Stress Case scenario, Project metrics remain robust, with EBITDA of $49.0m per annum (first 10 years), payback period of 7.1 years and post-tax IRR of 13.3%.

Project Cash flows	Unit	Base Case	Stress Test
EBITDA (10-year average)	$m	57.1	49.0
Returns – Project ungeared	**Unit**		
Payback period (Post Tax)	years	6.1	7.1
Payback period (Pre Tax)	years	5.0	5.8
Post-tax IRR	%	15.4	13.3
Post-tax $NPV_{7\%}$	$m	244	180

Table 3: Project Returns

1 – Equity returns and NPV estimates are indicative, subject to completion of the project financing process

In comparison to the February DFS, a more conservative approach has been applied to the revenue forecast in a number of areas, including:

- Frequency Control Essential System Services (**FCESS**) – nil value applied, whereas in the previous study, revenue of $2.5m to $3.0m per year was assumed;
- LGCs – lower pricing; and
- Reserve Capacity – lower pricing, despite a significant increase to the Benchmark Reserve Capacity Price (**BRCP**) compared to last year (Section 8) and a number of other positive changes to the Reserve Capacity structure that will likely further enhance revenues.

In each of these revenue areas, the Company considers that there is potential upside. It should also be noted that whilst a more conservative approach has been applied, independent energy advisor Aurora Energy Research (**Aurora**), has forecast higher energy price (10% - 15%) compared to the February assumptions. In addition, the use of a larger battery allows for greater exposure to peak market conditions, whilst further reducing exposure to lower, mid-day energy prices.

The Company believes this serves as significant upside in the future that could further enhance returns. All major financial outputs remain strong and are similar to the February DFS, as highlighted in Table 4 below.

DFS Key inputs	Units	Nov 24	Feb 24	Difference
Life of operation	Years	30	30	-
Energy Production (yr 1)	GWh	258	258	-
Battery duration	MW/hrs/MWh	80/4.75/380	80/4.0/320	nil/0.75/60
Initial Capex – Stage One	$ m	283	304	(21)
Key Financial Returns (10 Yr Average)	**Units**	**Nov 24**	**Feb 24**	**Difference**
Revenue	$ m	65	70	(5)
EBITDA	$ m	57	63	(6)
NPV 7%	$ m	244	262	(18)
IRR – Ungeared (100% equity)	%	15.4%	14.8%	0.6%
Payback (post-tax)	Years	6.1	5.8	(0.3)

Table 4: Comparison to February 2024 DFS

Upside opportunities

The Study has adopted conservative revenue assumptions that are likely to further enhance Project economics in the future.

While energy is the primary commodity bought and sold in the WEM, other services are also required to maintain security and reliability of supply – for example, providing flexibility to ramp up or ramp down generation capacity quickly or frequency control. These services have previously been referred to as Ancillary Services however, from 1 October 2023 when the new market commenced, are now referred to as Essential System Services.

Aurora has estimated the potential revenue from FCESS services in the range of $2.5m to $3.5m per annum. However, as the FCESS market in the WEM is immature, no FCESS revenue has been included in the Project economics. Future FCESS revenue and margin provides significant upside potential for the Project.

In addition, a number of recent favourable updates to WA's energy policy and frameworks for Reserve Capacity payments that will have a positive impact on the economics have not been included in Aurora's forecasts. The most significant of these is the minimum reserve capacity price floor at 50% of the BRCP, to ensure revenue certainty (as opposed to the current zero price floor). A change to the peak price curve (Figure 18), may also further enhance the forecast Reserve Capacity Price.

Next Steps

With the DFS now completed, the Company is progressing multiple funding strategies in parallel to ensure the optimal strategy can be implemented. Funding for the Project's development is expected to consist of both debt and equity financing. Multiple debt funding options are currently under consideration, including bonds, traditional bank debt and equipment supplier financing. The Company is assessing all financing options.

The Company is reviewing the merits of a power purchase agreement (**PPA**), which provides a higher level of revenue certainty and is therefore attractive to debt financiers. PPAs typically lock in a predetermined quantity of energy to be sold at a fixed price for a fixed period of time, with the Company having commenced discussions with a number of parties.

In addition to debt financing, equity funding will be required. The Company has the option to either raise funds in the corporate entity (Frontier Energy Limited) or alternatively at the Project level. Project level investments may be attractive to strategic investors and discussions with a number of potential partners have recently been initiated.

Contents

1. Background and Location

The Waroona Project is located 120km south of Perth in the Shire of Waroona, in Western Australia. The Project's location provides the Company with several strategic advantages for developing a renewable energy project including:

- Mediterranean climate, characterised by warm to hot, dry summers and mild, wet winters. Year-round solar radiation that is well suited for solar energy generation.

- Freehold land holding of 868ha on flat, largely cleared agricultural land where native title has been extinguished. The Stage One development sits on 303ha and comprises largely cleared farming land that is currently used for grazing, with small patches of native vegetation.

- Skilled workforce in several regional population centres located within 60km of the Project site, including Waroona, Collie, Mandurah and Bunbury.

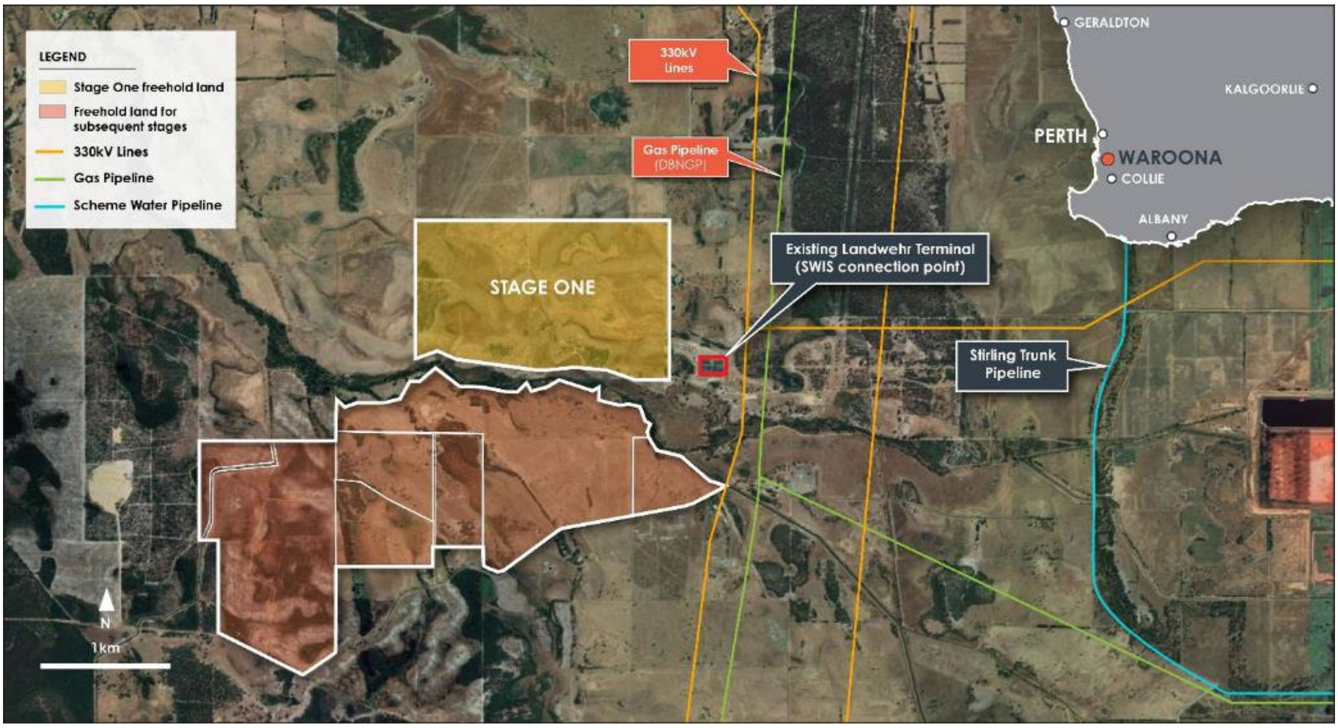

Figure 2: Waroona Renewable Energy Project Footprint

Stage One of the Project comprises 120MWdc photovoltaic (**PV**) solar energy production with an integrated battery energy storage system (**BESS**) comprising an 80MW 4.75-hour battery. Both are fed into a 33kV/330kV Substation on site, which in turn is connected to the existing Western Power Landwehr Terminal substation via a 330kV single circuit transmission line.

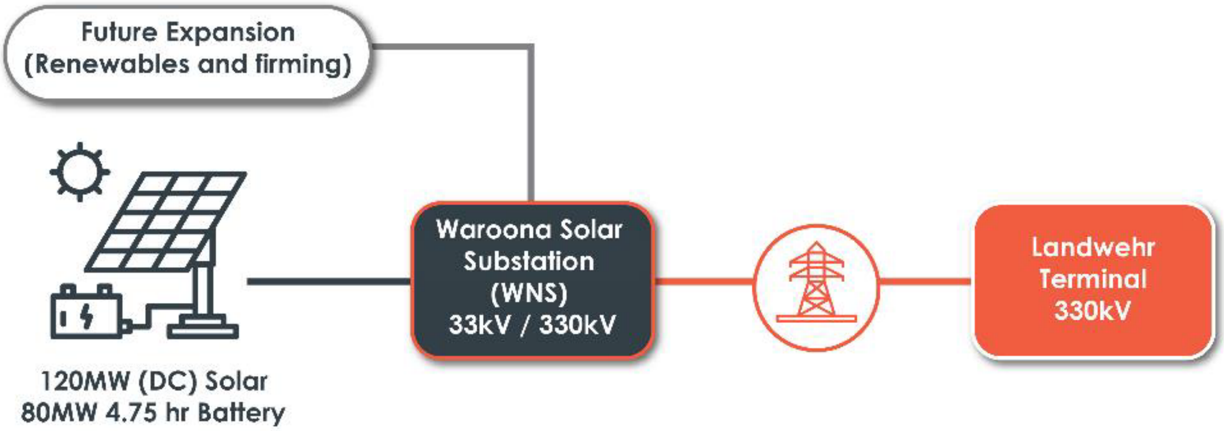

Figure 3: Project Schematic

2. SWIS - Grid Connection

A key strategic advantage is the Project's proximity to the Landwehr Terminal, a major connection point into the SWIS – WA's main electricity network. The Landwehr Terminal is within 0.5km of the Project providing the Company access to one of the least constrained portions of the transmission network between Collie, the current coal-fired electricity producing centre, and the Perth metropolitan area, with large industrial consumers including at Oakley, Kemerton, Boddington and southern Perth nearby (Figure 4).

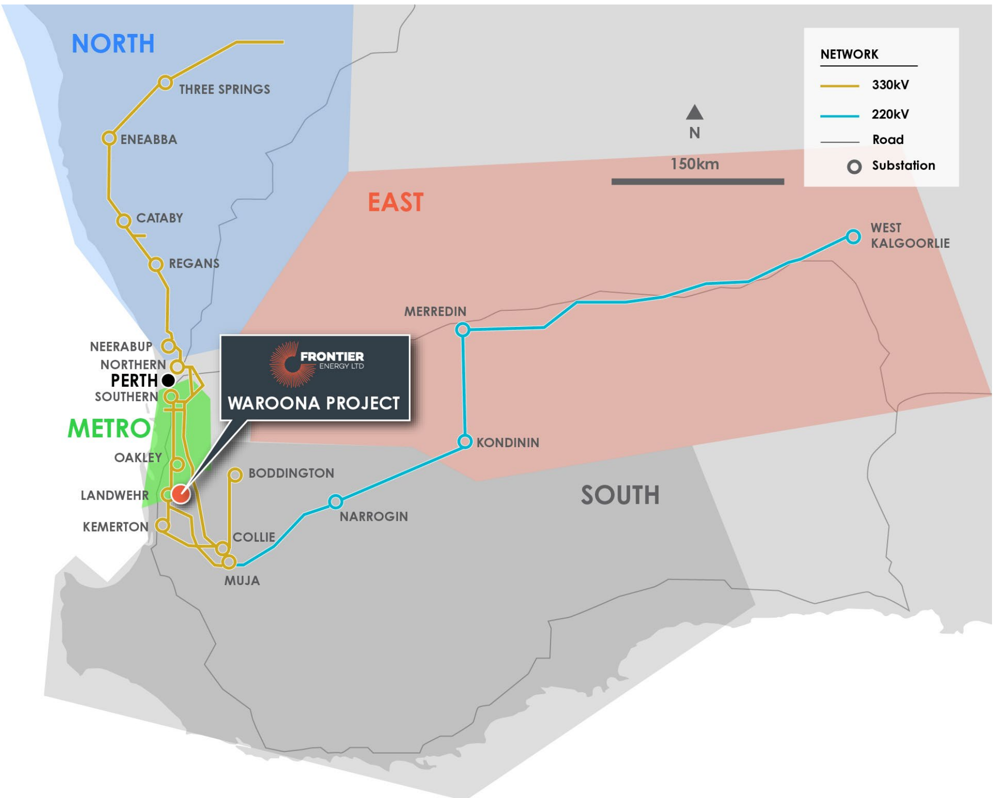

Figure 4: SWIS 330kV and 220kV networks

Overview of the SWIS and the WEM

The SWIS is the main electricity network in WA and serves most of the WA's population, including in the South West to Albany, north of Geraldton in the Mid-West and Kalgoorlie in the east, with a total of ~7,750km of transmission lines and 72 registered generation facilities trading > 17TWh per year[5].

The SWIS is physically separate from the National Electricity Market (**NEM**) in the eastern states of Australia (New South Wales, Queensland, South Australia, Victoria and Tasmania) and approximately one tenth of the size of the NEM.

[5] https://aemo.com.au/-/media/files/electricity/wem/wholesale-electricity-market-fact-sheet.pdf

The WEM comprises markets for energy and capacity on the SWIS and is operated by the Australian Energy Market Operator (**AEMO**).

Reserve Capacity

The Reserve Capacity Mechanism (**RCM**) is unique to Western Australia and does not exist in other Australian jurisdictions.

The RCM is designed to ensure that there is adequate generation capacity available to meet forecast peak electricity demand (i.e. on hot summer evenings).

All electricity generation and electricity storage facilities that become certified are allocated capacity credits based on the size of a facility's generation capacity. Once a project receives reserve capacity allocation, and provided they continue to meet their obligations, they will continue to receive reserve capacity payments in future years.

AEMO, which is responsible for managing the electricity and gas systems and markets across Australia, releases an annual Electricity Statement of Opportunities (**ESOO**) for the WEM. The primary purpose of the ESOO is to identify the investment in capacity from generation, storage, and demand side management needed to ensure a secure and reliable electricity supply over the coming decade.

In its 2024 WEM ESOO Report[6] published in June 2024, AEMO restated its forecast of a growing capacity deficit and forecast a significant shortfall of power generation in WA from 2027 onwards, again highlighting a need for new electricity generation and storage to be brought online.

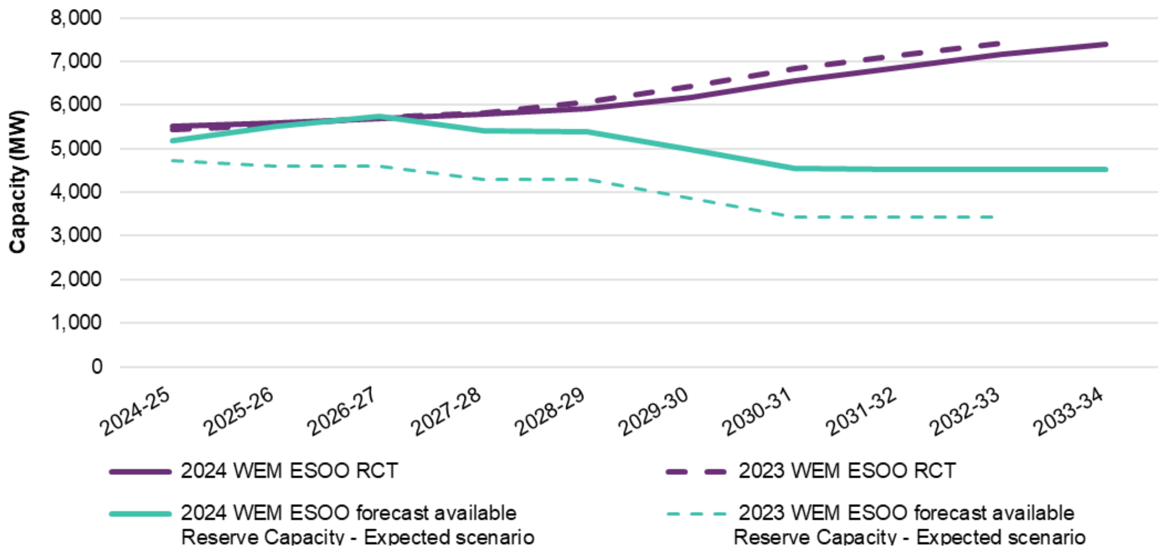

Figure 5: 2024 WEM ESOO Forecast supply / demand balance, Expected Demand scenario

Whilst there are multiple factors highlighted in the Report affecting both supply and demand, the key drivers are:

[6] 2024-wem-electricity-statement-of-opportunities.pdf (aemo.com.au).

- **Significant growth in business, industrial and electrification (Demand)** – Demand is forecast to grow significantly due to growth in business electrification, along with growth in cooling load (air-conditioning), electric vehicles, and the expansion of industrial loads. Demand is now forecast to grow at an average annual rate of 4.6%[7] and reach 27.9TWh[8] per year in 2033-34, a 57% increase over 10 years. In the High Scenario, demand is forecast to grow 11.7%[9] annually or 202% over 10 years.

- **Renewable Energy Transition (Supply)** – In September 2022, the Australian Federal Government legislated to reduce emissions by 43% by 2030 and achieve net zero emissions by 2050[10]. In WA, the State Government targets are to reduce Government emissions by 80% below the 2020 level by 2030, and to meet net zero by 2050[11]. This has seen the WA State Government announce the closure of coal-fired power generation in WA by 2029.

The ESOO identifies that substantial and sustained investment in new capacity will be required beyond existing and committed capacity

Recent positive changes to Reserve Capacity

The BRCP is set each year, with reference to the cost of adding generation capacity. It was historically based on the cost to build and connect an open cycle gas turbine, however the Economic Regulation Authority has proposed the benchmark value of capacity be based on a cost estimate of building and connecting a hypothetical 200 MW / 800 MWh Battery Energy Storage System to the SWIS.

This change results in the BRCP increasing to $354,000/MW for the 2027/28 capacity year, a 54% increase on the 2026/27 capacity year ($230,000/MW). The BRCP is set two years in advance of the energy generation period.

Subsequent to Aurora's forecast (Chapter 8), Energy Policy WA released the final WEM Investment Certainty Review outcomes, and exposure draft WEM Amending Rules (**Amending Rules**) to give effect to these outcomes[12]. The Rule changes include a revised RCP curve shown in Figure 6.

[7] 2024-wem-electricity-statement-of-opportunities.pdf (aemo.com.au
[8] 2024-wem-electricity-statement-of-opportunities.pdf (aemo.com.au
[9] 2024-wem-electricity-statement-of-opportunities.pdf (aemo.com.au
[10] https://www.pm.gov.au/media/australia-legislates-emissions-reduction-targets
[11] https://www.wa.gov.au/service/environment/business-and-community-assistance/government-emissions-interim-target
[12] https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-rules

Figure 6: RCP as a function of BRCP - proposal

Importantly, the new proposed curve provides a minimum capacity price floor at 50% of the BRCP, to improve investment certainty for renewable generation and new firming capacity (as opposed to the current zero price floor).

These changes will have a positive impact on the revenue related to reserve capacity, and more importantly, provide a floor for reserve capacity prices, which will enhance the Project's bankability.

The Amending Rules also finalise arrangements for the implementation of the RCM review, including for the flexible capacity product in time for its commencement in the 2025 Reserve Capacity Cycle. These rules are designed to continue to make the SWIS attractive for new renewable energy and storage investments.

Connection Agreements

The Company has a network connection access contract in the form of an Electricity Transfer Access Contract (**ETAC**) and Interconnection Works Contract (**IWC**) with Western Power, the WA Government owned utility. These agreements provide for Western Power to carry out the necessary work to connect the Project to the network (the SWIS) and then for the Project's ongoing connection to the network for the power it generates, respectively. The ETAC is the standard access contract that Western Power proposes and works within the WEM framework.

A revised ETAC was signed with Western Power in June 2024 incorporating the necessary changes for the latest DFS design. The revised ETAC was to align the Stage One output and upgrade to the latest available inverters. Western Power is also due to supply an updated IWC.

An application to increase the CMD on the ETAC has been submitted to allow charging of the battery from the network in the event of unfavourable weather conditions. Western Power has indicated that it should be approved in the ordinary course and will not have an impact on the Project's timeline.

In June 2024, Frontier signed contracts with Western Power to commence detailed design and procurement of long-lead items to enable connection to the SWIS, as the interconnection works were identified as a critical path item to ensure construction is completed during 2H 2026. A variation was submitted in November 2024 to include procurement of the high voltage cable as part of Western Power's scope.

3. Solar Farm and BESS

The 120MWdc Waroona Solar Farm with BESS is a large-scale solar power generation facility designed to harness solar energy efficiently, and store and discharge energy at peak demand intervals. The BESS also has the capability of providing certain network stability related services.

The 120MWdc solar farm with 26 inverters and six DC-coupled battery units per inverter represents a state-of-the-art renewable energy facility that will produce an estimated 258 GWh/year of solar energy.

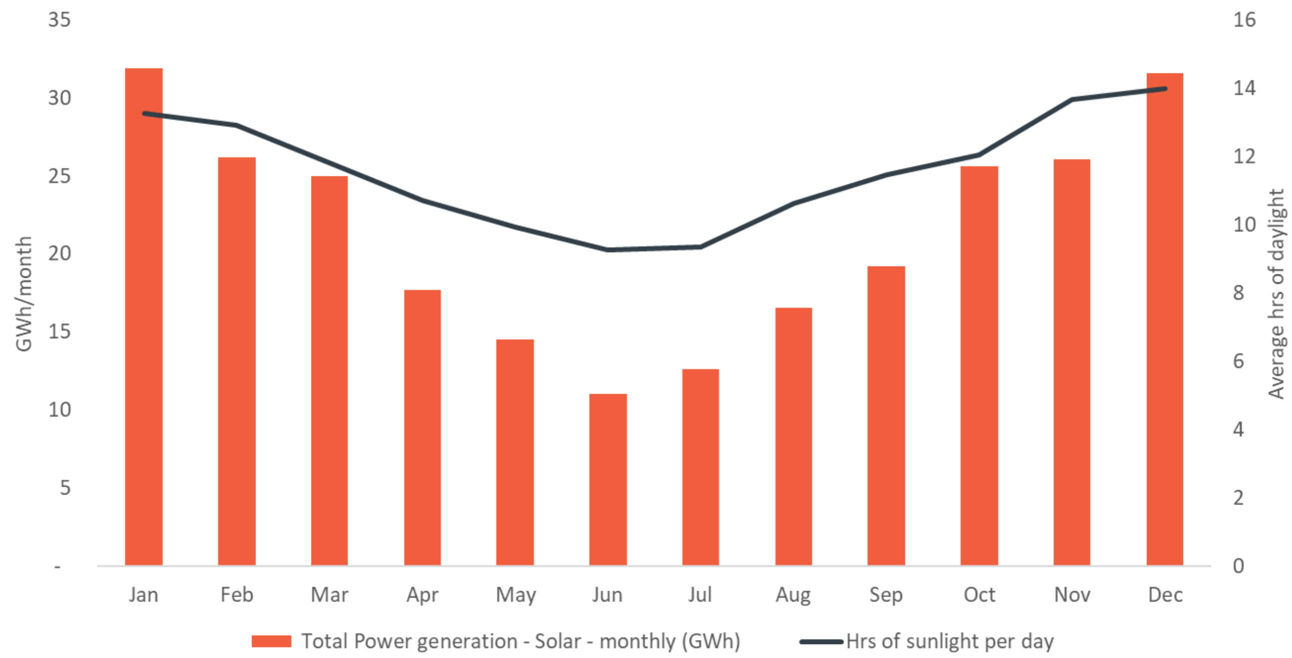

Figure 7: Solar energy generation by month, Year One

The main components of the solar facility are:

Solar Panels: The solar farm consists of ~198,500 bifacial ~605W solar panels, which convert sunlight into direct current (**DC**) electricity through the photovoltaic effect.

Tracker system: The tracker system consists of a robust mechanical structure that supports the solar panels. This structure typically includes a framework, mounting brackets, bearings, and motors. Single axis trackers will be used that rotate the solar panels along the north-south axis, to follow the sun's path from east to west. The tracker system is controlled by a sophisticated control system that determines the position of the sun based on time, date, and geographical location, optimising the tracking algorithm of each individual row.

Inverters: Inverters are devices that convert the DC electricity generated by the solar panels into alternating current (**AC**) electricity, compatible with the electricity network. There are 26 inverters, with each inverter connected to ~ 8000 solar panels.

DC-Coupled Battery Units: Each inverter is paired with six DC-coupled battery units via six DC-DC converters. Solar panels generate electricity in the form of direct current at varying voltages, depending on factors such as sunlight intensity and temperature, which fluctuate throughout the day. However, batteries require a specific voltage to charge efficiently. The DC-DC converters regulate the voltage from the solar panels to provide a stable voltage input and control the direction of flow. DC-coupled battery systems integrated with the solar array allow storage of solar energy directly from the solar panels before it is converted to AC by the inverters.

BESS: The battery units store solar energy generated during periods of high sunlight and can discharge stored energy during periods of low solar irradiance or high energy demand. They also provide grid stability, peak shaving, and ancillary services to the electricity network. There are 6 battery units (and 6 DC-DC converters) per inverter, disseminated throughout the solar farm. The total BESS capacity is nominally 80 MW / 380 MWh i.e. the battery is capable of storing and discharging 80MW for 4.75 hours.

This size of battery can be fully charged from the 120MWdc solar farm throughout the year, including during winter months, when solar power generation is at its lowest.

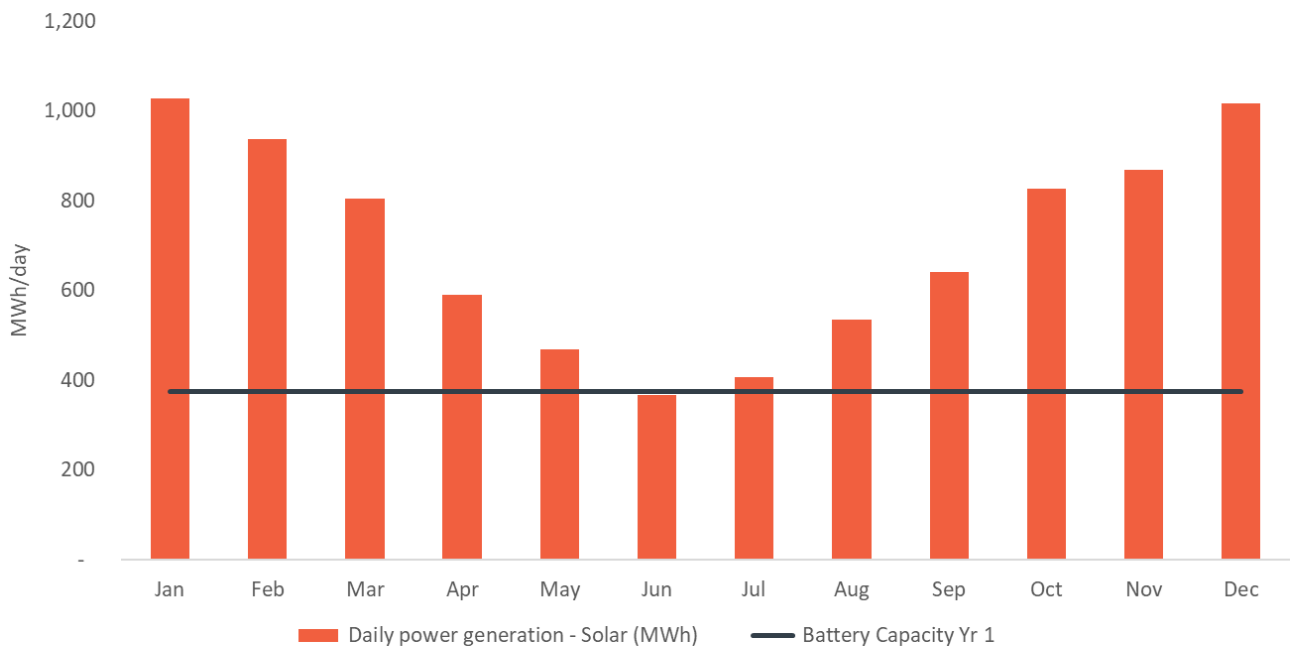

Figure 8: Battery capacity vs average solar generation, Year One

The battery is in a DC coupled configuration, which results in the lowest possible energy loss between charging and discharging cycles.

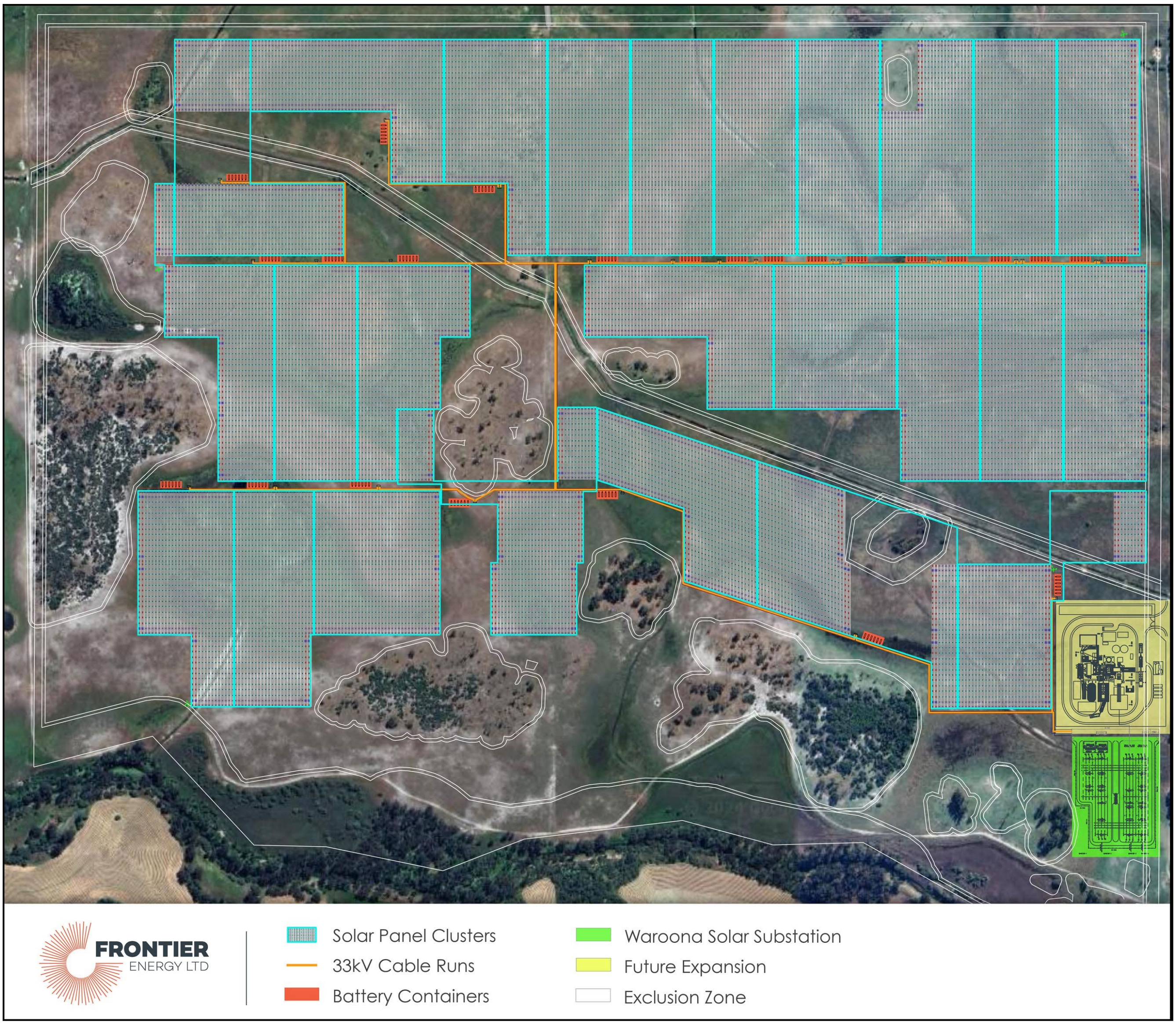

Figure 9: Waroona Solar Farm Stage One layout

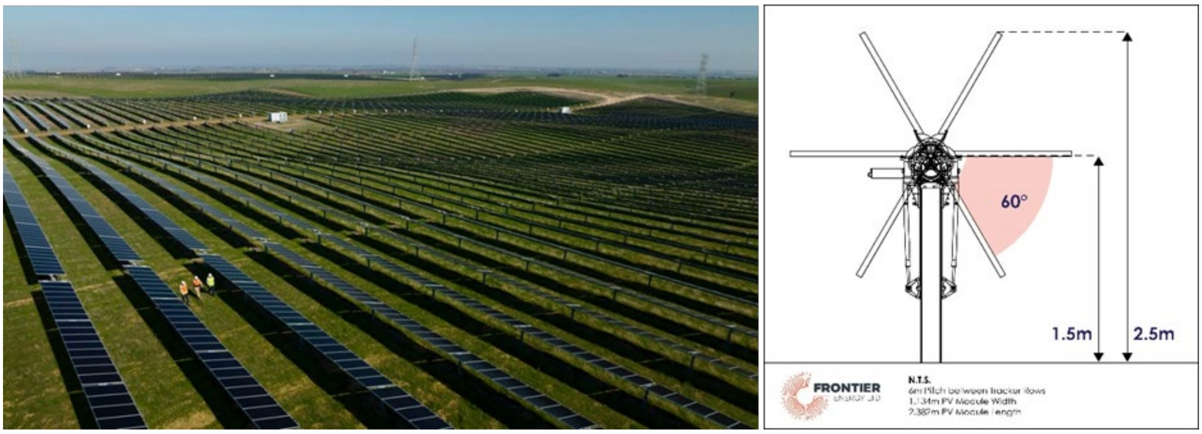

Figure 10: Typical solar farm arrangement with tracker

33kV Switch room: The switch room serves as a central hub for the solar farm and contains switchgear rated at 33 kV to handle the high voltage output from the 26 inverters. The switchgear includes circuit breakers, disconnect switches, and other protective devices to control the flow of electricity and ensure safe operation of the system. When combined with isolation devices available at the inverter and within the solar panel clusters, it is possible to isolate any one of the inverters, associated BESS and groups of solar panels for maintenance, while the remainder are operational. From the 33kV switch room the energy is fed through a 33kV/330kV transformer to the 330kV switchyard.

Environmental Considerations: The solar farm is designed with environmental sustainability in mind, utilising clean and renewable solar energy to generate electricity without producing greenhouse gas emissions or air pollutants. It is estimated that the facility will save 5,427,951 tonnes of CO_2 based on the carbon intensity quoted by the International Energy Agency for grid lifecycle emissions for Australia.

4. Details on Battery Integration

In late 2023, Energy Policy WA announced that the reference technology to be used for future BRCP determination would be a 200 MW / 800 MWh Battery Energy Storage System. Following this, the Company evaluated the approach for integrating a battery. After reviewing the preliminary results of this work, compared to a range of alternative strategies, Frontier concluded that the optimal strategy for a Stage One development consists of a 120MW solar facility and a battery with a capacity of at least 80MW, i.e. the battery is capable of storing and discharging 80MW for at least four hours when measured at the point of connection.

Rationale for selecting DC coupled BESS over AC coupled BESS

In an AC coupled system, the battery is connected to the AC side of the electrical system. AC coupling allows for greater flexibility because the battery system is not directly tied to the DC output of the renewable energy source, such as solar panels. AC coupled systems typically use inverters to convert the DC electricity generated by solar panels into AC electricity before it enters the battery system. This type of system can be easier to retrofit into existing solar installations or grid connections since it does not require changes to the existing DC infrastructure.

In a DC coupled system, the battery is connected directly to the DC side of the renewable energy source, such as solar panels. DC coupling eliminates the need for an additional inverter to convert DC to AC, since the battery system operates directly with the DC electricity generated by the renewable source. DC coupled systems can be more efficient, particularly if using energy generated from the solar PV system since it avoids the conversion losses associated with DC to AC inversion and vice versa. These systems are often integrated into new renewable energy installations where the design can optimize the direct connection between the renewable source and the battery system.

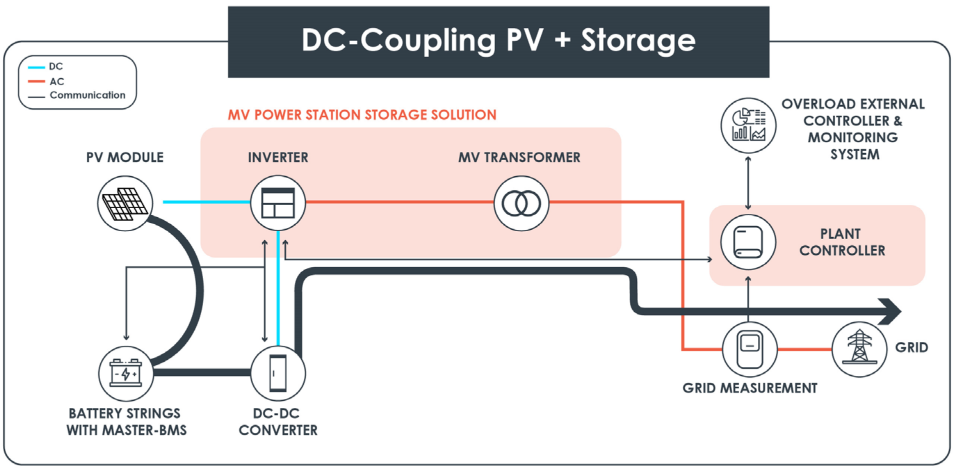

Figure 11: DC Coupling PV plus storage

A DC coupled battery integrated in the solar facility, sharing the solar inverters, will have a lower capital cost and will also provide a greater efficiency compared to an AC coupled, separate BESS facility. This strategy provides the strongest potential financial returns with the lowest risk.

Battery degradation

Lithium Iron Phosphate (**LFP**) batteries have been selected for the Project as they are proven technology with superior safety, long cycle life, high energy density, fast charging capabilities, wide operating temperature range, and lower environmental impact, when compared to other battery technologies.

Utility-scale LFP batteries experience capacity degradation over time due to factors such as calendar aging, cycle aging, temperature, state of charge management, manufacturing quality, and usage patterns. These factors contribute to a gradual reduction in the battery's capacity and performance over its lifespan. A degradation curve assumed in the DFS is based on the offer received from the likely battery supplier and is presented below, showing a degradation of ~18% over the initial 10 years and ~30% over the first 20 years of battery life.

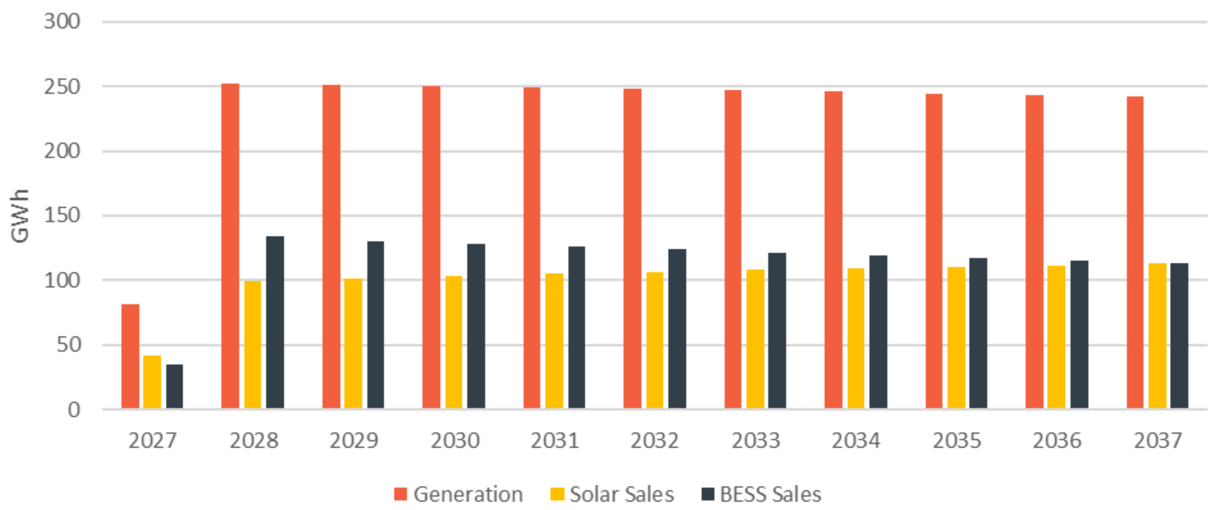

Figure 12: Electricity generation and sales

It is possible to supplement the battery capacity (likely between years 10 and 20) to bring it back to its starting condition and thereby increase revenues in later years. Given the fast pace at which battery technology is evolving, it is difficult to predict the method that will be used, and the costs involved. The Company anticipates evaluating the potential economic benefits and implementing some battery capacity augmentation in future, when it makes financial sense to do so.

5. Project Approvals and Heritage Survey

A summary of the Project's approval status is provided in the Table below.

Approval	Status
Environmental Protection Biodiversity Conservation Act 1999	
Referral of a Proposed Action – Solar farm	Completed – Level of Assessment: Not a Controlled Action.
Environmental Protection Act 1986	
Native Vegetation Clearing Permit for the solar farm	Granted – Clearing Permit CPS 8758/1. Amendment application lodged Sept 2024 to extend the duration of the permit to 2030.
Native Vegetation Clearing Permit for the transmission line to connect the Project with the Landwehr Power Terminal	Granted – Clearing Permit CPS 9351/1. Amendment application lodged to vary condition from overhead transmission line to buried transmission line and extend expiry date an additional 3 years. Discussions with Department of Water and Environmental Regulation (DWER) are underway.
Planning and Development Act 2005	
Waroona Solar Farm Planning Application	Granted – Development Assessment Panel (DAP) Application TP2115 Determination (Dap/19/01667) for Construction and operation of a 165 MW Solar Farm. Note – The capacity of the proposed solar farm is not limited by the title of the development approval (i.e. 165 MW). Amendment for changes to battery and revised layout approved
Application for the Transmission Corridor	Granted – DAP Application: TP2115 Determination Amendment – Extension of the Approval Period. July DAP amendment approved to November 2026
Application for an Extension of the Approval Period	Granted – DAP Application: TP2115-2 Determination Amendment – for revised project description for the decentralised and increased capacity BESS (80 MW).
Waroona Solar Farm Planning Application amendment	Granted – DAP Application: TP2115 Determination Amendment – Extension of the Approval Period. July DAP amendment approved to November 2026
Land Administration Act 1997 (LAA)	
Application to Close a Public Road	The Company has commenced discussions with the Shire of Waroona to close the Road Reserve ((Land ID no – 3629759, 3629760) on Lot 25 (981) Buller Road. An offer has been received from the Department of Planning, Lands and Heritage to purchase the unconstructed road and has been approved by Frontier management to initiate a Sales and Purchase agreement.

Table 4: Project approvals status

The Company has engaged constructively with the Gnaala Karla Booja Aboriginal Corporation (**GKB**) board and the Cultural Advice Committee **(CAC).** GKB has identified potential commercial opportunities which it hoped would be favourable to Frontier for First Nations employment and contracting participation. Frontier considers the opportunities for participation identified by the GKB and CAC to be very reasonable. GKB has proposed in its correspondence signed by the Chair of the CAC that further information be provided so a Memorandum of Understanding can be signed with Frontier to engage with suitable GKB suppliers.

Frontier has provided all the necessary information to GKB to enable the signing of a Heritage Agreement for the Project. The Heritage Agreement will cover Stage One of the Project and areas proposed for future Project expansions.

Frontier has appointed a dedicated manager to develop mechanisms assisting GKB with employment and contracting opportunities as the Project progresses.

6. Capital Costs

The Project capital cost estimate developed for the Study is based upon engineering, quantity take-offs, budget price quotations for major equipment and bulk commodities. Unit rates for installation were based on market enquiries specific to the Project and benchmarked to those achieved recently on similar projects in which Incite Energy was involved. The estimate is quoted to a level of accuracy of +/-15%.

A summary of the capital cost estimate, including contingency, is set out in Table 6 below.

Capital Item	A$m (nominal)
Solar modules (incl freight and traceability)	18
Tracker system	15
Inverters	14
BESS	81
Waroona Solar (WNS) Substation	24
Network connection (Western Power)	8
Solar farm construction / commissioning	88
Owner's costs (incl operational readiness and pre-production costs)	8
Transport / logistics (port costs and Fremantle to site)	4
Technical advisor	1
Sub Total	261
Contingency	22
Total Project Cost	**283**

Table 5: Capital cost breakdown

The estimate is expressed in Australian dollars based on an exchange rate of 0.66 AUD/USD. There are four major contracts that are exposed to exchange rate fluctuations, being the supply of solar panels, tracking systems, inverters and BESS. Current market pricing for equipment, labour and bulk rates is incorporated into the capital cost estimate. The installation rates include all charges necessary to deliver the requirements of the Project.

7. Operating Costs

Project operating costs have been developed using a range of sources. Costs are based on prices received during the 4th Quarter of 2024. The cost estimates are considered to have an accuracy of +/-15%.

All of the operating costs are fixed costs, there is no variable cost component that is affected by the availability of the facility or the amount of energy generated.

Unit Cost – average of first 10 years	$m per year (nominal)
Operations – maintenance and cleaning	2.0
Operations – monitoring and control	0.4
Insurance	2.1
Labour	0.7
Market participation – fees and settlement costs	0.7
BESS Warranty	0.2
Inverter maintenance	0.2
Western Power fees	1.3
Other	0.4
Total operating costs per year	**8.0**

Table 6: Operating cost breakdown

The operating cost estimate excludes provision for exchange rate variations, project financing costs, interest charges, contingency, corporate overheads, GST and ongoing recruitment costs. Administration operating costs have been determined to reflect the Project location, scale of operation and accepted requirements in Western Australia. The operating cost estimate includes a notional annual fee for the Project SPV to lease the land from the Company.

8. Revenue – Wholesale Electricity Market

The Study has assumed the Project will deliver electricity into the WEM, providing the revenue generation through three separate revenue streams:

1) Reserve Capacity Payments;
2) Electricity sales;
   a. peak period (energy from battery between 5pm and 9pm);
   b. day-time sales (energy direct from solar); and
3) Large-Scale Generation Certificates.

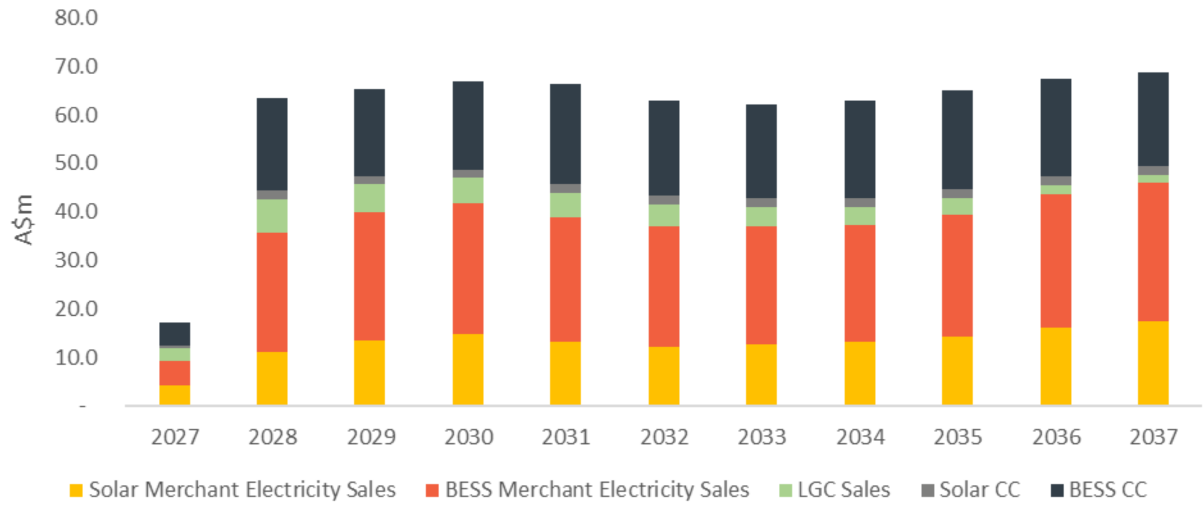

Figure 13: Revenue forecast (Base Case)

It is also probable that the Project will receive revenues from the FCESS, however given this market remains in its infancy in WA, the Study has assumed this to provide nil revenue.

Independent Price Forecasts

Aurora, a global energy market expert, was engaged to provide independent forecasts for each of these markets over the life of the operation. These forecasts are reflected in the 'Base Case' and 'Stress Test' scenarios.

Aurora models the WEM in an integrated fashion, with detailed modelling of demand drivers including industrial electrification and adoption of EVs, and modelling of supply drivers including new renewables generation, battery capacity installations (both behind-the-meter and utility scale BESS), the decommissioning of coal fired generation, and cost drivers such as domestic gas and capital to install new capacity.

In its forecasts, Aurora takes a more conservative view on demand than AEMO. As shown in Figure 14 – Aurora's demand forecast is in line with or lower than AEMO's lower case in the forecast period to 2034.

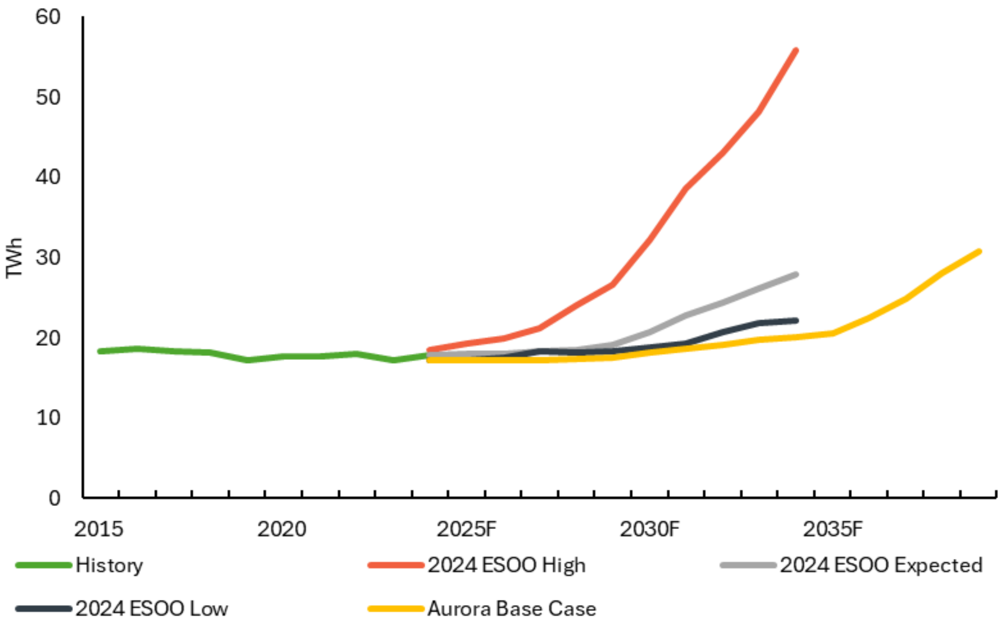

Figure 14: WEM Electricity demand forecast scenarios

The supply response differentiates Aurora's Base Case from Stress Test scenarios.

The Base Case scenario has coal fired plant closures as announced by the Government and retirement of the Bluewaters coal fired power station by 2029, two years earlier than modelled in the Stress Case. Additional transmission lines are built as outlined in the Government's SWIS Demand Assessment[13], and renewable capacity is added with a one-year delay to account for construction and grid connection timeline risk.

Recent announcements regarding the development of multiple projects within the SWIS Demand Assessment, indicate it is unlikely that this will be completed within the initial target completion dates, with multiple proposed changes already behind schedule, the most recent relating to the Clean Energy Link – North.[14]

In the Stress Test scenario, there is no delay in renewable capacity additions and Bluewaters remains operating until 2031.

Aurora generated price forecasts specific to the Project's location in the SWIS, the Project's size and the discharge capacity of the battery.

[13] *https://www.wa.gov.au/system/files/2023-05/swisda_report.pdf*

[14] *https://www.wa.gov.au/system/files/2024-11/consultation-paper-changes-to-the-access-code-modification-of-aa6-dates.pdf*

Reserve Capacity Payments

The RCM is designed to ensure that there is adequate generation capacity available to meet forecast peak electricity demand. The RCM is unique to Western Australia and is not available in other Australian states.

Under the RCM, electricity generation and electricity storage facilities are certified and allocated capacity credits based on the facility's capacity to supply power at peak intervals.

A BRCP is set each year by the Economic Regulation Authority, with reference to the cost of adding generation capacity, to inform the RCPs received by generators. The BRCP is set two years in advance.

The Government changed the reference technology to a 200MW / 800MWh lithium-ion four-hour BESS, with a 330kV connection, in late 2023. Subsequently, the formula to determine the BRCP has been applied for the 2027/28 cycle. This saw the BRCP increase to $354,000 per MW for the 2027/28 year[15], a 54% increase on the previous year. Figure 15 highlights the historical BRCP.

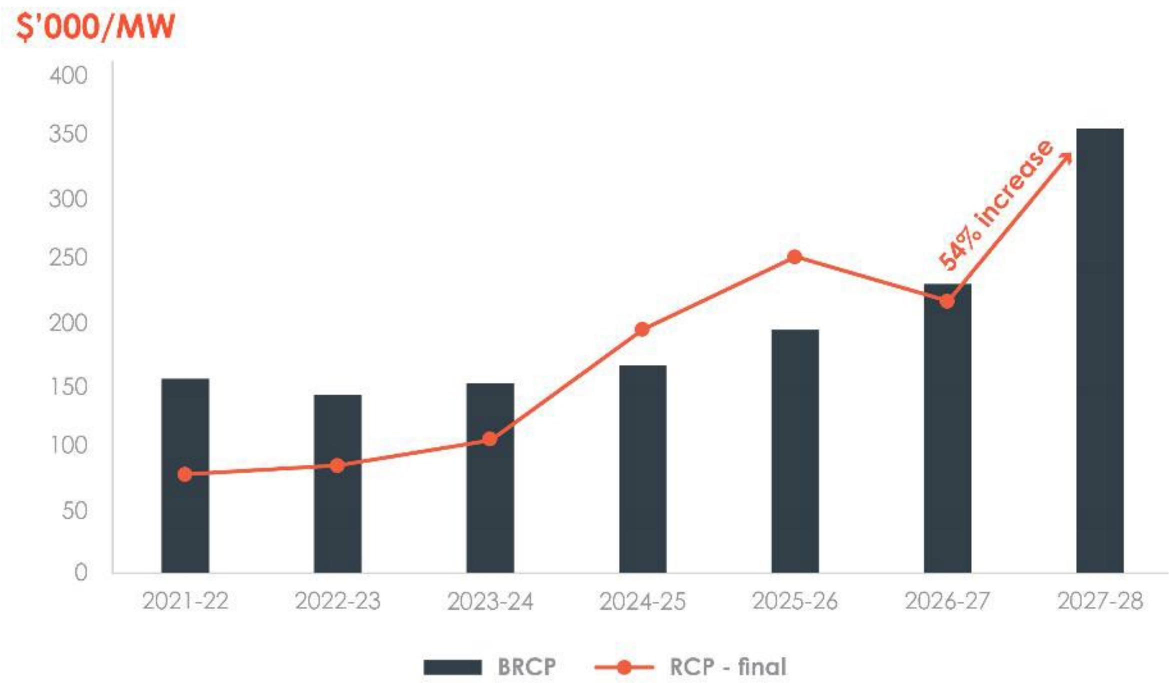

Figure 15: Benchmark Reserve Capacity Price history

[15] *https://www.erawa.com.au/cproot/24394/2/BRCP-2025-Draft-Determination-for-publication-clean.PDF*

The BRCP informs the actual RCP a facility receives, depending on the percentage of target Reserve Capacity that is available in a given year. The current relationship is shown in Figure 16.

Figure 16: RCP as a function of BRCP

Figure 17 below highlights Aurora's forecast BRCP and RCP for the Project.

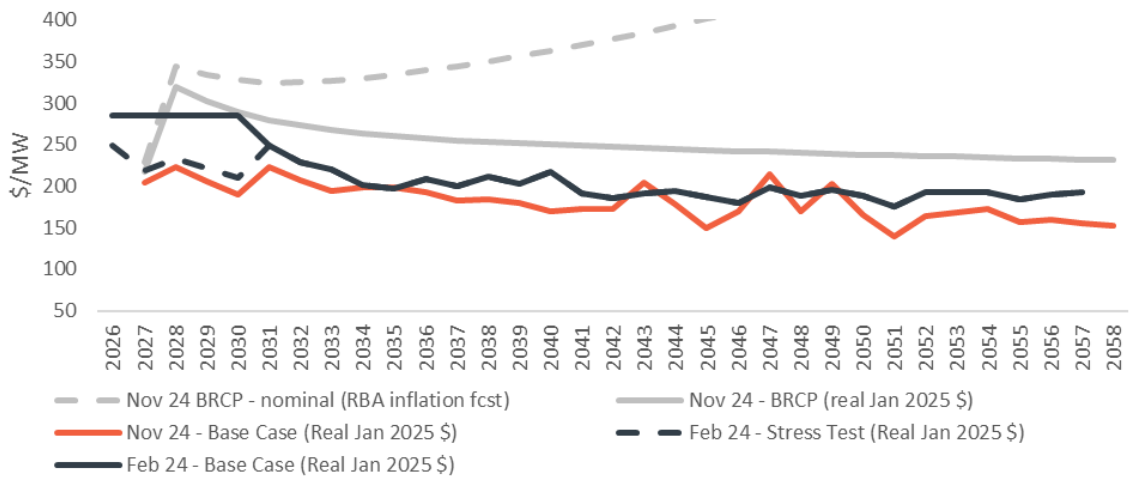

Figure 17: BRCP and RCP forecast

The Company was historically assigned 87.2MW Certified Reserve Capacity (**CRC**) for Stage One of the development. The Company has maintained this forecast. It should be noted that as a battery degrades in the future and the battery duration is reduced below four hours, the assigned CRC will also fall in line with the degradation. The longer duration battery ensures that a maximum RCP is now applied under current rules for the first eight years of operation based on current WEM rules.

Subsequent to Aurora's forecast, Energy Policy WA released the final WEM Investment Certainty Review outcomes, and exposure draft WEM Amending Rules to give effect to these outcomes[16]. The Rule Changes include a revised RCP curve, as shown in Figure 18.

Figure 18: RCP as a function of BRCP - proposal

Importantly, the new proposed curve provides a minimum capacity price floor at 50% of the BRCP, to ensure revenue certainty and sufficiency (as opposed to the current zero price floor).

It is likely these changes will have a positive impact on the revenue related to reserve capacity, and more importantly provide a floor for reserve capacity prices, which will enhance the Project's bankability.

The Amending Rules also finalise arrangements for the implementation of the RCM review, including for the flexible capacity product in time for its commencement in the 2025 Reserve Capacity Cycle. This may represent a further revenue opportunity for the Project that is not included in the Base Case.

Electricity Sales

Electricity prices have increased by ~64% over the past three years, from A$50/MWh in 2021 to A$82/MWh in 2024[17].

[16] *https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-rules*

[17] *Source: AEMO. No adjustment for curtailment has been applied when averaging.*

Intra-day price variation has increased significantly in the last twelve months, as the market has moved from half-hourly trading to five-minute interval trading, with lower lows and higher peaks during the day, due to supply and demand dynamics.

In WA, large intra-day fluctuations are caused primarily by WA's high installation rates of rooftop solar (PV) at 38%[18], one of the highest in the world. Prices dip during the morning, when solar generation peaks. Of late, prices have frequently turned negative for some intervals at mid-day. Renewable generators can absorb negative prices as they receive LGCs, however, this is not the case for baseload fossil fuel generators.

In the afternoon, demand increases while solar generation declines, causing prices to rise sharply and peak in the early evening.

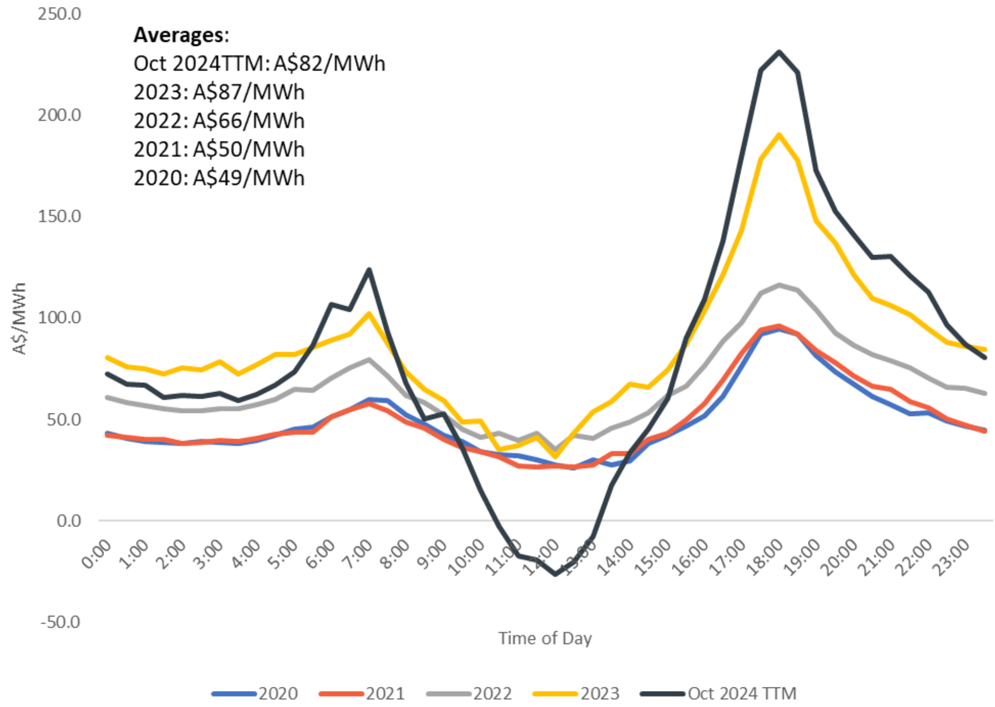

Figure 19: Historical energy price in WA – 2020 to 2024YTD, half hourly

The integrated solar and battery is designed to benefit from high peak prices, by storing the renewable electricity generated by the solar farm in the low or negative price mid-day period and selling it in the high price evening period. This is illustrated in Figure 20.

[18] *https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2023/2023-wholesale-electricity-market-electricity-statement-of-opportunities-wem-esoo.pdf?la=en*

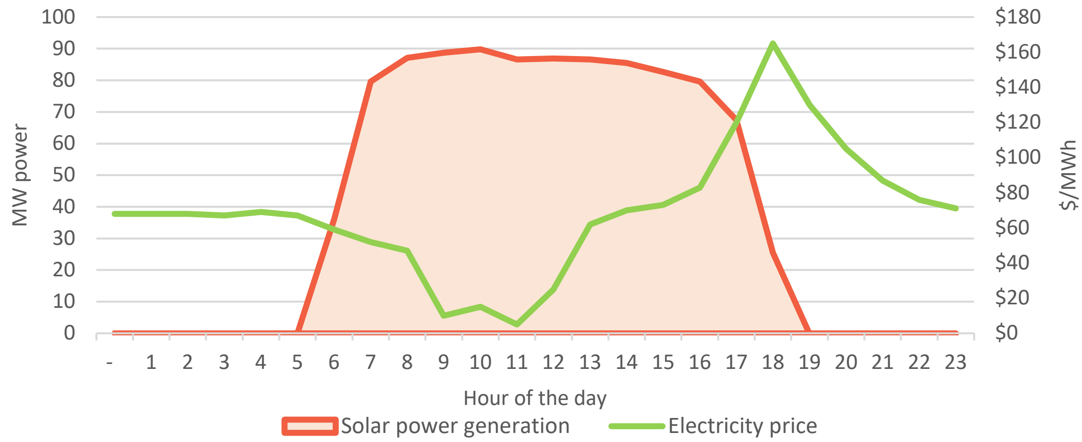

Figure 20: Typical solar generation and energy price in summer months

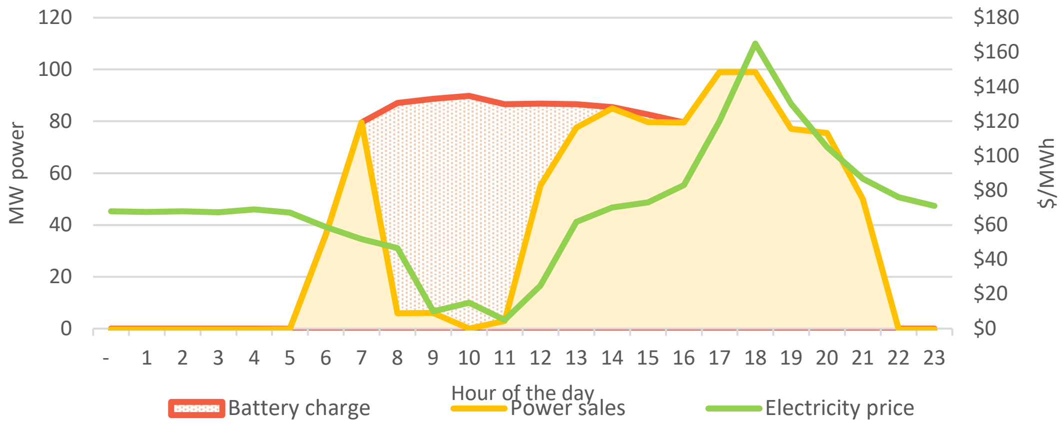

Figure 21: Integrated solar and battery enables price 'shifting'

Table 8 below shows the average prices for 24 hours and during peak times (the interval from 4pm to 9pm). Average energy prices have increased by ~64% in the past three years to $82/MWh in 2024, while peak energy trading interval prices have increased by 114% to average ~$170/MWh in 2024.

Year	Average 24 hours $/MWh	Peak (4pm-9pm) $/MWh
2020	48.9	75.1
2021	49.9	79.2
2022	65.9	97.1
2023	87.2	143.0
2024 (TTM)	**81.9**	**169.5**
Increase 2024 TTM vs 2021	**64%**	**114%**

Table 7: Historical WEM electricity prices[19]

[19] *Source: AEMO; straight averages of half hourly intervals, no cap or floor applied*

The revenue from electricity sales is modelled in two parts, one being the battery revenue and the second the solar revenue. Aurora developed these forecasts with specific reference to the Project's location in the grid, size of the solar farm and storage capacity of the battery. Figure 22 shows the battery price forecast and Figure 23 the solar price forecast.

The Base Case battery price forecast is around $170/MWh long term (similar to the spot price) with $150/MWh in the Stress Test scenario. The volatility in the early years is caused by the impact of adding battery storage of >1GW by 2027 and rolling off ~1GW of coal fired capacity by 2029.

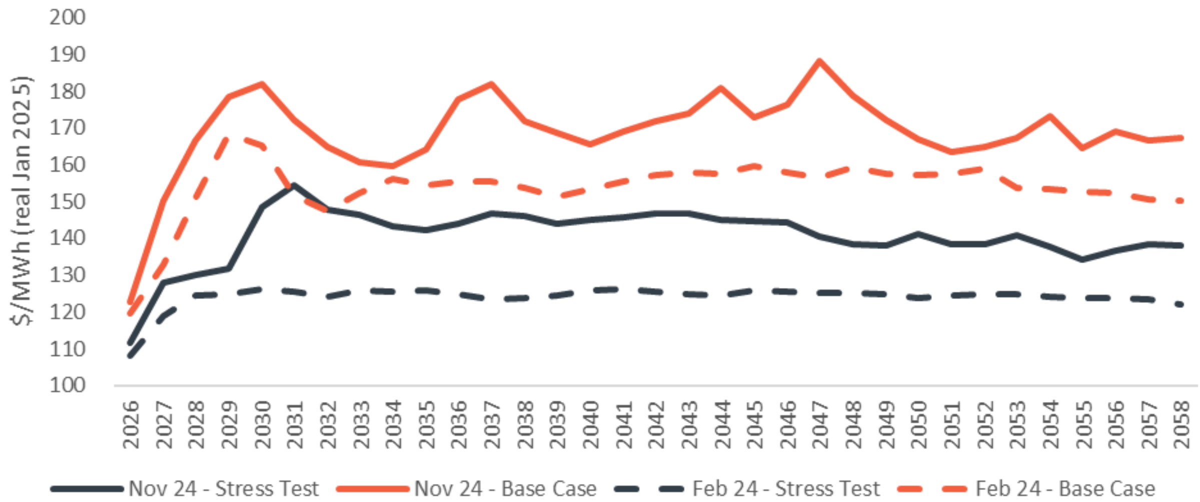

Figure 22: Forecast price – battery[20]

Aurora's solar price forecast applies only during those hours that the battery is not being charged, i.e. in the very early morning before charging commences, and in the late afternoon shoulder period once the battery has been charged and solar energy is again available to be dispatched to the grid.

As a result, the solar price applied to the Project appears to be inflated compared to the actual energy price as the low to negative price intervals are not included as the battery is charging and minimal solar power is dispatched to the grid.

The Base Case and Stress Test scenarios are ~$100/MWh and ~$80/MWh, respectively.

[20] *2025 real dollar forecasts use RBA's November 2024 inflation forecast https://www.rba.gov.au/publications/smp/2024/nov/outlook.html#section-35*

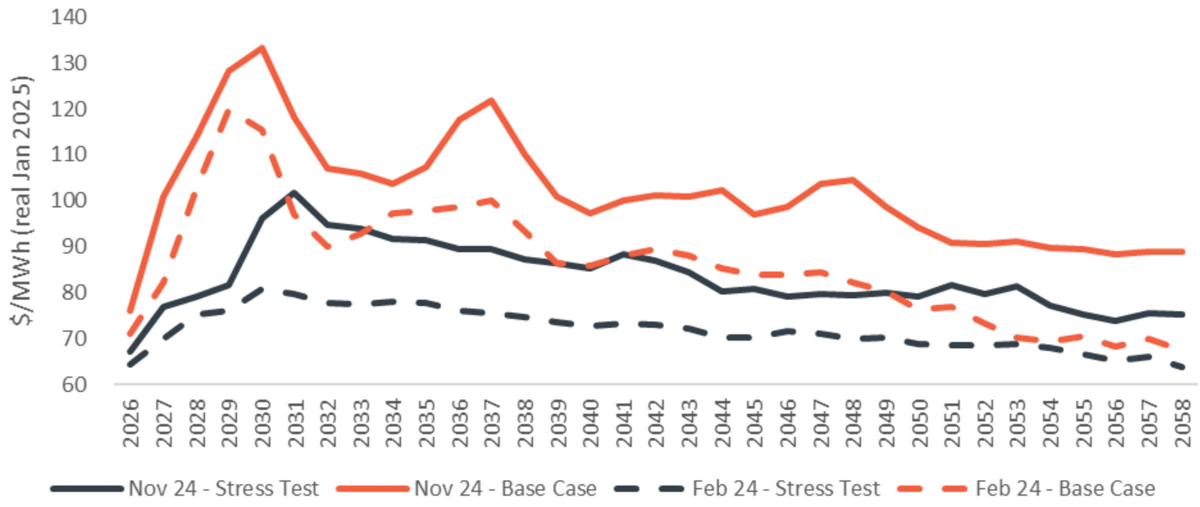

Figure 23: Historical and forecast electricity price – solar[21]

With the addition of more than 1.5GW of standalone batteries, which are new loads prior to dispatching, and their requirement to be available for daily sales under RCP obligations, there is potential for further upside in mid-day solar prices, most notably as the development of new generation capacity has been delayed.

Marginal Loss Factors

Aurora has forecast the Project to see robust Marginal Loss Factors (**MLFs**), due to its well-connected surrounding network and adjacency to the industrial load. Generation MLFs are expected to remain highly robust over the forecast horizon, in the 0.984 – 0.993 range, as are load MLFs, in the range of 0.987 – 0.999.

Key factors that result in the Project's robust MLFs include:

- Located adjacent to industry load centres, particularly the Wagerup alumina production facility, which means the Project will make minimal contribution to the network loss
- The transmission lines connecting Waroona and industrial loads are at high voltage (330 kV)

The low density of solar farms around the Waroona area means the Waroona Solar Farm usually generates at times of low network congestion.

[21] *2025 real dollar forecasts use RBA's November 2024 inflation forecast https://www.rba.gov.au/publications/smp/2024/nov/outlook.html#section-35*

Essential Services Revenue

While energy is the primary commodity bought and sold in the WEM, other services are also required to maintain security and reliability of supply – for example, providing flexibility to ramp up or ramp down generation capacity quickly or frequency control.

These services have previously been referred to as Ancillary Services and, from 1 October 2023 when the new market commenced, have been referred to as Essential System Services (**ESS**).

There are five FCESS markets (which replace the existing non-co-optimised LFAS market), including:

- Regulation Raise;
- Regulation Lower;
- Contingency Reserve Raise;
- Contingency Reserve Lower; and
- Rate of Change of Frequency (**RoCoF**) Control Service.

Aurora assesses that the BESS will only participate in the Contingency Reserve Raise and has estimated a potential revenue of $2.5-3.5m by benchmarking to the NEM.

However, as the FCESS market in the WEM is immature, no revenue has been factored into the Base Case Scenario. Future FCESS revenue and margin provides significant upside potential for the Project.

Large-Scale Generation Certificates

Renewable energy producers in Australia with an accredited power plant may create LGCs. This is effectively a carbon credit that was created by the Australian Government to meet its initial Renewable Energy Target (**RET**). One LGC can be created per megawatt hour (MWh) of eligible electricity generated by a power station.

The price of an LGC has declined materially since February 2024, and is currently around $26/MWh, having ranged between $25 and $68 over the past three years.

The Stress Test forecasts a green value to persist by 2030, but to quickly decline as additional supply enters the market, and demand from current retailers/electricity consumers for green certificates may fall as the demand post-2030 is purely voluntary.

Potential for carbon fungibility with Australian Carbon Credit Units (**ACCUs**) could provide revenue upside for the Project. Whilst the market futures for LGCs are downward sloping, futures for carbon prices are upward sloping due to the Government's Safeguard Mechanism, which requires Australia's largest greenhouse gas emitters to keep their net emissions below an emissions limit (a baseline). The Government will gradually reduce emissions limits under the Safeguard Mechanism to help Australia reach net zero emissions by 2050. With a value of $50 – 80/t for ACCUs, a carbon fungibility scheme would result in

LGC prices of $8 – 35 in the 2030s, which informs the Base Case. Figure 24 highlights the LGC price scenarios, compared to those applied in the February 2024 DFS.

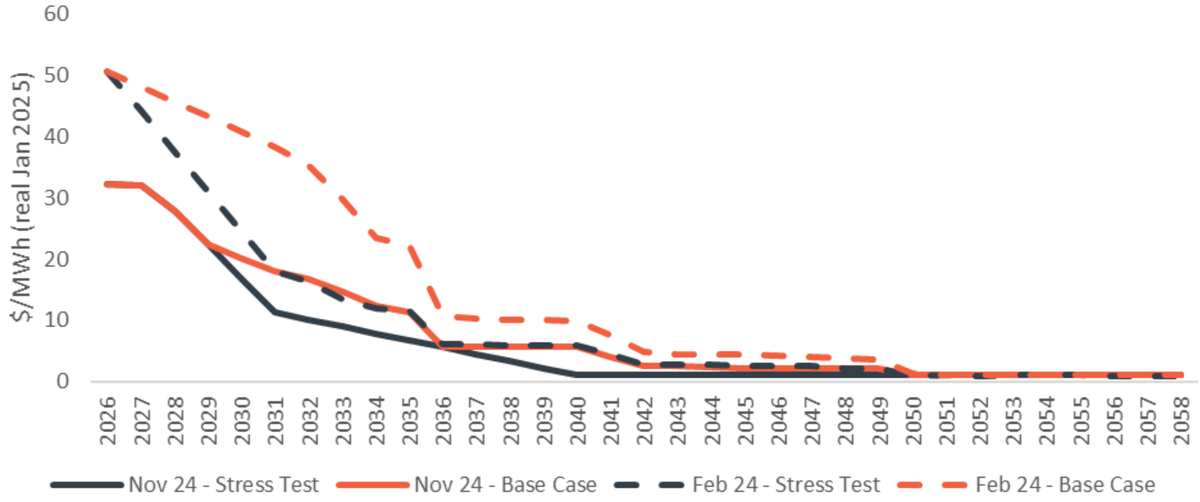

Figure 24: Forecast LGC prices[22]

It is also likely that a form of Guarantee of Origin certificate will be designed and implemented by the mid-2020s.

[22] *2025 real dollar forecasts use RBA's November 2024 inflation forecast https://www.rba.gov.au/publications/smp/2024/nov/outlook.html#section-35*

9. Financial Analysis

Profitability

The Base Case assumptions result in robust revenue generation and robust EBITDA margins of > 85%.

		10-year Average	
Revenues – Base Case		**Base Case**	**Stress Test**
Energy Sales - Battery	$m	25.8	21.7
Energy Sales - Solar (direct)	$m	13.8	10.8
Reserve Capacity Credits – Battery	$m	19.5	19.5
Reserve Capacity Credits – Solar	$m	1.8	1.8
LGCs	$m	4.2	3.3
FCESS	$m	-	-
Total Revenue	**$m**	**65.1**	**57.0**

Table 8: Project Revenue – average over first 10 years

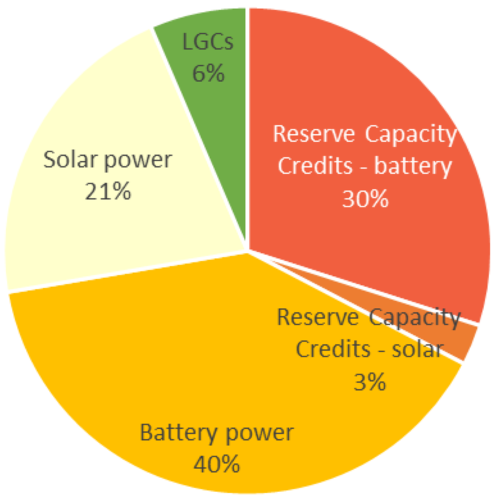

Figure 25: Project Revenue Split – first 10 years

Operating costs are ~$8m per year (nominal). The Project is expected to generate annual EBITDA of $57m in the first 10 years of operation. Figure 26 shows revenue and cost drivers with EBITDA margins above 85%.

Nominal		10-year Average	
P&L items	**Unit**	**Base Case**	**Stress Test**
Revenues	$m	65.1	57.0
Operating Costs	$m	8.0	8.0
EBITDA	**$m**	**57.1**	**49.0**
EBITDA Margin	%	88%	86%

Table 9: Project EBITDA – annual average over first 10 years (nominal)

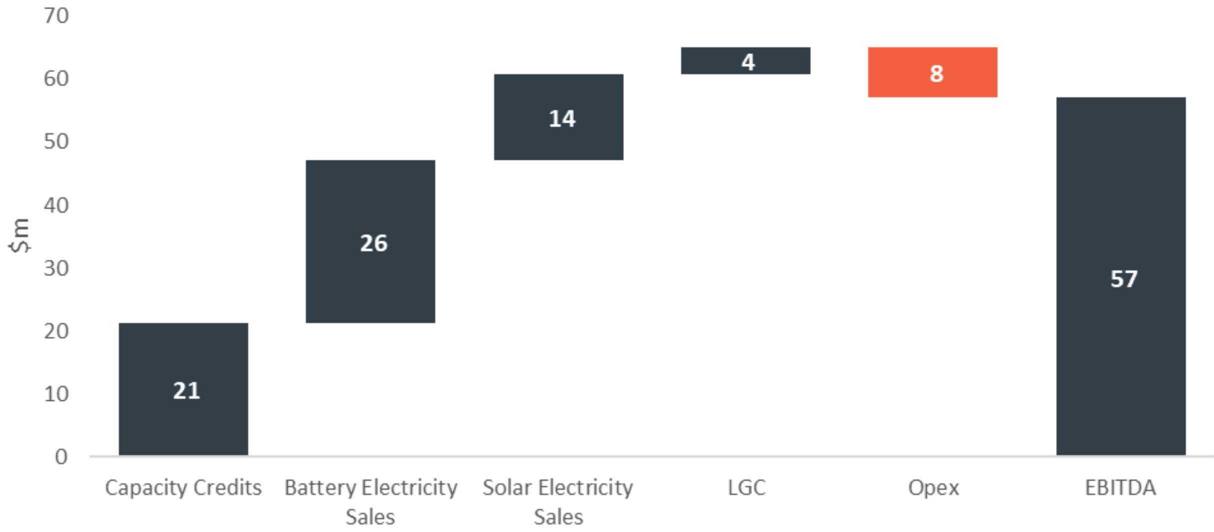

Figure 26: EBITDA waterfall – first 10 years

Returns on Capital

The robust profitability drives a payback period of 6.1 years and post-tax unleveraged IRR of 15.4%.

Project Cash flows	Unit	Base Case	Stress Test
EBITDA (10-year average)	$m	57.1	49.0
Returns – Project ungeared	**Unit**		
Payback period	Years	6.1	7.1
Post-tax IRR	%	15.4%	13.3%
Post-tax $NPV_{7\%}$	$m	244	180

Table 10: Project Returns

The modelled life of operation cumulative post tax cash flow (nominal) totals $1.1 billion, as shown in Figure 27. Cash flow generation can be applied to expansions, extensions of Project life and / or future dividends.

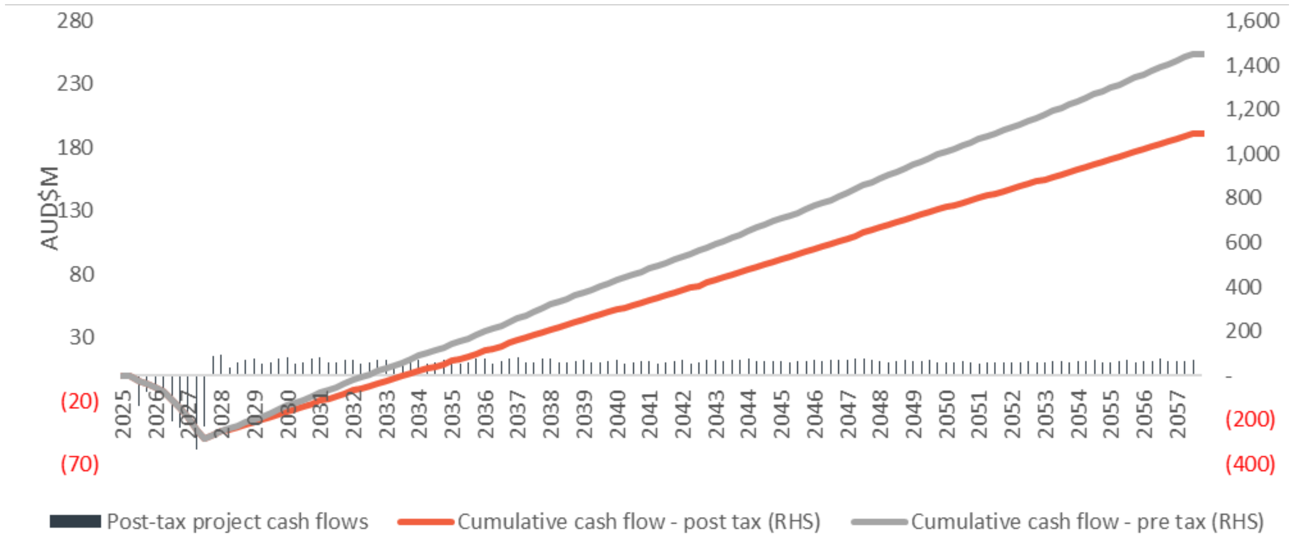

Figure 27: Cumulative Cash Flows – Base Case

Debt capacity

The Company is currently assessing a number of funding opportunities for development of the Project. Funding of the Project is expected to consist of both debt and equity financing. Debt financing could include a combination of bonds, traditional bank debt as well as equipment supplier financing. The Company is assessing all options to ensure the most appropriate funding strategy is implemented.

The Company is assessing the merits of a PPA, which provides a higher level of revenue certainty and is therefore attractive to debt financiers. PPAs typically lock in a predetermined quantity of energy to be sold at a fixed price for a fixed period of time. The Company has commenced discussions with a number of parties to investigate this option.

The Company has also held discussions with key equipment suppliers regarding equipment financing. Large scale equipment suppliers can offer flexible credit financing solutions to support Project development and seize market opportunities. Equipment suppliers have indicated an appetite to provide equipment financing to the Project.

In addition to debt financing, equity funding will also be required. The Company has the option to either raise funds in the corporate entity (Frontier Energy Ltd) or alternatively at the Project level. Project level investments may be attractive to strategic investors and discussions with a number of potential partners have recently been initiated.

With the DFS now completed, the Company is progressing all funding options in parallel.

10. Project Schedule

Frontier plans to commence Enabling Works in 4Q24, in preparation for FID in 3Q25.

Western Power delivery is on the critical path. As per the Interconnection Works Contract, Western Power is expected to take 24 months to complete its scope ready for commissioning, which is expected to take a further four months. As a result, there will be 28 months from Western Power project initiation to first sale of energy onto the grid.

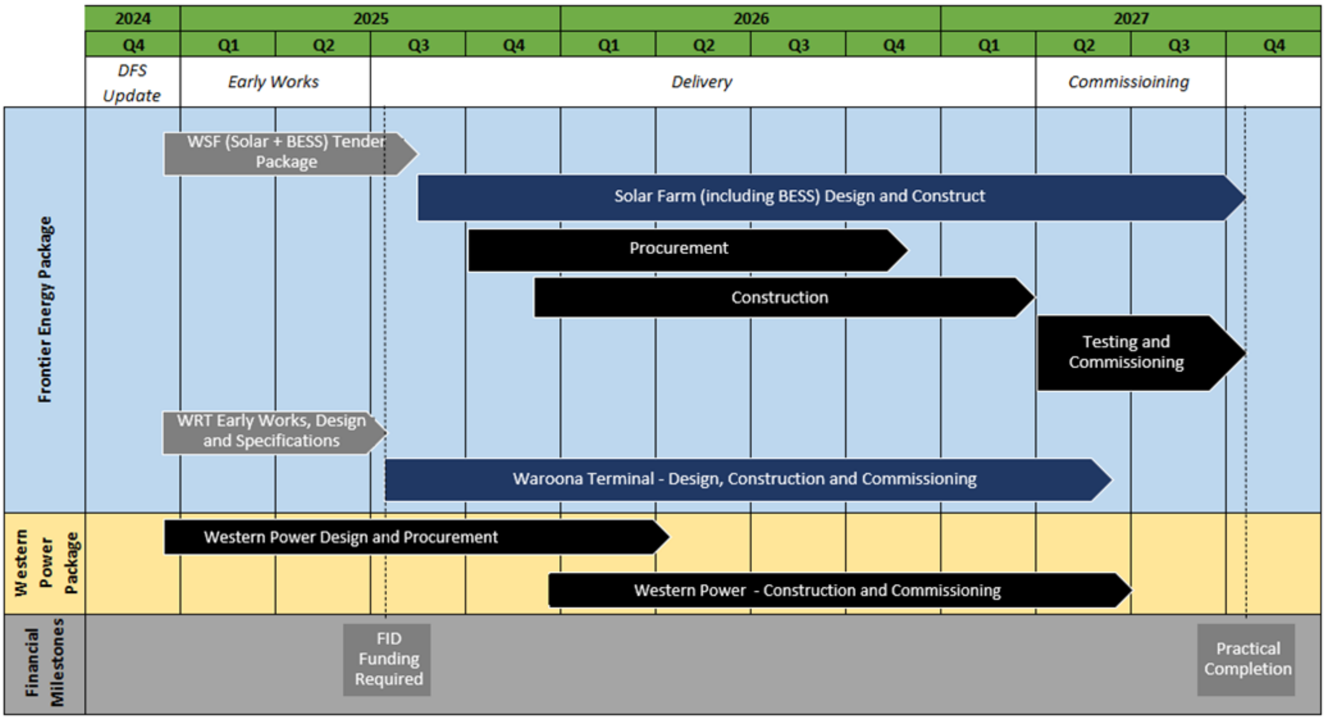

Figure 28: Schedule for Project delivery

11. Glossary

Abbreviation	Meaning
AC	Alternating Current
ACCU	Australian Carbon Credit Unit
AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage System
BRCP	Benchmark Reserve Capacity Price
CRC	Certified Reserve Capacity
DC	Direct Current
DSOC	Direct Sent Out Capacity
ESOO	Electricity Statement of Opportunities
ESS	Essential System Services
ETAC	Electricity Transfer Access Contract
FCESS	Frequency Control Essential System Services
FID	Final Investment Decision
GKB	Gnaala Karla Booja Aboriginal Corporation
IWC	Interconnection Works Contract
LFP	Lithium Iron Phosphate
MLF	Marginal Loss Factor
MW DC	Megawatt Direct Current
NEM	National Electricity Market
PPA	Power Purchase Agreement
PV	Photovoltaic
RCM	Reserve Capacity Mechanism
SWIS	South West Interconnected System
WAASTIC	Waroona Aboriginal and Torres Strait Islander Corporation
WEM	Wholesale Electricity Market

Authorised for release by Frontier Energy's Board of Directors.

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