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8 February 2021

Ms Anna Collyer
Chair
Australian Energy Market Commission
Sydney South NSW 1235

By online submission

Dear Ms Collyer

Rule change proposal: NEM settlement in zero and negative demand conditions

AEMO requests the AEMC to consider the attached proposal to amend the National Electricity Rules (NER) to address an urgent issue that could cause the settlements process in the National Electricity Market to fail, potentially as early as spring 2021.

As the proposal explains, an incidence of net demand (or customer energy) below one megawatt hour in a region over a trading interval means that the allocation equations currently used to recover non-energy costs cannot be solved. This will in turn cause the broader integrated settlement process to fail, impacting energy and reallocation transactions and prudential monitoring.

Increasingly low regional demand – with many 'load' connection points now exporting energy to the grid for much of the time due to the installation of rooftop PV – has highlighted significant issues with the ongoing application of existing non-energy cost recovery rules. These costs include the amounts payable by AEMO under the NER for ancillary services, market-based compensation, and reserve contracts. In short, there is a diminishing base of energy at load connection points from which to recover an unpredictable amount of costs. The AEMC is currently consulting on possible future non-energy cost recovery arrangements in response to AEMO's integrating energy storage systems rule proposal. AEMO continues to engage with the AEMC on this very significant issue, and the attached rule change proposal is not intended to preclude options to comprehensively address the broader issue in the longer term.

After informing AEMC and AER staff and preliminary consultation with Market Customers, AEMO has identified a systems solution that will keep the settlement systems working in zero or negative demand conditions, but otherwise involves no change to the current allocation of non-energy costs. The solution involves the substitution of average customer energy values, and would not be consistent with the existing NER. AEMO is therefore requesting the NER be amended to recognise the substitution mechanism.

AEMO has identified the possibility that zero regional demand could occur in South Australia as early as spring 2021, based on analysis described in the attached fact sheet. Accordingly, implementation and testing of the system solution is currently targeted during August 2021.

AEMO would appreciate consideration of this proposal as an urgent rule, should the AEMC consider that it may not be feasible to complete its normal rule change procedure by the end of August 2021.

AEMO welcomes the opportunity to discuss this proposal further. Should AEMC staff wish to discuss any of the matters raised in this submission, please contact Kevin Ly, Group Manager Regulation on kevin.ly@aemo.com.au

Yours sincerely

Violette Mouchaileh
Chief Member Services Officer

Attachments:

- AEMO rule change proposal, NEM settlement in zero and negative demand conditions
- AEMO Fact sheet, Minimum demand in South Australia

ELECTRICITY RULE CHANGE PROPOSAL

NEM SETTLEMENT UNDER ZERO AND NEGATIVE DEMAND CONDITIONS

February 2021

CONTENTS

1. SUMMARY

Non-energy costs in the national electricity market (NEM) include payments for market and non-market ancillary services, compensation for directions, market suspension or administered pricing, and reserve contract payments. Under the National Electricity Rules (NER), AEMO recovers non-energy costs from market participants based on their registration category and the energy associated with the connection points they have classified in that category.

The established registration categories and associated connection point classifications under the NER are set up to represent either 'generation', with flow predominantly into the network, or 'load', with flow predominantly from the network. The NER framework assumes that any electricity flows in the opposite direction will be immaterial for cost recovery purposes.

As the number of connection points with significant bi-directional electricity flows continues to grow, this assumption no longer holds and challenges emerge. One of these challenges is the impact of minimum demand conditions on AEMO's settlement and prudential functions. AEMO has identified that its settlement systems as currently configured will not operate to settle the NEM if there is zero or negative regional demand in a trading interval or other cost-recovery period.

Depending on the type of non-energy cost, the NER require AEMO to allocate those costs to Market Customers, Market Generators or Market Small Generation Aggregators, based on their share of energy at relevant connection points in a given trading interval, or set of defined trading intervals. For amounts to be recovered from Market Customers (at 'load' connection points), the cost recovery formulas in the NER use aggregate regional energy in the relevant trading interval(s) as the denominator for allocation. Each Market Customer's share is based on the sum of the net metered energy amounts for all its load connection points in the region for the same time period.

AEMO considers that zero or negative demand conditions are most likely to first occur in South Australia, due primarily to high bi-directional flows with continuing growth in distributed energy resources (DER) installed at load connection points. Some of AEMO's most recent sensitivity studies indicate the possibility of regional demand reaching zero in South Australia in spring 2021[1]. Should this occur, the likelihood of one or more entire trading intervals being affected by zero or negative regional demand increases with the introduction of five-minute settlement from 1 October 2021[2]. Although currently not considered a probable scenario for 2021, the consequences for NEM settlement and prudential operations are so significant that AEMO considers it essential for market system changes to be implemented by September 2021.

To prepare for a potential zero or negative demand trading interval, AEMO must change its systems to ensure that at least 1 MWh regional customer energy value is always available for cost allocation. Following initial consultation with market participants[3], AEMO will automate the substitution of average customer energy values (AGE) for the previous four completed billing weeks if (and only if) less than 1 MWh net regional customer energy is recorded in a trading interval or other relevant cost-recovery period.

The calculation of non-energy cost recovery amounts using substituted values to settle the NEM, where required, will not be compliant with the NER. This rule change proposal seeks to address the non-compliance associated with this workaround, as a temporary solution to address a system critical issue resulting from the application of the current cost recovery framework in very low operational demand conditions.

[1] Refer to Attachment 1 for more information – AEMO Minimum Demand in South Australia Fact Sheet

[2] Refer to Schedule 2 of the National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019 commences on 1 October 2021

[3] Consultation papers and submissions available at: https://aemo.com.au/en/consultations/current-and-closed-consultations/nem-settlement-under-zero-and-negative-regional-demand-conditions

AEMO's Integrating Energy Storage Systems in the NEM rule change proposal (ESS rule change)[4] recognised that the NEM must adapt to deal with bi-directional energy flows and assets, including non-energy cost recovery arrangements. AEMO considers that non-energy cost recovery amounts should be recovered from relevant market participants based on energy flows in each direction (both consumption and sent out energy) for relevant trading intervals, once the necessary metering data is available[5]. This approach would address the present challenge of allocating non-energy costs to market loads in zero or negative demand conditions, but would also provide a long-term solution to redress the balance of efficiency and equity for non-energy cost recovery in a low net demand market where load and small generation connection points increasingly operate in opposite directions to the flow assumed by the NER.

While the AEMC's consultation on the ESS rule change progresses, in the short-term AEMO must ensure the NEM's settlement and prudential systems and processes continue to work if a zero or negative net regional demand occurs in a region. AEMO's approach seeks to minimise the impact of these changes on market participants, at the lowest feasible cost and least risk to ongoing market change projects.

2. REQUEST FOR URGENT RULE

AEMO requests the AEMC to consult on this rule change proposal as an urgent Rule under section 96 of the National Electricity Law.

If a rule that facilitates settlement in zero or negative demand conditions is not made and implemented before an incidence of those conditions, AEMO considers that the results would include:

- Significant disruption to NEM energy and non-energy settlement.
- Potential for significant market participant margin calls to lead to prudential defaults should this disruption coincide with high pricing events.
- AEMO having to choose between either not paying non-energy costs, in breach of the NER, or being left with no avenue to recover them.

Zero or negative demand conditions could potentially occur as early as spring 2021 in South Australia. Outcomes of this nature would present a serious threat to the effective operation and administration of the wholesale exchange.

AEMO requires the proposed rule to be effective by August 2021, which aligns with the expected market system implementation date. If the AEMC is considering a 'more preferable' rule to address the issues raised in this rule change proposal, AEMO will need to assess whether this impacts its ability to implement the required NEM settlement systems changes before spring 2021.

3. RELEVANT BACKGROUND

3.1 NER requirements

Under Chapter 3 of the NER, one of AEMO's key responsibilities is to settle NEM transactions for traded energy, and to make and recover payments for non-energy costs. These include market and certain non-market ancillary service payments, reserve contract costs and regulated compensation amounts for specified events.

[4] Available at: https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

[5] Separate consumption and sent out metering datastreams are expected to be provided to AEMO to facilitate the implementation of the Global Settlements and Market Reconciliation rule, scheduled to come into full effect in May 2022 and available at: https://www.aemc.gov.au/rule-changes/global-settlement-and-market-reconciliation.

For market settlement, and to calculate and non-energy cost recovery amounts, AEMO uses net metering data ('N' datastreams) for each connection point assigned to a market participant in that trading interval. The net metering data provides an energy value for settlement, fees and recovery calculations for all market participants.

AEMO has been using net metering data for settlements since NEM start, reflected in the NER by the term adjusted gross energy (AGE)[6]. This represents the net flow of electricity at the participant's connection points in the relevant category for recovery (either load or generation). Where a connection point both consumes and sends out energy, the AGE is calculated on the net energy either supplied to the network (expressed as a positive quantity) or consumed at the connection point (a negative quantity), over the whole trading interval.

The NER require AEMO to allocate non-energy costs to market participants based on the classification of their connection points as load, generation, or small generation. Allocations to Market Customers are determined using the AGE for their load connection points, as a share of the aggregate total regional customer demand in a trading interval or other specified period. Table 1 shows the types of non-energy costs to be recovered (in whole or part) from Market Customers based on their AGE.

Table 1 Current NEM non-energy cost recovery from Market Customers

Payment type	Cost recovery based on aggregate regional demand	NER clause
Market ancillary services		
FCAS – contingency lower	Trading interval	3.15.6A(g)
FCAS – regulation	Trading interval	3.15.6A(i)(2)
Non-market ancillary services		
Network support control ancillary services (NSCAS)	Trading interval	3.15.6A(c8),(c9)
System restart ancillary services (SRAS)	Trading interval	3.15.6A(e)
Interventions		
Compensation for direction – energy, FCAS or other services	Trading interval(s) when direction in effect	3.15.8(b),(f),(g)
Reliability & Emergency Reserve Trader (RERT) payments Affected participant compensation for RERT	Split between: • RERT usage charges and compensation payments – trading intervals when RERT was used • RERT availability/other charges – billing week when paid	3.15.9(d)
Compensation - market suspension – energy and FCAS	Trading interval(s) within a market suspension pricing period	3.15.8A(b),(f)
Other events		
Administered price cap or administered floor price compensation	Market Customers	3.15.10(b)

[6] For load, also referred to as 'customer energy' in clause 3.15.6A and 3.15.8

3.2 Changes in operational demand

AEMO uses 'operational demand'[7] for forecasting purposes as a measure that best reflects the consumed energy from the grid, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units. In the NEM, levels of minimum operational demand are decreasing as more energy generation capability is installed at customer connection points, in particular distributed photovoltaic (DPV) generating systems. While there are already high amounts of DPV across the NEM, South Australia has recorded the lowest minimum demand of all NEM regions, and AEMO's modelling shows it will likely be the first region where a zero or negative operational demand occurs.

Minimum demand levels in the mainland NEM regions now typically occur in spring, on non-work days that are mild but sunny with low energy consumption and high DPV output. On 11 October 2020, South Australia recorded a new low operational demand of 300 MW, around 160 MW lower than the previous minimum recorded in 2019[8]. Based on the latest data from the Clean Energy Regulator[9], approximately 1,660 MW of DPV had been installed in South Australia by the end of 2020, an increase of approximately 330MW on the installed capacity 12 months earlier. Over the same period, the ESOO's Central and Central Downside High DER scenarios forecast DPV growth of 232 MW and 259 MW, respectively[10].

AEMO's 2020 Electricity Statement of Opportunities (ESOO)[11] identified that South Australia is likely to experience periods of negative demand in 2024-26 under the ESOO scenarios[12]. However, the record low South Australian operational demand in October 2020 was already in line with the POE90[13] minimum for the ESOO's Central Downside High DER scenario. AEMO therefore explored further sensitivities based on actual demand from 2017, 2018 and 2019 which was adjusted for the current uptake of DPV and increases in large loads. In figure 1, the reference years (as represented by the yellow lines) indicate the possibility of zero or negative operational demand in South Australia from as early as spring 2021 for each year. Attachment 1 provides further information on AEMO's sensitivity analysis.

[7] For more information refer to AEMO's demand definitions at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/demand-forecasts/operational-consumption-definition.pdf

[8] AEMO, Operational management of low demand in South Australia – 22 October 2020

[9] CER, Postcode data for small-scale installations – January 2021. Available at: http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations and Large-scale Renewable Energy Target supply data (only non-scheduled generation) – January 2021. Available at: http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/Large-scale-Renewable-Energy-Target-market-data/large-scale-renewable-energy-target-supply-data

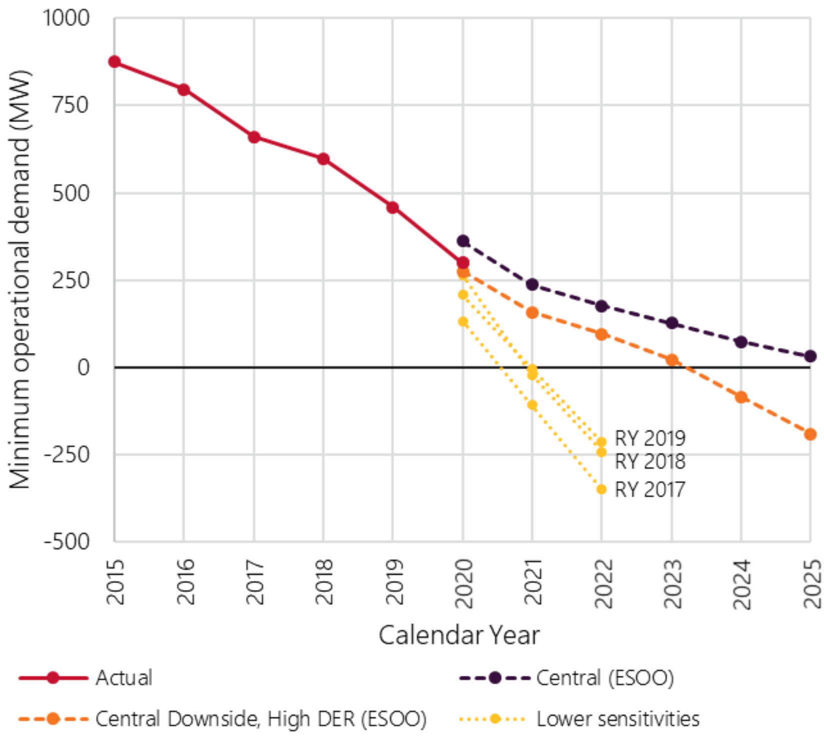
[10] Refer to Attachment 1, AEMO Minimum Demand in South Australia Fact Sheet

[11] August 2020. Available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2

[12] Includes spring 2024 (the 2024-25 financial year) in the Central Downside High DER scenario and spring 2026 (the 2026-27 financial year) in the Central scenario.

[13] 90% probability of exceedance

Figure 1 Minimum demand in South Australia (linear DPV growth)



As discussed in section 4, the NER non-energy cost recovery calculations rely on there being positive energy consumption in a region in every trading interval. Should the sensitivity forecasts be realised, the probability of zero or negative demand in one or more trading intervals will naturally increase when trading intervals move from 30 minutes to five minutes from 1 October 2021.

3.3 Integrating energy storage systems in the NEM rule change

In August 2020, the Australian Energy Market Commission (AEMC) commenced consultation on AEMO's Integrating Energy Storage Systems into the NEM rule change proposal (ESS proposal), submitted in August 2019. The ESS proposal provides for non-energy costs to be recovered from the proposed new Bi-directional Resource Provider category and Market Small Generation Aggregators based on both their consumed and sent out energy (as appropriate) where they contribute to the need for, or benefit from the provision of, the associated services.

AEMO's ESS proposal foreshadowed the need to consider moving to a similar approach for the allocation of non-energy costs to Market Customers and Market Generators, as the current methodology fails to capture true production or consumption in a market with increasing bi-directional flows at load connection points. AEMO noted that the ability to recover non-energy costs based on the gross energy flow in each direction would be facilitated by the provision of separate metering datastreams ('E' and 'B'), which will be available from the introduction of the Global Settlement and Market Reconciliation Rule (Global Settlement rule). This is scheduled to commence in May 2022.

4. STATEMENT OF ISSUE

This proposed rule focuses specifically on non-energy recovery amounts to be allocated to Market Customers under rule 3.15 of the NER. These provisions assumed that market loads would almost always be net consumers of energy, with few and infrequent exceptions. This is increasingly no longer true, primarily as a result of the growth in installed DER at load connection points, particularly DPV. New records for minimum operational demand are consistently being set and broken in the NEM, with South Australia moving most rapidly towards zero operational demand.

4.1 A broader issue

As total regional net energy for Market Customers reduces, largely due to DPV and other DER offset, there is a diminishing total volume of energy at load connection points from which to recover an unpredictable amount of costs. These will be recovered from a smaller base of Market Customers. The AEMC is currently consulting on possible future non-energy cost recovery arrangements in response to AEMO's ESS proposal, including the option of recovering non-energy costs from Market Customers and Market Generators based on separate metering for both consumed and sent out energy at each connection point. As noted in section 3.3, should that be the final outcome, implementation could not commence until after May 2022 when the necessary metering datastreams become available.

AEMO will continue to engage with the AEMC on this very significant issue, and opportunities to comprehensively address it in the longer term.

4.2 The urgent risk

The NER non-energy cost recovery formulas include numerators and denominators based on AGE for relevant trading intervals. If the aggregate AGE of all Market Customers in a region is less than 1 MWh for one or more trading intervals in a region, these NER formulas cannot be solved by market settlement systems. As explained in section 3.2, some projections indicate the possibility that zero or negative operational demand could occur in South Australia as early as spring 2021, noting that aggregate AGE will be calculated in 5 minute intervals from October 2021[14].

If zero or negative regional demand occurs in a region during a trading interval in which non-energy costs are to be recovered from Market Customers in a billing period, AEMO has no means of recovering those costs. If the recovery amount cannot be allocated, the calculation will fail and AEMO's automated settlement runs will stop working. Because settlement is an integrated process, this will impact settlement of all transactions, including energy and reallocations.

This in turn will make the prudential assessment processes ineffective, because they rely on settlements data to determine the maximum credit limit of each market participant, the corresponding amount of credit support to be provided, and when margin calls need to be made.

While it would be theoretically possible to calculate trading amounts for energy and reallocation transactions using manual processes, this would introduce delay in NEM settlement publication and invoicing, the potential for manual errors and significant cost to AEMO and market participants in reconciling statements. Non-energy transactions, however, could not be completed at all, even manually, because the NER provide no alternative basis to determine recovery amounts, or to reduce the amounts payable for non-energy costs. This puts AEMO in a position where it either cannot pay these amounts (which would breach the NER and related contracts), or it has no authorised means of recovering them. It is

[14] Refer to Schedule 2 of the National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019 commences on 1 October 2021

therefore necessary to amend the NER to permit a workable way of allocating non-energy costs to Market Customers.

AEMO considers a solution that minimises the risk of the automated settlement systems failing must be implemented by September 2021, because the consequences of AEMO's settlement systems not working in when regional demand is less than 1 MWh in a trading interval would have a significant negative impact on all market participants and AEMO, and result in non-compliance with its settlement and prudential obligations.

In view of the limited time for consultation and the prospect that the broader issue may be resolved in a different way following the outcome of the AEMC's ESS proposal consultation, AEMO considers that the interim solution to address the urgent issue must be low cost and low impact. That is, the minimum change necessary to adequately address the plausible risks.

5. HOW THE PROPOSAL WILL ADDRESS THE ISSUE

AEMO's proposal addresses the urgent issue by allowing AEMO to substitute AGE values when necessary to create numerators and denominators for non-energy cost recovery formulas that will work in AEMO's settlement systems. This substitution will need to be an automated process.

Considering the low cost, low impact objective, AEMO considered the following three essential aspects of a substitution mechanism with a view to establishing the minimum necessary change:

- The categories of non-energy costs for which a substitution option is most likely to be needed:

  – To minimise the scope of work and cost required to implement in system changes, AEMO excluded the categories of non-energy costs that are, by their nature, highly unlikely to be incurred during minimum demand periods. On this basis RERT costs and compensation for administered price cap or floor events have been excluded from the proposed rule.

- The threshold level of actual aggregate AGE for substitution to occur:

  – Non-energy cost recovery settlement calculations will fail when the denominator of any applicable formula is less than 1 MWh. To ensure AEMO is only changing settlement outcomes to the extent absolutely necessary for the systems to work in zero or negative demand conditions, AEMO selected this value as the aggregate regional AGE threshold below which substitution is required.

- The substitute AGE value to be used:

  – Informed by consultation with stakeholders (as described below), AEMO will determine substitute energy values using an average of the AGE amounts in the last four complete billing periods for each relevant Market Customer. This uses a period that is long enough to smooth any unusual events and produce a net positive demand figure overall while using actual demand for a Market Customer's own connection points, but is short and proximate enough to minimise the impacts of customer churn and seasonal differences.

  – AEMO recognises that stakeholders had different views and there are several variables that can impact whether the selected period produces a representative substitute demand or, conversely, could have unintended outcomes for Market Customers. AEMO's proposed rule allows for a review of the period after a minimum period of operational experience, if AEMO or a Market Customer consider it necessary.

Stakeholder consultation

AEMO consulted on the issue and proposal with stakeholders by way of an information session and options paper between November 2020 and January 2021[15]. The consultation focused on options for determining the substitute appropriate AGE values. Table 2 shows the four options AEMO initially proposed.

Table 1 AEMO options for substitution of AGE

Option	Reference AGE values for substitution
1 (AEMO's preferred option)	Market Customer's AGE with its average AGE for all relevant connection points in the region over the previous calendar year; and Aggregate regional demand (represented by AAGE) with the sum of the substituted Market Customer average AGEs in the region over the previous calendar year
2	Use a rolling 365-day period average energy consumption which is calculated dynamically every time a factor is required
3	Use the last interval which has a total region consumption larger than 1MWh
4	Divide the non-energy cost to be recovered by the number of active Market Customers and recover equally from all

AEMO received six submissions to the Issues Paper and all submissions indicated support to address the urgent settlement issue before September 2021. Engie and Origin supported Option 1 (AEMO's preferred approach) based on it being relatively simple to implement. The Australian Energy Council (AEC), AGL, Infigen and SA Water noted that Option 1 was not the ideal solution and (along with Origin) suggested alternative approaches, these are in table 3.

Table 2 Alternative approaches and AEMO's response

Alternative	Stakeholder	AEMO's response
Modify option 1 by calculating Market Customer's average energy values using a one-month's data instead of for a year. This would reduce the risk of retail customer churn over a longer period.	AGL	As discussed, AEMO considers that a shorter reference period to calculate the average customer energy (AGE) amounts would reduce the risk of significantly under-or over-representing a Market Customer's demand due to customer churn.
Option 3 was preferable because it is the closest approximation to real-time pricing and would reflect adjustments in a Market Customer's load and generation.	SA Water	This option is more complex and costly to implement. Potentially, in the absence of actual metering data this approach could require AEMO to use substituted metering data for affected trading intervals. This could under-or-over represent a Market Customer's demand and is more likely to result in inequitable outcomes.
Implement a simplified approach similar to what AEMO proposed in the ESS rule change, that is, based on the consumed and sent out energy.	SA Water	AEMO is unable to implement this option by September 2021 because the consumed and sent out energy metering data is only available to AEMO once the Global Settlement rule comes into effect on 1 May 2022. Without this metering data, AEMO is unable to implement this alternative.
AEMO consider applying a manual adjustment following the settlement week that provides for a more accurate allocation of non-energy costs to relevant market participants.	Origin	Using substituted energy values, the market settlement system will calculate Market Customers' AGE each time with the latest data. Therefore, if the proposed solution is implemented, there is no need to apply a manual adjustment.

Some stakeholders raised additional issues relating to non-energy cost recoveries in the information session, in submissions and stakeholder meetings. Although AEMO considers these are material, they have not been addressed in the proposed urgent rule because they will not cause the settlement systems to fail. However, it will be important that a solution to the broader market design issue outlined in section 4.1

[15] AEMO's options paper and stakeholder submissions are published at: https://aemo.com.au/en/consultations/current-and-closed-consultations/nem-settlement-under-zero-and-negative-regional-demand-conditions

incorporates the necessary rule and system changes necessary to resolve unintended market outcomes. In particular, stakeholders noted:

- If a Market Customer has a net negative AGE overall for the entire recovery period, some non-energy cost recovery formulas could result in that participant receiving a payment, funded by Market Customers consuming in the affected trading interval(s) in addition to the total non-energy cost amount[16].

  – This is a potential settlement outcome because the settlement systems were set up not to 'floor' load amounts at zero, based on the differences between the definitions of customer energy, generator energy and small generator energy in clauses 3.15.6A(o) and 3.15.8(h) of the NER.

  – AEMO agrees that in most cases it is unlikely to have ever been intended for Market Customers to receive payments under these recovery calculations.

- A 1 MWh threshold value for substitution would still mean that non-energy costs are potentially being allocated based on very low levels of regional customer energy, resulting in Market Customers without significant DPV bearing a disproportionate share of those costs. Selecting a different threshold value (e.g. 100 MWh) could achieve more equitable and efficient market outcomes. While AEMO agrees that this is a significant concern, using another value would be a departure from the scope of this urgent rule change. As the AEMC has incorporated this more fundamental market design issue into its consultation on the ESS proposal, AEMO considers that is the appropriate mechanism to determine a long term solution.

6. PROPOSED RULE

A draft of AEMO's proposed rule is provided in Appendix A. The structure recognises that the proposed rule is a temporary solution to this issue, which it is hoped will be replaced by a permanent change that addresses cost recovery in a low net demand market more generally.

The proposed substitution mechanism is therefore described in a single clause, 3.15.6AA, to facilitate its removal from the NER in due course. This new clause modifies the energy values for Market Customers in each relevant cost recovery provision within rule 3.15 when the applicable aggregate customer energy value in a region is less than 1 MWh. A note has then been included in each of those provisions, pointing to the possible application of new clause 3.15.6AA. This avoids the need to include full details of the substitution mechanism in each clause. New terms are defined and used only within new clause 3.15.6AA.

The drafting is described in more detail in Table 2.

[16] The issue was raised in the stakeholder session (30 November 2020) and Infigen's submission

Table 2 Proposed rule description

Clause 3.15.6AA(a) – definitions
Defines two key terms: • The reference period for averaging the customer energy (AGE) amounts to be substituted when actual values in relevant calculations cannot work in settlement systems, because they are effectively zero or negative. This 'demand substitution reference period' is defined initially as the last four complete billing weeks ended prior to the target cost recovery period, with provision for AEMO to review that period if necessary with the benefit of operational experience. The review provisions are set out in paragraphs (d) and (e). • The cost recovery periods ('relevant recovery periods' which may consist of one or more trading intervals), by reference to the non-energy cost recovery calculations in the NER that will be affected in zero demand periods. As discussed in section 4, these are limited to the Market Customer recovery components for: – Network support and control ancillary services - 3.15.6A(c8) and (c9) – Contingency lower FCAS - 3.15.6A(g) – Regulation FCAS not attributable to individual market connection points – 3.15.6A(i)(2) – Compensation for directions for energy, ancillary services or other services – 3.15.8(b), (f) and (g). – Compensation for market suspension periods for energy or ancillary service generation – 3.15.8(b) and (g).
Clause 3.15.6AA(b) – trigger conditions
Sets out the conditions when substitution of AGE values for Market Customers will occur, namely: • when determining an amount in a formula that relies on one of several terms representing aggregate customer energy, and • the value of that term is less than 1 MWh.
Clause 3.15.6AA(c) – substitution calculation and application
Describes how the substituted customer energy values are determined for Market Customers individually and in aggregate, and applied in the relevant formulas, as follows: • AEMO will determine an average AGE (or the equivalent term, depending on the formula) for each Market Customer's relevant connection points in the relevant region over the demand substitution reference period. • This will yield an energy value per trading interval. As the relevant recovery period may be longer than a single trading interval, the substitution energy value will be aggregated for each trading interval in the recovery period. • Scheduled load bid into dispatch during the actual intervention period is excluded from the energy amounts used for the recovery of compensation for directions, under clause 3.15.8(b). Therefore, the substituted average trading interval value representing scheduled load would be excluded from a Market Customer's AGE. • The regional customer energy, which acts as the denominator in each cost recovery formula, is the aggregate of the substituted Market Customer AGE (or equivalent) values.
Clause 3.15.6AA(d) & (e) – review description, requirement and process
AEMO will review the demand substitution reference period if either AEMO itself considers that it may not yield a representative average adjusted gross energy value for relevant recovery periods, or a Market Customer forms that view and requests AEMO to review. The draft rule also specifies that there must be a minimum number of five billing weeks in which substitutions have occurred before a review can be required. The purpose of a review is to ascertain whether or not the existing period remains fit for purpose. Paragraph (d) specifies minimum process requirements as: • consultation with Market Customers on the suitability of the current demand substitution reference period and any proposed alternatives; • publication of a report of the review and reasons for any variation of the period; • effective date for any variation to be at least four weeks after the date of publication of the report, noting that it will be applied to all relevant settlement calculations from the effective date, including settlement revisions relating to earlier billing periods.

7. HOW THE PROPOSED RULE CONTRIBUTES TO THE NATIONAL ELECTRICITY OBJECTIVE (NEO)

Many Market Customer (load) connection points currently have bi-directional energy flows occurring, and as more DPV and 'small' batteries are installed behind the meter, both the number of connection points and the amount of sent out energy from 'load' connections will increase. This has created an underlying inequity issue as non-energy costs are required to be recovered, based on net metering data, from a diminishing customer energy base. While this needs to be addressed, and is currently being considered in the context of consultation on the ESS rule change, AEMO considers that a temporary market system solution must be implemented as soon as possible so that the entire automated NEM settlements system continues to work if there is no net regional demand in a trading interval. If this occurs before the necessary changes are made, the disruption to critical market participants will be significant, as described in this proposal. AEMO will not be able to calculate and recover non-energy costs. This is likely to affect and delay other processes (including energy and reallocations settlement and prudential calculations) that are critical to the overall operation of the NEM and its market participants. A market disruption of this magnitude will impact all market participants and have flow on impacts on consumers.

The proposed rule allows AEMO to substitute Market Customers' energy values for NER rule 3.15 cost recovery provisions where regional demand is less than 1 MWh in an affected trading interval or multiple consecutive trading intervals. AEMO considers this provides a low cost and impact solution to allow the market settlements systems to operate with minimal disruption. This avoids the costs and impacts that would otherwise occur if the market settlements system failed. Therefore, the proposed rule is in the long-term interests of electricity consumers as it facilitates more efficient operation of the NEM.

8. EXPECTED BENEFITS AND COSTS OF THE PROPOSED RULE

The expected benefit of the proposed rule is to allow AEMO to calculate a Market Customer's non-energy cost recovery amounts for trading intervals where a zero or negative regional demand occurs, which in turn will ensure AEMO's automated settlement system continues to work. This allows AEMO's NER rule 3.15 obligations to be met, including settling all market participants' energy, FCAS and reallocation transactions and maintaining adequate prudential support. This will maintain the integrity of the wholesale market and minimise the potential disruption to market participants and flow-on consequences for the retail market.

AEMO will incur costs associated with the development, testing and certification of the system changes needed to implement the proposed rule. These costs are not yet finalised, as AEMO is seeking to align the work effort as far as possible with other settlement system development required for the Wholesale Demand Response project, to minimise additional cost. Market Customer settlement outcomes will only be affected if zero or negative regional demand occurs and AGE values are substituted. As described in this proposal, the impact of that substitution should be minimised by using an average of recent AGE values specific to each Market Customer.

APPENDIX A. PROPOSED DRAFT RULE

AEMO's proposed draft rule is based on version 156 of the NER, with additions shown underlined in red.

3. Market Rules

3.15 Settlements

3.15.6AA Substitution of regional customer energy values for no-net demand recovery periods

(a) In this clause:

(1) **demand substitution reference period** means the last four complete *billing periods* prior to the start of the relevant recovery period, or another period determined by *AEMO* following a review in accordance with paragraph (b4); and

(2) **relevant recovery period** means a *trading interval* or other period of multiple *trading intervals* for which *AEMO* must calculate amounts to be recovered from *Market Customers* under:

(i) clause 3.15.6A(c8), (c9), (e), (g) or (i), to fund payments for *ancillary services*;

(ii) clause 3.15.8(b), (f) or (g), to fund compensation for *directions*; or

(iii) clause 3.15.8A(b) or (f), to fund compensation for *market suspension pricing schedule periods*;

(b) Where the following conditions apply:

(1) amounts are to be recovered by *AEMO* from *Market Customers* in respect of a relevant recovery period by reference to a formula that includes the value of AAGE, ATCE, RATCE or ∑E; and

(2) the applicable value of AAGE, ATCE, RATCE or ∑E for the relevant recovery period is equal to or less than 1 MWh,

AEMO must calculate the amounts to be recovered from each *Market Customer* using substituted values determined under paragraph (c) for the following corresponding terms in each formula (as applicable):

(3) AGE and AAGE;

(4) TCE and either ATCE or RATCE; and

(5) E and ∑E.

(c) For each *trading interval* that makes up a relevant recovery period to which paragraph (b) applies:

(1) the substituted value of AGE for each *Market Customer* is the average per *trading interval* of the total *adjusted gross energy* figures over the demand substitution reference period for that *Market Customer's* relevant *connection points* in the relevant *region*;

(2) the substituted value of AAGE is the aggregate of the substituted AGE amounts under sub-paragraph (1);

(3) the substituted value of TCE for each *Market Customer* is the average per *trading interval* of the total *customer energy* figures over the demand substitution reference period for that *Market Customer's* relevant *connection points* in the relevant *region*;

(4) the substituted value of ATCE is the aggregate of the substituted TCE amounts under sub-paragraph (3);

(5) the substituted value of E for each *Market Customer* is the average per *trading interval* of the sum of the *adjusted gross energy* figures over the demand substitution reference period at each *connection point* for which that *Market Customer* is *financially responsible* in the relevant *region*;

(6) for the purpose of clause 3.15.8(b), the *adjusted gross energy* amount representing any *scheduled load* is to be excluded from the substituted value of E for the relevant *Market Customer* and *intervention price trading interval*; and

(7) the substituted value of ∑E is the aggregate of the substituted E amounts under sub-paragraphs (5) and (6).

(d) If required under paragraph (e), *AEMO* must review whether the current demand substitution reference period is a suitable period for the purpose of determining a representative average *adjusted gross energy* value for *Market Customers* in respect of potential relevant recovery periods, and may vary the demand substitution reference period based on its findings. In conducting the review *AEMO* must:

(1) consult with *Market Customers* on the suitability of the current demand substitution reference period and any proposed alternatives;

(2) publish a report on the review on its website, including reasons for varying the demand substitution reference period if applicable; and

(3) specify an effective date for the application of any varied demand substitution reference period in *settlements* calculations (including revisions) no earlier than four weeks after the date of publication of the report.

(e) *AEMO* is required to conduct a review under paragraph (d) if:

(1) values have been substituted under this clause 3.15.6AA for relevant recovery periods occurring in at least 5 *billing periods* since the commencement of this clause or, if applicable, since the date of the report on the previous review; and

(2) *AEMO*, or a *Market Customer* by notice to *AEMO*, considers the current demand substitution reference period may not be suitable for the purpose of determining a representative average *adjusted gross energy* value for *Market Customers*,

provided that *AEMO* is not required to conduct a review more than once in any 12 month period.

3.15.6A Ancillary service transactions

[…]

(c8) In each *trading interval*, in relation to each *Market Customer* for each *region*, an *ancillary services* transaction occurs, which results in a *trading amount* for the *Market Customer* determined in accordance with the following formula:

$$TA_{P,R} = \left(\sum_{\text{for all 'S'}} (TNSCAS_{S,P} \times RBF_{S,P,R}) \right) \times \frac{AGE_{P,R}}{AAGE_{P,R}} \times -1$$

Where

Subscript 'P' is the relevant period;

Subscript 'R' is the relevant

Subscript 'S' is the relevant *NSCAS*;

TAp,r (in $) =*trading amount* payable by the *Market Customer* in respect of the relevant *region* and *trading interval*;

TNSCASs,p the total amount payable by *AEMO* for the provision of the relevant *NSCAS* under an *ancillary services agreement* in respect of the relevant *trading interval*;

RBFs,p,r (number) = the latest regional benefit factor assigned to the provision of the relevant *NSCAS* under an *ancillary services agreement* in respect of the relevant *region* and *trading interval*, as determined by *AEMO* under paragraph (c7);

AGEp,r (in MWh) = the sum of the *adjusted gross energy* figures in respect of the *Market Customer's* relevant *connection points* located in the *region* for the relevant *trading interval*; and

AAGEp,r (in MWh) = the aggregate AGEp,r figures for all *Market Customers* in respect of the relevant *region* and *trading interval*.

Note:

The values of AGEp,r and AAGEp,r are subject to substitution in accordance with clause 3.15.6AA.

(c9) In each *trading interval*, in relation to each *Market Customer*, an *ancillary services* transaction occurs, which results in a *trading amount* for the *Market Customer* determined in accordance with the following formula:

$$TA_P = TNSCAS_P \times \frac{AGE_P}{AAGE_P} \times -1$$

Where

Subscript 'P' is the relevant period;

TAp(in \$) = the *trading amount* payable by the *Market Customer* in respect of the relevant *trading interval*;

TNSCASp (in \$) = the sum of all amounts payable by *AEMO* for the provision of *NSCAS* under *ancillary services agreements* in respect of the relevant *trading interval* minus the sum of the *trading amounts* calculated for all *Market Customers* in respect of all of the relevant *trading interval* under paragraph (c8);

AGEp (in MWh) = the sum of the *adjusted gross energy* figures in respect of all the *Market Customer's* relevant *connection points* for the relevant *trading interval*; and

AAGEp (in MWh) = the aggregate AGEp figures for all *Market Customers* in respect of the relevant *trading interval*.

Note:

The values of AGEp and AAGEp are subject to substitution in accordance with clause 3.15.6AA.

[…]

(e) In each *trading interval*, in relation to each *Market Customer*, for each *region*, an ancillary services transaction occurs, which results in a *trading amount* for the *Market Customer* determined in accordance with the following formula:

$$TA = \sum\left(\left(\frac{SRP_i \times RBF_{Ri}}{2}\right) \times \frac{TCE_R}{ATCE_R}\right) \times -1$$

Where

TA (in \$) = the *trading amount* to be determined in respect of the relevant *region* and *trading interval* (which is a negative number);

SRP_i (in \$) = has the meaning given in clause 3.15.6A(d);

RBF_{Ri} (number) = the latest regional benefit factor assigned to the provision of the relevant *system restart ancillary service* under an individual *ancillary services agreement* in respect of the relevant *region* and *trading interval*, as determined by *AEMO* under paragraph (c7);

TCE_R (in MWh) = the *customer energy* for the *Market Customer* for the *trading interval* in that *region*; and

$ATCE_R$ (in MWh) = the aggregate of the *customer energy* figures for all *Market Customers* for the *trading interval* in that *region*.

Note:

The values of TCE_R and $ATCE_R$ are subject to substitution in accordance with clause 3.15.6AA.

[…]

(g) The total amount calculated by *AEMO* under clause 3.15.6A(a) for each of the *fast lower service*, *slow lower service* or *delayed lower service* in respect of each *dispatch interval* which falls within the *trading interval* must be allocated to each *region* in accordance with the following procedure and the information provided under clause 3.9.2A(b). *AEMO* must:

(1) allocate for each *region* and for each *dispatch interval* within the relevant *trading interval* the proportion of the total amount calculated by *AEMO* under clause 3.15.6A(a) for each of the *fast lower service*, *slow lower service* or *delayed lower service* between *global market ancillary service requirements* and *local market ancillary service requirement* pro rata to the respective marginal prices of each such service;

(2) calculate for each relevant *dispatch interval* the sum of the costs of acquiring the *global market ancillary service requirements* for all *regions* and the sum of the costs of acquiring each *local market ancillary service requirement* for all *regions*, as determined pursuant to clause 3.15.6A(g)(1); and

(3) allocate for each relevant *dispatch interval* the sum of the costs of the *global market ancillary service requirement* and each *local market ancillary service requirement* calculated in clause 3.15.6A(g)(2) to each *region* as relevant to that requirement pro-rata to the aggregate of the *customer energy* figures for all *Market Customers* in each *region* during the *trading interval*.

For the purpose of this clause 3.15.6A(g) **RTCLSP** is the sum of:

(i) the *global market ancillary service requirement* cost for that *region*, for all *dispatch intervals* in the relevant *trading interval*, as determined pursuant to clause 3.15.6A(g)(3); and

(ii) all *local market ancillary service requirement* costs for that *region*, for all *dispatch intervals* in the relevant *trading interval*, as determined pursuant to clause 3.15.6A(g)(3).

In each *trading interval*, in relation to each *Market Customer* in a given *region*, an ancillary services transaction occurs, which results in a *trading amount* for that *Market Customer* determined in accordance with the following formula:

$$TA = RTCLSP \times \frac{TCE}{RATCE} \times -1$$

where:

TA (in $)	=	the *trading amount* to be determined (which is a negative number);
RTCLSP (in $)	=	the total of all amounts calculated by *AEMO* as appropriate to recover from the given *region* as calculated in this clause 3.15.6A(g) for the *fast lower service*, *slow lower service* or *delayed lower service* in respect of *dispatch intervals* which fall in the *trading interval*;

TCE (in MWh)	=	the *customer energy* for the *Market Customer* in that *region* for the *trading interval*; and
RATCE (in MWh)	=	the aggregate of the *customer energy* figures for all *Market Customers* in that *region* for the *trading interval*.

Note:

The values of TCE and RATCE are subject to substitution in accordance with clause 3.15.6AA.

(i) In each *trading interval* in relation to:

(1) each *Market Generator*, *Market Small Generation Aggregator* or *Market Customer* which has *metering* to allow their individual contribution to the aggregate deviation in *frequency* of the *power system* to be assessed, an ancillary services transaction occurs, which results in a *trading amount* for that *Market Generator*, *Market Small Generation Aggregator* or *Market Customer* determined in accordance with the following formula:

$$TA = PTA \times -1$$

and

$$PTA = \text{the aggregate of} \left(TSFCAS \times \frac{MPF}{AMPF} \right)$$

for each *dispatch interval* in the *trading interval* for *global market ancillary service requirements* and *local market ancillary service requirements* where:

TA (in \$)	=	the *trading amount* to be determined (which is a negative number);
TSFCAS (in \$)	=	the total of all amounts calculated by *AEMO* under paragraph (h)(2) for the *regulating raise service* or the *regulating lower service* in respect of a *dispatch interval*;
MPF (a number)	=	the contribution factor last set by *AEMO* for the *Market Generator*, *Market Small Generation Aggregator* or *Market Customer*, as the case may be, under paragraph (j) for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*; and
AMPF (a number)	=	the aggregate of the MPF figures for all *Market Participants* for the *dispatch*

interval for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*.

or

(2) in relation to each *Market Customer* for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1), an ancillary services transaction occurs, which results in a trading amount for that *Market Customer* determined in accordance with the following formula:

$$TA = PTA \times -1$$

and

$$PTA = \text{the aggregate of}\left(TSFCAS \times \frac{MPF}{AMPF} \times \frac{TCE}{ATCE}\right)$$

for each *dispatch interval* in the *trading interval* for *global market ancillary service requirements* and *local market ancillary service requirements* where:

TA (in $)	=	the *trading amount* to be determined (which is a negative number);
TSFCAS (in $)	=	has the meaning given in subparagraph (1);
MPF (a number)	=	the aggregate of the contribution factor set by *AEMO* under paragraph (j) for *Market Customers*, for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1) for the *region* or *regions* relevant to the *regulating raise service* or the *regulating lower service*;
AMPF (a number)	=	the aggregate of the MPF figures for all *Market Participants* for the *dispatch interval* for the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*;
TCE (in MWh)	=	the *customer energy* for the *Market Customer* for the *trading interval* in the *region* or *regions* relevant to the *regulating raise service* or *regulating lower service*; and

ATCE (in MWh)	=	the aggregate of the *customer energy* figures for all *Market Customers*, for whom the *trading amount* is not calculated in accordance with the formula in subparagraph (1), for the *trading interval* for the *region* or *regions* relevant to that *regulating raise service* or *regulating lower service*.

Note:

The values of TCE and ATCE are subject to substitution in accordance with clause 3.15.6AA.

[…]

3.15.8 Funding of Compensation for directions

[…]

(b) *AEMO* must, in accordance with the *intervention settlement timetable*, calculate a figure for each *Market Customer* in each *region* applying the following formula:

$$MCP = \frac{E}{\sum E} \times \frac{RB}{\sum RB} \times CRA$$

where

MCP is the amount payable or receivable by a *Market Customer* pursuant to this clause 3.15.8(b);

E is the sum of the *Market Customer's adjusted gross energy* amounts at each *connection point* for which the *Market Customer* is *financially responsible* in a *region*, determined in accordance with clauses 3.15.4 and 3.15.5 in respect of the relevant *intervention price trading intervals* excluding any *loads* in respect of which the *Market Customer* submitted a *dispatch bid* for the relevant *intervention price trading interval* in that *region*; and

RB is the regional benefit determined by *AEMO* pursuant to clause 3.15.8(b1) at the time of issuing the *direction*.

CRA is the *compensation recovery amount*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

Note:

The values of E and ∑E are subject to substitution in accordance with clause 3.15.6AA.

[…]

(f) The *trading amount* must be calculated as follows:

(1) subject to clause 3.15.8(f)(2) and (3) *AEMO* must use the appropriate formula set out in clause 3.15.6A(c8), (c9), (d), (e), (f), (g), (h) or (i) depending on which *ancillary service* was the subject of the *direction*;

(2) TNSCASP, TSRP, RTCRSP, RTCLSP or TSFCAS (as applicable) in the relevant formula is equal to the *ancillary service compensation recovery amount* for the relevant *ancillary service* in respect of the *direction*; and

(3) if TCE, TGE, TSGE, AGE, ATCE, ATGE, ATSGE or AAGE is used in the relevant formula, then the words 'the *trading interval*' in the definitions of those terms in the formula are to be read as 'all of the *trading intervals* during which the *direction* applied'.

Note:

The values of TCE, AGE, ATCE and AAGE are subject to substitution in accordance with clause 3.15.6AA.

(g) Any compensation payable by *AEMO* under clause 3.12.2 and 3.15.7 not recovered under clauses 3.15.8(b) and 3.15.8(e) must be recovered from *Market Customers*, *Market Generators* and *Market Small Generation Aggregators*. *AEMO* must, in accordance with the *intervention settlement timetable*, calculate a figure for each *Market Customer*, *Market Generator* and *Market Small Generation Aggregator* in each *region* applying the following formula:

$$MCP = \frac{TGE + TSGE - TCE}{RATGE + RATSGE - RATCE} \times \frac{RB}{\Sigma\, RB} \times CRA \times -1$$

where:

MCP	=	the amount payable or receivable by a *Market Customer*, *Market Generator* or *Market Small Generation Aggregator* under this clause 3.15.8(g);
TGE	=	the generator energy for the *Market Generator* in that *region* of the relevant *trading interval* for the period of the *direction*;
TSGE	=	the small generator energy for the *Market Small Generation Aggregator* in that *region* of the relevant *trading interval* for the period of the *direction*;
TCE	=	the customer energy for the *Market Customer* in that *region* of the relevant *trading interval* for the period of the *direction*;

RATGE	=	the aggregate of the generator energy for all *Market Generators* in that *region* of the relevant *trading interval* for the period of the *direction*;
RATSGE	=	the aggregate of the small generator energy for all *Market Small Generation Aggregation* in that *region* of the relevant *trading interval* for the period of the *direction*;
RATCE	=	the aggregate of the customer energy for all *Market Customers* in that *region* of the relevant *trading interval* for the period of the *direction*;
RB	=	the regional benefit determined by *AEMO* under clause 3.15.8(b1) at the time of issuing the *direction*; and
CRA	=	the *compensation recovery amount*.

Note:

The values of TCE and RATCE are subject to substitution in accordance with clause 3.15.6AA.

[…]

3.15.8A Funding of compensation for market suspension pricing schedule periods

[…]

(b) *AEMO* must, in accordance with the *intervention settlement timetable*, calculate a figure for each *Market Customer* in each *region* applying the following formula:

$$MCP = \frac{E}{\sum E} \times \frac{RB}{\sum RB} \times CRA$$

where

MCP is the amount payable by a *Market Customer* pursuant to this clause 3.15.8A(b).

E is the sum of the *Market Customer's adjusted gross energy* amounts at each *connection point* for which the *Market Customer* is *financially responsible* in a *region*, determined in accordance with clauses 3.15.4 and 3.15.5, in respect of the *trading intervals* that occur during a *market suspension pricing schedule period*.

RB is the regional benefit determined by *AEMO* pursuant to paragraph (e).

CRA is the *market suspension compensation recovery amount*.

Note:

The values of E and ∑E are subject to substitution in accordance with clause 3.15.6AA.

[…]

(g) The *trading amount* must be calculated as follows:

(1) subject to clause 3.15.8A(g)(2) and (3) *AEMO* must use the appropriate formula set out in clause 3.15.6A(c8), (c9), (d), (e), (f), (g), (h) or (i) depending on which *market ancillary service* was provided during a *market suspension pricing schedule period*;

(2) TNSCASP, TSRP, RTCRSP, RTCLSP or TSFCAS (as applicable) in the relevant formula is equal to the *ancillary service compensation recovery amount* for the relevant *ancillary service* in respect of that *market suspension pricing schedule period*;

(3) if TCE, TGE, TSGE, AGE, ATCE, ATGE, ATSGE or AAGE is used in the relevant formula, then the words 'the *trading interval*' in the definitions of those terms in the formula are to be read as 'all of the *trading intervals* within the *market suspension pricing schedule period* in which the *Market Suspension Compensation Claimant* provided *market ancillary services*'.

Note:

The values of TCE, AGE, ATCE and AAGE are subject to substitution in accordance with clause 3.15.6AA.

Minimum demand in South Australia

This fact sheet provides information on the possibility of zero or negative operational demand being experienced in South Australia in 2021.

The possibility of zero demand

A review of AEMO's operational and market systems has revealed that there are some elements that will not operate properly under zero or negative demand[1] conditions.

Minimum demand levels have been declining across all NEM regions in recent years, with continuing growth in distributed photovoltaics (PV). On 11 October 2020, South Australia experienced a minimum operational demand record of 300 MW.

AEMO's 2020 Electricity Statement of Opportunities (ESOO)[2] forecasts zero operational demand occurring in South Australia during the period 2024-2026. However, since these forecasts were developed, distributed PV growth has accelerated. The rate of growth of distributed PV in South Australia has grown from approximately 5 MW/month in 2016 to almost 30 MW/month by December 2020. Approximately 330 MW of new distributed PV was installed in South Australia in 2020. By comparison, the ESOO forecast PV growth of 232 MW and 259 MW over the same period for the Central and Central Downside High DER scenarios, respectively. This means that zero demand could occur earlier than indicated by AEMO's ESOO forecasts.

Furthermore, the forecasts used in AEMO's planning studies are based on 50% and 90% probability of exceedance forecasts (one in two, and one in ten year forecasts). This is suitable for economic planning, but does not capture the breadth of scenarios that could occur under more extreme conditions. For example, a 95% probability of exceedance, or one in twenty year forecast, would show lower minimum demand levels. These possible but less probable scenarios are important to consider when examining the operability of AEMO's systems.

This fact sheet provides an indication of possible levels of minimum operational demand that could eventuate in South Australia in 2021, for the purpose of exploring when interventions should be implemented to ensure the power system and NEM settlement systems operate properly under conditions of zero or negative demand. These levels of minimum demand are not considered probable, but the simple projections in this fact sheet indicate that they are possible under some conditions.

Approach

The demand and distributed PV generation patterns from three historical "reference" years (2017, 2018, and 2019) were used to explore possible demand conditions in 2021 and 2022[3]. Different reference years were used because low demand conditions are strongly dependent on the coincidence of clear skies, mild weather, and low economic activity, which can vary between years.

The capacity of distributed PV installed was increased from the reference year to late 2020 based on historical installations recorded by the Clean Energy Regulator (CER). The capacity of distributed PV was then increased further from the present to future years, continuing at the rate observed in 2020 (330 MW per year).

It was assumed that underlying demand remains constant from the relevant reference year, apart from an increase of 100 MW from 2017 and an increase of 20 MW from 2018 due to increases in industrial load since that time. This implicitly assumes

[1] The demand referenced in this memo is operational demand. Scheduled demand can be up to approximately 400 MW lower than operational demand, due to non-scheduled wind capacity in the region.

[2] AEMO (August 2020) 2020 Electricity Statement of Opportunities, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2

[3] The term "reference year" is used in this memo to refer to a historical year from which the patterns of underlying load and DPV generation were projected forward, assuming no change in half hourly, daily and seasonal patterns but scaling up DPV generation in each half hour, according to the increased capacity installed.

Minimum demand in South Australia

there was no change in demand patterns (such as consumers without distributed PV taking advantage of possible low prices during low demand conditions), no change to usage of distributed batteries or virtual power plants, and no intervention to prevent low demand conditions. It was also assumed there is no reduction in large industrial load due to closure or planned or unplanned outages (beyond those represented in the reference year trace).

Underlying load and distributed PV generation levels in each half hour of the relevant reference year were projected forward based on the higher level of distributed PV installed. A scaling factor of 0.9 was applied to the total distributed PV generation, accounting for the following factors:

- The efficiency of distributed PV panels degrades over time, and additional capacity may replace existing capacity. This is not captured in the CER’s database of distributed PV capacity.
- Some customers with distributed PV shift their load to daylight hours to increase self-consumption of distributed PV generation.
- Not all distributed PV capacity installed in South Australia is connected to the NEM.

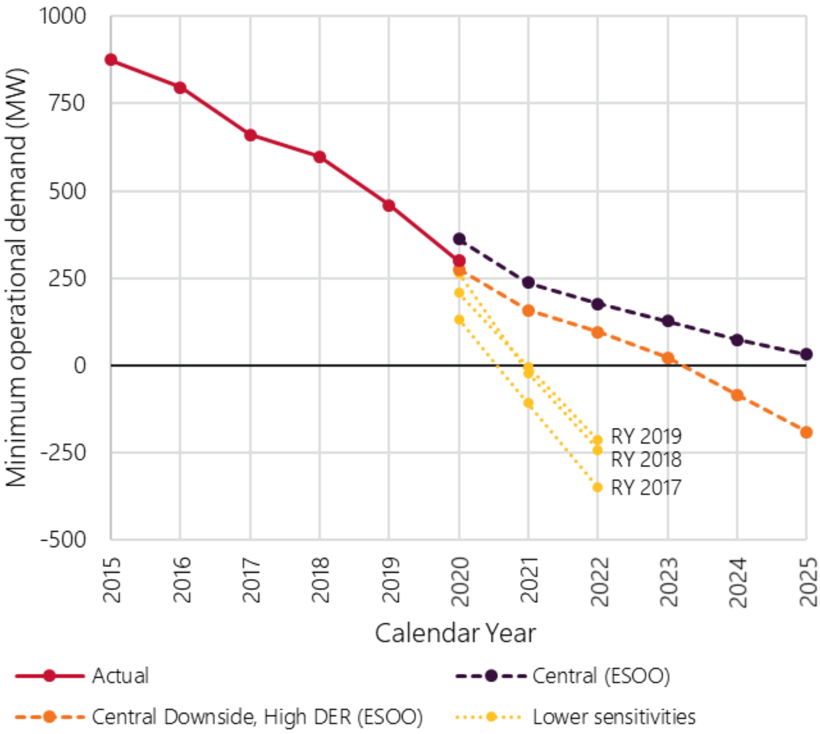
These projections do not constitute formal forecasts and have not been developed through a full forecasting process in consultation with stakeholders. They are only intended as indicative ‘order of magnitude’ sensitivities to explore possible outcomes.

Minimum demand projections

Figure 1 shows the 90% probability of exceedance minimum demand projections from the 2020 ESOO (Central Scenario and Central Downside, High DER Scenario). The alternative minimum demand sensitivities, shown in yellow, are based on actual demand from 2017, 2018 and 2019 with updated PV installation figures and assumed continuation of recent uptake rate. The yellow lines also include known increases to large industrial loads to bring them on par with loads in 2020, they however do not include growth in underlying demand or population growth. All three reference years show the possibility of minimum demand levels below zero occurring in 2021. If it occurs, this is most likely to occur on a public holiday or weekend in Spring (October to December) 2021.

Minimum demand in South Australia

Figure 1 Minimum demand in South Australia (linear DPV growth)

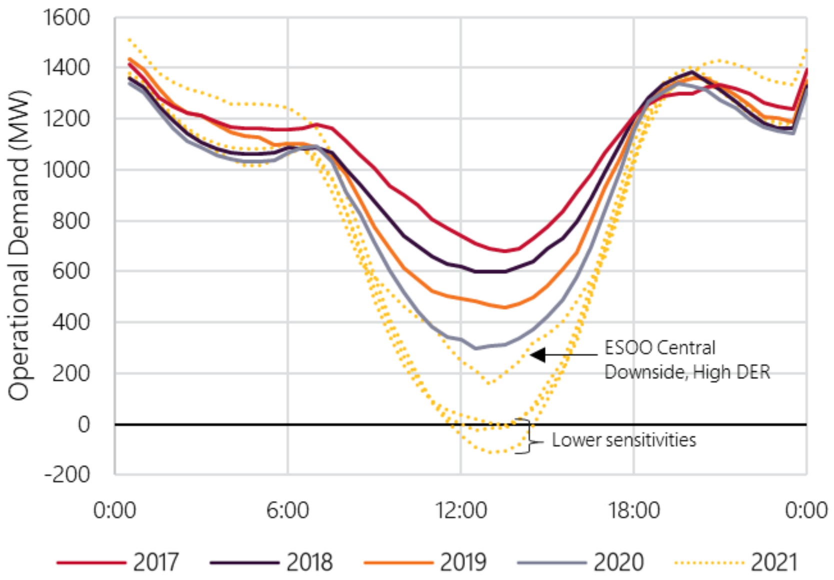


Based on these reference year projections, if demand and distributed PV generation patterns from 2017 were repeated in 2021 with the higher amount of distributed PV installed, South Australia could experience more than 10 trading intervals in which operational demand falls below zero. For context, in 2017 operational demand reached a minimum of 661 MW, and since this time, over 800 MW of distributed PV has been installed in South Australia.

Figure 2 shows an indicative minimum demand profile for the lowest demand day, showing observed operational demand for the most recent historical years, and possible projections for 2021 based on the three reference years. In some of these sensitivities, operational demand could be below zero for multiple hours.

Minimum demand in South Australia

Figure 2 Lowest demand day in South Australia (linear PV growth projections)



Operational demand versus scheduled demand

The above analysis focuses on operational demand. However, some of AEMO's systems rely on scheduled demand. Scheduled demand can be up to approximately 400 MW lower than operational demand on windy days, due to non-scheduled wind capacity in South Australia. This means that periods with zero or negative scheduled demand will occur earlier than zero or negative operational demand.

Next steps

This analysis is indicative only. AEMO is also working with stakeholders to update the forecasts used for AEMO's planning processes, taking the latest observations into account.

This analysis suggests that AEMO and stakeholders should prepare to be able to manage the power system and market systems safely, securely, and reliably in periods with zero or negative operational demand in South Australia, possibly occurring as early as October 2021. AEMO has a program of work underway to identify and implement the required adaptations.

Where can I find more information?

For any further enquiries, please contact AEMO's Information and Support Hub via:

- supporthub@aemo.com.au or
- call 1300 236 600