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Declan Kelly
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

12 September 2019

Dear Mr. Kelly

**RE: Wholesale demand response mechanism, draft determination**

Thank you for the opportunity to provide feedback on the draft determination for the *Wholesale demand response mechanism* rule change requests.

Enel X works with commercial and industrial energy users to develop demand-side flexibility and offer it into wholesale capacity, energy and ancillary services markets worldwide, as well as to network businesses. We have over 50 demand response programs in 12 countries, which involve altering customers' consumption patterns and controlling onsite generation. In the NEM, Enel X participates in the energy and FCAS markets, offers network support to NSPs, and has developed reserves for AEMO under the RERT framework, including through the ARENA/AEMO demand response trial.

The AEMC's draft decision is a big step in the right direction on a long overdue reform. In the context of high wholesale and retail electricity prices, reliability and security issues, and the high costs of network augmentation, it is timely to put in place a framework that more explicitly values participation by the demand side.

Enel X therefore commends the AEMC for finding a way to enable demand response to participate in the wholesale market, while balancing the various concerns of energy users and market participants. In Enel X's view, the proposed mechanism will enhance consumer choice and promote competition in the NEM, to the benefit of all electricity users, and should be introduced earlier than July 2022.

This submission sets out Enel X's feedback on specific aspects of the draft determination. If you have any questions relating to this submission, please contact Elisabeth Ross at elisabeth.ross@enel.com.

Regards

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## 1. PARTICIPATION CATEGORY AND REGISTRATION

For the reasons set out in detail in our submission to the consultation paper, Enel X supports the following aspects of the draft determination:

- The creation of the DRSP registration category.
- The ability for DRSPs to participate directly in the wholesale market using demand response, and to do so independently of the relevant customer's retailer.
- The ability for DRSPs to compete to be dispatched in the NEM alongside other sources of supply, and be paid the prevailing spot price for the quantity of demand response delivered.
- The requirement for AEMO to develop a guideline that sets out what is required to classify wholesale demand units and establish scheduled wholesale demand response units.
- The ability for DRSPs to access and receive NMI standing data and metering data.

Enel X provides the following comments in relation to other aspects of the DRSP framework.

### 1.1. Combining the DRSP participant category with the MASP participant category

Enel X supports efforts to streamline and reduce overlap between the participant categories in the NEM. We therefore support the proposal to roll the MASP participant category into the DRSP participant category. It makes sense for there to be one participant category that enables the aggregation of load flexibility by someone other than the customer's FRMP for participation in either the energy market, the FCAS market, or both.

We strongly support the AEMC's decision to retain separate processes for the classification of loads for FCAS market participation and the classification of loads for participation in the wholesale demand response mechanism. This separation will ensure that the loads in a DRSP's portfolio have the flexibility to participate in whichever market/s they choose, and will only have to comply with the obligations that are relevant to that market.

### 1.2. Adding and removing NMIs from a portfolio

Enel X seeks the AEMC's confirmation that DRSPs will be able to add and remove NMIs/ wholesale demand response units from a scheduled wholesale demand response unit, once established. The draft determination and draft rule are not currently clear on whether this is the case. Allowing this will maximise participation in the mechanism.

It's also important that the process for adding and removing NMIs from a DRSP's portfolio is simple and efficient. Again, this will maximise participation in the mechanism, and also support competition in the DRSP market.

As an example, the EU's Electricity Market Design Directive treats a customer's choice of demand response aggregator very similarly to their choice of retailer, and requires member states to make it easy for customers to churn between aggregators. An arduous or complex process for adding and removing NMIs from a DRSP's portfolio would prevent this.

A useful comparison of the benefits of facilitating efficient portfolio management lies in the Small Generation Aggregator framework. The rule reduced the administrative burden associated with adding a small generating unit to a portfolio from a full Generator registration to an MSATS transaction. The argument for streamlining portfolio management for wholesale demand response is even stronger, as (in most cases) much less physical work needs to be done on site, and it is reasonable to expect that the DRSP market will be competitive.

### 1.3. Technical requirements for participation

The draft rule does not specify what technical requirements a load must comply with in order to be classified as a wholesale demand response unit. Rather, the draft rule states that "adequate communications and/or telemetry must be in place" to be eligible for classification as a wholesale demand response unit, presumably for the purposes of submitting dispatch offers and receiving dispatch instructions. While not clear in the draft rule, Enel X's understanding is that AEMO will determine these requirements through the development of the *Wholesale demand response guidelines*.

The draft rule is also not clear on whether SCADA capability will be required to provide AEMO with operational visibility of either a DRSP's portfolio or the individual wholesale demand response units that comprise it. As set out in our submission to the consultation paper, Enel X does not consider it necessary or appropriate to require DRSPs to have SCADA capability. SCADA links are expensive and take considerable time to establish. In the context of building a power station, these costs are reasonable. In the context of customer signing up to provide flexibility, they would be prohibitive. A requirement to have SCADA capability, particularly on an individual load basis, is likely to be incredibly costly and outweigh any benefits of participation in the mechanism. Much more flexible and cost effective communications technologies exist and can be used to provide AEMO the operational visibility it needs. Some markets (e.g. PJM) do not have any telemetry requirements for demand response, while others have one-minute or five-minute requirements, which can be met at a much lower cost.

As decisions about telemetry and other technical requirements have the potential to significantly affect incentives to participate in the mechanism, any policy guidance the AEMC can provide to AEMO on these matters in the final determination would be beneficial. As a general comment, in Enel X's view, technical requirements should:

- be proportionate to the service being provided, and AEMO's actual requirements
- accommodate the various characteristics and capabilities of the assets providing the service
- be flexible and adaptable to changing technology.

### 1.4. Participation by spot-exposed customers

Enel X seeks further clarification on whether customers on spot-exposed retail contracts should be able to participate in the wholesale demand response mechanism.

Allowing this to occur raises the potential for double dipping. If a customer takes on spot exposure it is signalling an intention to interact with the wholesale price, for example by reducing consumption when spot prices are high. While customers on such contracts are not guaranteed or contractually obliged to reduce demand in response to high spot prices, it's a fair assumption that the types of customers who take on the risks of spot exposure will tend to do so.

DRSPs are likely to offer their wholesale demand response capability into the NEM when spot prices are high. It is hard to see how a spot-exposed customer's provision of wholesale demand response via the mechanism could be seen as additional if it is already very likely that it will reduce its demand in response to the high spot price. Thus, in Enel X's view, it is more transparent and more consistent with the additionality principles to prohibit spot-exposed customers from participating in the mechanism.

Such an approach would also provide a clean resolution to the issues that spot-exposed customers raise under the settlement model. Retailers who offer spot-exposed retail contracts are passing on the risk of wholesale price volatility to their customers, which eliminates/diminishes their need to hedge that risk through vertical integration or the contract market. The reimbursement rate is intended to compensate retailers for the discrepancy between what they recover from customers doing wholesale demand response via a DRSP, and what they are charged in the wholesale market. The draft determination notes that this includes the costs of hedging. As retailers that offer spot-exposed contracts pass on what they are charged in the wholesale market directly to customers, plus a margin, there is no discrepancy between what they recover from the customer and what they are charged in the wholesale market. Enabling spot-exposed customers to participate in the mechanism would therefore result in the retailer benefiting inefficiently via the reimbursement rate.

## 2. INTEGRATION WITH CENTRAL DISPATCH

Enel X supports the following aspects of the draft determination:

- The requirement that DRSPs participate on a scheduled basis. Participation as a scheduled resource is what distinguishes a demand response mechanism from unilateral responses to spot prices. Scheduling means demand response forms part of the bid stack and can directly influence wholesale market outcomes. It also gives AEMO greater visibility and control over wholesale demand response.
- The requirement for DRSPs to offer into the NEM on a “scheduled negawatt” basis. For reasons set out in detail in our submission to the consultation paper, requiring DRSPs to participate as scheduled loads would severely limit the attractiveness of the mechanism and thereby limit the significant benefits of wholesale demand response.
- The ability for DRSPs to elect when they participate in central dispatch, and to not be subject to causer pays liabilities when not participating.
- The fact that DRSPs will be dispatched based on actual, physical capability at the time, and for settlement to occur based on a subsequent assessment of how much wholesale demand response was provided, with reference to the baseline.
- The recognition that loads are different to generators and thus the technical characteristics of their participation in the NEM will be quite different.
- The decision to not subject DRSPs to directions under clause 4.8.9 of the NER.

Enel X provides the following comments in relation to other aspects of the market participation framework.

### 2.1. DRSP notification of scheduled capacity, and participation in pre-dispatch / dispatch

The draft rule requires that DRSPs inform AEMO of their available capacity for each trading interval of the trading day, two days ahead of each trading day. This information is to include:

- a MW capacity profile that specifies the wholesale demand response available for dispatch for each of the 288 trading intervals in the trading day
- an up ramp rate and a down ramp rate.

Enel X seeks clarification on whether this is an obligation on DRSPs to provide AEMO with an assessment of their *technical* capacity to provide wholesale demand response (i.e. regardless of expected wholesale prices), or whether DRSPs would have the ability to specify through this process that they do not intend to make capacity available.

The draft rule also requires that DRSPs submit dispatch offers for each of the 288 trading intervals in the following trading day for the purposes of providing information for AEMO’s pre-dispatch schedules.

These offers are to specify whether the DRSP is intending to participate in dispatch for the relevant dispatch interval. If it is intending to participate in central dispatch, the offer:

- may contain up to 10 price bands, and must specify an incremental MW amount for each price band
- must specify an up ramp rate and a down ramp rate
- must specify the profile of demand response to be provided if the DRSP is dispatched, relative to a loading level of zero
- must specify an expected consumption profile for the 30 minutes after that dispatch interval, if the DRSP ceased to participate in central dispatch.

The draft determination notes that, even when not "participating in dispatch", a DRSP will still need to participate in pre-dispatch. It is not clear from the draft rule or draft determination what obligations are associated with participation in pre-dispatch.

It is also not clear what is meant by "participating in dispatch" and how and when this is determined – through the notification of scheduled capacity, participation in pre-dispatch, or the provision of dispatch offers? The draft determination states that "when a DRSP has elected to not participate in central dispatch, it will not be required to submit dispatch offers." However, the rules above suggest that DRSPs will be required to submit dispatch offers for every interval of every trading day.

To be clear, Enel X supports the general policy intent that DRSPs should not be required to offer into every dispatch interval, and should not be subject to scheduling obligations when they do not offer / do not clear in the market.

The meaning of "participating in central dispatch" and the impact this has on how DRSPs present dispatch offers, will also have implications for the following two aspects of the draft rule:

- the ability for AEMO to give instructions to DRSPs to provide wholesale demand response "consistent with dispatch offers made in accordance with Chapter 3", and for DRSPs to receive and act on these instructions
- the requirement for a DRSP to comply with dispatch instructions in accordance with its availability as specified in its dispatch offer if constrained on as a result of a network constraint.

Enel X asks that the final determination and final rule clarify and address the above issues.

### 2.2. Compliance with dispatch instructions

Consistent with the existing arrangements for other scheduled participants, the draft rule specifies that AEMO will declare a scheduled wholesale demand response unit to be non-conforming and unable to be used for the basis for setting spot prices if it fails to respond to a dispatch instruction "within a tolerable time and accuracy (as determined in AEMO's reasonable opinion)". Enel X assumes that AEMO's assessment of this will consider a range of factors, including the ramp up and ramp down rates specified in DRSP's offer.

It will be challenging for most loads to accurately follow a linear dispatch trajectory or provide their full dispatch capability immediately following the receipt of a dispatch instruction. For this reason, it may not be appropriate for a DRSP's compliance with dispatch instructions to be assessed based on an expectation that the portfolio will ramp down in a linear fashion. Similarly, it may not be possible to accurately predict how the customers in a DRSP's portfolio will restore load following a dispatch, or to expect them to do so in a linear fashion. Only a very small subset of loads can be proportionately controlled in such a way.

It will be important for AEMO to commence consideration of this issue well ahead of the rule's commencement, and in consultation with stakeholders. Any policy guidance the AEMC can provide to AEMO in the final determination, including through a more detailed discussion of the role of dispatch inflexibility profiles, would be beneficial.

A framework that recognises and accommodates the various capabilities and characteristics of all sources of supply will support participation and competition in the mechanism, and thus maximise the potential benefits to consumers. Alternatives to assessing compliance with dispatch instructions based on a linear dispatch trajectory include:

- requiring DRSPs to provide a staggered response (i.e. to avoid everything coming on and off simultaneously)
- a requirement for DRSPs to meet their dispatched quantity *on average* over the dispatch interval
- adopting a complementary approach to that which applies to semi-scheduled generators – that is, the DRSP is deemed to be compliant as long as it delivers *at least* as much response that it is dispatched for.

Enel X supports the third option, as it more closely reflects DRSPs' actual capabilities. The NEM's contingency FCAS markets operate in this way.

Enel X also seeks clarification on the rules that apply if a DRSP submits an offer to provide wholesale demand response, but is not cleared by NEMDE. As discussed with the AEMC previously, the draft determination and draft rule are not entirely clear on this matter, and in some cases contradict other AEMC materials that cover the issue. In Enel X's view, when a DRSP is not cleared, it should not be subject to compliance with dispatch instructions or regulating FCAS costs.

### 2.3. Calculation of contribution factors

Under the current rules, contribution factors for market generators and market customers are determined based on assessed deviations from a reference trajectory – either expected dispatch or expected consumption. These deviations are calculated every four seconds using SCADA data.

As noted above:

- Enel X does not consider it necessary or appropriate to require DRSPs to provide four second data in real time, via SCADA or any other means.
- Most loads are unlikely to be able to follow a linear dispatch trajectory (unless coupled with storage capability).

Thus, if DRSPs are to be liable for regulating FCAS costs, an alternative means to calculate contribution factors may be required.

## 3. INFORMATION PROVISION

Enel X supports the following aspects of the draft determination:

- The recognition that the information provision requirements that currently apply to generators should be modified and only applied where necessary, due to the differences in the characteristics and operation of DRSPs compared to other market participants.

- The decision not to require DRSPs to provide information to AEMO as an input to the EAAP.

Enel X provides the following comments in relation to other aspects of the information provision requirements.

As a general comment, it would be helpful if the final determination provided further information about the impact that the five-minute settlement rule change will have on the various information provision obligations.

### 3.1. Requirement for DRSPs to provide information to AEMO

The draft rule requires that DRSPs provide information relating to the availability of wholesale demand response to AEMO for the purposes of the ESOO, MT PASA and ST PASA.

As a potential DRSP, Enel X would do its best to provide accurate information to the above processes in good faith. However, it is likely to be very difficult for a DRSP to provide accurate information for the ESOO and MT PASA timeframes. Scheduled generators have much greater foresight and control of planned maintenance and other longer-term activities than DRSPs will. It may therefore be more appropriate to only subject DRSPs to ST PASA obligations, or to find ways for DRSPs to feed into the ESOO and MT PASA forecasts less formally.

If the final decision is to subject DRSPs to the ESOO and MT PASA obligations, Enel X seeks assurance that DRSPs would not be penalised if there were legitimate reasons for any information provided turning out to be incorrect. In addition, Enel X seeks clarity on whether a DRSP's inputs to the these processes would relate to existing, contracted capacity only, or is expected to also include the DRSP's projections of the amount of additional demand response capacity it expects to contract with over the forecast period.

### 3.2. Information about which customers are offering wholesale demand response via a DRSP

The draft rule provides that the relevant retailer will be notified (via MSATS) when a DRSP is assigned to a NMI, the identity of the DRSP, and the baseline methodology that has been assigned to that NMI. Comments made at the public workshops on the draft determination indicate that some retailers want visibility of when a customer enters into a contract with a DRSP so that it can amend its retail contract terms with that customer.

Given that the general intention of the framework proposed by the AEMC is to make sure that retailers are indifferent to their customers providing wholesale demand response via a DRSP, Enel X is unclear on retailers' intentions in requesting such information. Enel X is concerned that giving retailers visibility of when a customer enters into an agreement with a DRSP will undermine the success of the framework. Specifically, Enel X is concerned that retailers will force or threaten a change in the price, terms or conditions of their retail contract such that the DRSP's offer now looks unattractive to the customer. A retailer might do this because it would rather the customer signed up to provide wholesale demand response with them directly, or simply because it prefers a market with less wholesale demand response. Either way, the retailer would be taking advantage of its position in the retail market to influence competition in the wholesale demand response market.

In principle, due to retail competition, the customer would have the ability to switch to a retailer that is more supportive of it offering demand response via a DRSP. However, there is a risk that the customer will consider it all to be too hard and instead choose to retain its existing retail contract with its retailer and not pursue a demand response offering via a DRSP. In many cases, a small change in retail price will have a bigger impact on the customer than any earnings they could receive from offering their flexibility in the wholesale market, so this would not be irrational behaviour. Further, the ability to switch retailers may not be available to customers in jurisdictions or regions with little or no retail competition, e.g.

South Australia, regional Queensland. Giving retailers such notification therefore has the potential to greatly reduce participation in the mechanism.

An obligation to notify the relevant retailer when its customer has entered into an agreement with a DRSP may also give the retailer an opportunity to capitalise on the customer's interest in wholesale demand response and offer them a product at a price just below what the DRSP is offering. Again, a retailer that does this would be taking advantage of privileged information it receives as the incumbent in the retail market to hamper competition in the wholesale demand response market.

### 3.3. Information about when a customer is dispatched to provide wholesale demand response

Comments made at the public workshops on the draft determination indicate that some retailers want access to information about a customer's availability, when it is dispatched, and how much it is settled for. The rationale for wanting this information seemed to be an interest in determining whether DRSPs or individual customers are gaming their baseline, and thus the argument was that providing public visibility would promote transparency of any such behaviour. There was a suggestion that this information should be provided and published in real time.

As noted above, the general intention of the framework proposed by the AEMC is to make sure that retailers are indifferent to their customers providing wholesale demand response via a DRSP.

It is reasonable to expect DRSPs' actions to be subject to the same level of transparency as other scheduled participants. Under the draft rule, DRSPs will be required to provide the same level of information as scheduled generators for the purposes of the ESOO, MT-PASA and ST-PASA. DRSPs will provide this information on a portfolio basis – i.e. as a representation of the wholesale demand response units under its control in each region. Further, under the draft rule, AEMO is required to publish details of:

- final dispatch offers by scheduled wholesale demand response units, including actual availabilities, details of any rebids made, the dispatch offer prices, quantities for each trading interval, ramp rates, and other information
- the dispatched wholesale demand response for each scheduled wholesale demand response unit
- actual wholesale demand response provided by each scheduled wholesale demand response unit.

This information mirrors that which is currently published for other scheduled participants.

Enel X does not agree that such information should be made publicly available on an individual NMI / wholesale demand response unit basis. Retailers presumably have access to the meter data of their customers who are offering demand response via a DRSP. Allowing retailers (and the public) to have visibility of such information for customers that aren't theirs raises privacy and competition concerns, and would limit participation in the mechanism.

Enel X seeks further clarification from those who raised these proposals on:

- why they believe they need this information on an individual NMI, not aggregate, basis
- what information they believe they need over and above what they would already have access to via meter data
- why such information is needed in real time, not after the fact
- why it should be made publicly available.

If the concern is about the potential for baseline gaming, Enel X would argue that this is better addressed through the development of robust baseline methodologies and proper monitoring and enforcement by the AER, not by public policing.

## 4. DETERMINATION OF BASELINES

Enel X supports the following aspects of the draft determination:

- The development and settlement of baselines on a centralised basis.
- The determination of baselines ex post for settlement purposes only, not in real time for dispatch.
- The requirement for AEMO to develop a guideline that sets out the various aspects of the baselining framework.
- The ability for DRSPs to choose the baseline methodology that it proposes be applied to a wholesale demand response unit in its portfolio, provided that the methodology satisfies AEMO's baseline metrics.
- The ability for DRSPs to inform AEMO when an event or circumstance will materially change the consumption pattern of a wholesale demand response unit to maintain compliance with the baseline methodology metrics.
- The ability for registered participants to propose alternative baseline methodologies, to use these for its wholesale demand response units where approved by AEMO, and to keep these methodologies confidential where it would reveal commercially sensitive data.
- The requirement for the AER to develop a guideline providing more detail on the application of the additionality principles and how it will monitor compliance with them.
- The ability for a DRSPs' portfolio to be made up of NMIs on different baseline methodologies. While not explicitly clear in the draft rule, it is our understanding that this is the case. Clarification of this in the final determination would be helpful.
- The requirement for AEMO to report annually on the operation of the wholesale demand response mechanism, including outcomes relating to the use and accuracy of baseline methodologies.

Enel X provides the following comments in relation to other aspects of the baseline framework.

### 4.1. AEMO baselining guidelines

As above, Enel X supports the decision to leave much of the detail of determining the baseline framework to AEMO. Setting this out in AEMO guidelines, rather than in the NER, makes the framework easier to amend and improve over time.

However, given that baselines are an essential component of the wholesale demand response mechanism, it will be important for AEMO to give early and proper consideration to the various issues it will need to address in the guideline, and to do so in consultation with stakeholders. As set out in section 6 of this submission, Enel X proposes that AEMO establish a dedicated team to commence consideration of these issues as soon as possible after the final rule is made, and create working groups of relevant stakeholders to inform the development of the guideline.

As noted in our submission to the consultation paper, baseline methodologies are not a new concept or unique to this mechanism. There is much to be learnt from markets that already have methodologies that are well-tested and robust to errors and gaming. AEMO should seek to draw on what it can learn from those markets where possible to make sure we are learning from others' mistakes, and to expedite the development of the guideline.

### 4.2. Annual reporting on baselines

As above, Enel X supports the requirement for AEMO to report annually on the operation of the wholesale demand response mechanism.

However, Enel X seeks clarification on whether clause 3.10.6(c)(2) of the draft rule is intended to mean that information about individual wholesale demand response units and their capacity will be published. We do not support the publication of detailed information about which individual NMIs are providing wholesale demand response, and thus suggest that this clause be amended to refer to "total" or "average" capacity.

### 4.3. Additionality

The draft rule requires that a DRSP must only make a dispatch offer where the wholesale demand response, if dispatched, is the result of actions taken by the DRSP (i.e. would not occur but for the dispatch instruction).

Enel X seeks clarity on whether energy users providing wholesale demand response via a DRSP would also be able to provide network support services to the local DNSP. While network peaks are likely to occur when wholesale prices are high (and when a customer might want to provide wholesale demand response), this is not always the case. Demand reductions for the purposes of providing network support serve a different purpose to demand reductions through a wholesale demand response mechanism.

In Enel X's view, customers should be able to contract with DRSPs and DNSPs to provide both wholesale demand response and network support services. However, if there is a concern about double dipping, it may be appropriate to only allow the customer to be compensated for the program that is called, or require the DRSP to bid that customer out of the wholesale market for any dispatch intervals where it has been called by the DNSP to provide network support.

The draft rule requires the AER to develop a guideline that sets out how it will monitor compliance with this obligation. However, any policy guidance the AEMC can provide to the AER on these matters in the final determination would be beneficial.

It will also be important to consider the implications that participation in multiple demand response programs will have for the calculation of baselines, e.g. so that network support dispatches are treated as event days, rather than normal consumption.

## 5. SETTLEMENT AND COST RECOVERY

While we remain supportive of the settlement model proposed by PIAC, The Australia Institute and the Total Environment Centre, the model in the draft rule is a pragmatic solution to the concerns raised by retailers and AEMO about the potential costs of billing customers on baseline consumption.

Enel X supports the following aspects of the draft determination:

- Settlement determined by reference to the relevant baseline, not on physical dispatch outcomes.
- Settlement on the NMI level.

- A centrally determined, simple and transparent reimbursement rate. In Enel X's experience, jurisdictions that require negotiation of such rates between individual retailers and DRSPs (as in Japan, and Germany before it realised this approach didn't work) have seen limited success as these negotiations tend to be complex and protracted.
- Settlement between the DRSP and relevant retailers via AEMO, not directly.

Enel X provides the following comments in relation to other aspects of the settlement and cost recovery framework.

### 5.1. Clarity on the purpose of the reimbursement rate

Discussions at the workshops on the draft determination indicate that stakeholders do not have a clear understanding of the purpose of the reimbursement rate, and the costs that it is intended to reimburse the retailer for. Further clarity on this, either through a published document ahead of the final determination, or consultation on the issue through the Technical Working Group, would be helpful.

While much has been said about the potential for retailers to under-recover their costs under the reimbursement rate approach, it is important to note that there is also the potential for retailers to receive a windfall gain if the reimbursement rate is too high. The original settlement model, or a requirement for retailers to reveal their true costs, would address this issue. However, we understand the AEMC's reasons for not pursuing such approaches.

We therefore agree with the AEMC that the intention should be to make the reimbursement rate as accurate a reflection of retailers' costs as is feasible, whilst still being simple and transparent. When this is the case, you would expect that any under- or over-recovery would cancel out over time.

### 5.2. DRSP visibility of the reimbursement rate

The draft rule states that the AER will calculate the rate and provide it to AEMO. Enel X seeks clarification that DRSPs will also have visibility of the reimbursement rate, or that it will be made publicly available. It is important that DRSPs have visibility of this rate as it will affect their assessment of the value of offering wholesale demand response.

### 5.3. Alternative reimbursement rate metrics

Enel X's understanding is that the reimbursement rate is intended to cover what a retailer would have paid for electricity had its customers not provided demand response. The rate is proposed to be calculated based on average spot prices for the previous 12 months and determined by the AER on a quarterly basis.

A number of retailers have argued that a rate based on average wholesale prices does not account for the costs of hedging, particularly during the periods when demand response is most likely to be dispatched. Some have suggested that quarterly futures prices might be a better approximation of these costs. Using futures prices to determine the reimbursement rate raises a number of questions:

- Are futures prices a good enough reflection of how all retailers choose to hedge? If not, the reimbursement rate will be inaccurate for some retailers.
- Can futures prices be manipulated? The more months used in the calculation, the less likely it is that the futures price could be manipulated and thus have a big impact on the reimbursement rate.
- What if there is no liquidity in the futures market (as is the case in South Australia) or no futures market at all (as is the case in Tasmania)? What is used as the basis for calculating the reimbursement rate then?

It may also be important to clarify which rate will apply: the rate that applies at the time the wholesale demand response is provided, the rate that applied when the retailer entered into the contract with the customer (and thus when it made its assessment of wholesale market risk), or an annual average?

### 5.4. Retailer visibility of customer dispatches

Some have argued that retailers should receive information about their customers' wholesale demand response dispatches so that they can change their hedging strategies. For the reasons explained below, it's not clear to Enel X why a retailer should need to change its hedging strategy as a result of its customers providing wholesale demand response, and thus why they would need visibility of customer dispatches.

The draft determination states that retailers will be charged by AEMO for two amounts in the wholesale market, both at the prevailing wholesale price:

- The customer's actual level of consumption.
- The quantity of demand response provided by the customer (i.e. baseline consumption minus actual consumption).

The total of these two amounts is the customer's baseline consumption. It reflects what the retailer should have been expecting to pay for in the wholesale market if there was no wholesale demand response. The fact that a customer provides wholesale demand response therefore makes no difference to the volume of electricity that the retailer has to buy at the spot price for that customer. Thus there is no extra exposure to hedge and no obvious reason for a retailer to change its hedging strategy.

The only thing that changes is that, instead of being paid at the retail rate for the quantity of demand response provided, the retailer is being paid at the reimbursement rate. While there may be a mismatch between these two rates, a change in hedging strategy will not correct it. This is because the retailer's spot exposure for a customer providing wholesale demand response is the same as if it wasn't providing wholesale demand response.

This point is recognised in the draft determination, where the AEMC states that the settlement model "should result in the retailer's hedging position being largely unaffected" and "will minimise the extent of any changes in relation to contract market positions and the associated costs of maintaining these hedging positions." Thus it is not clear to Enel X why retailers need visibility of customer dispatches.

Further, given that retailers have (in most cases) no real-time visibility of their customers' consumption and presumably make hedging decisions on forecasts, it's not clear why retailers would need real-time visibility of customers' demand response dispatches.

## 6. IMPLEMENTATION

### 6.1. Commencement date

Enel X is disappointed that the draft rule proposes a commencement date of 1 July 2022. The main justification for this appears to be resourcing constraints at AEMO in the context of the implementation of the five minute and global settlement rule changes. While understandable, Enel X is not convinced that this is sufficient reason to delay the significant potential benefits of the mechanism for 2.5 years after the rule is made.

We are buoyed by the AEMC's commitment to explore options to bring the implementation date forward, and AEMO's willingness to explore these options.

Enel X is keen to work with the AEMC, AEMO and other stakeholders to determine ways in which the implementation date can be brought forward, and to make sure that all parties are ready when the rule commences.

### 6.2. Work to be done ahead of the commencement date

The draft rule requires AEMO and the AER to develop and publish a number of guidelines ahead of the commencement date. Enel X is concerned that the rules consultation procedure, if only commenced when necessary to have published these guidelines by the commencement date, will not provide sufficient time for AEMO, the AER and stakeholders to consider the broad and complex range of issues that the guidelines are to cover.

Given that the content of these guidelines will form essential components of the wholesale demand response mechanism, it is important that AEMO and the AER give proper and early consideration to the various issues they will need to address, and do so in consultation with stakeholders. Enel X proposes that AEMO establish a dedicated team to commence consideration of these issues as soon as possible after the final rule is made, and create working groups of relevant stakeholders to inform the development of the guidelines.

Proper and early consideration of these issues will help to ensure that the whole framework is robust and all relevant stakeholders are prepared for when the mechanism commences.

### 6.3. AEMC review

Enel X supports the requirement for the AEMC to conduct a review of the wholesale demand response mechanism three years after its commencement. Such a review will provide transparency on the costs, benefits and effectiveness of the mechanism, and will identify any areas that may need improvement.

### 6.4. Other implementation issues

One implementation issue not mentioned in the draft determination is the fact that some retailers will need to amend their contracts to remove clauses that prevent customers from engaging with a third party for the purposes of providing demand response. As noted in our submission to the consultation paper, many business customers have retail contracts that inhibit or explicitly prohibit their ability to engage in any demand response activities with a third party.

Given the general intent of the framework is to make retailers indifferent to their customers providing wholesale demand response, any such clauses should be required to be removed to avoid unnecessarily restricting competition. It may also be worth considering whether the rules should explicitly prevent retailers from being able to do this, as is the case in Singapore.[1]

## 7. OTHER ISSUES

This section sets out Enel X's views on other aspects of the draft determination and draft rule that are not covered above.

### 7.1. Requirement for DRSPs to pay contingency raise FCAS costs

Under the draft rule, DRSPs are liable for contingency raise FCAS costs in proportion to the demand response provided. This mirrors the liability that currently applies to generators.

[1] Clause 2.2.2(l) of the Electricity Market Authority of Singapore's *Code of conduct for retail electricity licensees* states that a retailer shall "not discourage, restrict or prohibit consumers from participating in demand response-related or energy efficiency-related initiatives."

The AEMC's issues paper for the *Frequency control frameworks review* stated that the purpose of the cost recovery framework for FCAS is to "provide a price signal that incentivises market participants to act in a way that minimises the need to procure the services." It concluded that "in order to succeed in this aim, a cost recovery framework needs to transparently and accurately map cost recovery to actions that create the need for the services."[2]

Contingency raise FCAS are needed when grid frequency falls, often as a result of a generator tripping. AEMO sets the contingency requirement by reference to the loss of the largest generator. Exposing generators to contingency raise FCAS costs therefore gives generators an incentive to do what they can to prevent a trip.

However, the same logic cannot be applied to DRSPs. In theory, under frequency events could occur as a result of a rapid, unexpected increase in load. However, Enel X is not aware of any circumstances where this has or could occur. Even so, given that:

- only a proportion of loads would be expected to be offering wholesale demand response via a DRSP
- DRSPs will likely only have control over a portion of those customers' loads
- any control a DRSP does have will only enable it to curtail load, not increase it, as the mechanism only supports load reductions,

DRSPs' ability to mitigate the risk of any rapid, unexpected increases in load is very small.

Thus it is not possible to conclude that making DRSPs liable for contingency raise FCAS costs "provides a price signal that incentivises [them] to act in a way that minimises the need to procure the services."

The provision of wholesale demand response does not increase the risk of a contingency event and thus shouldn't change the amount of contingency raise FCAS that AEMO procures. Further, energy users that provide wholesale demand response will already be paying (via their retailer) for contingency lower costs – that is, they are already required to pay a portion of the costs of maintaining grid frequency.

For these reasons there doesn't appear to be a logical reason to require DRSPs to pay for contingency raise services.

### 7.2. On-site generation and batteries

Enel X's understanding is that the mechanism proposed in the draft rule is primarily targeted at net load reductions at a site, but that net exports (for example as a result of having an onsite generator or battery) could also be credited as wholesale demand response. However, this is not clear in the draft determination and it is not explicitly addressed in the draft rule.

Allowing net exports to be counted toward a site's wholesale demand response would allow more wholesale demand response capability to participate in the NEM, for example sites that have a mix of load reduction, generation and storage capability. We would welcome the opportunity to discuss this issue further with the AEMC so that it can be explicitly addressed in the final determination.

[2] AEMC, *Frequency control frameworks review*, Issues paper, 7 November 2019, p. 94.