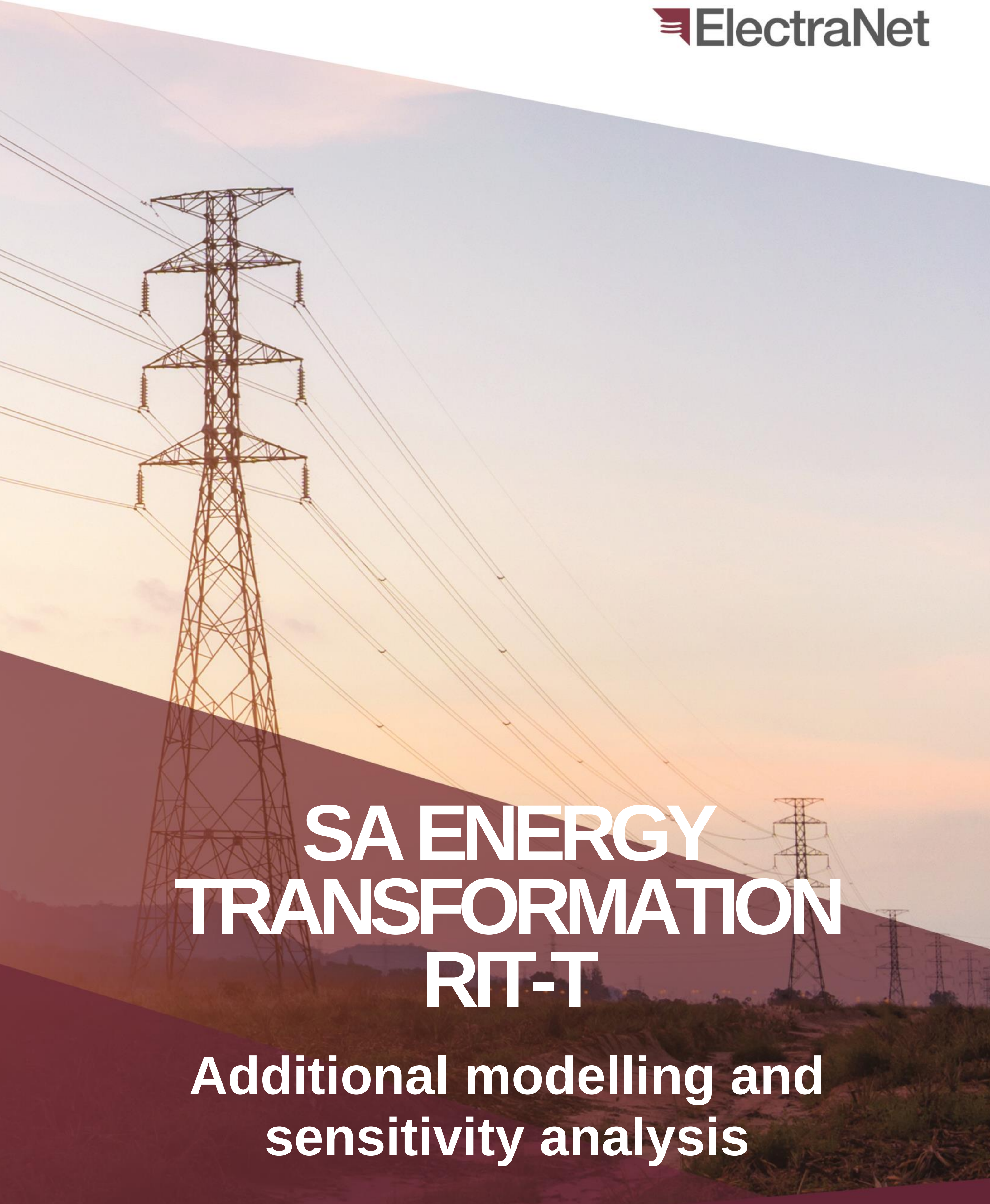


SA ENERGY TRANSFORMATION RIT-T

Additional modelling and sensitivity analysis

16 January 2020

Revision Record

Date	Version	Description	Author	Checked By	Approved By
31 October 2019	1.0	Draft submitted to the AER	P Rositano	B Harrison S Appleby	R Korte
16 January 2020	2.0	Final submitted to the AER	P Rositano	B Harrison S Appleby	R Korte

Executive Summary

ElectraNet has applied the Regulatory Investment Test for Transmission (RIT-T) and published the SA Energy Transformation Project Assessment Conclusions report (PACR) on 13 February 2019. This assessment identified a new high-capacity 330kV interconnector between South Australia and New South Wales (Project EnergyConnect) as the preferred option to meet the identified need.

On 5 June 2019, the AER formally commenced its determination process on whether the preferred option identified in the PACR satisfies the RIT-T. As part of this determination process, we have worked with the AER to perform a range of updated and additional sensitivity analysis to 'stress test' the results presented in the PACR.

We have updated the PACR central scenario results to reflect the latest AEMO Integrated System Plan (ISP) planning assumptions and the final form of ElectraNet's project to install synchronous condensers in South Australia, based on information that was available prior to publishing the PACR, but not in sufficient time to be incorporated in the final analysis. These results confirm the substantial economic benefits of Project EnergyConnect to customers.

The updated central scenario demonstrates increased net present value benefits of over $1.3bn compared to the $765m reported in the PACR for the central scenario. Key changes driving increased benefits include higher gas prices and the impact of the commitment of renewable energy projects along the proposed interconnector route. AEMO has concluded consultation with stakeholders on these changed ISP planning assumptions in preparation for the 2020 ISP.

As part of its determination process, the AER has 'stress tested' the PACR outcomes by requesting ElectraNet run additional sensitivity studies that materially change the operation of gas plant in South Australia. These sensitivity cases are largely based on combinations of factors already examined individually in the PACR. These sensitivities result in generation output profiles that have annual gas consumption dropping immediately by around 75% compared to historical usage – this is not considered a credible outcome. Adopting the AER's 'stress test' sensitivity inputs for gas plant in South Australia is also not aligned with advice from AEMO and the inputs AEMO has consulted on and is planning to adopt for the 2020 ISP. This reinforces the extreme nature of this 'stress testing'.

Notwithstanding this, the AER 'stress test' sensitivities still deliver positive benefits and are therefore consistent with the outcome of the PACR – the benefits remain robust even if costs were to substantially increase compared to the PACR by up to about 30 per cent.

On a more balanced view than the AER 'stress test' sensitivities, the updated PACR central scenario demonstrates the project economic benefits are substantial and remain positive for a much wider range of cost outcomes.

The additional analysis undertaken reinforces the outcomes of the PACR and provides increased confidence and assurance regarding the economic benefits of Project EnergyConnect.

In addition, a range of benefits that are not material to selection of the preferred solution have not been quantified in the RIT-T assessment. Amongst other things, these include competition benefits, Frequency Control Ancillary Service (FCAS) benefits and the support Project EnergyConnect provides to further renewable investment.

While required to be considered on a stand-alone basis, Project EnergyConnect is also strongly complementary to the other priority projects identified in the ISP and would deliver even greater benefits when combined with projects such as HumeLink, which would reinforce the network deeper into New South Wales and further improve power transfer capacity with Sydney.

Contents

1. Introduction

ElectraNet published the SA Energy Transformation (SAET) Regulatory Investment Test for Transmission (RIT-T) Project Assessment Conclusions Report (PACR) on 13 February 2019.[1]

On 5 June 2019, the Australian Energy Regulator (AER) formally commenced its consideration of our request to make a determination that the preferred option identified in the PACR satisfies the RIT-T.[2]

The preferred option identified is a new 330 kV interconnector between Robertstown in South Australia and Wagga Wagga via Buronga in New South Wales, with a link from Buronga to Red Cliffs in north west Victoria (identified as Option C.3 in the PACR). The PACR found that this option would deliver substantial economic benefits to customers and the broader Australian economy as soon as it can be implemented.

We have undertaken extensive engagement with the AER to share and discuss market modelling results as part of our early engagement activities since May 2018.

The AER has requested that we perform additional market modelling and sensitivity analysis to stress test the results presented in the PACR. To address this request, we conducted the additional sensitivity analysis set out in this report, which has been developed in consultation with the Australian Energy Market Operator (AEMO) and has been guided by discussions with the AER.

Consultation with AEMO has included advice on the extent to which changes to certain market modelling inputs are credible, based on its modelling of the 2018 Integrated System Plan (ISP) and with reference to AEMO's report to the AER of 9 August 2019, *Assumptions for South Australian GPG in the 2018 Integrated System Plan*.

The purpose of this report is to set out the results of our additional modelling and sensitivity analysis. We may also publish the report or an abbreviated form of the report to supplement the already comprehensive information published with the PACR for the information of customers and broader stakeholders.

1 ElectraNet, SA Energy Transformation RIT-T Project Assessment Conclusions Report, 13 February 2019.

2 Our determination request, in accordance with clause 5.16.6 of the National Electricity Rules (NER) is available on the AER's website at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-sa-energy-transformation-regulatory-investment-test-for-transmission-rit-t.

2. AER sensitivity testing

On 21 June 2019, as part of its RIT-T review process, the AER requested we perform additional market modelling and sensitivity analysis to stress test changes to several key modelling inputs. The request included variations to multiple key modelling inputs for both the base case and the preferred option under the PACR central scenario. We consulted AEMO to assist in assessing the credibility and reasonableness of these variations, as described in section 1, which informed subsequent discussions with the AER. Having taken into account AEMO's advice, the specific variations to modelling inputs requested by the AER, as amended through subsequent information requests, are set out in Table 1 below.

Table 1: Variations to key modelling inputs requested by AER

Item	Requested variation in modelling input
1	**Minimum capacity factors** Remove minimum capacity factors on South Australian gas plant in both the short term and long-term models.
2	**Gas plant cycling and generator minimum load assumptions** Thermal plant cycling assumptions for gas plant should be based on assumptions from the "Fuel and Technology Cost Review – Data" published alongside the 2018 ISP and applied NEM-wide or removed, with the following exception: • a minimum on/off time of 4 hours for Torrens Island B power station, consistent with cycling assumptions for Pelican Point and Osborne power stations. Generator minimum load assumptions to be based on AEMO 2018 ISP modelling assumptions, and no additions to be made unless sourced and applied to all generators of the same type, with the following exceptions: • a minimum load of [redacted] for Pelican Point power station consistent with its approved Generator Performance Standards (GPS). • a minimum load of [redacted] for Osborne power station consistent with the input currently assumed for AEMO's 2019/20 ISP.
3	**Plant investments and retirements** No plant investments or retirements should be imported from other modelling results (e.g. SA gas plant retirements). Exogenous closures should be based on end of life dates as published by AEMO.
4	**Synchronous condensers and system security constraints** The modelling should account for 4 synchronous condensers being in place at their anticipated installation date and any other system security constraints should be appropriately adjusted (e.g. the non-synchronous cap).
5	**Coal prices for export-exposed black coal generators** Export-exposed black coal generators should adopt the ISP 2018 Central estimate of new entrant coal prices (netback) sourced from the 2018 ISP database, Central estimate for new entrants. Export-exposed black coal generators include Bayswater, Liddell, Eraring, Mt Piper, Vales Point B, Callide B, Callide C, Gladstone, and Stanwell.
6	**Pumped hydro costs** Pumped hydro capital costs of \$1.9m/MW for South Australia based on the updated assumptions contained in the Entura report released in December 2018.

The AER requested that we perform the following modelling runs based on these variations as follows:

- AER Sensitivity 1 - that tests variations 1-5 above together but excludes updated pumped hydro costs (item 6);
- AER Sensitivity 2 - that tests variations to 1-4 above together but excludes variations to coal prices for export-exposed black coal generators (item 5) and updated pumped hydro costs (item 6);
- AER Sensitivity 3 – that tests the impact of all variations together.

The AER stated that the modelling period should begin in 2019 and the relevant states of the world under each modified scenario should include (and demonstrably meet) carbon constraints as modelled for the PACR.

The AER also requested that any additional changes made to the modelling inputs since publication of the PACR, as a result of implementing the variations requested in Table 1 or otherwise, be itemised.

3. Consideration of requested changes to key modelling inputs

Each of the variations to key market modelling inputs that appear in Table 1 above are discussed in turn below, together with the basis of the original inputs and range of sensitivity analysis presented in the PACR.

Section 4 that follows sets out the way in which we have applied the combination of varied modelling inputs requested by the AER, including any modifications required to maintain credible inputs, as supported by AEMO advice.

3.1 Minimum capacity factors

The PACR market modelling includes minimum annual operating levels of South Australian gas plant generally consistent with the 2018 ISP, published in July 2018.

These operating levels are represented as minimum annual capacity factors which were introduced in response to several submissions to our Project Assessment Draft Report (PADR), published in June 2018, which raised questions about the assumed timing of the retirement of gas-fired plant in South Australia in the PADR modelling.[3]

In the PACR, generator input assumptions were aligned with the 2018 ISP to better reflect the historical operation of plant and key system security, operational and fuel supply considerations relevant to gas fired generation in South Australia based on detailed integrated modelling by AEMO. For instance, the use of short run marginal cost (SRMC) bidding in the PACR model without minimum capacity factors on SA gas plant results in significant and sustained underutilisation of these generators when compared with historical utilisation rates and expected real world outcomes. This is not considered to be a realistic or credible market outcome.

For completeness, the PACR included a sensitivity test which removed minimum capacity factors on South Australian gas plant.[4] This is a highly conservative assumption given that aggregated historical gas usage by this plant is around 4 times higher than the usage assumed under this sensitivity (as shown in Figure 23 of the PACR). Nevertheless, the preferred option continued to deliver the highest net market benefit ($209 million in net present value terms) under this sensitivity.

We have updated Figure 23 of the PACR to include the actual gas usage of SA gas plant for the 2018-19 financial year. This is presented in Figure 1 below.

[3] The PADR modelling largely used assumptions from AEMO's prevailing National Transmission Network Development Plan (NTNDP).

[4] See section 8.5.3 of the PACR.

Figure 1: Aggregate gas usage for SA GPG under the base case

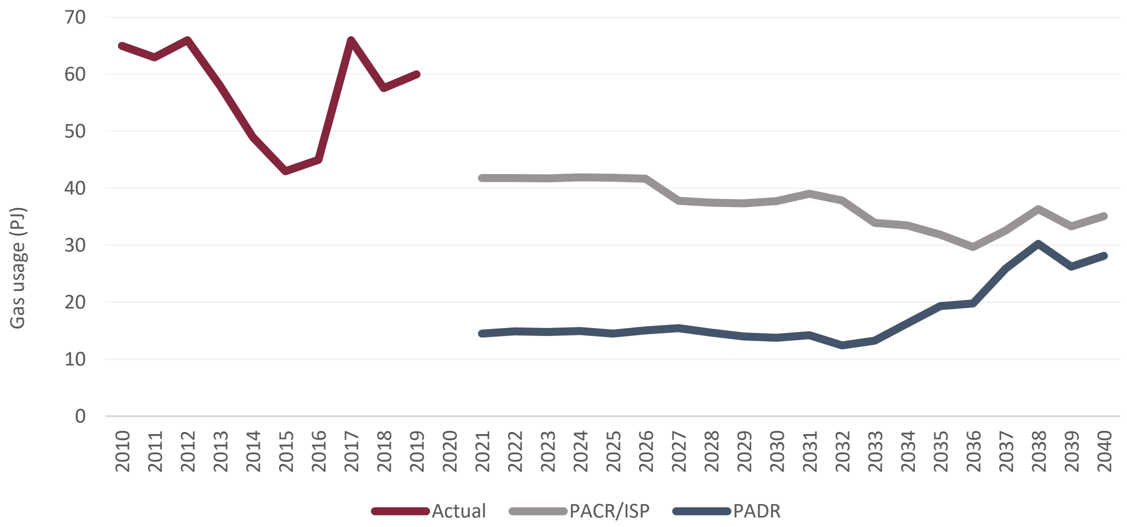


Figure 1 shows that the actual gas utilisation of SA gas powered generation (GPG) under the base case remains significantly higher than that assumed in both the PADR and the PACR/ISP.

In fact, despite the inclusion of minimum capacity factors on SA gas plant, the PACR modelling already results in a reduction in the energy usage of SA gas plant in 2019-20 of 30% when compared with actual gas usage in 2018-19. Usage trends indicate this is already a conservative assumption that leads to underestimating the market benefits of the preferred option.

The more extreme sensitivity analysis presented in the PACR that removed these capacity factors was undertaken to demonstrate that, irrespective of the reasonableness of completely removing minimum capacity factors on SA gas plant, this did not alter the PACR finding that Option C.3 was the preferred option and continued to deliver a significant net market benefit.

Discussions in early July 2019 between ElectraNet, the AER and AEMO have developed further understanding that completely removing the SA gas plant minimum capacity factors does not represent a realistic or credible state of the world.

AEMO has advised the following[5]:

- Minimum annual utilisation rates of 60% for Osborne Power Station, 50% for Pelican Point Power Station and effectively a minimum capacity factor of 20% for Torrens Island[6] were assumed by AEMO in its 2018 ISP.

5 AEMO, *Assumptions for South Australian GPG in the 2018 Integrated System Plan,* August 2019, p. 8-10.

6 The operation of Torrens Island was managed through a minimum operation constraint of 160 MW, equivalent to a 20% capacity factor.

- AEMO analysed the historical dispatch profiles of these power stations while also validating outcomes against a broader set of criteria for these units (reflecting minimum operating levels and system security requirements) to arrive at these minimum utilisation rates based on a 64% and 42% capacity factor being recorded for Osborne and Pelican Point power stations respectively over the two financial years ending 2017 and 2018.

AEMO further advised that it is essential to include minimum capacity factors, in addition to minimum load constraints, in economic modelling to adequately represent the physical constraints present in the gas and electricity systems. AEMO's ISP modelling reflected the expected real-world conditions of SA gas plant that result either through the operation of the market or through AEMO's direction of synchronous generation for system strength, inertia and frequency control in the event of islanding.[7]

For the reasons stated above, we do not consider the complete removal of minimum capacity factors applied to SA gas plant would result in a realistic representation of real-world limits. This is consistent with the conclusion reached by AEMO when modelling its 2018 ISP.

The way we have treated capacity factors to address the sensitivity sought by the AER is explained in section 4.1 below.

3.2 Gas plant cycling and generator minimum load inputs

3.2.1 Gas plant cycling

In response to submissions to the PADR, we updated the wholesale market modelling assumptions included in the PACR to consider the cycling of gas generators in order to capture the minimum run up and run-down times to which the plant can physically operate.

As set out in Table 1, the AER has requested that gas plant cycling assumptions be drawn from the "Fuel and Technology Cost Review – Data" ("2014 ACIL Allen dataset") published alongside the 2018 ISP, and be applied NEM-wide or removed.[8] AEMO's 2018 ISP database states that this data was sourced from ACIL Allen in 2014 (based on its assessment of AEMO's NTNDP dataset).

For comparison we have compared the gas plant cycling assumptions included in our PACR modelling with the 2014 ACIL Allen dataset on a NEM-wide basis and note several significant differences. The most significant differences relate to minimum plant up and down times for SA gas plant as presented in Table 2 below.

7 AEMO, *Assumptions for South Australian GPG in the 2018 Integrated System Plan,* August 2019, p. 6.

8 This data is available on AEMO's website at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan/ISP-database. Alongside the link which attaches this data, AEMO states that some of the properties for existing generators included in this dataset are used in the 2018 ISP, unless they are included in planning studies, in which case the properties for planning studies take priority.

Table 2: Modelled cycle times for SA gas plant

Station	PACR		2014 ACIL Allen Dataset	
	Min. up time	Min. down time	Min. up time	Min. down time
Osborne	24	12	4	4
Pelican Point	24	12	4	4
Torrens Island A	24	12	1	1
Torrens Island B	24	12	1	1

The minimum up and down times for SA gas plant used within our PACR modelling were chosen to represent reasonable estimates based on historical behaviour.

We consider that a reduction in these values would result in unrealistic generator behaviour in our wholesale market modelling that is inconsistent with historical behaviour and the physical constraints of the plant.

For example, the reduced values that appear in Table 2 are expected to result in an unrealistic number of generator starts, in particular, for Torrens Island Power Station which may exceed 10 starts in a single day. This is not a practical or realistic outcome. A significant increase in starts and stops will also increase generator wear and tear and the associated increase in costs is not currently captured by our market model.

To assist in assessing the reasonableness of these values, we obtained advice from GHD, who were engaged by ACIL Allen Consulting to review generator technical parameters and capital cost estimates for the 2014 Fuel and Technology Cost Review, including cycling times for gas plant.[9]

The final report for this review acknowledged that, in consultation with AEMO, it was decided to remove “Minimum on/off times” from scope and instead allow ACIL Allen and GHD to estimate these values via industry survey.[10]

GHD advised that the reported minimum on/off times should not be used to inform long-term network planning due to the complexity of the decision making involved to start and stop plant at an operational level. Whilst plant may be physically capable of cycling as reported, the increased costs associated with adequately maintaining plant to allow such operation mean most plant are not operated in this manner in practice. For example, most maintenance programs are defined with reference to hours of operation and/or number of starts (where one start is often equivalent to a specific number of operating hours).

Therefore, we consider GHD’s advice supports our view that the cycling times for gas plant used in the PACR modelling represent a more reasonable and realistic set of assumptions than those presented in the 2014 ACIL Allen dataset for market modelling purposes.

[9] ACIL Allen Consulting, Fuel and Technology Cost Review – Final Report, 10 June 2014, p. 29.
[10] ACIL Allen Consulting, *Fuel and Technology Cost Review – Final Report*, 10 June 2014, p. 3.

However, as explained in section 4.2, for the purposes of the sensitivity tests described in section 2 above, we have adopted the ACIL Allen cycling assumptions for all plant except Torrens Island B power station, for which we have used a 4-hour minimum on/off constraint consistent with that for Pelican Point and Osborne power stations, as requested by the AER.

3.2.2 Generator minimum loading

The PACR sourced, in the first instance, all available minimum load information from the 2018 ISP. Minimum load assumptions are used to represent the minimum stable output levels at which generating plant can physically operate. Where information required for the modelling was not available in the ISP dataset, ElectraNet referred to GPS data and cross-checked these values against market outcomes and relevant advice from plant operators.

We understand that the ISP inputs and assumptions dataset published by AEMO did not apply minimum loads for Osborne and Pelican Point power stations in calculating market benefits. For Torrens Island B the dataset published by AEMO included a station-wide minimum loading limit of 160 MW (equivalent to 40 MW for each of the four units).

For the purposes of the PACR modelling, we therefore sourced a minimum load value of [redacted] for Osborne directly from its operators (in a confidential submission dated February 2017) and calculated minimum loads for Pelican Point using GPS data prevailing at the time of the PADR, adjusted based on historical observation.

The minimum loads for Osborne, Pelican Point and Torrens Island B power stations as applied in the PACR modelling are presented in Table 3 below.

Table 3: Minimum loads for SA gas plant included in the PACR

Station	Minimum load (MW)
Osborne	[redacted]
Pelican Point	[redacted]
Torrens Island B units 1-4	40

The February 2017 submission from the operators of Osborne indicated that works were underway to reduce the minimum load of the power station, however, at the time of PACR publication, there was no information to confirm completion of these works.

The GPS for Osborne at the time of the PACR specified a minimum operating level for the plant of [redacted]. It is also noted that this aligns with the assumptions subsequently adopted for the 2019/2020 ISP.

The GPS data for Pelican Point was updated in May 2018 following a turbine upgrade, with the minimum loading level revised to [redacted] for the GTs and [redacted] for the steam turbine, providing a minimum stable output level of approximately [redacted].

While these reduced output levels for both power stations have yet to be regularly observed in recent history, we have adopted a minimum loading level of [redacted] and [redacted] for Osborne and Pelican Point power stations respectively for the purposes of the sensitivity testing described in section 2 for completeness, as requested by the AER and detailed in section 4.2.

3.3 Plant investments and retirements

Section 4.1.1 of the PACR describes the estimated operation and retirement dates for SA gas plant in the PACR modelling and compares these timings with those found in the PADR and ISP.

To maintain consistency with the ISP, for states of the world with the new SA-NSW interconnector, the PACR aligned the retirement timings for Pelican Point and Osborne power stations with those found in the ISP. The ISP found that the retirement of this plant coincides with the commissioning of the new SA-NSW interconnector.

The retirement of Torrens Island Power Station was determined by the PACR model. This resulted in an earlier retirement date for Torrens Island in the base case when compared with the ISP base case. The PACR model confirmed the ISP finding that Torrens Island retirement upon commissioning of the SA-NSW interconnector was efficient.

Section 8.6.8 of the PACR tested the sensitivity of the preferred option to AEMO's retirement decisions for Pelican Point and Osborne. This sensitivity did not retire the plant and continued to operate Pelican Point and Osborne using the same minimum capacity factors used in the base case. Under this highly conservative sensitivity, expected net market benefits are reduced, however, the SA-NSW interconnector remains the preferred option.

The 2018 ISP modelling undertaken by AEMO co-optimised electricity generation and transmission investment and withdrawals, along with gas production and pipeline infrastructure, to efficiently meet future operational demand and government policy objectives at lowest cost. Consequently, the timing of SA gas plant retirements found in AEMO's 2018 ISP was determined using integrated gas and electricity market modelling that exceeded the scope and capabilities of the PACR market modelling.

The treatment of these assumptions for the purposes of the sensitivity testing described in section 2 is explained in section 4.3 below.

3.4 Synchronous condensers and system security constraints

The PACR base case included a requirement for four synchronous machines. Two were modelled as synchronous condensers at Davenport and the remaining two as two synchronous generator units in metropolitan Adelaide, noting that the four synchronous condenser solution proposed by ElectraNet was not confirmed by AEMO at that time.

The PACR base case also included a 1,870 MW SA system-wide cap on non-synchronous generation. The cap is dynamic and increases with exports and decreases with imports, ranging from 1,220 MW (with SA importing 650 MW across Heywood) to 2,520 MW based on current limits.

Since publication of the PACR four synchronous condensers have been approved by AEMO as the technical solution to meet the minimum system strength and synchronous inertia requirements. These four synchronous condensers are expected to increase the above cap of 1,870 MW to 2,000 MW, subject to Heywood interconnector flows, and reduce the need for generator direction.

ElectraNet understands that after the installation of the four synchronous condensers, at least two large synchronous generators will always be required online in order to meet minimum requirements for system security in South Australia, as reflected in AEMO's 2018 ISP assumptions[11].

This is consistent with ElectraNet's economic evaluation of the synchronous condenser solution, which assumed a cost range based on the indicative capital cost of the recommended four-unit solution, which remained subject to AEMO confirmation at that time.

This evaluation assumed the two-unit requirement would remain in place once a synchronous condenser solution was in place and factored in the corresponding reduction in direction cost savings based on the assumed level of AEMO market directions which would continue thereafter in order to meet this requirement.[12]

3.5 Coal prices for export-exposed black coal generators

Section 8.6.4 of the PACR presented the results of a sensitivity using higher coal prices in response to PADR submissions that higher coal prices should be assumed to align with current export parity.

This sensitivity tested a higher coal price and faster retirement of black coal generators. While it significantly reduced the net market benefits of the preferred option it did not change the PACR finding.

[11] AEMO, *Assumptions for South Australian GPG in the 2018 Integrated System Plan,* August 2019, p. 14.
[12] ElectraNet, *Addressing the System Strength Gap in SA - Economic Evaluation Report*, 18 February 2019, p25.

3.6 Pumped hydro costs

The PACR assumed 6-hour storage pumped hydro costs of $1.4m/MW for South Australia, consistent with ISP assumptions. Following publication of the ISP, AEMO engaged Entura to perform studies aimed at informing market modelling with a better view of potential costs and capabilities for pumped hydro energy storage across the NEM. Entura's December 2018 report[13] provides a 6-hour storage pumped hydro cost of $1.9m/MW for South Australia.

We have included an additional sensitivity ('AER Sensitivity 3') to test the impact of higher costs for pumped hydro in South Australia, as requested by the AER.[14]

13 Entura, *Pumped Hydro Cost Modelling*, 7 December 2018. This report was included in the planning and forecasting consultation documentation which will inform the 2020 ISP. Table 2.5 of the report contains 6-hour storage pumped hydro costs.

14 Requested by the AER in its information request dated 30 August 2019 (and subsequent email dated 1 October 2019).

4. Modelled changes to key inputs

This section confirms the changes in key modelling inputs included within the sensitivity tests requested by the AER as described in section 2, taking into consideration the discussion outlined in section 3 above.

4.1 Minimum capacity factors

For the reasons stated in section 3.1, we do not consider the removal of minimum capacity factors applied to SA gas plant would result in a realistic representation of real-world limits.

However, in order to stress test the PACR results, we have removed minimum capacity factors from all plant for the purposes of the sensitivity tests described in section 2, as requested by the AER.

4.2 Gas plant cycling and generator minimum load assumptions

As discussed in section 3.2, reduced minimum up and down times for SA gas plant may result in unrealistic generator behaviour by over and under estimating the number of starts and run times respectively, particularly for Torrens Island. However, as requested by the AER, for the purposes of the sensitivity tests described in section 2 we have adopted the run times from the 2014 ACIL Allen dataset for all plant except Torrens Island B power station, for which we were asked to adopt a 4-hour minimum on/off constraint consistent with that for Pelican Point and Osborne power stations.

Similarly, as requested, we have modelled generator minimum load assumptions consistent with AEMO's ISP modelling assumptions. For Pelican Point and Osborne power stations, for which minimum loads were not defined in the ISP dataset, we have modelled minimum loads of [redacted] and [redacted] respectively.

Consistent with the PACR modelling, for other South Australian gas plant that did not have minimum loads defined in AEMO's 2018 ISP modelling assumptions, we have modelled minimum loads consistent with GPS values, cross-checked against observed market outcomes. Although the inclusion of these values in the modelling has minimal impact on the estimation of expected benefits, the modelling of system security constraints relevant to the South Australian transmission network requires minimum loads to be defined for these generators.

4.3 Plant investments and retirements

The AER has requested that no plant investments or retirements be imported from other modelling results.

Whilst we consider that the work undertaken by AEMO to assess the retirements of generators in South Australia and indeed across the NEM is reasonable and rigorous, we have allowed all retirement and new entrant decisions to be made by the model for the purposes of the sensitivity testing described in section 2.

4.4 Synchronous condensers and system security constraints

All sensitivity testing presented in this report assumes four synchronous condensers will be installed and commissioned in SA consistent with the approved synchronous condenser solution and the anticipated dates set out in our Economic Evaluation Report.[15]

As these synchronous condensers will be high-inertia units (fitted with flywheels), we have updated the 1,300 MWs inertia capability assumed in the PACR to 4,400 MWs, in line with the technical solution as approved by AEMO on 8 March 2019.

All testing also assumes that the SA system-wide cap on non-synchronous generation will be increased from 1,870 MW to 2,000 MW, as discussed in section 3.4.

The requirement for a minimum of two large synchronous generators to be online in order to meet minimum requirements for system security in South Australia will continue to be assumed in our modelling, consistent with the PACR, the 2018 ISP, AEMO's latest advice and the economic evaluation of the synchronous condenser solution.

4.5 Coal prices for export-exposed black coal generators

The AER has requested that export-exposed black coal generators adopt the central estimate of new entrant coal prices (netback) from the 2018 ISP.

In combination with the other changes in key modelling inputs requested by the AER as described in section 2, we have conducted sensitivity testing with ('AER Sensitivity 1' and 'AER Sensitivity 3') and without ('AER Sensitivity 2') this change in coal pricing.

4.6 Pumped hydro costs

Given that the December 2018 Entura report was available when the PACR was published, albeit too late to be incorporated into the final modelling, we have tested the impact of using 6-hour storage pumped hydro costs for South Australia of $1.9m/MW in combination with the other changes requested by the AER ('AER Sensitivity 3').

15 ElectraNet, *Addressing the System Strength Gap in SA - Economic Evaluation Report*, 18 February 2019.

5. Summary of sensitivity testing performed

We have performed additional sensitivity modelling for both the base case and the preferred option (identified as Option C.3 in the PACR) that varies the required inputs included in the PACR for the central scenario.

The additional modelling and sensitivity testing performed for the purposes of this report is itemised below:

- Corrected PACR central scenario
- AER Sensitivity 1
- AER Sensitivity 2
- AER Sensitivity 3
- Updated PACR central scenario

A description of the corrections and adjustments made to the 'Corrected PACR central scenario' and the updated inputs modelled in 'the 'Updated PACR central scenario' is provided below. We also summarise the key input assumptions and model outputs for all sensitivities tested.

5.1 Corrected PACR Central Scenario

This scenario includes both corrections to the PACR model inputs and post-processing of model outputs identified as a result of addressing AER information requests since publication.

The following model input corrections were performed under this scenario:

- *Corrections to escalate all price inputs to real $2018-19*

  We identified a minor discrepancy in escalating prices in the PACR. While ElectraNet's Market Modelling assumptions workbook has correctly applied escalation, the original inputs to the workbook were not all escalated consistently to real $2018-19, and in some cases, remain in real $2016-17 and $2017-18.

- *Correction to generator expansion hand over to the time sequential model*

  We have identified an input error in the translation of the PACR long-term model into the short-term model, with the short-term model not using the final version of the long-term expansion. This has resulted in a minor underestimation of the benefits in the central scenario.

The following post-processing corrections were performed under this scenario:

- *Variable operating and maintenance (VOM) cost and fixed operating and maintenance (FOM) cost corrections for two new entrant pumped hydro facilities*

  We have identified that the variable operating and maintenance costs and fixed operating cost of two new entrant pumped hydro power stations were not included in the estimation of costs and benefits.

- *Corrections to FOM costs for gas powered generation*

  We have identified that the fixed operating and maintenance costs of the retired plant in South Australia were incorrectly included in the estimation of costs and benefits.

- *Replace capital expenditure and FOM linear build costs with integer builds*

  We identified that the estimation of costs and benefits utilised the 'linear' costs from the long-term model and have replaced this with the 'integer' (i.e. whole number) outcomes assumed for the time sequential model. For example, this anomaly would have resulted in estimating the 'linear' cost of 0.8 gas turbines rather than the 'integer' cost of 1 gas turbine.

- *Corrections to storage build costs*

  Some storage objects did not have the connection costs appropriately added to the build costs. These connection costs have been included.

5.2 AER sensitivity tests

We have performed the sensitivity testing requested by the AER based on the 'Corrected PACR Central Scenario' described above. These sensitivities apply the amended market modelling inputs as described in section 4, as summarised in Table 4 below.

Table 4: Key inputs and assumptions modelled in the AER sensitivity tests

Item	Corrected PACR Central Scenario	AER Sensitivity 1	AER Sensitivity 2	AER Sensitivity 3
1. **Minimum capacity factors**	PACR Central • OSB – 60% • PPPS – 50% • TIPS B – 25%	Removed	Removed	Removed
2. **SA GPG cycling and min. loads**	PACR Central (see Tables 2 & 3)	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated
3. **Plant investments & retirements**	PACR Central[16]	ElectraNet Long-term model	ElectraNet Long-term model	ElectraNet Long-term model
4. **Synchronous condensers & system security constraints**	• Inertia capability – 1,300 MWs • Non-synchronous cap – 1,870 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW
5. **Coal prices for black coal generators**	PACR Central	2018 ISP central estimate of new entrant coal prices (netback)	PACR Central	2018 ISP central estimate of new entrant coal prices (netback)
6. **Pumped hydro costs**	PACR Central ($1.4m/MW for SA)	PACR Central ($1.4m/MW for SA)	PACR Central ($1.4m/MW for SA)	Entura Report ($1.9m/MW for SA)

Taken together, the combination of revised assumptions applied in these sensitivities is an incomplete sample of updated key inputs, which is likely to lead to a skewed result in the calculation of market benefits.

To provide a complete and more balanced update in the range of key inputs based on a consistent set of information that was available at the time of the PACR, we have undertaken further modelling that builds on the modelling inputs in the above sensitivities to present an additional sensitivity, as set out below.

16 Figure 5 of the PACR shows how the operation of SA gas plant was modelled in both the PACR base case and SA-NSW interconnector case.

5.3 Updated PACR central scenario

As noted above, we have modelled an additional sensitivity, the 'Updated PACR central scenario', that includes information on long-term gas prices that was available and generator investments that were committed before publication of the PACR, but after we finalised the inputs for our market modelling. These inputs are described in more detailed below.

5.3.1 2020 ISP gas prices

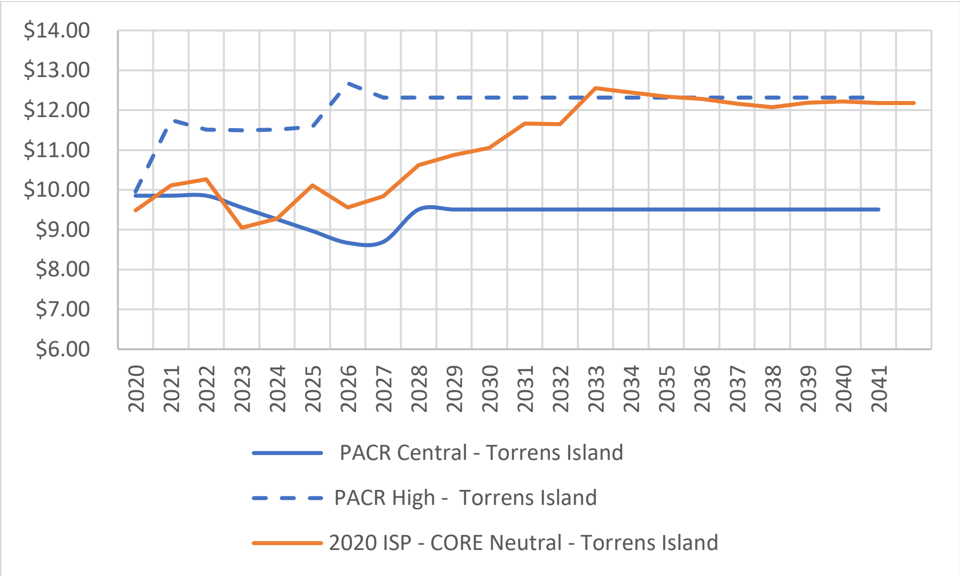
Gas price inputs for the 'Updated PACR Central Scenario' have been updated based on AEMO's draft 2020 ISP neutral scenario and market information on gas pricing which was available at the time of PACR publication.

AEMO is currently consulting on its 2020 ISP. Planning and forecasting publications for the 2020 ISP use the gas prices revised in December 2018 by AEMO in collaboration with external consultant Core Energy & Resources Pty Limited (CORE).

In its January 2019 report on the outlook for wholesale gas prices over the next 20 years, "CORE considers it feasible that there will be a future price path that is materially above that presented under the Neutral and Fast Change scenarios for eastern Australia."[17]

Figure 2 below presents Core Energy's neutral gas price forecast delivered to Torrens Island Power Station relative to gas prices included in the PACR central and high scenarios.

Figure 2: Modelled gas prices for SA GPG in the PACR and for the 2020 ISP



[17] Core Energy and Resources, *Delivered Wholesale Gas Price Outlook 2019-2040*, January 2019, p.24.

Figure 2 shows that gas prices modelled beyond 2030 as part of consultations for the 2020 ISP are closer to those in the PACR high scenario than the central scenario. This Core Energy gas forecast was used in the 'Updated PACR Central Scenario'.

5.3.2 Inclusion of committed generation

The 'Updated PACR Central Scenario' includes the impact of committed generators published on AEMO's Generator Information Page prior to PACR publication.[18]

The PACR made specific references to new entrant generators, particularly along the path of the preferred option, that obtained committed status on AEMO's generator information page prior to publication of the PACR but after we finalised the committed generation assumed in our market model.

Details of the committed generators included in this scenario based on the information that was available at this time are provided in Table 5 below.

Table 5: Additional committed generation included in 'Updated PACR central scenario'

Generator	Region	Location	Capacity (MW)
New South Wales			
Bomen Solar Farm	NSW	Wagga Wagga	120
Darlington Point Solar Farm	NSW	Darlington Point	275
Finley Solar Farm	NSW	Wagga – Darlington Pt 132 kV loop	133
Limondale Solar Plant 1	NSW	Balranald	220
Limondale Solar Plant 2	NSW	Balranald	29
Sunraysia Solar Farm	NSW	Balranald	200
Victoria			
Cohuna Solar Farm	VIC	Kerang	28
Kiamal Solar Farm - Stage 1	VIC	Red Cliff	200
Numurkah Solar Farm	VIC	Shepparton	100

18 See generator information published for 21 January 2019 on AEMO's website at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

5.3.3 Summary of inputs for the 'Updated PACR Central Scenario'

The inputs modelled in 'Updated PACR Central Scenario' are consistent with those for the 'Corrected PACR Central Scenario', updated to include information that was available at the time of PACR publication for the relevant parameters, namely:

- gas prices consistent with AEMO's draft 2020 ISP Neutral Scenario (as described in section 5.3.1)
- the inclusion of the impact of committed generation identified in Table 5 (as described in section 5.3.2)
- synchronous condenser inertia capability of 4,400 MW and non-synchronous generation cap of 2,000 MW (consistent with Table 4, item 4, AER Sensitivities 1-3)
- SA pumped hydro costs of $1.9m/MW (consistent with Table 4, item 6, AER Sensitivity 3).

The outcomes of this sensitivity are reflective of an updated central scenario if the PACR modelling were to be repeated today based on the input assumptions of the latest ISP.

5.4 Model outputs

The model outputs that have been provided for the sensitivity tests outlined above comprise the following:

- On an hourly basis (i.e. from the short-term model):
  - Load modelled (from demand forecasts, excluding endogenous loads) presented at a nodal level
  - Generator output at the level modelled (e.g. physical or dispatch unit)
  - Storage pump/generation/charge/discharge at the level modelled (e.g. physical or dispatch unit)
  - Interconnect flows
  - Interconnect losses
  - Regional reference prices (i.e. marginal prices)
  - Regional emissions
- On a load block basis (i.e. from the long-term model):
  - Load modelled (from demand forecasts, excluding endogenous loads)
  - Generator output at the level modelled (e.g. physical or dispatch unit)
  - Storage pump/generation/charge/discharge at the level modelled (e.g. physical or dispatch unit)
  - Interconnect flows

    - Interconnect losses
    - Regional reference prices (i.e. marginal prices)
    - Regional emissions
- On an annual basis:
    - Spreadsheets detailing annual summaries of the key market modelling outputs including those necessary for the calculation of net market benefits
    - Investment/retirement schedule at the level modelled (e.g. physical or dispatch unit) including capacities for each generation/storage unit modelled each year differentiated by committed status (i.e. endogenous or assumed), with both long term (i.e. linear) outcomes and short-term (i.e. discretised) outcomes reported. This includes capacities and endogenous/exogenous status of all generation/storage units modelled for all years.

6. Results of sensitivity testing

This section outlines the results of all sensitivities described in section 5, including testing the sensitivity of the results to the underlying capital cost of Project EnergyConnect.

6.1 Sensitivity tests

The adjustments applied in the 'Corrected PACR Central Scenario' result in an in increase in net market benefits for the central scenario from $765m published in the PACR to $924m. This reflects the net impact of the discrepancies in escalation and other minor omissions identified in the course of this further analysis which were resulting in an underestimation of the net market benefits.

The 'Updated PACR Central Scenario' reflects the latest AEMO ISP planning assumptions and the final form of ElectraNet's project to install synchronous condensers in South Australia, based on information that was available prior to publishing the PACR, but not in time to be incorporated in the final analysis.

The results of this sensitivity demonstrate increased net market benefits of over $1.3bn compared to the $765m reported in the PACR for the central scenario[19], and confirm the substantial economic benefits of Project EnergyConnect to customers. Key changes driving increased benefits include higher gas prices and the impact of the commitment of additional renewable energy projects along the proposed interconnector route. AEMO has consulted on these changed ISP planning assumptions with stakeholders in preparation for the 2020 ISP.

The 'stress testing' of the PACR outcomes requested by the AER through sensitivity tests that materially change the operation of gas plant in South Australia and other parameters is reflected in AER Sensitivities 1-3. These sensitivity cases are largely based on combinations of factors examined individually in the PACR.

As discussed in section 6.3 below, these sensitivities assume a significant drop in the annual gas consumption of South Australian gas plant, which is not considered a credible outcome and is not consistent with AEMO advice and inputs proposed for the 2020 ISP. This reinforces the extreme nature of this stress testing. Notwithstanding this, the AER 'stress test' sensitivities still deliver positive benefits and therefore do not change the outcomes of the PACR. These results also demonstrate that variations to coal price assumptions and pumped hydro capital costs do not have a material impact on net benefits.

The additional sensitivity analysis undertaken reinforces the outcomes of the PACR and provides increased confidence and assurance regarding the economic benefits of Project EnergyConnect.

The results of all sensitivities in net present value (NPV) terms, together with a summary of the inputs relevant to each sensitivity test, are presented in Table 6 below.[20]

[19] See section 8.1 of the PACR, p.95.

[20] Presented in $2018-19, consistent with the PACR.

Table 6: Summary of inputs and estimated net benefits for all sensitivity tests ($2018-19, $m)

Corrected PACR Central Scenario	AER Sensitivity 1	AER Sensitivity 2	AER Sensitivity 3	Updated PACR Central Scenario
Minimum capacity factors				
PACR Central • OSB – 60% • PPPS – 50% • TIPS B – 25%	Removed	Removed	Removed	PACR Central • OSB – 60% • PPPS – 50% • TIPS B – 25%
SA GPG cycling and minimum loads				
PACR Central (see Tables 2 & 3)	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated	• Min on/off times – 2014 ACIL Allen Dataset + TIPS B updated • Min load – PACR Central + PPPS & OSB updated	PACR Central (see Tables 2 & 3)
Plant investments and retirements				
PACR Central	ElectraNet Long-term model	ElectraNet Long-term model	ElectraNet Long-term model	PACR Central
Synchronous condensers and system security constraints				
• Inertia capability – 1,300 MWs • Non-synchronous cap – 1,870 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW	• Inertia capability – 4,400 MWs • Non-synchronous cap – 2,000 MW
Coal prices for black coal generators				
PACR Central	2018 ISP central estimate of new entrant coal prices (netback)	PACR Central	2018 ISP central estimate of new entrant coal prices (netback)	PACR Central
SA Pumped hydro costs				
PACR Central ($1.4m/MW)	PACR Central ($1.4m/MW)	PACR Central ($1.4m/MW)	Entura Report ($1.9m/MW)	Entura Report ($1.9m/MW)
Gas price				
AEMO 2018 ISP	AEMO 2018 ISP	AEMO 2018 ISP	AEMO 2018 ISP	AEMO 2019/20 ISP
Committed Generation				
AEMO generator information published 2 Nov 2018	AEMO generator information published 2 Nov 2018	AEMO generator information published 2 Nov 2018	AEMO generator information published 2 Nov 2018	AEMO generator information published 21 Jan 2019
NPV Results				
924	269	234	315	1,333

6.2 Capital cost sensitivities

As in the PACR, we have tested the sensitivity of the results to the underlying capital cost of Project EnergyConnect. We have tested capital cost increases 10%, 20% and 30%, including the breakeven capital cost whereby positive net market benefits are no longer generated.

The results of this capital cost sensitivity testing are presented in Table 7 below.

Table 7: Sensitivity of Project EnergyConnect to capital cost increases ($2018-19, $m)

Capital Cost sensitivity	Corrected PACR Central scenario	AER Sensitivity 1	AER Sensitivity 2	AER Sensitivity 3	Updated PACR Central Scenario
+10% capital costs	828	173	137	219	1,237
+20% capital costs	731	76	41	122	1,140
+30% capital costs	635	(20)	(55)	26	1,044
Breakeven capital cost/increase (%)	$3.05bn (+100%)	$1.95bn (+28%)	$1.89bn (+24%)	$2.03bn (+33%)	$3.65 (+138%)

These results demonstrate that Project EnergyConnect continues to deliver positive net market benefits across a wide range of cost outcomes, even under the extreme sensitivity tests undertaken to ‘stress test’ the outcomes of the PACR. This provides added confidence in the PACR outcome.

On a more balanced view than the AER ‘stress test’ sensitivities, the ‘Updated PACR Central Scenario’ demonstrates the project economic benefits are even more substantial than modelled at the time of the PACR and remain positive for a much wider range of cost outcomes.

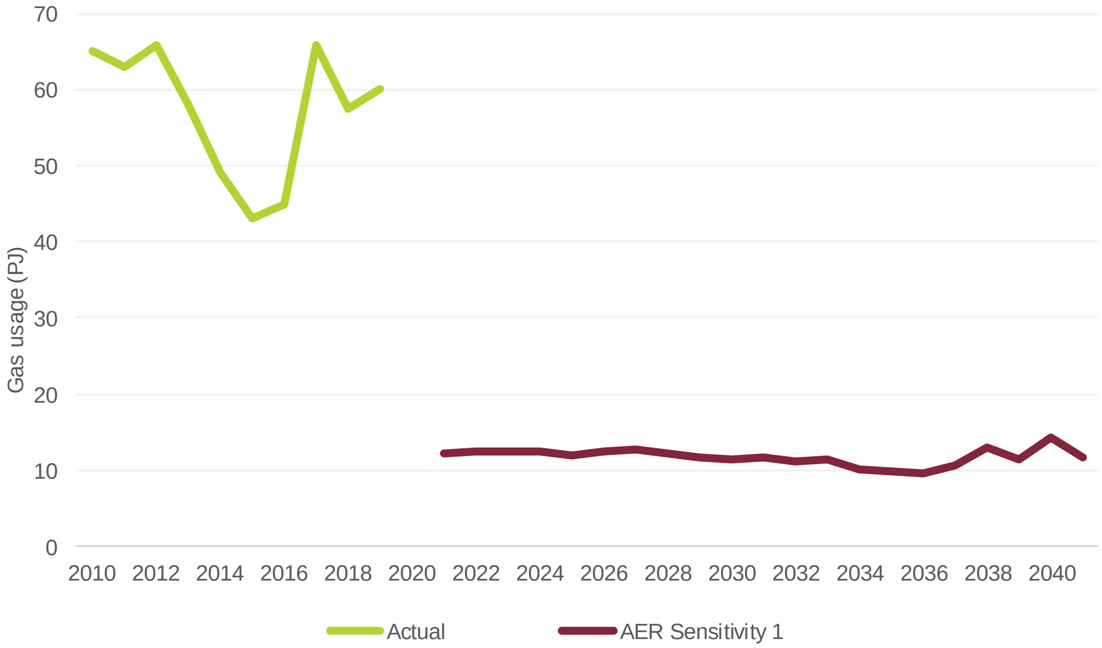
6.3 Gas consumption of SA GPG in AER ‘stress test’ sensitivities

As noted above, the ‘stress test’ sensitivity input assumptions (as modelled for AER sensitivities 1-3) for gas plant in South Australia are not aligned with advice from AEMO and the inputs AEMO has consulted on and is planning to adopt for the 2020 ISP.[21]

These ‘stress test’ sensitivities result in generation output profiles that have annual gas consumption falling immediately by around 75% compared to historical usage, as shown in Figure 2 with reference to ‘AER Sensitivity 1’. We do not consider this to be a credible outcome consistent with expected market behaviour, and again highlights the extreme nature of these ‘stress test’ sensitivities.

21 AEMO advice provided in its report dated 9 August 2019, *Assumptions for South Australian GPG in the 2018 Integrated System Plan*.

Figure 2: Actual and modelled aggregate gas usage for SA GPG under the base case



6.4 Market benefits not considered material

The PACR describes each category of market benefit that was not included in the RIT-T assessment because its inclusion was not likely to materially affect the outcome of the assessment of credible options, in accordance with RIT-T requirements.[22] In the context of the magnitude of net market benefits identified for both the PADR and PACR, we considered certain benefit classes not to be material given that their inclusion would be unlikely to affect the ranking of the credible options for the RIT-T analysis.

However, in the context of the AER 'stress test' sensitivity test results shown in Table 6 (and particularly the capital cost sensitivity test results shown in Table 7), the inclusion of one (or all) of these benefits may be considered material if it significantly affects the magnitude of net market benefits delivered.

The sources of market benefits that were not required to be included in the RIT-T for the purposes of option assessment but may be considered material to the outcome of certain sensitivities include:

- *Generator start costs*

  Excluding these costs underestimates the total benefits of increased interconnection. We did not include generator start costs in the PACR modelling. However, the 2014 ACIL Allen data published alongside the ISP (see section 3.2 above) did capture

22 In accordance with NER clause 5.16.1(c)(6). See Appendix D of the PACR (and section 8.2 of the PADR).

generator start costs. AEMO's 2018 ISP database states that this data was sourced from ACIL Allen in 2014 (based on its assessment of AEMO's NTNDP dataset).

As requested by the AER, we have excluded generator start costs from the post-processing adjustments used to estimate net market benefits for the sensitivity analysis presented in this report. We note, however, that the unit start costs included in ACIL Allen's 2014 dataset do not capture the full costs of operating plant in the manner assumed by the cycling constraints, as discussed in section 3.2.1.

- *Changes in Frequency Control Ancillary Services (FCAS) costs*

  By increasing interconnection with the NEM and reducing the risk of South Australia becoming islanded, Project EnergyConnect is expected to reduce FCAS costs by reducing local FCAS requirements and delivering associated market benefits.

- *Competition benefits*

  By allowing higher transfer capacity, Project EnergyConnect is expected to open the NEM to more competition and deliver associated market benefits.

- *Terminal value methodology*

  All economic analysis conducted as part of this RIT-T and for the sensitivity analysis presented in this report adopts terminal values based on the discounted undepreciated cost of the option at the end of the modelling period (i.e. 2040). Oakley Greenwood's external review of the SAET RIT-T identified that its preferred modelling methodology, in the context of this assessment, was for terminal values to be based upon an assessment of the market benefits expected beyond the end of the modelling period and that ElectraNet's methodology resulted in a conservative estimate of terminal values. [23]

In addition, while required to be considered on a stand-alone basis, Project EnergyConnect is also strongly complementary to the other priority projects identified in the ISP and would deliver far greater benefits when combined with projects such as HumeLink, which would reinforce the network deeper into New South Wales and further improve power transfer capacity with Sydney.

[23] Oakley Greenwood, *SA Energy Transformation RIT-T: External Review*, February 2019, p.14.

ElectraNet