SA ENERGY TRANSFORMATION RIT-T

Market Modelling Methodology Report

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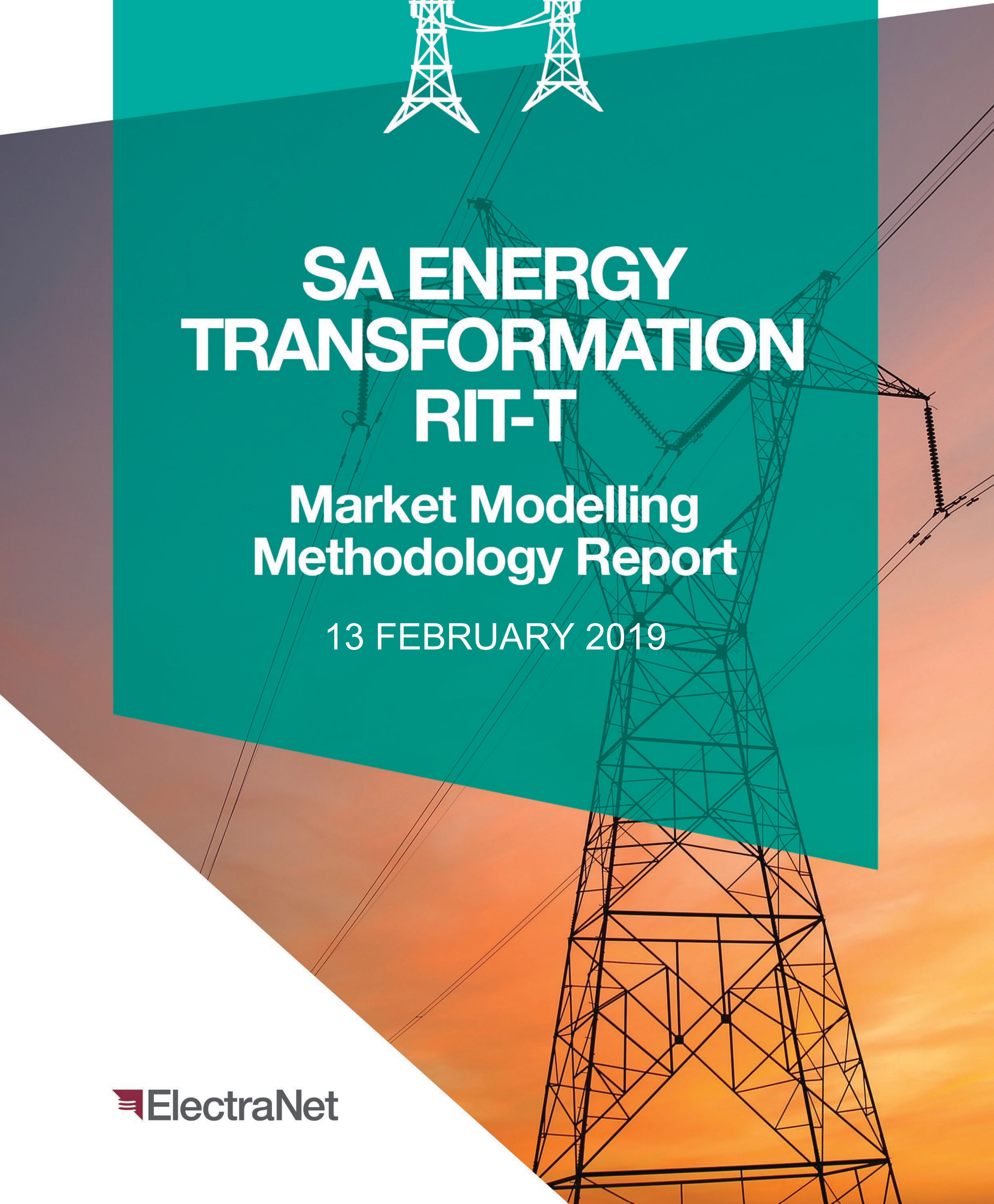

ElectraNet

Revision Record

Date	Version	Description	Author	Checked By	Approved By
13 February 2019	1.0	Issued for PACR	Brad Harrison	Henry Nguyen Tho	Hugo Klingenberg

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Glossary of Terms

Term	Description
AEMO	Australian Energy Market Operator
NEFI	National Electricity Forecasting Insights
SAT	Single Axis Tracking
DAT	Dual Axis Tracking
FFP	Fixed Flat Plate
PV	Photo voltaic
ISP	Integrated System Plan
SAET	South Australian Energy Transformation
RIT-T	Regulatory Investment Test Transmission
RIT-D	Regulatory Investment Test Distribution
PSCR	Project Specification Consultation Report
PADR	Project Assessment Draft Report
PACR	Project Assessment Conclusions Report

1. Introduction

This report summarises some of the inputs and outputs from economic modelling for the SAET RIT-T. This report supersedes the report of the same name published with the Project Assessment Draft Report (PADR) and needs to be read in conjunction with:

- SAET RIT-T Project Assessment Conclusions Report (PACR);
- Network Technical Assumptions Report;
- Consolidated non-interconnector option (prepared by Entura); and
- Cost Estimates Report.

The intention of this report is to provide greater insights into ElectraNet's market modelling. This report focusses on the base case across the three scenarios. The methodology for the base case and the options evaluated are the same.

Where inputs have been modified from original sources, this document describes the amendments made.

This report also seeks to explain some of the changes from the modelling undertaken in the draft report and examines how these changes have influenced the results.

2. Scenarios

We have constructed three 'core' scenarios that we consider reflect a sufficiently broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered:

- a **high scenario**, intended to represent the upper end of the potential range of realistic net benefits from the options:
- a **central scenario**, which reflects the best estimate of the evolution of the market going forward, and is aligned in all material respects with AEMO's ISP neutral scenario; and
- a **low scenario**, intended to represent the lower end of the potential range of realistic net benefits associated with the various options.

The key variables that influence the net market benefits of the options are summarised below.

These variables do not reflect all of the future uncertainties that may affect future market benefits of the options being considered but are expected to provide a sufficiently broad 'envelope' of where these variables can reasonably be expected to fall.

In addition to the scenarios, ElectraNet has tested a range of sensitivities including:

- the potential for a South Australia to Queensland interconnector (Option B) to defer the second stage of a QNI upgrade;
- the impact of the Western Victoria Renewable Integration augmentation not going ahead;
- removing the minimum operation constraints on South Australian gas plants (ie, consistent with the approach taken the PADR, as discussed in section 4.1.1 of the PACR);
- the estimated capital costs of the interconnector options;
- the commercial discount rate applied;
- removing the ‘avoided REZ transmission cost’ benefit;
- lower non-network costs;
- lower HVDC costs;
- higher coal prices for NSW generators; and
- a shorter assessment period.

Table 1 – Summary of scenarios considered

Variable	Central Scenario	Low Scenario	High Scenario
Electricity demand (including impact from distributed energy resources)	AEMO 2018 ESOO neutral demand forecasts	AEMO 2018 ESOO slow change demand forecasts	AEMO 2018 ESOO fast change demand forecasts plus potential SA spot load development of 345 MW
Gas prices – long-term	$9.17/GJ (AEMO ISP Neutral scenario)	$7.40/GJ ($0.62/GJ lower than AEMO ISP Slow change)	$11.87 GJ in Adelaide ($1.68/GJ higher than AEMO ISP Fast change scenario)
Emission reduction renewables policy – in addition to Renewable Energy Target (RET)	Emissions reduction around 28% from 2005 by 2030 (AEMO ISP Neutral scenario; Federal government policy)	No explicit emission reduction target beyond current RET	Emissions reduction around 52% from 2005 by 2030 (AEMO ISP Fast change scenario)
Jurisdictional emissions targets	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030		
SA inertia requirement – RoCoF limit for non-credible loss of Heywood Interconnector	3 Hz/s (current SA Government requirement)		
Generator capital costs	AEMO 2018 ISP	15% lower than central scenario	15% higher than central scenario

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3. Differences from the PADR

ElectraNet has updated the economic inputs to align with AEMO's 2018 ISP input assumptions. These assumptions were not all available in time for inclusion in the draft report. The inputs are collated in the Additional modelling data and assumptions spreadsheet.

The material changes to the model from the PADR and from updating inputs to the ISP assumptions include:

- Incorporation of the Renewable Energy Zones and calculation of the cost of long term transmission augmentation;
- Adoption of minimum operational constraints on South Australian GPG;
- New renewable input traces;
- Full chronological representation of demand in the long term with 3 discrete 8 year steps for optimisation of capital investment decisions resulting in the earlier retirement of Torrens Island B in the base case (the significance of which is tested through sensitivities);
- Adoption of retirement decisions as found in the ISP for Pelican Point and Osborne power stations in South Australia (the significance of which is tested via sensitivities);
- battery costs are higher than assumed in the draft report; and
- pumped hydro storage is now included.

ElectraNet has modified the following inputs from the ISP:

- Build limits in South Australia for transmission limitations have had additional limitations applied to reflect the mid north region as a central corridor that must be augmented to connect further renewables if other REZ are also augmented;
- ElectraNet has adopted firm capacity constraints on the Heywood interconnector and on the interconnector options. This assumption is detailed in section 10.4 and in the Assumptions modelling workbook. The firm transmission limits are derived from limitations on the Heywood interconnector or the combined import limits when with another interconnector under a prior outage;
- Gas prices in the high and low scenarios are modified to reflect a wider range of future prices than the prices adopted by the AEMO core scenarios; and
- Combined cycle generators in South Australia that are represented as steam and gas turbines have had the gas turbine heat rates increased and the steam turbine heat rates increased to reflect the average heat rates of the ISP.

4. Methodology

ElectraNet has assessed the merits of additional interconnection using a least cost expansion and operation approach based on the short run marginal cost of generators – sometimes referred to as Short Run Marginal Cost (SRMC) bidding. A linear program has been used to build and dispatch the market, much like AEMO employs.

This approach is consistent with the requirements of the RIT-T published by the AER. [1]

This method leads to the most efficient dispatch and therefore least cost of operation, without the need to assess market prices or the commerciality of generator decisions. There is a presumption that the design of the market will lead to prices that support entry and exit and market bidding that leads to the lowest underlying capital and fuel and other operating cost.

This presumption will hold if the nature of entry and exit of capacity and the relative order in which generation is dispatched in the least cost analysis are like that which would occur in the market, but with market prices set by market behaviours. Put another way, the analysis presumes that this will be the case if the market is competitive and that the order of dispatch will be substantially unchanged even if prices are not competitive which is the rationale for requiring least cost analysis in a RIT-T.

Units will exit the market when the model sees a potential to avoid costs and replace capacity with lower cost replacements. Existing sources of supply tend to be preferred as capital costs are sunk whereas new entrants must recover the capital and operating costs of entry. Where existing generators do not recover full costs, there is a presumption that commercial pricing decisions will lead to outcomes more closely aligned with the costs of replacement rather than the costs of dispatch.

Decisions for major Pelican Point and Osborne power stations in South Australia have been taken from the ISP. The influence of these retirements on the calculation of benefits have been extensively tested.

A material difference from the ISP is that Torrens Island B has been found to retire before the end of the horizon in the base case. In addition, we have also tested an earlier retirement of Torrens Island B that sees Torrens Island B exit the market by 2027, 50 years after commissioning in 1976. This assumption aligns with the assumptions that coal units have a technical operational life of 50 years. Note, that whilst Torrens Island A is scheduled to retire it has surpassed 50 years of operation, having been commissioned in 1967.

A further benefit of SRMC based approach is that it avoids making arbitrary long-term decisions about the level and nature of contracting in the NEM. The NEM is undergoing an unprecedented rate of change with the emergence of intermittent sources of supply and the rapidly growing need for storages. This is all taking place during a well-publicised disruption to east coast gas markets. All of this will influence the level of contracting required by market participants.

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1 AER, Regulatory Investment Test for Transmission, 2010, paragraph 21

The alignment of input assumptions with regards to the operation of South Australia gas plant has gone some way to addressing the observation that competitive bidding practices will increase the level of gas generation in South Australia in the base case.[2]

4.1 Long term approximations

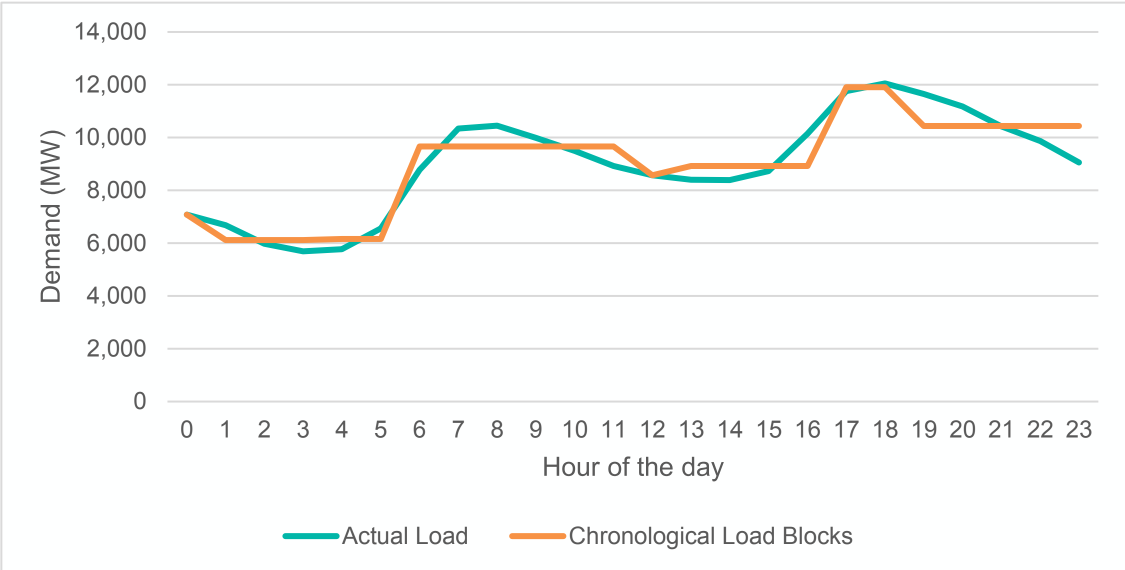
The Long Term (LT) approximation makes several simplifications to allow for the significant challenge of making new entrant decisions. The new entrant decisions are tested in the more detailed time sequential representation.

The LT models chronological steps of 8 years at a time, with perfect foresight over the step. The demand traces are aggregated to the national level 8 chronological blocks per day. Demand traces are offset by 'Behind the Meter' solar PV. The size of the blocks is determined by a least squares' approximation of the aggregated regional traces that is each block can be of a different size.

For renewable resources, the average output of each renewable generator is applied for the block. In addition, no chronological block overlaps between the day time (7 am – 6 pm) and night time (1 am – 6 am and 7 pm – 12 pm). This makes sure that the solar outputs will not appear during night time operations.

The advantage of chronological blocks is that the time-of-day diversity of renewables and demands are captured across the NEM in the long-term representation.

Figure 1 - Example NSW blocks per day



[2] Delta submission, Figure 3, page 10

4.2 Minimum Reserve Levels

The least cost expansion builds enough plant to meet the reliability standard. This is achieved by requiring supply to exceed the level of 10% Probability of Exceedance (PoE) demand plus a reserve margin.

ElectraNet notes recent concern that market prices will not result in the type of capacity needed to give assurance that reliability can be delivered. This has led to development of the Reliability Limb of the National Energy Guarantee – consistent with the presumption underlying the use of least cost analysis that, at least in the longer term, the design of the market and associated rule making, and regulatory bodies will support investment.

Whilst there is uncertainty that the NEG will be delivered, the Federal Government has sought registrations of interest in new firm generation through the 'Underwriting New Generation Investments program'[3], whilst the South Australian government is pursuing a 'Grid Scale Storage Fund'[4] and 'South Australia's Home Battery Scheme'[5] the presumption that a policy mechanism will be developed to ensure reliability is met remains valid.

ElectraNet has assumed a Minimum Reserve Level (MRL) within each region. These are presented in the assumption's workbook on the worksheet "Reserve Levels".

4.3 Out-of-merit-order dispatch

In addition to generation entry and exit decisions, the least cost analysis makes dispatch decisions to achieve 'Security Constrained Economic Dispatch'. This means dispatch may involve operation that does always not see dispatch of the absolute lowest cost available generation instead it will result in dispatch of the lowest cost generation that meets requirements to maintain operational security.

For example, the RoCoF constraint on the Heywood interconnector in ElectraNet's model will at times require generators in South Australia to be on line and providing inertia services to improve interconnector capability.[6] These generators are not the lowest cost generators, they are the lowest cost generators to meet security constrained economic dispatch. This interaction of generator commitment and interconnector flows will lead to price outcomes in some instances that are lower than the dispatched generators SRMC.

This is currently counter to the commercial incentives of the plant as there is no existing market payment that would facilitate this behaviour. In the absence of a market mechanism this outcome is unlikely to occur in the NEM. It is expected, that in dispatch,

3 https://www.energy.gov.au/government-priorities/energy-supply/underwriting-new-generation-investments-program

4 http://www.energymining.sa.gov.au/energy_implementation/grid_scale_storage_fund

5 https://homebatteryscheme.sa.gov.au/

6 Details of the constraints are in the Network Technical Assumptions Report, along with assumed inertia capability of South Australian generators.

these interactions will result in more expensive plant that does not provide inertia entering the market. At the extreme, where such outcomes may lead to the potential for unserved energy, AEMO may exercise its power to direct generators. Compensation is payable to the directed parties to ensure they are not operating at a loss.

A modelling approach that reflects the commercial incentives rather than a least cost optimisation, will increase the costs of matching supply and demand within South Australia in the base case. As a result, commercial bidding outcomes will increase the benefits of greater interconnection with South Australia as greater interconnection removes the RoCoF constraint specifically and increases the markets capability to meet security constrained economic dispatch at lower costs.

4.4 Assumptions about changes in mode of generator dispatch

By the end of the modelling horizon the analysis shows conventional thermal generators being operated in ways quite differently to today. For those coal generators still in service ElectraNet has recognised existing assumptions about continuous operation will no longer be valid and has allowed the model to economically cycle these units off with a minimum shutdown time of 12 hours. Where extreme changes have been observed, generators have been required to operate for five days at a time.[7]

A 12-hour shutdown period has proven to be enough to prevent most short start up and shutdown cycles. However, this observation highlights that existing generators will be required to be more flexible than they currently are. In addition, generator operation at minimum operating levels will increase.

As these effects are most pronounced at the end of the modelling horizon and any changes to the operating constraints, such as the 12 hours minimum downtime are an assumption ElectraNet has made to ensure the forecast operation of fleet matches our understanding of the capability of the fleet.

Further complexities could also be considered that would likely increase the costs of dispatching the market and hence increase the potential to generate economic benefits through greater efficiencies. For example, ElectraNet has not considered the effects on generator wear-and-tear that rapid cycling of plant between minimum and maximum loading levels causes nor the reduced efficiency of plant operation at minimum loading levels compared the full output. ElectraNet’s models have used an average heat rate for all operating points. As these costs accumulate towards the end of the modelling horizon, the scale of the benefit would be discounted.

Similarly, ElectraNet has not included the additional costs for starting and shutting down conventional generators. These costs, whilst significant for a commercially minded operator are not currently major costs in the NEM[8]. The operation of the plant is captured by the minimum up and down time constraints. Including these costs in the model is expected to marginally increase the costs of dispatch and provide greater

7 This has not been applied universally due to interactions with other constraints most notably maximum capacity factor limits.

8 Preliminary modelling from ElectraNet estimated start and stop costs added less than 5% to the costs of dispatching the NEM in a year.

opportunities for dispatch efficiencies to be delivered by increased interconnection. Further, these costs are greatest for the coal fleets outside of South Australia and can expected to be similar in all terminating jurisdictions of the options consider and would not impact on the choice of interconnection.

5. Long term and short-term representations

ElectraNet's economic model estimates the majority of the benefits of the different options in the SA Energy Transformation. This model is split into two different representations to facilitate different considerations within the RIT-T framework and applies the appropriate network resolution to perform these assessments whilst making the problems tractable.

5.1 Long term representation

The long-term representation measures the effect of the options considered by the SA Energy Transformation on long term investment decisions required to meet the NEM's Reliability Standard. Generation and storages (battery and pumped hydro) are built to ensure the Reliability Standard is met. Benefits of interconnection can be measured as a change (reduction) in the cost of new entrant capital decisions and changes in fixed operating costs. Alternatively, increased interconnection can lead to an increase in the capital costs of new plants so long as this is offset by a greater reduction in the operating costs of the fleet.

Some supply decisions are fed into the long-term representation – that is, the optimisation of the future happens around these inputs, and in some cases the utilisation of these sources is optimised but the development of these sources is not. This is a common modelling technique. The consequence is that optimisation of the costs and hence changes in the costs of developing these resources is not included in the benefits of increased interconnection and hence may underestimate these benefits. This includes development of:

- Distributed Energy Resources made up of behind-the-meter PV, battery systems, and
- Investment in additional voluntary load curtailment capability.

The long-term representation performs a least cost expansion of the grid out to 2043. The linear program solves across the horizon in three 8 year passes with perfect foresight over the 8 increments. Generator build decisions are treated as annualised costs based on the 6% discount rate. Battery build decisions are treated as the full costs including funding costs in the year that they are built.[9] The costs of new build decisions are considered 'over-night'.[10]

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[9] This is a limitation of the software

[10] The cost of build decisions are included from the time the generator or storage object is built. Actually, costs would begin to accrue two years before commercial operation.

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5.2 Time sequential “Short Term” representation

The short-term representation measures the detailed effects of the options considered on the costs of dispatching the market. This includes all:

- Inter- and intra-regional constraints relevant to the SA Energy Transformation;
- network losses; and
- the diversity of renewables.

Tasmania is represented by a single node. Tasmania retains the regional representation in the short-term representation due to being electrical isolated with a single DC connection to the mainland.

The short-term representation is dispatched according to Short Run Marginal Cost (SRMC) as required by the RIT-T. The short-term representation solves each year individually with the fleet of generators made available by the long term representation. Each year is optimised across the full year to ensure seasonal variations are accounted for and then undertakes a furthermore detailed time-sequential optimisation of each day of the year. The short-term representation has access to generator sources that are determined in the long term representation and does not make new entry or exit decisions.

Within the RIT-T framework the short-term representation quantifies changes in:

- fuel costs;
- transmission losses (which is in effect captured by changes in fuel costs); and
- voluntary load curtailment (demand side participation).

5.3 Differences between long term and short-term representations

The long term and short-term representations take common inputs on the economics of supply and demand. The two models differ in the following respects.

The long-term representation is a regional model that models demand and supply connecting at a single bus in each region. Regions are connected by notional interconnectors. Intra-regional limitations apply on new entrant build decisions. That is it will not allow generators representative of renewable zones to build and exceed the local capability of the network without in the first instance, coupling with batteries, before reaching a fixed capability.

The long-term representation considers chronologically 8 blocks per day of variable length, covering a span of 8-year blocks. The short-term representation considers every hour of the year in sequence.

The short-term model captures greater diversity of renewables and includes the full network representation of all transmission reactance, resistance and ratings. Demands are modelled across the NEM at the local bus.

Differences between the long term and short-term representations are summarised in the table below

Summary	Description
Intra–regional constraints	LT representation has minimal representation of intra-regional limitations. The time sequential model uses the full network representation with all important intra-regional constraints modelled. For example, intra-regional constraints in Tasmania are not modelled.
Inter-regional constraints	Inter-regional constraints are modelled a the notional level in the LT. The ST takes a more detailed representation of thermal constraints. Notional limits remain for the approximation of complex constraints.
Renewable diversity	Diversity in the ST is enhanced from the LT by simulated every hour rather than average intermittent output over approximately 4-hour blocks.
Nodal demands	In the ST, demands are represented at the local bus. In the LT demands are aggregated and represented at the regional reference node.

6. Reserves

Reserve margins are modelled in the LT in addition to demand to ensure additional sufficient supply is provided by the model to meet the reliability standard. These values are an approximation of the additional supply that would be required to meet the reliability standard.

The reserve margins are not a critical input to the calculation of market benefits in the RIT-T. Sufficient generation is met to meet the reserve requirements in each region. To the extent that the interconnector can assist in meeting reserve requirements at lower cost, a capital deferral benefit will be realised. This benefit is in practice small.

Grid scale and distributed storages are assumed to be firm at time of maximum demand in the LT.

AC Interconnectors that connect to South Australia are assumed to have a firm capability based on the capability of the interconnectors under a prior outage. The limits are presented in the assumption report in the worksheet “Interconnector Firm Capacity”. Firm capability is only considered by the LT during the time of maximum annual demand.

At other times – that is not under time of maximum demand – all interconnectors can operate up to the limits presented in the modelling and assumption report under notional interconnector limits.

Intermittent renewable generation has firm capacity assumptions detailed in the modelling and assumptions workbook in worksheet “Firm Capacity”

Reserve margins are not modelled in the ST model. Demand is met based on the available generation at the time. Deployment of storages, network capacity and interstate generators will be dispatched to minimise the costs of meeting the supply and demand balance. If storages are not able to operate according to the assumptions of the LT, this will be revealed as Unserved Energy (USE) and should not exceed the reliability standard of 0,002 % per region per annum.

7. High Impact Low Probability events

The addition of an alternative and strong AC path will significantly strengthen the South Australian grid reducing the risk of High Impact Low Probability Events. One emerging HILP event that will be avoided will be the risk of islanded operation under low demand. Soon, such operation would be very challenging with Heywood out-of-service. We are expecting to cross the minimum demand threshold in a few years.

As the grid shifts towards a reliance on storages for dispatchable power, the amount of storage will become important in managing long term reliability. The interconnector will facilitate the shift to renewables-based storages resulting in 4,200 MWh of pumped hydro development in South Australia. If GPG was replaced entirely with batteries instead of pumped hydro, this would be facilitating 1,400 MWh of storage. It is also expected that by the time the interconnector is delivered, distributed storages will account for an additional 76 MWh of storage. Distributed storages are expected to continue growing over time.

ElectraNet has examined the risks to the system of long-term outages of the new interconnector after the removal of GPG in South Australia, noting that the retirement of these plant remains uncertain. Should they not retire then this risk is obviated.

It should be also be noted that this risk is only evident at night with solar generators in South Australia being highly reliable on days of high demand.

ElectraNet has recently observed a worst-case day with Adelaide reaching its hottest day on record: on 24 and 25 January 2019. Demand on this day was high, exceeding the 10% POE forecasts from AEMO.

To stress the market, this analysis assumes the new interconnector is out-of-service with a double circuit outage between Robertstown and Buronga. Demand on these days the capability of the Heywood and Murraylink interconnectors[11] and the remaining gas and diesel fleet for 5 hours. South Australia would be reliant on solar, wind and storages if this outage were to occur on a day of record temperatures.

Given the very high demands and the long duration of high demands, this is informative of the worst case.

The demands on this day were forecast, this is significant as the probability of a planned outage on this day is effectively zero. The assumption of a double circuit interconnector outage on this day is very low. In general, the potential exposure to demand high enough for this risk to emerge occurs for only 1 per cent of the year; is inherently forecastable and tends to last for very short periods.

This analysis is also predicated on the assumption that should the necessary condition of a double circuit outage of the highest capacity interconnector eventuate, AEMO would ensure that storages were fully charged before the sun set and would only be used as a last resort.

This analysis has also made no allowance for voluntary load curtailment also know as demand side participation. This is a true demand reduction (for example switching off pool pumps via a retailer arrangement) rather than the use of distributed batteries, which has been included.

The total amount of energy at risk, assuming zero output from wind generators in South Australia on this day was 2,002 MWh. Considering wind generation, the energy requirement dropped to 280 MWh, and then further accounting for existing grid storages this fell to 91 MWh. On this day, the residual risk is almost entirely accounted for by the expected emergence of distributed storages (76 MWh by 2023-24 and growing). Of the pumped hydro found to be developed by the model, only 15 MWh or 0.3% would have been required effectively leaving 6 hours of redundancy.

This however is not a worst case due to the good levels of wind output after 8 pm on this day (operating at approximately 25 per cent of full output after 8 pm and 36 per cent over the course of the day). Observing wind output on other days of high demand indicates that wind output could be lower. This analysis is informed by observation assumes 6 per cent output of wind generation. Assuming lower wind output, the residual risk of 2,002 MWh falls to 1,388 MWh and further reduced by existing storages to 1,199 MWh. This residual energy risk would deplete the assumed pumped hydro facilities by around 28 per cent leaving over four hours of storages. Should batteries be developed instead of pumped hydro, with a smaller energy storage component, the batteries will still provide enough storage being only 85 per cent exhausted.

The conclusion is that there is a very low risk that a combination of a double circuit interconnector outage, less GPG, low wind and very high demand would result in the exhaustion of predicted storages in South Australia.

[11] MurrayLink will be capable of full imports into South Australia should the new interconnector be unavailable.

8. Demand

Demand forecasts are based on AEMO's August 2018 ESOO publication.

The demand profile used is from 2009-10 as reported in AEMO's Market Management Systems (MMS) as Initial Supply. 2009-10 is used as the base year as it predates behind-the-meter-PV generation. Each state has a different profile.

Each 2009-10 state demand profile is "grown" to meet forecast maximum demand and annual energy consumption forecasts out to 2040.

The grown demand traces are then distributed to the nodes (or busses) in the model: 78 nodes across South Australia and to 432 across the rest of the NEM.

Industrial loads have been excluded from the generation of growing the input traces and have assumed to be unchanged over the horizon from recent history. Some loads have been treated as constant loads.[12]

Behind-the-meter PV is added to the nodes separately and hence can be tested at different values against the same demand forecast.

The market modelling input assumptions spreadsheet presents the ranges of energy demand input and provides the calculated outputs from Plexos for grid scale storage load, transmission losses, generator auxiliary loads, voluntary load curtailment and net DER injection (the combination of PV injection and storage).

Net DER injection has taken the PV forecasts from the 2018 ISP along with aggregated distributed battery forecasts. The treatment of distributed batteries is discussed in more detail in section 9.4

8.1 Maximum demand

The maximum demands presented below are the maximum demands as an output of the market modelling. They have been derived from AEMO's 10% and 50% POE demand. The range of South Australian maximum demands are presented below and demonstrate the range of futures considered.[13] Interstate demands are not believed to be material drivers of market benefits to the SAET RIT-T outcomes and have not been presented.

[12] Information relating to large loads across the NEM is confidential.
[13] Note that the maximum demand recorded in South Australia is 3,413 MW on 31 January 2011

Table 2 - 50% South Australian POE maximum demand by scenario

Fiscal Year	High	Central	Low
2021	2,607	2,593	2,551
2022	2,590	2,585	2,549
2023	2,613	2,655	2,553
2024	2,646	2,633	2,580
2025	2,679	2,662	2,568
2026	2,745	2,662	2,536
2027	2,748	2,691	2,570
2028	2,744	2,660	2,530
2029	2,797	2,650	2,520
2030	2,829	2,671	2,539
2031	2,898	2,709	2,526
2032	2,930	2,707	2,530
2033	2,996	2,750	2,532
2034	3,028	2,742	2,490
2035	3,065	2,808	2,504
2036	3,075	2,831	2,475
2037	3,113	2,788	2,508
2038	3,125	2,881	2,536
2039	3,183	2,841	2,553
2040	3,258	2,915	2,598

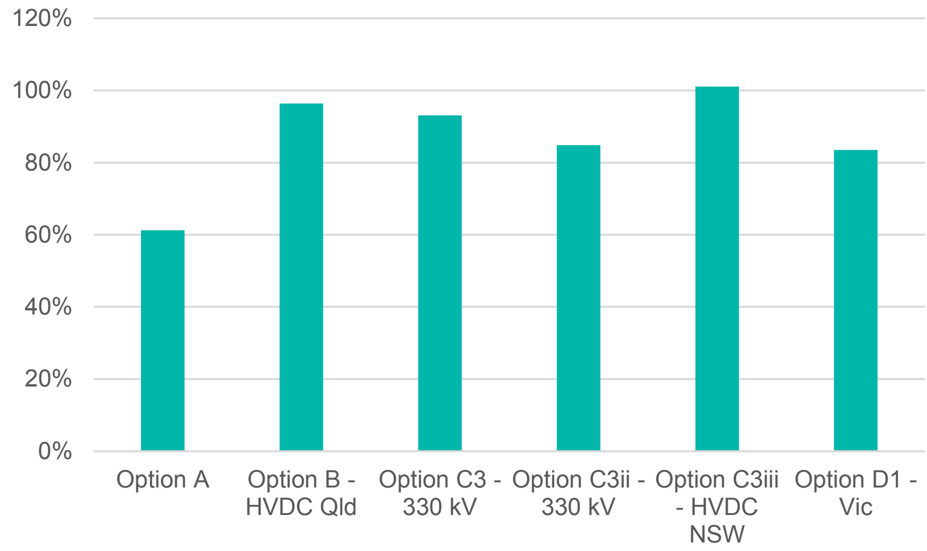
8.1.1 10% POE demand

ElectraNet has adopted the latest ESOO demand forecasts for the PACR. ElectraNet tested the effects of 10% PoE demand outcomes alongside of the 50% PoE outcomes but found that the higher demands did not have a material impact on the estimation of market benefits. 10% PoE demands can be expected to be the same as 50% PoE for the vast majority of the year, only differing on the maximums.

The generator expansions plans have been developed using the 10% PoE demand. Figure 2 below highlights the effects that the high demand had on gross market benefits. Option A and D both appeared to be the worst performing options when considering 10% POE demand. Given neither is the preferred option, and this outcome makes them less favourable, this was not considered material.

The preferred option had lower NPV benefits by around $50 million over the horizon to 2040 or around a 6% reduction in benefits.

Figure 2 – Effect of 10% PoE on gross modelled market benefits



8.2 Minimum demand

South Australia's minimum demand presented below is an outcome of the modelling considering the effects of distributed energy resources: behind the meter PV and batteries. Behind the meter PV is an input to the model, distributed batteries are treated as either smart – that is effectively controlled by the market operator or operated according to a predefined profile. See 9.4 for more details. Exogenous assumptions regarding growth in distributed batteries, as well as the model's development of storages is providing support for minimum demand. This demonstrates the range of minimum demands that have been tested by the SAET.[14] Interstate minimum demands are not material to the SAET RIT-T and have not been presented.

Table 3 – South Australia's minimum demand (MW) by financial year and scenario[15]

Fiscal Year	High	Central	Low
2020	1,011	675	555
2021	1,000	687	553
2022	1,055	667	566
2023	994	561	446
2024	926	541	343
2025	905	446	375

14 If storages, in particular the exogenous inputs to the model are to develop at a slower rate, minimum demands could reach zero around 2025

15 Values presented were calculated for the result in the draft report and have not been reproduced for the conclusions report.

Fiscal Year	High	Central	Low
2026	713	482	241
2027	829	418	265
2028	825	470	285
2029	775	455	178
2030	722	370	133
2031	764	350	94
2032	659	312	-13
2033	766	513	88
2034	752	505	18
2035	750	384	-26
2036	831	453	-78
2037	762	312	-139
2038	893	379	-44
2039	791	563	-94
2040	1,064	684	-5

9. Supply

This section describes some of the inputs and outputs of the SAET modelling.

9.1 Renewable energy targets

The following renewable energy targets have been modelled in all scenarios and options. Details are presented in the modelling assumptions workbook.

- National Large Scale Renewable Energy Target ~ 20 per cent renewable by 2020
- Queensland Renewable Energy Target ~ 50 per cent renewable by 2030
- Victorian Renewable Energy Target ~ 40 per cent renewable by 2025

Due to the rapid increase in committed renewable projects and the inclusion of the Queensland RET and the Victorian RET, the National LRET is met in all scenarios and has no impact on the outcomes.

9.2 Installed capacity

This section presents the generator expansion outcomes across the three base case results in each scenario.[16] These outputs demonstrate the range of investment required across the NEM by the SAET modelling ranging from – a low level of capital investment

[16] These results are drawn directly from PLEXOS and do not include assumed distributed energy resources.

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that sees the level of installed capacity in the NEM remain little changed over the modelling horizon, to a doubling of the installed capacity in the high scenario.

Investment in all scenarios is driven firstly by the need to replace retiring capacity. In the high scenario there is also the added drivers of increasing demand and a stronger emissions reduction trajectory. Whilst the emissions trajectory in the high scenario is stronger than the central, it affects dispatch rather than having a material impact on further retirements than in the central scenario. The cost of these investments are summarised in section 9.5.

Figure 3 – High Scenario Installed Capacity

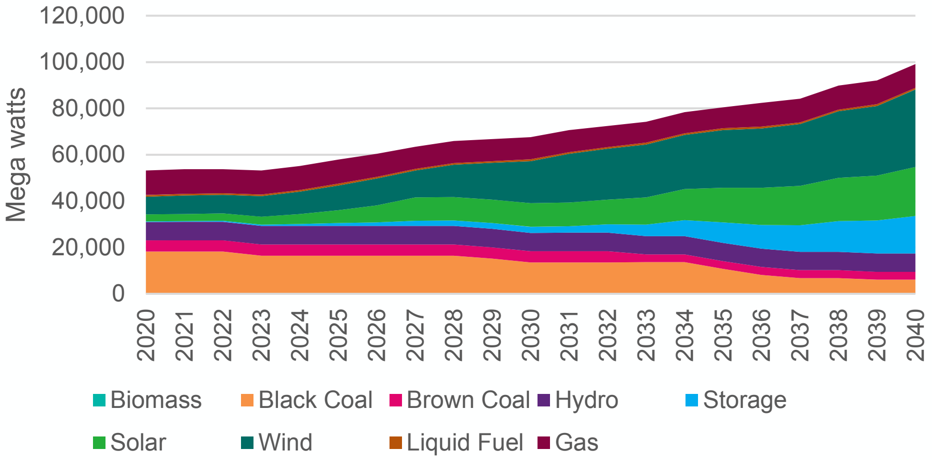


Figure 4 – Central Scenario Installed Capacity

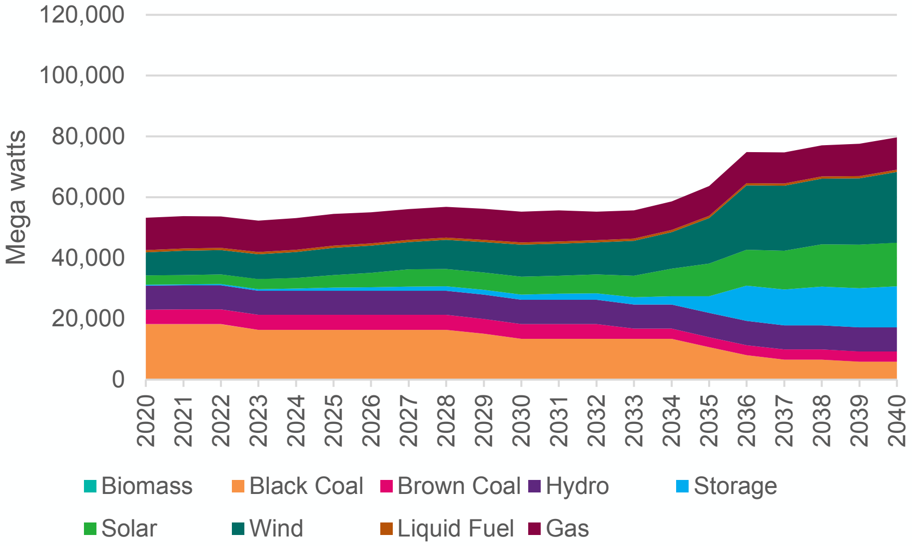
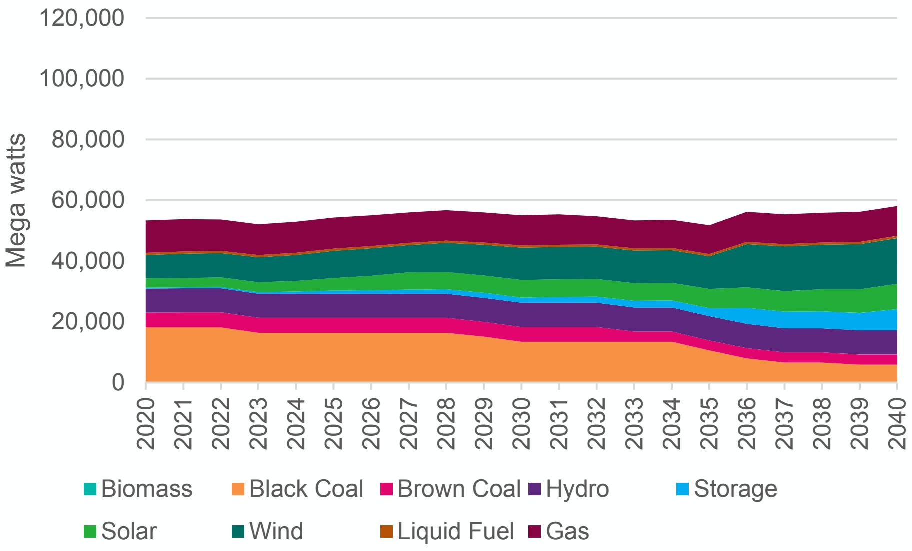


Figure 5 – Low Scenario Installed Capacity



9.3 Retirements

Retirements have been determined by the model based on the inputs provided. In general, retirement decisions are made as cheaper alternatives allow fixed costs to be avoided.

For brown and black coal, the model allows generators to undertake up to, but no more than, two refurbishments. The number and timing of refurbishment choices for each generator are presented in the assumption's workbook on the worksheet "Refurbishment". The number of refurbishments available to each has been determined by AEMO.

Investing in refurbishment will extend a generators operational life by ten years for each refurbishment until a technical 'end of life' date is reached. At that time, the model retires the generator from service. Should a refurbishment be found not to be economic by the model, the generator will retire at that refurbishment date. The cost of a refurbishment includes:

1. Refurbishment costs and
2. Consecutive six months outage for each unit of the power station.

The outcome of the refurbishment and retirement costs are presented below. In almost every case, investments were made to refurbish plant and extend the operational life to the maximum technical life.

The retirement of Torrens Island A has been assumed as an input to the model.

Table 4 – Central and Low scenario retirements in the Base Case

Generator	State	Registered Capacity (MW)	Financial Year Ending
Torrens Island A 1 - 4	SA	480	2021
Liddell	NSW	2,200	2023
Vales Point	NSW	1,360	2028
Gladstone	QLD	1,680	2029
Yallourn	Vic	1,480	2032
Eraring	NSW	2,880	2034
Bayswater	NSW	2,640	2035
Tarong	QLD	1,400	2036
Callide B	QLD	700	2038

The model was able to retire gas plant in South Australia. The following tables present the retirements in South Australian GPG in the base case across the three core scenarios excluding committed retirement of Torrens Island A.

Table 5 – South Australia GPG retirements in the High, Central, and Low scenario base case

Generators	State	Register Capacity (MW)	Scenarios		
			High	Central	Low
Osborne	SA	188	-	-	-
Pelican Point	SA	454	-	-	-
Torrens Island B1	SA	200	2025	2025	2022
Torrens Island B2	SA	200	2025	2031	2026
Torrens Island B3	SA	200	2026	2032	2031
Torrens Island B4	SA	200	2026	2033	2034

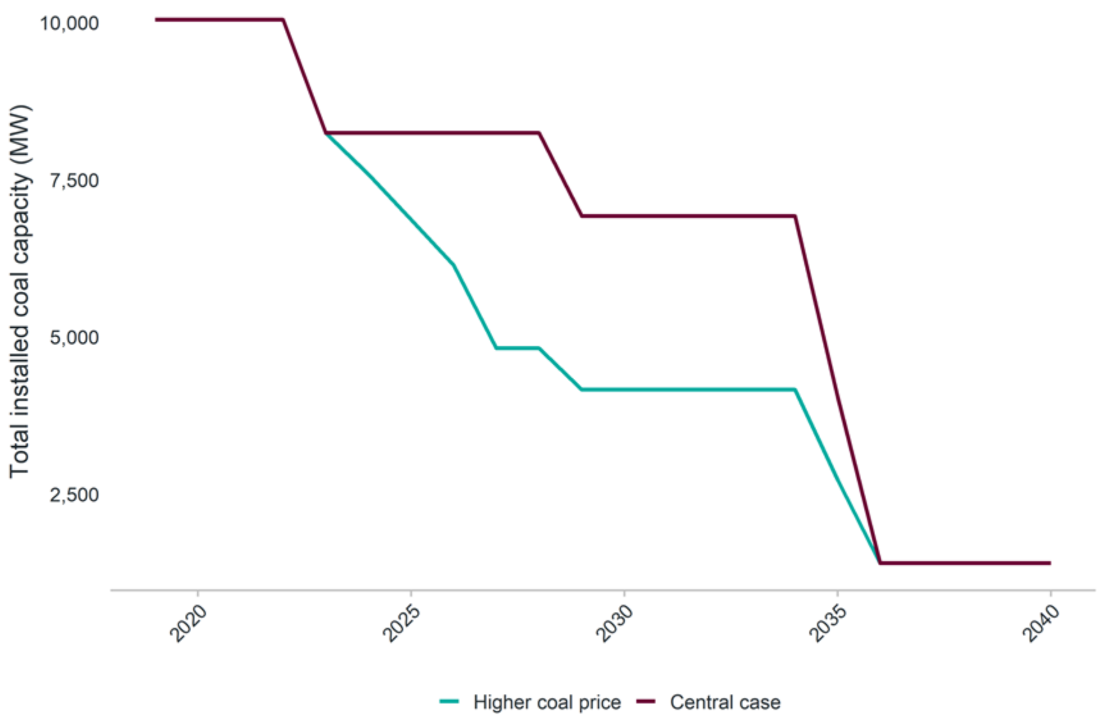
ElectraNet has also tested the sensitivity of the net market benefits to different retirement decisions. This has included the early retirement of Torrens Island B or the case where Pelican Point and Osborne do not retire following completion of the interconnector options.

ElectraNet has tested a high coal price in NSW which led to a faster retirement of NSW coal along with reducing the price gap between SA gas and NSW coal prices. The following table presents the retirement dates and identifies the increase in Short Run Marginal costs for the NSW black coal fleet in the base case. There preferred option had minimal impact on retirement of the coal fleet, delaying the retirement of Eraring unit 4 by 1 year.

Table 6 – Early retirement of black coal

Generator	State	SRMC ($/MWh)	Base case Financial Year Ending
Liddel 1-4	NSW	-	2022
Bayswater 1	NSW	65.4	2036
Bayswater 2	NSW	65.4	2036
Bayswater 3	NSW	65.4	2027
Bayswater 4	NSW	65.4	2027
Eraring 1	NSW	66.0	2035
Eraring 2	NSW	66.0	2025
Eraring 3	NSW	66.0	2035
Eraring 4	NSW	66.0	2025
Vales Point 5	NSW	66.9	2028
Vales Point 6	NSW	66.9	2023
Mount Piper 1	NSW	64.1	-
Mount Piper 2	NSW	64.1	-

Figure 6 - Early retirement of NSW Black coal



The removal of conventional generators creates a potential inertia deficit in the NEM. This is not a problem caused by consideration of the interconnector but represents a possible risk to modelled outcomes that are assuming major coal retirements across the NEM.

Whilst the replacement of firm capacity will involve some combination of generation sources, some of which do provide inertia (pumped hydro, solar thermal and gas generators), there will be a need to replace some inertia.

In testing the plausibility of a future without coal, ElectraNet have taken AEMO's inertia requirements[17] that would be required for islanded operation of each state. This is considered a worst-case situation as regions such as NSW would rarely operate as an island. The requirements are presented below in Table 7

Table 7 - Islanded inertia requirements

Region	Inertia – post contingency (MWs)	Inertia -Secure operation (MWs)
QLD	12,800	16,000
NSW	10,000	12,500
VIC	12,600	15,400

Inertia can be provided by several generation sources that are either currently a feature of the NEM or could potentially become a feature of the NEM over the modelling horizon. These sources include hydro, solar thermal and gas generators. As a result, some of the inertia can be expected to be made available anyway.

Alternative non-generation sources also exist. ElectraNet is procuring synchronous condensers in South Australia that will also provide inertia. Based on tender responses, the capital cost for inertia is around $35 thousand/MWs.

Scaling this up to a full replacement of the inertia requirement for secure operation of NSW as an island – 12,500 MWs - would have an annualised capital cost of around $30 million.

Comparing this charge to the costs of procuring 10,000 MWs inertia from the Bayswater units. Assuming

1. the full fixed annual charges of the power station of $145 million;

2. operating the plant at minimum load for the year and

3. that Bayswater recovers $60/MWh from the spot market requiring a top-up payment of $60 million per annum.

In total, to procure the inertia from a large coal unit in NSW would cost around $205 million total per annum.

Procuring the inertia from synchronous condensers appears plausible and cost effective in the long term and hence the retirement of the black coal fleet appears plausible.

[17] AEMO, *Inertia Requirements Methodology*, 2018

9.4 Distributed energy resources

Distributed energy resources are a growing source of supply options for the market, however some of these sources may not be controllable by the market operator (via bids or any other mechanism). This section describes the distributed energy resources assumed and identifies if the utilisation of these inputs is optimised by the market model.

9.4.1 Distributed PV

Distributed PV growth is based on AEMO's 2018 ISP inputs. The energy injection at each hour of the year is based on a single trace in each region. The trace is based on the solar renewable zone that was closest to the states regional reference node. For example, in South Australia this is the ADE trace for PV.[18] The contribution of distributed PV has been allocated to nodes across the NEM based on each node's contribution to state-wide energy demand. Known large industrial loads have been excluded from this process.

These inputs are not controllable by the market model. This input can lead to net demands that are less than zero.

9.4.2 Distributed batteries – controllable

The model has taken AEMO's ISP battery aggregation forecasts using the Neutral 45% forecast for the High and the Central. The Low is based on AEMO's Neutral 90% forecast.

The 45% and 90% aggregations are batteries, these have been located at the regional reference node. Placing all these at the regional reference node rather than distributing around the grid has reduced the number of storage objects to introduce, and hence has allowed the model to solve in a reasonable time frame. In practice, these batteries will be distributed around the grid.

The utilisation of these aggregations is optimised by the model. The remaining batteries are considered 'uncontrollable' and are described in the next section. The dispatch of these batteries is considered as load on the network and provides support for to demand effectively propping up minimum demand.

9.4.3 Distributed batteries – uncontrollable

Uncontrollable distributed batteries are utilised based on a daily input trace that specifies when they are injecting power or charging. The average nominal 1 MW profile is presented below. These batteries are located at the regional reference node. A positive number represents an injection of power into the grid. These assumptions are sourced from AEMO.[19] These batteries, when charging is considered load.

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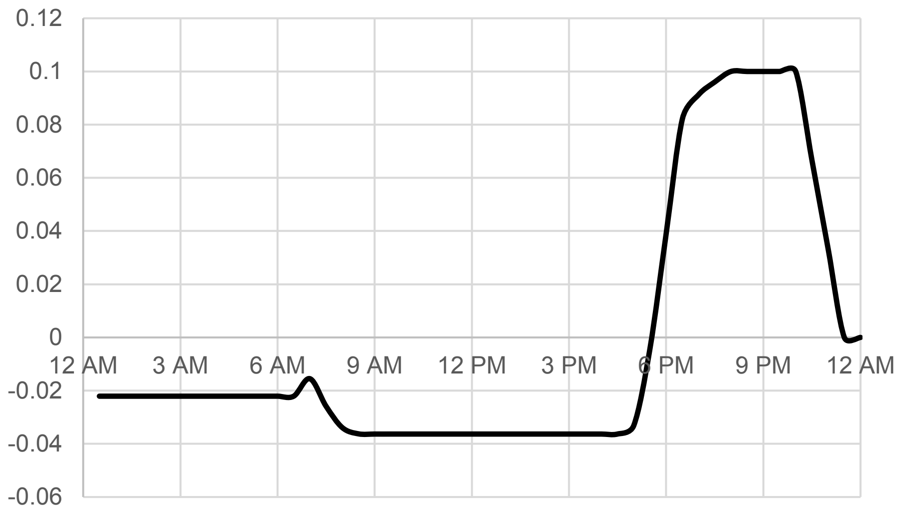
[18] Referred to as Fixed Flat Plate.

[19] AEMO, January 2018.

Figure 7 – Daily charge and discharge profile of uncontrollable distributed batteries.



9.4.4 Demand side participation

Demand side participation is aggregated at the regional reference node.

The SAET economic model does not make investments in demand side participation. The model is able to optimise the utilisation of demand side participation.

9.5 NEM cost outcomes

This section presents the range of cost outcomes in the base cases. This demonstrates the scale of the investment in the 'do nothing' base case required to meet the

- fixed operating costs of the existing fleet and new entrants;
- the variable costs of dispatching the existing fleet and new entrants; and
- the build cost of new entrant generation and storage.

The total range of costs of building and dispatching the NEM to 2040 presented in table 9 range from $73 billion in the low scenario to $106 billion in the high scenario.

Table 8 – Total NPV cost of each scenario ($ million)[20]

Fiscal Year Ending	Fixed costs	Variable costs	Generator and storage Build Costs	Transmission[21]	Total
High	34,609	43,670	26,219	1,187	105,685
Central	32,264	42,432	10,975	486	86,157
Low	31,417	35,595	5,761	165	72,938

9.6 Build limits

9.6.1 State-wide PV build limits

To manage the development of solar with sufficient accompanying firm capacity ElectraNet has required all new builds of solar to be accompanied by storage in South Australia. The storages that are included in the non-interconnector option: pumped hydro (150 MW) and two large batteries (150 MW each) are taken to relieve this constraint by 450 MW.

Table 10 displays the level of new build PV before storage is required at the regional level.

Table 9 - Regional solar PV build limits

State	PV limit without storage (MW)
South Australia	0
Victoria	300
Queensland	2,300
New South Wales	3,300

9.6.2 Annual solar build limits

ElectraNet has adopted annual solar build limits at the REZ level and nationally. Build limits reflect the markets capacity to add capacity to the network both from a market perspective to not over build capacity as well as to maintain a reasonably sized and highly skilled workforce.

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20 A 6% discount rate has been applied

21 AEMO, 2018. Transmission investment in the 'no interconnector' option.

Table 10 – Annual build limits

Resolution	
Renewable Energy Zone	500 MW
National	3,000 MW

9.7 Maintenances and forced outages

Maintenances and forced outages are modelled in the time sequential "short term" studies. Maintenance events (planned) are scheduled during high reserve margin periods (high generation capacity and low demand) and respect the required maintenance rates of each generator. Forced outages (unplanned) happen randomly based on the force outage rate of each generator.

In response to submission, maintenance rates also serve the purpose of reducing the capacity factors of coal plants. There are no other restrictions placed on the utilisation of black and brown coal plants.

9.8 Committed Generation

ElectraNet has assumed all committed generation as reported by AEMO as of July 2018.[22]

Since July, a number of additional plants have progressed to committed status, much of this is occurring within the Murray River Renewable energy zone that the preferred option will intersect.

The list of committed projects as at January 2019 that have not been included in the economic models of the NEM are presented below. This totals more than 1,000 MW of generation at or west of Wagga Wagga.

ISP assumed the transmission capability of the Murray River NSW REZ had no capacity to connect further renewables in the base case. This assumption has been applied to ElectraNet's models.

Following implementation of the preferred option, ElectraNet assumed the Murray River NSW REZ could connect another 800 MW of capacity.

The base case and the augmented case have been exceeded by the newly committed projects.

22 AEMO, Generator Information Page, July 2018.

Table 11 – South west NSW renewables not included in the economic models.

Generator	Location	Capacity (MW)
Bomen Solar Farm	Wagga Wagga	120
Darlington Point Solar Farm	Darlington Point	275
Hillston	Darlington Point	80
Finley Solar Farm	Wagga – Darlington Pt 132 kV loop	133
Limondale Solar Plant 1 & 2	Balranald	249
Sunraysia Solar Farm	Balranald	200

In addition to the south west NSW solar generators, the following list of solar projects in Victoria have also reached committed status but have not been included in the economic models.

10. Transmission

This section presents some of the transmissions assumptions that have been used in the SAET RIT-T.

10.1 Renewable Energy Zones

10.1.1 Long term REZ modelling

ElectraNet has modelled Renewable Energy Zones with the same input assumptions as published by AEMO as part of the inaugural Integrated System Plan.

The assumptions for each renewable energy zone include the following components:

1. A theoretical resource limit in MW across high and medium wind resources and solar resources.

2. The existing transmission capability limit, this tends to be significantly lower than the aggregate resource limit.

3. The nominal cost per MW that is required to be spent on transmission infrastructure in addition to the capital costs of generation for every MW in excess of the existing transmission network limit.

A simple hypothetical example for REZ A has the following parameters:

1. 1,000 MW solar capacity and no wind capacity;
2. Input traces representing time of day capability;
3. 200 MW transmission limit; and
4. $500,000/MW transmission build cost.

Hypothetical example 1, the model builds 200 MW of solar capacity in REZ A.

New solar capacity in REZ A does not exceed the existing transmission capability limit yet. There is no extra cost on upgrading the transmission infrastructure.

Hypothetical example 2: the model builds 700 MW of solar capacity in REZ A.

New solar capacity in REZ A exceeds the existing transmission capability limit by 700 – 200 = 500 MW. Extra cost of 500×$500,000=$250,000,000 is required to upgrade the existing transmission infrastructure. These costs are presented as annualised payments.

ElectraNet has adopted additional constraints in South Australia to reflect that the mid-north is a corridor that all other REZ developments will need to navigate in the base case should they exceed the limit of the mid-north.

The additional constraints are reflected in 18 additional constraints documented in the worksheet 'Build Limits'.

10.1.2 Time sequential REZ modelling

The time sequential model of the NEM includes a full representation of the transmission network. This required the REZ decisions of the Long-Term representation to be translated into a consistent Time Sequential network representation. This has been done by connecting zones to the regional reference node with imaginary lines that have losses of 5% assumed.

10.2 Region reference nodes

Table 12 - Regional reference nodes

State	Regional reference node
Queensland	South Pine (46020_4SPN275A_275)
New South Wales	Sydney West (20750_2SYW_S1_330)
Victoria	Thomastown (36854_3THO_66B_66)
South Australia	Torrens Island (55380_TIPS_66)
Tasmania	Georgetown (Georgetown 66kV)

10.3 Notional interconnector capabilities

The notional interconnector capabilities assumed are presented below. Notional limits on Victoria to New South Wales are higher in the short-term representation, noting that the short-term network representation will provide limits that the long-term representation does not reflect.

Table 13 – Notional interconnector capabilities in LT.

Interconnector	Export (MW)	Import (MW)
New South Wales to Queensland (QNI)	300	1,200
DirectLink (NSW to Qld.)	107	210
Victoria to New South Wales	700	400
Victoria to South Australia (Heywood)	650	650
Murraylink (Vic. to SA)	220	200
BassLink (Tas. to Vic.)	594	478

Table 14 – Notional interconnector capabilities in ST.

Option	Export (MW)	Import
New South Wales to Queensland (QNI)	300	1,200
DirectLink (NSW to Qld.)	107	210
Victoria to New South Wales	1,500	1,000
Victoria to South Australia (Heywood)	650	650
MurrayLink (Vic. to SA.)	220	200
BassLink (Tas. to Vic.)	594	478

10.4 Firm transmission capacity

Firm transmission capacity is only modelled into South Australia in the long-term representation. Firm transmission represents the capability of AC interconnectors into South Australia under a prior outage condition considering the next worse contingency which results in severing of a single path.

For example, in the base case the firm capacity is set under an outage of South East to Heywood. The next worst contingency is the loss of the remaining South East to Heywood line. In the presence of the preferred option, the firm capacity is set by assuming the same prior outage and contingency or a prior outage of Robertstown to Buronga to Robertstown for the loss of the remaining Robertstown to Buronga line.

The firm transmission limits modelled are presented in the Modelling and Assumptions report under the worksheet “Interconnector Firm Capacity”.

The effect of the firm transmission limits is to reflect the need for firm dispatchable capacity in South Australia.

10.5 Southern NSW

Southern NSW between Wagga Wagga and Sydney is an intra-regional limitation on flows of the preferred option and between NSW and Victoria. These constraints will also restrict the ability of the South Australia to New South Wales interconnector from accessing the Sydney load centre thereby restricting the benefits of the preferred option when flowing into NSW.

Constraints between Wagga Wagga and Sydney have been represented by the following outage and overload pairs in the model:

- Overload of Canberra – Lower Tumut for loss of Lower Tumut to Yass
- Overload of Canberra – Yass for loss of Canberra to Capital
- Overload of Canberra – Yass for loss of Dapto to Kangaroo Valley
- Overload of Lower Tumut to Upper Tumut for the loss of Canberra to Lower Tumut
- Overload of Marulan to Yass for the loss of the other Marulan to Yass
- Overload of Marulan to Yass for the loss of Capital to Kangaroo Valley
- Sydney West to Bannaby for the loss of Dapto to Sydney South
- Wagga – Jindera over load Wagga – Lower Tumut

In addition to these constraints, the presence of the upgrades between Darlington Point and Wagga are dual contingencies that manage the additional Darlington Point to Wagga circuit over loading the existing parallel circuit.

In general, constraints east of Wagga Wagga tend to experience minor congestion until 2034 as the typical direction of flow is into South Australia, and the thermal capability of the Darlington Point to Wagga Wagga (915 MW on the existing line) and the 330 kV exits from Wagga Wagga are higher again. The capability on the eastern side of the interconnector is greater than the notional capability of the Robertstown to Buronga section (notional 800 MW).

Following the retirement of Bayswater and Eraring congestion increases materially as New South Wales requires more interstate imports, southern NSW renewables and Snowy Hydro.

Note that the very rapid emergence of renewables along the path has not been accounted for in the economic models.

Table 15- Hours of binding congestion in Southern NSW

	2020-2034	2035-2040
Average annual hours of congestion in option C3.	58	2,565

Whilst material congestion is forecast to increase as the coal fleet retires, the rapid development of renewables along the corridor may hasten this congestion, bringing

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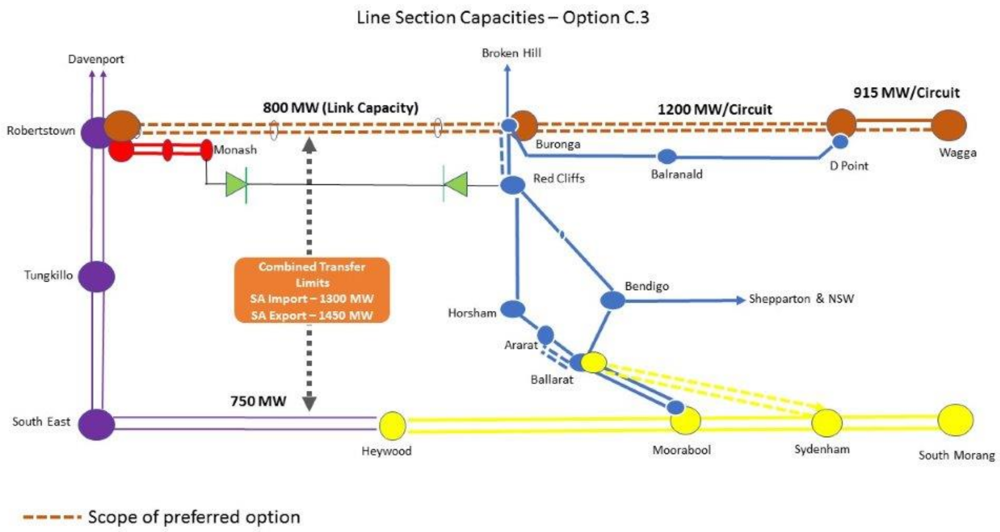
forward the future development of the Wagga Wagga to Sydney corridor. The generators not considered are discussed in section 9.8.

It is important to note, that whilst this congestion may increase faster than found in the SAET models, this will also be occurring in the base case. In the base case, the congestion can be expected to be shallow, that is it will occur between Balranald and Wagga. With the preferred option, this shallow congestion will be addressed – delivering a market benefit that has not been assessed - and the next point of congestion will be revealed, this will be west of Wagga Wagga.

Figure 8 –Line section capabilities of the preferred option



It is in this context that AEMO's Integrate System Plan and the NSW Government's Transmission Strategies are valuable.

The ISP identified the transmission developments required for Snowy 2.0 may independently strengthen the corridor between Wagga Wagga and Sydney. Longer term, development of a stronger Victoria to New South Wales interconnector may run through Wagga Wagga.

In November 2018, the NSW government released a transmission strategy identifying the Murray River NSW REZ as having the capability to connector 4,950 MW of renewables into Sydney from the Murray River NSW REZ centred on Hay.

Should either of these developments take place, the benefits of the preferred option would be increased.

10.6 Integrated System Plan

The Integrated System Plan has found the need for urgent group 1 projects and further group 2 and 3 projects that will occur at some distance into the future.

ElectraNet has assumed all group 1 projects in the base case.

ElectraNet has adopted only 1 group 2 project. This project is the augmentation of the Queensland to New South Wales interconnector with an estimated capital cost of $560[23] million. This project has the potential to be delayed by the Queensland to South Australia interconnector option and so is required in the base case.

ElectraNet has not assumed the SnowyLink North projects in the base case but has tested the benefits of the options with SnowyLink North in place. Snowy 2.0 is expected to improve the benefits of the preferred option by alleviating congestion between Canberra and Sydney which is identified as an emerging constraint if the preferred option is developed.

No other group 2 or 3 projects have been assumed or tested.

10.7 Ratings

Most ratings in the model are using static ratings. Where congestion has been observed to be material and additional information was available on ratings under different atmospheric conditions, a time base approach has been used to alter ratings.

In Victoria, where time-based ratings have been applied to lines experiencing congestion, the following assumption has been made based on seasons.

Ratings have been sourced from AEMO's ratings database.[24]

Table 16 - Victorian seasonal ratings

Season	Temperature assumed
Summer	35 degrees
Spring / Autumn	25 degrees
Winter	15 degrees

23 See https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity

24 http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Network-Data/Transmission-Equipment-Ratings