



SA ENERGY TRANSFORMATION RIT-T

Market Modelling Report

29 JUNE 2018

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Glossary of Terms

Term	Description
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 provides an overview of the National Electricity Market (NEM) modelling undertaken for the South Australian Energy Transformation (SAET) RIT-T.

The report needs to be read in conjunction with:

- the SAET RIT-T Project Assessment Draft Report;
- the Market Modelling and Assumptions Data Book (spreadsheet);
- Network Technical Assumptions Report;
- Consolidated non-interconnector option report (prepared by Entura); and
- Basis of Estimates report (capital cost estimates of options).

The intention of this report is to provide greater transparency and insights into ElectraNet's market modelling, with a focus on how the base case for three future scenarios investigated has been modelled. The methodology applied for the base case and the consideration of the various interconnector and non-interconnector options is the same.

The report documents input assumptions to the market modelling and the sources of these input assumptions.

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 considered are summarised in Table 1 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 broad enough 'envelope' of where these variables can reasonably be expected to fall.

Table 1 – Summary of scenarios considered

Variable	High scenario	Central Scenario	Low Scenario
Electricity demand (including impact from distributed energy resources)	AEMO 2018 EFI ¹ strong demand forecasts plus potential SA spot load development of 345 MW	AEMO 2018 EFI Neutral demand forecasts	AEMO 2018 EFI Weak demand forecasts
Gas prices – long term	\$11.87/GJ in Adelaide (\$1.68/GJ higher than the AEMO ISP strong forecast)	\$ 8.40/GJ (AEMO 2017 GSOO ² Neutral forecast; \$0.77 lower than AEMO ISP Neutral forecast)	\$7.40/GJ (\$0.62/GJ lower than the AEMO ISP weak forecast)
Emission reduction renewables policy – in addition to Renewable Energy Target (RET)	Emissions reduction around 45% from 2005 by 2030 (Federal opposition policy)	Emissions reduction around 28% from 2005 by 2030 (Federal Government policy)	No explicit emission reduction beyond current RET
Jurisdictional emissions targets	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030
SA inertia requirement – RoCoF limit for non-credible loss of Heywood Interconnector	1 Hz/s (International standard)	3 Hz/s (current SA Government requirement)	3 Hz/s (current SA Government requirement)
Capital costs	15% higher than central scenario	AEMO 2016 NTNDP with some updates from 2018 ISP.	15% lower than central scenario

3. Sources

We have predominately taken inputs from AEMO's 2016 National Transmission Network Development Plan (NTNDP) and the more recently published Integrated System Plan (ISP) assumptions workbook. Many of the NTNDP and ISP sources are derived from AEMO's collection of planning documents. More information can be found on AEMO's website. The inputs are collated in the Market Modelling and Assumptions Data Book (spreadsheet).

¹ AEMO National Electricity Forecasting Insights March 2018.

² AEMO Gas Statement of Opportunities December 2017, which drew on the gas price forecasts contained in the 2016 National Gas Forecasting Report. ElectraNet notes that this gas price is below the central gas price assumption of \$9.17/GJ adopted by AEMO in the ISP, and therefore represents a conservative assumption that can be expected to lower market benefits overall.

Table 2 below highlights the different sources of information for specific inputs.

Table 2 – Sources for modelling inputs

Summary	Description	Source
Effective LRET	Effective LRET, Green Power and ACT Scheme Trajectories	ISP
QRET	Queensland Renewable Energy Target ~50% by 2030	ISP
VRET	Victorian Renewable Energy Target ~40% by 2025	ISP
COP21 Emission Trajectory	28% and 45% Emission Reduction Trajectories	2016 NTNDP
Energy	Input sources of information and the outputs from base case economic modelling	2016 NTNDP, AEMO March 2018 EFI update
DSP	Lists assumed demand side participation	2016 NTNDP
Hydro Storage	Contains information regarding hydroelectric storage inflows	2016 NTNDP
Storage Initial Level	Initial hydro storage level	2016 NTNDP
Interconnector Capability	Lists forward and backward interconnector capability	2016 NTNDP
MRL	Minimum Reserve Level	2016 NTNDP
Max Capacity Factors	Maximum Capacity Factors	2016 NTNDP
Installed Capacity	Installed capacities for scheduled generators	2016 NTNDP, Generator Information Page December 2017
Build Cost	Capital cost for New Entrant generators	2016 NTNDP
Storage costs and properties	Capital cost for New Entrant large scale batteries	2016 NTNDP, Draft ISP assumptions
Announced retirements	Committed generator retirements	ISP
Retirement	Generator end of technical life and retirement costs	ISP
Refurbishment	Generator refurbishment costs, dates and supporting parameters	ISP
WACC	Weighted cost of capital for New Entrant generators	ISP
Coal Cost	Coal cost	2016 NTNDP, submissions
Gas Cost	Gas cost	2017 GSOO, ElectraNet, EnergyQuest
Heat Rates	Heat rates	2016 NTNDP

Summary	Description	Source
FOM	Fixed operating and maintenance cost	2016 NTNDP
VOM	Variable operating and maintenance cost	2016 NTNDP, ElectraNet
Emissions Rate	Emissions Rate	2016 NTNDP
Auxiliaries	Generator Auxiliary	2016 NTNDP
Min up and down times	Minimum operating and down times for coal plant	ElectraNet

4. Methodology

We have 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 to dispatch the NEM.

This approach is consistent with the requirements of the RIT-T published by the AER.³

This method leads to the most efficient dispatch outcomes 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 market 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 similar to 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 also 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 assessment.

Minimum Reserve Levels

The least cost expansion builds sufficient plant to meet the NEM reliability standard. We note that recent concerns that market prices will not result in the type of capacity needed to give assurance that reliability can be delivered 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 will support the needed investment.

ElectraNet has assumed a Minimum Reserve Level (MRL) within each region determined by AEMO. These are presented in the assumptions data book.

³ AER, Regulatory Investment Test for Transmission, 2010, paragraph 21

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 not see dispatch of the absolute lowest cost available generation at all times, but rather 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 our modelling will at times require generators in South Australia to be on line and providing inertia services in order to improve interconnector capability.⁴ These generators may not be the lowest cost generators operating at the time, but 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 occur in the NEM.

However, in dispatch, these interactions are expected to 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 in these circumstances 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. This will increase the benefits of greater interconnection with South Australia as greater interconnection removes the RoCoF constraint and increases the market’s capability to meet security constrained economic dispatch at lower costs.

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, we have recognised existing assumptions about continuous operation will no longer be valid, and have 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.⁵

A 12 hour shutdown period has proven to be sufficient 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.

⁴ Details of the constraints are in the Network Technical Assumptions Report, along with assumed inertia capability of South Australian generators.

⁵ This has not been applied universally due to interactions with other constraints most notably maximum capacity factor limits.

The 12 hours minimum downtime is a simplifying assumption we have made to ensure the forecast operation of the generation fleet matches our understanding of the capability of the fleet.

Other generator dispatch simplifying assumptions in the modelling include:

- Use of average heat rates;
- Excluding the impacts of generator wear and tear from rapid cycling of plant; and
- Excluding generator start-up costs.

These simplifying assumptions are expected to have the effect of reducing the cost of dispatching the market and therefore underestimating the potential market benefits of the options considered.

5. Long-term and short-term representations

Our economic model estimates the majority of the benefits of the different options considered in the SA Energy Transformation RIT-T. This model is split into two different representations to facilitate different considerations within the RIT-T framework and applies the appropriate resolution to perform these assessments while making the problems computationally tractable.

Long-term representation

The long-term representation models the effect of the options considered on long-term investment decisions required to meet the NEM Reliability Standard.

The model builds generation and energy storage (battery and pumped hydro) to ensure the Reliability Standard is met. Benefits of the options considered can be measured as a reduction in the cost of new entrant capital decisions and changes in fixed operating costs. Alternatively, the options considered can lead to an increase in the capital costs of new plant so long as this is offset by a greater reduction in the operating costs of the fleet.

The long-term representation includes input assumptions about future sources of supply with the model optimising future developments and operations around these inputs. However, the development of the future sources of supply is not fully optimised in the analysis.

The consequence is that optimisation of the costs of developing these resources is not included in the benefits of the options considered 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.

The long-term representation performs a least cost expansion of the grid out to 2040. The linear program solves across the horizon in one pass with perfect foresight.

Generator build decisions are treated as incurring annualised costs based on the 6% discount rate. Battery build decisions are treated as incurring the full costs including funding costs in the year that they are built.⁶ The costs of new build decisions are considered ‘over-night’.⁷

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:

- relevant inter and intra constraints;
- network losses; and
- diversity of renewables.

Tasmania is represented by a single node. Tasmania retains this 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 a further more detailed time-sequential optimisation of each day of the year is then undertaken. The short-term representation has access to generator sources that are determined in the long-term representation and does not make new generator 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).

Differences between long-term and short-term representations

The long-term and short-term representations use common electricity demand and generator operating cost inputs.

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.

⁶ This is a limitation of the software

⁷ The cost of build decisions are included from the time the generator or storage object is built. Costs would in fact begin to accrue two years before commercial operation.

That is, the model will not allow generators representative of renewable energy 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 treats demand as a load duration curve selecting 20 load blocks per month, including the minimum and maximum demand as two of these load blocks, while the short-term representation considers every hour of the year in sequence.

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

Differences between the long-term and short-term representations can be summarised as follows:

- the short-term representation includes all material intra-regional constraints on generation
- the short-term representation includes transmission losses in the optimisation of generator dispatch
- The long-term representation includes notional inter-regional constraints to the extent they are lower than the notional interconnector limits in the short-term representation due to constraints not specifically modelled in the long-term model.
- The short-term model has full renewable generation diversity whereas the long-term model takes the average output of the renewables for each load block.
- The long-term model aggregates demand to the regional reference node, whereas in the short-term demand is allocated at the transmission exit point.

6. Demand

Demand forecasts are based on AEMO's March 2018 publications. These will be updated to the 2018 ESOO figures before publication of the SAET PACR if the updated values demonstrate a material difference in either the range of the high and low forecasts or should the central forecasts move away from a 'flat' energy or demand growth forecast.

The demand profile is the time sequential demand given to the model. The profile is taken 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 demand profile.

The 2009-10 state demand profiles are "grown" to meet forecast maximum demand and annual energy consumption forecasts in each region 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 demand traces because they have been assumed to be unchanged over the time horizon based on recent history. Some loads have been treated as constant loads.⁸

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 and assumptions data book (spreadsheet) presents the ranges of energy demand inputs 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 is based on the PV forecasts from the 2016 NTNDP and the ISP aggregated distributed battery forecasts.

6.1 Maximum demand

The South Australian maximum demands presented below are the maximum demands as an output of the market modelling. They have been derived from AEMO's 50% POE demand forecast.

The range of South Australian maximum demands are presented below and demonstrate the range of futures considered.⁹ Interstate demands are not material to the SAET RIT-T outcomes and have not been included here.

Table 3 - 50% South Australian POE maximum demand by scenario

Fiscal Year	High	Central	Low
2019	2,885	2,541	2,266
2020	3,042	2,701	2,526
2021	3,093	2,720	2,594
2022	3,101	2,757	2,608
2023	3,025	2,656	2,523
2024	2,973	2,667	2,490
2025	2,998	2,643	2,520
2026	3,008	2,626	2,495
2027	2,935	2,583	2,465
2028	3,003	2,665	2,455
2029	2,896	2,540	2,396
2030	3,015	2,632	2,454
2031	2,875	2,520	2,390

⁸ Information relating to large loads across the NEM is confidential.

⁹ Note that the maximum demand recorded in South Australia is 3,413 MW on 31 January 2011

Fiscal Year	High	Central	Low
2032	3,045	2,621	2,523
2033	2,987	2,574	2,450
2034	2,935	2,501	2,396
2035	3,045	2,508	2,345
2036	2,966	2,529	2,317
2037	2,944	2,493	2,282
2038	3,014	2,530	2,307
2039	3,172	2,660	2,337
2040	3,115	2,561	2,307

6.2 Minimum demand

South Australia's minimum demand presented below is an outcome of the modelling taking into account 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 section 7.5 for more details.

Exogenous assumptions regarding growth in distributed batteries, as well as the model's development of energy storage is providing support for minimum demand. This demonstrates the range of minimum demands that have been tested by the SAET.¹⁰

Interstate minimum demands are not material to the SAET RIT-T and have not been included here.

Table 4 – South Australia's minimum demand (MW) by financial year and scenario

Fiscal Year	High	Central	Low
2019	977	678	578
2020	1,011	707	555
2021	1,000	713	553
2022	1,055	738	566
2023	994	647	446
2024	926	600	343
2025	905	579	375
2026	713	435	241

¹⁰ If storages, in particular the exogenous inputs to the model are to develop at a slower rate, minimum demands could reach zero around 2025

Fiscal Year	High	Central	Low
2027	829	413	265
2028	825	446	285
2029	775	422	178
2030	722	308	133
2031	764	411	94
2032	659	254	-13
2033	766	392	88
2034	752	306	18
2035	750	346	-26
2036	831	351	-78
2037	762	351	-139
2038	893	329	-44
2039	791	349	-94
2040	1,064	327	-5

7. Supply

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

7.1 Renewable energy targets

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

- 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

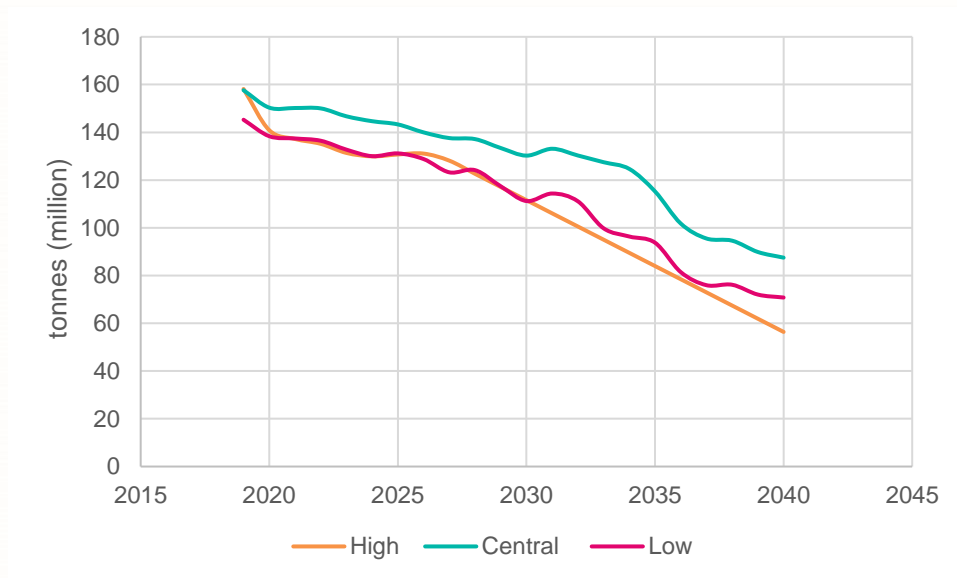
Due to the rapid increase in committed renewable projects and the inclusion of the Queensland RET and the Victorian RET, the National LRET is met in all scenarios.

7.2 National energy guarantee

The Federal Government is pursuing a National Energy Guarantee (NEG) to ensure Australia meets its international commitments. The NEG is assumed to have two limbs: an emissions reduction target and a reliability target. Two emissions reduction trajectories have been assumed with the Low scenario requiring no reduction – although as can be seen the low scenario results in material carbon emission reductions due to generator retirements and declining demand.

Details of the carbon emission reduction constraints can be found in the market modelling and assumptions data book. Carbon constraints are modelled as annual limits on carbon emissions. Emission outcomes in the base case for the three scenarios are represented in Figure 1 below.

Figure 1 - Carbon emission trajectories across the three base cases



The second limb of the NEG is a reliability guarantee. As the SAET economic model builds sufficient capacity to meet the NEM Reliability Standard, the NEG reliability limb has been implicitly met.

The NEG reliability limb will be further developed over the coming months, and we will update our modelling with the best information available before the Project Assessment Conclusions Report is published.

7.3 Installed capacity

This section presents the generator expansion outcomes for the base case in each scenario.¹¹ These outputs demonstrate the range of investment required across the NEM ranging from – a low level of capital investment 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.

Generator investment in the NEM is driven primarily by the replacement of retiring capacity. The high scenario in also results in further investment as a result of the stronger emission reduction targets. The cost of these investments are summarised in section 7.6.

¹¹ These results are drawn directly from PLEXOS and do not include assumed distributed energy resources.

Figure 2 – High Scenario Installed Capacity

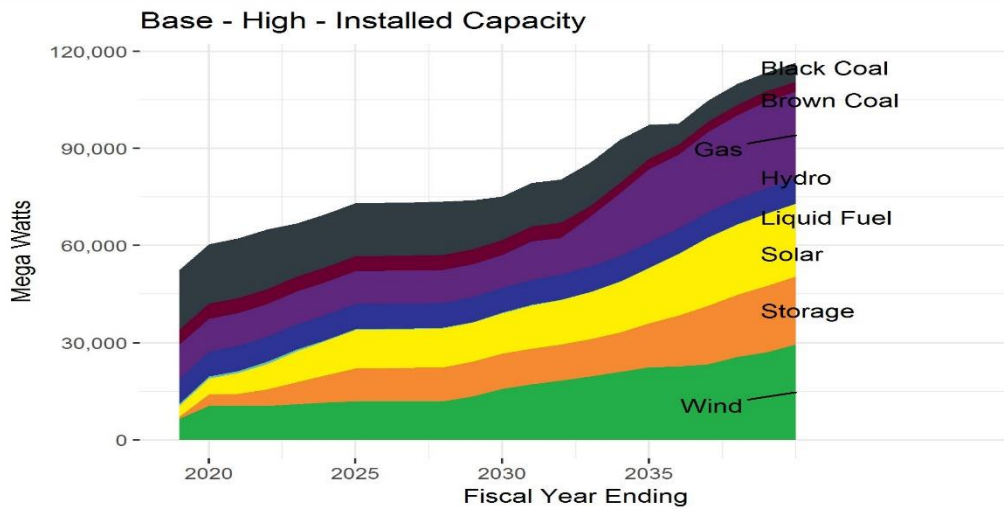


Figure 3 – Central Scenario Installed Capacity

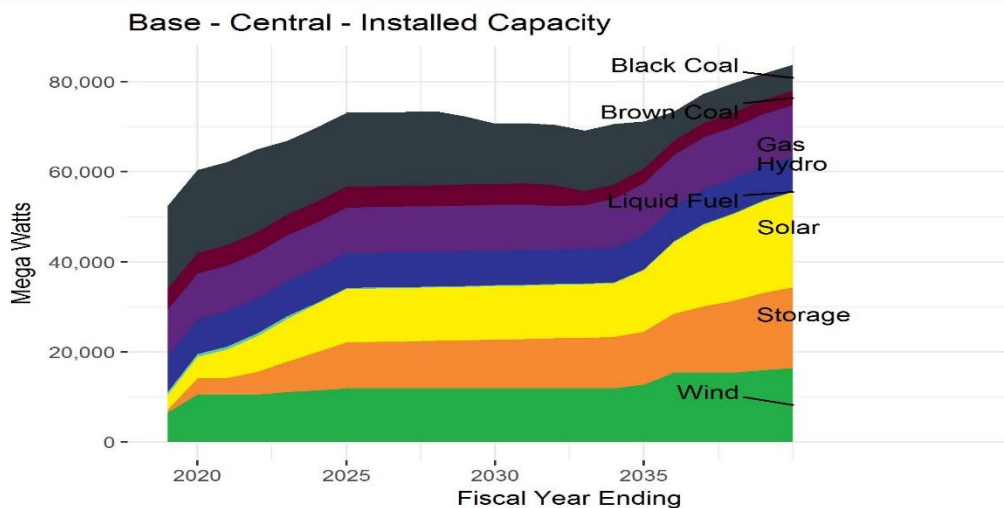
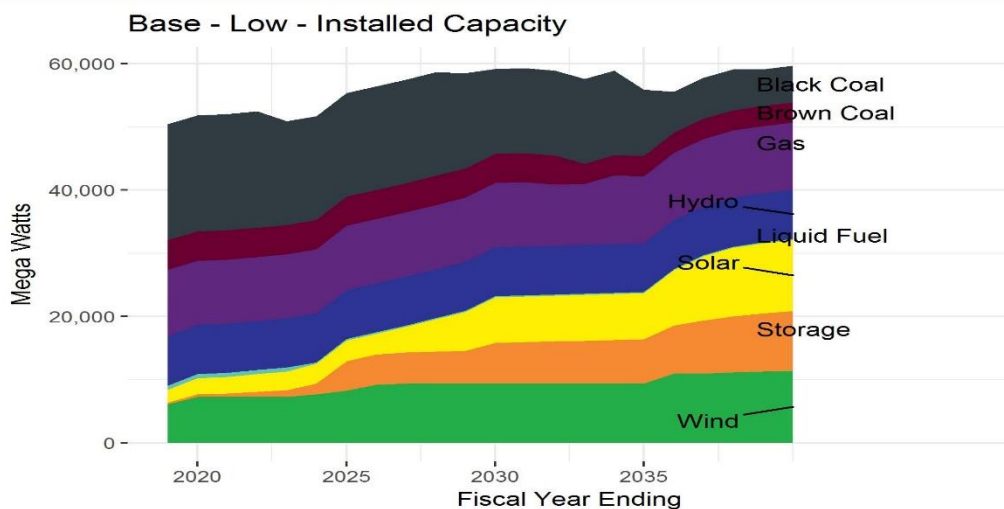


Figure 4 – Low Scenario Installed Capacity



7.4 Retirements

Generator retirements have been determined by the model based on the inputs provided. The inputs include the option to undertake up to, but no more than, two refurbishments. The number and timing of refurbishment choices for each generator are presented in the market modelling and assumptions data book.

The number of refurbishments available to each has been determined by AEMO subject to, amongst other things, the age of the plant.

Investing in refurbishment is assumed to extend a generator's 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:

- Refurbishment costs; and
- A consecutive six months outage for each unit.

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.

Table 5 – Central and Low scenario retirements

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 retirement of Loy Yang A has been assumed in the high scenario. Despite undertaking refurbishment, capacity factors were observed to be too low to expect that the refurbishment would be a viable decision.

Table 6 – Additional high scenario retirements

Generator	State	Registered Capacity (MW)	Date
Loy Yang A 1-4	VIC	2,250	2038

Taking into account the capacity factor of Torrens Island B power station, and as a response to submissions highlighting the effect of additional interconnection on the existing gas fleet, ElectraNet has assumed the Torrens Island B power station would retire with the commencement of a new interconnector.

This assumption has been applied uniformly across all interconnector options and does not impact on the choice of any particular interconnector option.

The market model does not choose to retire Torrens Island B power station for any option under any scenario or in the base case of any scenario.

Table 7 – Retirements as a result of increased interconnection

Generator	State	Registered Capacity (MW)	Date
Torrens Island B 1-4	SA	800	2023

7.5 Distributed energy resources

Disturbed energy resources are a growing source of supply 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.

7.5.1 Distributed PV

Distributed PV growth is based on AEMO's 2016 NTNDP 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.¹² The contribution of distributed PV has been allocated to nodes across the NEM based on the contribution of each node to state-wide energy demand. Known large industrial loads have been excluded from this process.

These inputs are not controllable by the market model and can lead to net demands that are less than zero as is the case for South Australia in the low scenario.

¹² Referred to as Fixed Flat Plate.

7.5.2 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 that are located at the regional reference node. The utilisation of these aggregations are optimised by the model.

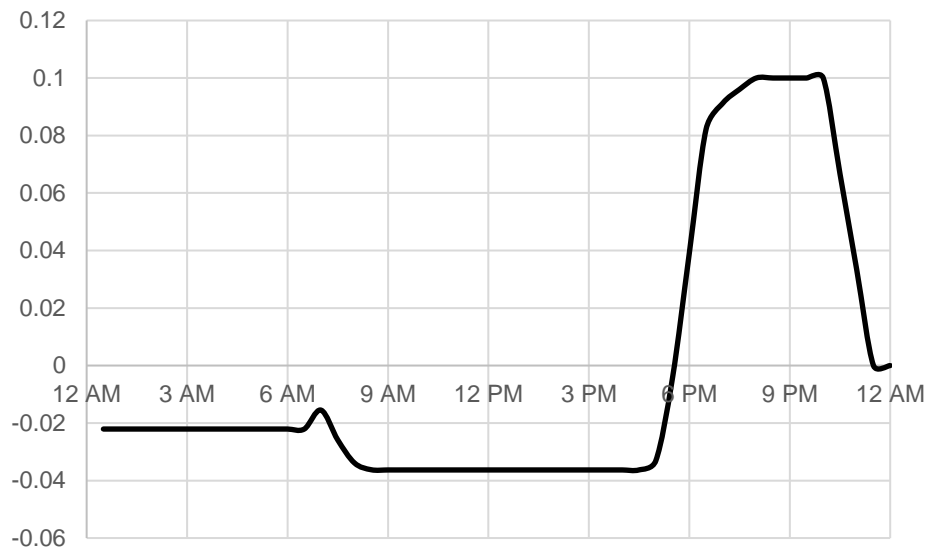
The remaining batteries are considered 'uncontrollable' and are described in the next section. The dispatch of these batteries is considered as load on the network and provides support for demand, effectively propping up minimum demand.

7.5.3 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.¹³ These batteries, when charging are considered load on the system.

Figure 5 – Daily charge and discharge profile of uncontrollable distributed batteries.



7.5.4 Demand side participation

Demand side participation is aggregated at the regional reference node.

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

¹³ AEMO, January 2018.

7.6 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 generation fleet and new entrants;
- the variable costs of dispatching the existing generation 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 ranges from \$78 billion in the low scenario to \$124 billion in the high scenario, as shown in Table 20.

Table 8 – Total NPV cost of each scenario (\$ million)¹⁴

Fiscal Year Ending	Fixed costs	Variable costs	Generator and storage Build Costs	Voluntary load curtailment	Transmission¹⁵	Total
High	35,066	50,268	38,172	34	682	123,540
Central	31,001	44,761	16,081	37	682	91,879
Low	30,476	34,978	12,224	12	682	77,690

Table 9 – High scenario annual cost (\$ million)

Fiscal Year Ending	Fixed costs	Variable costs	Generator Build Costs	Voluntary load curtailment	Storage build cost	Total
2019	2,670	3,587	190	2	112	6,562
2020	2,786	3,463	978	0	118	7,346
2021	2,779	3,495	978	0	0	7,252
2022	2,782	3,561	996	0	34	7,374
2023	2,686	3,893	1,087	0	92	7,757
2024	2,726	4,356	1,266	0	290	8,638
2025	2,808	4,221	1,748	0	1,605	10,382
2026	2,890	4,286	2,185	0	0	9,361
2027	2,956	4,506	2,537	0	0	9,999
2028	3,065	4,403	3,041	0	0	10,509
2029	3,107	4,374	3,557	0	0	11,039

¹⁴ A 6% discount rate has been applied

¹⁵ AEMO, 2018. Transmission investment in the ‘no interconnector’ option.

Fiscal Year Ending	Fixed costs	Variable costs	Generator Build Costs	Voluntary load curtailment	Storage build cost	Total
2030	3,103	4,241	3,885	0	0	11,229
2031	3,219	4,120	4,206	0	0	11,544
2032	3,266	4,399	4,464	0	87	12,217
2033	3,165	4,482	4,809	1	318	12,775
2034	3,267	4,518	5,137	2	374	13,298
2035	3,269	4,579	5,553	6	649	14,055
2036	3,200	4,895	5,853	10	457	14,416
2037	3,263	5,066	6,091	13	584	15,018
2038	3,379	5,111	6,375	13	546	15,425
2039	3,076	5,790	6,350	15	191	15,422
2040	3,183	5,980	6,051	45	140	15,399

Table 10 – Central scenario annual cost (\$ million)

Fiscal Year Ending	Fixed costs	Variable costs	Generator Build Costs	Voluntary load curtailment	Storage build cost	Total
2019	2,670	3,241	164	12	112	6,198
2020	2,727	3,186	524	3	142	6,582
2021	2,720	3,199	524	1	0	6,444
2022	2,724	3,239	541	1	93	6,598
2023	2,612	3,384	558	1	88	6,643
2024	2,633	3,435	634	2	240	6,944
2025	2,655	3,357	784	2	1,241	8,038
2026	2,692	3,416	956	1	0	7,065
2027	2,725	3,584	1,108	8	0	7,426
2028	2,767	3,552	1,216	6	0	7,541
2029	2,723	3,733	1,318	5	0	7,779
2030	2,662	3,736	1,413	5	164	7,979
2031	2,662	3,694	1,413	6	0	7,774
2032	2,646	3,786	1,413	3	0	7,847
2033	2,422	4,253	1,413	2	0	8,089
2034	2,433	4,431	1,430	0	2	8,295
2035	2,378	4,576	1,803	0	64	8,821
2036	2,393	5,258	2,425	2	283	10,360
2037	2,459	5,489	2,615	10	482	11,055

Fiscal Year Ending	Fixed costs	Variable costs	Generator Build Costs	Voluntary load curtailment	Storage build cost	Total
2038	2,526	5,142	2,722	6	366	10,762
2039	2,576	5,330	2,773	7	344	11,029
2040	2,646	5,169	2,624	4	229	10,673

Table 11 - Low scenario annual cost

Fiscal Year Ending	Fixed costs	Variable costs	Generator Build Costs	Voluntary load curtailment	Storage build cost	Total
2019	2,670	2,901	139	19	112	5,841
2020	2,724	2,850	432	3	49	6,058
2021	2,718	2,871	437	1	37	6,065
2022	2,722	2,906	452	0	93	6,174
2023	2,611	2,980	466	0	88	6,144
2024	2,635	2,973	547	2	290	6,447
2025	2,655	2,955	663	0	1,368	7,641
2026	2,692	2,994	809	0	0	6,496
2027	2,724	3,098	913	2	0	6,736
2028	2,765	3,115	1,004	1	0	6,885
2029	2,721	3,207	1,090	2	0	7,020
2030	2,660	3,073	1,171	2	379	7,285
2031	2,660	2,966	1,171	1	0	6,797
2032	2,645	2,921	1,171	0	0	6,737
2033	2,420	3,051	1,171	2	0	6,644
2034	2,425	2,929	1,171	2	1	6,528
2035	2,266	2,818	1,171	0	0	6,256
2036	2,212	3,027	1,505	0	99	6,843
2037	2,219	3,068	1,576	0	153	7,016
2038	2,253	2,838	1,643	0	72	6,805
2039	2,229	2,955	1,545	0	46	6,774
2040	2,246	2,912	1,336	0	33	6,527

7.7 Build limits

7.7.1 State-wide PV build limits

To manage the development of solar with sufficient accompanying firm capacity, we have required all new builds of solar to be accompanied by storage once certain regional limits have been reached.

Table 12 displays the level of new build PV before storage is required at the regional level. These constraints are applied across all scenarios and options.

These limits were determined from AEMO's 2016 NEFR 90% POE minimum demand forecasts. South Australia is forecast to experience negative grid demand within 10 years in the absence of major battery uptake and hence has a zero build limit before storage must accompany grid scale PV. Tasmania does not have a limit applied.

Table 12 - Regional solar PV build limits

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

7.7.2 Intra-regional build limits

Intra-regional build limits are applied to locational build decisions in the long-term representation. Intra-regional limits can be managed with coupling to local storage until a firm build limit is reached.

The original source of these limits is the 2016 NTNDP. These limits have been amended via a process of iteration between the long-term and short-term representation to ensure that, in general, capacity factors of generators in the short-term representation approach those in the long-term representation. The build limits are influenced by the effects of shallow and deep congestion limits. Some of these limits are relaxed when interconnector options are considered.

Build limits in some instances have been further refined in accordance with the ISP assumptions.

Build limits have been determined where generation builds in the long-term model have not had sufficient intra-regional access to achieve a capacity factor in the short-term representation that was achieved in the long-term representation.

Table 13 – Intra-regional build limits – these do not apply to committed generators

NTNDP Zone	Limit without storage (MW)	Limit with storage (MW)
NQ	250	1,250
SWQ	300	1,300
CAN	1500	2,500
NNS	300	1,300
SWNSW	0	500
SWNSW - (upgrade)	800	1,800
CVIC – Red Cliffs	300	1,300
CVIC – Horsham	0	1,000
CVIC – Horsham (upgrade)	600	1,600
CVIC – Terang	800	1,000
MEL	800	2,800
LV	82	1,100
NSA	500	1,000

8. Transmission

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

8.1 Region reference nodes

The regional reference nodes used in the market modelling are shown in Table 14.

Table 14 - 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)

8.2 Notional interconnector capabilities

The notional interconnector capabilities assumed are presented below.

Notional limits on the Victoria to New South Wales interconnector 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 15 – Notional interconnector capabilities in LT.

Interconnector	Export (MW)	Import (MW)
Queensland to New South Wales (QNI)	300	1,200
DirectLink	107	210
Victoria to New South Wales	700	400
Victoria to South Australia (Heywood)	650	650
Murraylink	220	200
Basslink	594	478

Table 16 – Notional interconnector capabilities in ST.

Option	Export (MW)	Import
Queensland to New South Wales (QNI)	300	1,200
DirectLink	107	210
Victoria to New South Wales	1,500	1,000
Victoria to South Australia (Heywood)	650	650
Murraylink	220	200
Basslink	594	478

8.3 Integrated System Plan

Under the high scenario, the 45% emissions reduction effectively creates an energy limitation in the model on the remaining brown and black coal in the NEM that becomes material from 2035 to 2040, particularly in New South Wales. Meeting the reliability standard in the short-term representation becomes heavily reliant on effective storage optimisation and additional network access between New South Wales and Queensland and Victoria in the base case.

We have assumed some network development in the high base case (and for all network options) to allow greater transfers into New South Wales. Growth in demand, major NSW coal retirements, carbon emission limits across the NEM, coupled with the build limits on renewables in NSW have required some increases in transmission in NSW.

These developments include strengthening QNI between Bulli Creek and Liddell by 2023 and strengthening southern NSW network between Wagga and Sydney West by 2035.¹⁶

8.4 Transmission line ratings

Most line ratings in the model are 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 for a more accurate representation of 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.¹⁷

Table 17 - Victorian seasonal ratings

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

¹⁶ These upgrades have been modelled on the AEMO's ISP.

¹⁷ <http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Network-Data/Transmission-Equipment-Ratings>