4 February 2016

Mr John Pierce
Chairman
Australian Energy Market AEMC
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce,

RE: AEMC Consultation Paper – *National Electricity Amendment (Local Generation Network Credits) Rule 2015* (Reference ERC0191)

Endeavour Energy welcomes the opportunity to provide feedback on the AEMC's consultation paper – *National Electricity Amendment (Local Generation Network Credits) Rule 2015* (the consultation paper). Overall, we support the AEMC's initial assessment of the proposed rule.

The AEMC's consultation paper followed the submission of a rule change request by the City of Sydney, Total Environment Centre and the Property Council of Australia (the proponents). The proponents consider the existing rules do not provide sufficient incentives for the efficient investment in, and use of, small-scale embedded generation leading to over-investment in network based solutions and unnecessarily high network costs.

The request seeks to address these perceived issues by amending the rules to introduce a network credit (i.e. a feed in tariff). The proposed credit would be a highly averaged energy based payment to all embedded generators based on the assumed benefits this generation provides to a network. It requires no firm capacity and has no Time of Use (TOU) or locational elements that would encourage the efficient investment in, and use of, embedded generation. It is ideological and asymmetric in nature with a proposed floor-price of zero even if the costs of embedded generation demonstrably outweigh the benefits. It fails to demonstrate positive value to the remaining customer base, which would be required to subsidise this payment in the form of higher network charges.

As such, Endeavour Energy does not consider the proposed rule will promote the National Electricity Objective (NEO), rather, we consider it would detract from its achievement. The proposed rule would impose an obligation on networks to provide an arbitrary credit to embedded generation customers based on an assumed and unsubstantiated network benefit. This would not constitute a cost-reflective pricing of embedded generation and is therefore likely to result in the inefficient investment in, and use of, embedded generation and in turn, higher network charges.

In forming this view, Endeavour Energy has considered the underlying intent of the rule change, the current policy programme, the existing regulatory framework and practical implementation issues. Our key observations are as follows:

- The issues identified by the proponents are immaterial as the value of any cost reflective credit is likely to be negligible and potentially positive where the network costs outweigh the benefits. There are unlikely to be opportunities where forecast, or existing, capacity constraints could effectively be addressed by pooled, excess local generation.
- The alleged issues with the current regulatory framework would be more effectively addressed by:
    - the suite of Power of Choice reforms that have, or will be, implemented by the AEMC. Particularly, the cost-reflective distribution pricing rule change, the small generation aggregator framework rule change and the various existing planning requirements and investment tests;
    - the existing and developing competitive market providing customers with third party aggregation services; and
    - Distribution Network Service Providers (DNSPs) paying local generators directly for their network support services.

- The proposed solution does not differentiate between:
    - small-scale embedded generators and larger-scale generators, despite the issues raised by the proponents only relating to small-scale generators; and
    - existing and new embedded generators who may require different price signals to encourage efficient behaviour.
- The network credit would be based on the assumed benefits associated with small-scale embedded generation. This would either:
    - result in higher network charges to maintain reliability and service demand as additional costs are incurred administering and paying a feed-in tariff based on an assumed benefit that is not realised to address a network need; or
    - match the long term network benefit provided by each embedded generator at a localised level by chance and simply result in a reallocation of wealth between market participants. Whilst these participants will be individually better or worse off there would be no overall reduction in network prices.
- The proposed network credit is not cost reflective as it does not consider the location, time, voltage level and source of generation. This means the credit does not signal to a customer the extent to which they are positively or negatively impacting the network. This would result in a cross subsidy and the inefficient investment in, and use of, embedded generation.

Endeavour Energy considers that a cost-reflective embedded generation tariff could be proposed and determined as part of Tariff Structure Statement (TSS) and annual pricing proposal processes. We consider the distribution pricing rules under Part I of Chapter 6 allow for the proposal of feed-in tariffs. However, a minor rule amendment may be required to remove or clarify clause 6.1.4(a) which prohibits applying any Distribution Use of System (DUOS) charges to the export of electricity. Removing this ambiguity from the rules would be a more preferable and proportional response.

We note that a generation feed-in tariff has not been proposed to date by Endeavour Energy due to practical limitations. A large scale roll out of advanced meters is required before we could consider designing and implementing an effective embedded generation feed-in tariff. Further, it will be important to ensure that such tariffs are implemented in parallel to the introduction of more cost-reflective consumption tariffs and not accelerated inappropriately. Any misalignment in cost-reflectivity between consumption and embedded generation tariffs would result in imbalanced incentives and inefficient outcomes.

In summary, the rule change request is inconsistent with its own stated intent and unnecessary in light of the significant reform program undertaken by the AEMC to date to promote efficient investment in non-network alternatives and to facilitate a transition to more cost-reflective distribution pricing. We consider the costs and negative impacts of the proposed rule clearly outweigh the benefits. As such, Endeavour Energy would support an expedited assessment of this rule change in order to focus industry resources on completing the Power of Choice reforms and addressing other emerging policy matters.

If you have any queries or wish to discuss this matter further please contact Jon Hocking, Manager of Network Regulation at Endeavour Energy on (02) 9583 4386 or via email at jon.hocking@endeavourenergy.com.au.

Yours sincerely,

Rod Howard

Rod Howard
Acting Chief Executive Officer
Endeavour Energy

Response to the AEMC's consultation questions
Question 1 Assessment framework

We consider that the proposed rule fails to satisfy the key questions and issues identified by the AEMC. This is because the existing NER provisions, particularly in light of the substantive Power of Choice reforms, provide sufficient incentives for customers to efficiently invest in and utilise embedded generation and for DNSPs to consider non-network alternatives and implement least cost solutions to address network needs.

Should the AEMC conclude that there is a deficiency to be addressed we do not consider the proposed rule would satisfy the AEMC's assessment framework. There are simpler and cost-reflective solutions available such as direct network support payments (taking the form of standard control service operating expenditure) and market-based third party aggregation services. In addition to these mechanisms, we consider it would be appropriate to review clause 6.1.4(a) of the NER to ensure it does not constrain the development and proposal of cost-reflective feed-in tariffs under Part I of Chapter 6 of the NER.

Addressing any deficiency (not that we consider there is one) through a network credit would be complex. We consider mandating the introduction of a credit would be premature and not feasible based on our existing metering population and broader transition of consumption tariffs. A basic and/or poorly specified credit that is not aligned with consumption tariffs would distort investment decisions and incentivise inefficient utilisation of embedded generation. The credit proposed in the rule change, or even a well-intentioned alternative approach, is likely to embed a subsidy in network prices at the expense of the remaining customer base.

1. **Would the proposed framework allow the AEMC to appropriately assess whether the rule change request can meet the NEO?**

Yes.

2. **What is the relevance, if any, of reliability and security for the purposes of assessing the proposed rule (or a more preferable rule)?**

The NEO seeks to promote the efficient investment in, and operation and use of, electricity services. We consider the components of the NEO; pricing, quality, safety, reliability and security of supply are all interrelated. Whilst the proposed rule will have more direct implications for the efficient pricing of services, the reliability and security of supply may also be affected.

The rule as proposed assumes there are beneficial network support services provided by embedded generators that should be recognised. The proponents consider that a credit would incentivise further support, which will reduce consumption and prices by correcting an alleged over-investment bias in network based solutions.

In assessing the costs-benefits of the proposed rule it will be important to analyse the extent to which embedded generation can be used to meet network needs whilst maintaining reasonable levels of reliability and safety. This will be important in assessing the potential scope and scale of any credit and the risks associated with paying a network credit based on an assumed network benefit.

As the AEMC quite rightly identifies in its consultation paper, the rule change could result in reduced network reliability and quality of supply. This could occur if a network relies on a certain level of embedded generation to address a network need. A network credit would be paid, but the embedded generation may fail to provide the expected level of support resulting in network security and reliability of supply issues that are addressed through unanticipated network expenditure. In this scenario there is a credit paid out with no realised benefit resulting in additional expenditure and lower quality services (at least temporarily) and therefore higher prices in the long term.

We consider this outcome is likely if the proposed rule is implemented. There is no evidence provided of the level of network support that can reliably be provided on a locational basis to address actual network needs to support the calculation of an accurate credit.

An ill-specified credit may also result in significant investment in, and usage of, embedded generation. In this scenario the reliability and quality of supply may be more directly impacted. A high penetration of local generation may create voltage control, protection and other network issues. These issues will result in the reduced quality of services as they emerge and additional costs to rectify.

3. **What changes, if any, to the proposed assessment framework do you consider appropriate?**

If it is determined that the NER could be improved by making a rule change the assessment framework contains a number of key considerations, including:

> *...how those long-run cost estimates are then used to determine a LGNC paid to eligible embedded generators*[1]

We would caution against any detailed analysis and prescription should the AEMC implement the rule or make a preferred rule. We support high level analysis to understand the complexity of the issue and to provide guidance. A more detailed analysis of the issues would best be reserved for the TSS and annual pricing proposal processes. The cost-reflective distribution pricing rule change is a well-designed framework through which DNSPs and the AER could determine the appropriate approach using the LRMC methodology and addressing the specific circumstances of the DNSP in question.

Question 2 Perceived issue with current NER

1. **Are the current NER provisions (including changes that have been made but not yet come into effect) likely to provide appropriate price signals for efficient embedded generation? That is, do the NER provide incentives to individually or collectively (including through small generation aggregators) invest in and operate embedded generation assets in a way that will reduce total long-run costs of the electricity system?**

Yes, with the exception of clause 6.1.4(a).

As outlined by the AEMC there are several NER provisions which facilitate efficient price signals and allow embedded generation customers to access the value they can create. Specifically:

- Network support payments: we consider the most effective price signal is networks directly procuring network support services from customers. The NER already supports such arrangements and further improvements are being made:
    - Large embedded generators (capacity greater than 5MW) can negotiate network support payments.
    - Small customers can sell network support services through small generator aggregators. This is particularly useful for customers who cannot offer a large amount of capacity or firm support. Whilst firms are already offering such services we consider the small generation aggregator framework rule change will increase the development and accessibility of this market in the near future.

[1] AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, p 16.

- The cost reflective distribution pricing rule change is specifically designed to ensure that networks provide appropriate price signals. We consider generation/feed-in tariffs can already be proposed under the amended Part I, Chapter 6 of the NER.

We consider that the rule change is primarily an issue of efficient pricing. As noted above, a rule change has already been implemented to reduce long-term network costs through efficient pricing. A separate solution or alternate mechanism in the NER would be duplicative and increase the risk of asymmetry.

As noted above, we consider the only potential issue in the NER is clause 6.1.4(a). This clause may restrict the operation of the cost reflective distribution pricing rule change. For instance, a network could propose a generation tariff under Part I of Chapter 6. The rule change proponents assume that this would take the form of a network credit as embedded generation is assumed to provide a net benefit to networks. Whilst this may be the case, there could be circumstances where the costs of embedded generation outweigh the benefits to a network. Under Part I of Chapter 6 a network could propose a network credit for embedded generation; however where the credit becomes a positive value clause 6.1.4(a) would prohibit a DNSP from proposing a cost-reflective price.

Therefore, we consider clause 6.1.4(a) represents an unnecessary restriction on the cost reflective distribution pricing rule change that should be removed.

2. **Do the current NER provisions (including changes that have been made but not yet come into effect) appropriately incentivise network businesses to adopt both network and non-network solutions to achieve efficient investment in, and operation of, the electricity system that minimises long-term costs?**

Yes

As outlined by the AEMC in the consultation paper, there are several mechanisms in the NER which incentivise non-network solutions to the extent they support the efficient investment in, and operation of, the electricity system.

DNSPs have various obligations under the Regulatory Investment Test for Distribution (RIT-D) and distribution network planning and expansion framework to inform, consider and include non-network alternatives in their reporting, planning and designing activities.

These mechanisms are supported by the Capital Expenditure Sharing Scheme (CESS) and Efficiency Benefit Sharing Scheme (EBSS) which incentivise DNSPs to implement least cost solutions to address network needs.

The demand management incentive scheme (DMIS) and demand management innovation allowance (DMIA) ensure non-network investments remain competitive on a least cost basis with more traditional network investments. They do so by providing an additional expenditure allowance in the case of the DMIA and an incentive payment capturing the full supply chain benefits of a non-network project in the case of the DMIS (once implemented by the AER in 2016).

In addition to these more direct mechanisms the cost-reflective distribution pricing rule change requires that efficient pricing signals are provided. This will incentivise non-network solutions to the extent they are efficient. The small generation aggregator framework will also facilitate efficient non-network investment by better enabling small generators to sell their output through a third party to DNSPs in a competitive market where they do not have sufficient capacity or firm capacity individually.

We consider the proposed rule only alleges a deficiency with the existing mechanisms and fails to substantiate this. If there is a deficiency with an existing mechanism, it should be identified and directly rectified rather than addressed through a new mechanism. For example, in our response to

Question 2.1 above we have identified a specific issue to be addressed; clause 6.1.4(a) of the NER.

It would be incautious and imprudent to implement a substantive rule change of this nature without compelling evidence. We fail to see how a deficiency with the existing mechanisms can be established when the Power of Choice reforms are still in the process of being finalised and implemented. It would be more appropriate to provide these changes an opportunity to mature so that more targeted and self-evident amendments can be made as required. Currently, we consider the AEMC has implemented a wide-ranging and effective suite of reforms to facilitate and incentivise the use of network and non-network solutions to achieve the NEO.

3. **If your answer to questions 1 or 2 is 'no', what is the specific area in which the current NER provisions do not achieve these outcomes – for example, is the issue with the current provisions only related to embedded generators of a certain type or below a certain size, or is there an issue for all embedded generators?**

N/A

Question 3 Determining avoided costs

1. **What are the factors that influence the long-run network costs that can be avoided through embedded generation? For example, do these cost savings depend on the location, voltage and type of generation?**

The AEMC has largely identified the factors that will impact the costs which can be avoided through embedded generation; such as location, voltage, timing and technology type (we consider technology type includes the compliance of a device with Australian Standards).

These factors may help defer costs or alternatively result in additional costs.

In order to avoid costs the local generation would need to satisfy a network need. It is typically assumed that local generation may help defer augmentation capital expenditure; however this benefit is difficult to realise in practice. Capacity constraints are typically addressed through large network investments in the form of zone substations. There would need to be an unprecedented amount of pooled local generation in a constrained area available at peak times to avoid network expenditure. It is highly unlikely customers will be able to offer network support services at critical times and at the level required at least until storage technologies become more economically viable. To date, shifting consumption through price signals such as off-peak tariffs has proven more effective than aggregating sparse local generation in deferring network investment.

The opportunity for local generation to provide material network support is particularly reduced for Endeavour Energy. This is because significant capacity related investment has already occurred over the 2009-14 period. We do not have material forecast capacity constraints over the coming years, Schedule 1 of our licence conditions has been removed and the majority of our augmentation capital expenditure relates to new Greenfield developments which unavoidably require the establishment of a network.

In the rare circumstance where a customer, or group of customers, can provide adequate levels of network support this would be a highly localised and specific scenario. In such a scenario, a direct network support payment from the DNSP to the demand aggregator who in turn would divide the payment among each customer based on their support would be a more appropriate and effective price signal as opposed to a generic, universal credit.

We consider another key factor is the firmness of the supply. In order to satisfy our obligations and factor generation into network planning processes there must be surety to the level of generation. Otherwise additional costs may be incurred where the generation fails to eventuate to the degree forecast and the network need must still be addressed through network investment. We consider that where customers cannot provide firm supply the small generation aggregator framework rule change will provide an efficient avenue through which these customers can still realise the benefits of their local generation. This is preferable to the rule change proponents' proposal where an arbitrary credit is provided irrespective of whether the generation occurs and a network benefit is realised.

As noted above, these factors will not only determine the costs which may by avoided through embedded generation but also the costs that may be incurred. Embedded generation may result in capital or operating expenditure to address protection, voltage control or other issues associated with high levels of local generation, for example:

- At certain levels of penetration, local generation may result in, or exacerbate, voltage levels which are not compliant with standards (namely AS61000.3.100). Weak LV circuits in semi-rural or rural networks can be particularly vulnerable to voltage control and reverse flow issues.
- Costs may be incurred to modify protection schemes to accommodate embedded generation. For instance, Endeavour Energy now wires voltage transformers in new protection relays for each distribution feeder in order to measure bi-directional power flows.
- As local generation continues to increase so too does the number of complaints and Quality of Supply investigations that a DNSP is required to undertake.

These are just a few examples of the costs DNSPs may incur in managing embedded generation. The rule change proponents have simply assumed there are universal network benefits without providing evidence or examining the potential costs. We consider the factors and high level issues identified above indicate that this is a complex calculation. The level of specificity required to provide an accurate generation price signal would be in excess of any existing consumption tariff available to small customers. The transition of our consumption tariffs is constrained by the available metering technology and consideration of customer impacts. We consider the introduction of any generation credit would also be subject to these limits. There would also be significant risks in mandating a generic or ill-specified credit. The time at which it is appropriate to introduce a cost-reflective credit will depend on the factors discussed above and will be specific to each DNSP's circumstances.

2. **Can embedded generation materially reduce DNSPs' ongoing operating and maintenance expenditure? If so, to what extent do these cost savings depend on the location, voltage and type of generation?**

No, we do not consider embedded generation could materially reduce operating and maintenance costs.

Embedded generation may increase the life of an asset or reduce the maintenance requirements where it helps alleviate the stress an asset is under. Conversely, embedded generation may increase the loads an asset would ordinarily experience and/or create voltage control and protection issues that require additional investigation, operating and maintenance expenditure.

As discussed in the question above, this is a complex issue that would require analysis at a highly localised and specific level to properly understand.

Question 4 Specificity of calculations

If LGNCs of some form were to be introduced:

1. **What is the appropriate degree of specificity in the calculation of avoided network costs and, if relevant, operating and maintenance costs? For example, should different calculations be made for different voltage levels and/or**

geographic locations and, if so, what would be the criteria for distinguishing between levels/locations?

We consider these matters are better determined as part of the TSS process. Significant analysis would be required to even establish generic categories of credits distinguishing between levels and/or locations. It is unclear what the optimal tariff and tariff structure would be at this stage.

We suspect a high degree of specificity would be required based on time, location and voltage levels. For this reason, direct network payments may be more appropriate to ensure a tailored and accurate price signal can be provided to customers. However, creating and administering such payments or tariffs would be a complex and costly exercise. It is unclear whether any benefits would be realised that would justify these costs.

We consider there are even greater risks associated with an ill-specified credit, such as the one proposed by the proponents. Recent experience with the Solar Bonus Scheme indicates that customers respond rapidly and substantively to a subsidy. A new subsidy for embedded generation would lead to customers inefficiently investing in generation in areas where there is no scope to provide an actual network benefit. Customers would then be provided an incentive to inject load into the network at any time irrespective of whether it is required by the network. In this scenario the network is incurring costs to fund and administer the credit and to manage the network impacts of embedded generation whilst not realising any off-setting network benefits.

2. **How often should this calculation be updated, recognising that the potential network cost savings can increase and decrease significantly over time as demand patterns change and network investments are made?**

We consider any credit or payment would need to be flexible and dynamic to ensure that customers are provided cost-reflective price signals. A customer should only be paid a credit where a network benefit is actually being realised. Any potential benefit would likely be locational and time variant and the credit should either be based on a sufficient amount of historical data to forecast this accurately or, preferably, able to vary in real-time to reflect this.

Question 5 Potential benefits of the proposal

1. **Compared with the current NER provisions, would the proposal:**

   (a) Provide superior or inferior price signals to embedded generators (including small-scale embedded generators) to incentivise them to invest in and operate those assets efficiently, thereby reducing long-term total system costs?

The rule as proposed is opportunistic rent-seeking that will impose an obligation on networks to provide an arbitrary credit to embedded generation customers based on an assumed and unsubstantiated network benefit.

Such a credit would provide a poor price signal leading to inefficient investment in, and use of, embedded generation. The proposed credit does not recognise the network costs and benefits associated with an individual embedded generator. Instead, it simply assumes a benefit exists that all embedded generators contribute equally to it. This creates cross-subsidisation between embedded generators in addition to the cross-subsidy between embedded generators and the remaining customer base more broadly.

In this scenario customers would be incentivised to invest in embedded generation irrespective of whether it provides a network benefit in order to obtain the network subsidy. The proposed rule is an energy based payment that is non-TOU and non-locational meaning customers would not be incentivised to deploy their generation at opportune times to support the network. We also note that we are currently in the process of efficiently transitioning consumption tariffs to greater levels of cost-reflectivity. As such, any asymmetry in the levels of cost-reflectivity between generation and consumption tariffs would further distort a customer's decision on whether to use their generation to off-set their consumption or separate their generation to only inject it into the network.

We consider that long term costs would be increased under the proposed rule as it does not promote efficient investment and usage of generation. DNSPs are likely to face increased costs to manage network issues associated with high penetration of generation technologies. There is unlikely to be material benefits realised as the generation technologies will not be deployed and utilised in areas where a genuine network constraint exists (in current conditions the opportunities are few). DNSPs would therefore pay a credit and incur costs to design and administer the payment whilst potentially incurring, rather than deferring, network expenditure and operating costs.

We accept that a well-specified and targeted generation tariff would provide an improved generation price signal to customers. We consider the development of such a tariff is in line with the purpose and objective of the cost-reflective distribution pricing rule change. As DNSPs transition all consumption tariffs to more cost-reflective tariffs, cost-reflective generation tariffs could also be introduced. It would be inappropriate to circumvent this process, which is subject to real world constraints such as customer impacts and the availability of metering technology, and prescribe a credit in the rules. As discussed in question 5.1(d) below an asymmetry between consumption and generation tariffs could further distort price signals and lead to overall higher network charges.

(b) Provide superior or inferior incentives to DNSPs to adopt efficient network and non-network solutions (including small-scale embedded generation) so as to reduce long-run total system costs?

The rule change would not change the incentives a DNSP faces to adopt efficient network and non-network solutions. Instead, the rule change would only change the incentives a generation customer faces as discussed above.

We consider it is more probable that the proposed rule simply increases the risk DNSPs face of increased network costs. This could occur in the following ways:

- The inefficient deployment and usage of generation technologies by customers may result in increased costs to manage voltage and reverse flow issues.
- An LGNC is paid based on the assumed deferral of long-run network costs or operating costs that do not in fact eventuate.
- The design, implementation and administration costs associated with an LGNC scheme.

As identified by the AEMC, if the credit is well-specified and the network support provided by generators is realised, then the credit simply results in a wealth transfer between parties without any reduction in a DNSPs costs.

We do not consider a sharing scheme (i.e. where the customer is paid a percentage of the benefit created) would rectify this issue. Additional wealth would not be created in this scenario as there would be a reduced incentive (because of the smaller payment) for customers to invest in embedded generation systems. It is important any scheme considers the impact on prospective embedded generators rather than only existing embedded generators who have a sunken investment (and therefore respond differently to price signals).
In the long term additional investment would be required by a network to address any shortfall in potential network support. Rather than generate wealth, a sharing scheme would simply incentivise DNSPs to invest in local generation to obtain a benefit in the short term. This would be duplicative as the DMIA, DMIS and RIT-D are existing mechanisms designed to rectify any potential network investment bias.

(c) Have any potential beneficial or detrimental effects on any non-price attributes of the service, such as network reliability and/or security of supply?

Yes

The proposed credit would operate as a subsidy that distorts efficient investment and usage decisions by networks and customers. This is likely to result in a high penetration of embedded generation without consideration of the network impacts.

As previously noted, a high penetration (or un-optimised use of) embedded generation may result in costs to; modify protection schemes, investigate and rectify voltage issues, manage reverse power flows and voltage control and other costs. These issues have the potential to impact the quality and reliability of supply as they emerge.

In addition to these direct issues, customers may experience network reliability and quality of supply issues if DNSPs rely on embedded generation to address a network need. Where the generation is not realised at the scale or time expected then the network issue is not addressed and other issues may also arise such as a power outage or voltage fluctuations.

(d) Reduce or increase the prices consumers pay for electricity?

The proposed rule in all likelihood will only increase the prices consumers pay for electricity. As noted in the consultation paper:

> *…the proponents' suggestion appears to be for all forecast reductions in a DNSP's total costs brought about by the presence of embedded generators to be paid to those generators as LGNCs. For every forecast reduction in long-run network capital expenditure or ongoing operating expenditure there would, therefore, be an equal and offsetting additional cost in the form of LGNC payments.*
>
> *It follows that the introduction of LGNCs of the form specified by the proponents would not reduce a DNSP's total costs. The DNSP would have to recover the same total amount of revenue from customers through network charges. The only difference is that a sum of money that is forecast to be paid to one group of market participants (eg engineering and construction firms that build network assets) is instead paid to embedded generators. In other words, the imposition of a negative tariff designed in this way does not appear to generate any additional wealth. It seems only to reallocate existing wealth from one group of market participants to another.*[2]

We strongly support this analysis and emphasis that even a zero-sum wealth transfer is unlikely to occur. This is because this scenario relies on the credit being cost reflective and well-specified so that is equal to the forecast reduction in long-run expenditure. The proposed credit is not cost-reflective and there would be costs involved in correctly specifying and administering a cost-reflective LGNC. As noted by the AEMC:

> *It follows that, even if LGNCs are designed so as to send exactly the right signals to embedded generators, it is likely that the proposal will result in at least a small increase in average electricity prices for consumers.*[3]

We consider the most likely scenario is that a DNSPs' total costs will increase and in turn electricity prices will also increase. This is because:

> *The payment of LGNCs rests on the assumption that the embedded generators that receive them will have given rise to long-run network cost and/or operating cost savings of an equivalent magnitude. In practice, that may not be the case.*

[2] AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, p 28.
[3] AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, p 29

…. if the calculation of avoided costs is not sufficiently specific, and the LGNCs do not send the right price signals to embedded generators, they may not invest when and where they are needed. In such circumstances, it is possible that the overall effect may be that a DNSP:

> *• does not avoid all of the long-run network costs and/or operating costs that it assumed that it would when it calculated and paid the LGNCs; but*
> *• still pays LGNCs to embedded generators as though it actually avoided all of those costs (when, in fact, it did not); and*
> *• must also incur any costs associated with designing, implementing and administering LGNCs*[4]

In addition to the scenarios outlined by the AEMC we consider the proposed rule or preferable rule could lead to increased prices through asymmetric tariffs. A well-specified LGNC may be on a customer, locational, time based, voltage or technology basis (or some combination of these factors). This would represent a far higher level of cost reflectivity than existing consumption tariffs. We are currently in the process of efficiently transitioning our consumption tariffs to higher levels of cost-reflectivity. However, this transition is dependent on the metering technology in a network area and must be made in consideration of the customer impacts. The sudden introduction of a generation credit with a differing level of cost reflectivity would create an asymmetry.

This asymmetry would create an imbalance in incentives and possibly result in arbitrage opportunities for customers. Under such a scenario small generator customers would be incentivised to:

- separate their consumption and generation activities;
- perpetuate network constraints by consuming inefficiently; and
- provide network support services with their small generation

This issue could eventuate on a larger scale where small generator aggregators exist.

2. To what extent do your answers to 1(a) to (d) depend on:

(a) To whom LGNCs are applied (eg whether it is applied to all embedded generators or whether there are criteria based on a generator's capacity, availability and/or location)?

(b) The degree of specificity in the calculation of avoided network costs (ie whether separate calculations are made for different voltage levels and/or locations) and how often it is updated?

(c) The proportion of the estimated avoided network costs that are reflected in the LGNCs paid to embedded generators?

All of these factors could be used to develop a more cost-reflective credit and efficient price signal. A cost-reflective credit would be costly and difficult to implement, however it would result in improved price signals. However, this would require a similar level of cost-reflectivity to be achieved in consumption tariffs in order to avoid asymmetric incentives as noted above. This level of accuracy would not be achievable for Endeavour Energy at least until a large-scale roll out of advanced metering occurs.

[4] AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, p 29.

The alternative is a more generic, non-TOU, non-locational credit as proposed by the proponents. As aforementioned, we consider this represents a much higher risk as it could result in an inefficient price signal. This could incentivise investment and usage decisions which increase network costs in excess of any potential benefits.

Overall, we consider the proposed credit is a subsidy that would provide inferior incentives to customers compared to existing arrangements. It is clear that a cost-reflective generation tariff which considers the factors (and more) outlined above would provide a superior price signal. The complexity will be in developing and implementing these tariffs at the appropriate time. The TSS provides the mechanism through which this can be achieved and this process should not be superseded by mandating a credit as proposed in the rule change.

3. **If you do not consider that the proposed rule would enhance the NEO, are there potential alternative approaches that may do so?**

As outlined in response to Question 2.1, we consider the only preferable approach would be to remove clause 6.1.4(a) from the rules. The revisions to Part I of Chapter 6 of the NER provide a robust framework for DNSPs to calculate and propose cost-reflective prices to the AER through the TSS and annual pricing proposal processes. Clause 6.1.4(a) of the NER restricts the operation of these provisions by preventing a generation tariff from being positive. There are legitimate circumstances where the costs imposed by embedded generation outweigh the benefits and a price signal should be provided in these instances to modify behaviour.

This simple change would ensure the cost-reflective distribution pricing rule change amendments could be utilised to propose a cost-reflective generation feed-in-tariff without restriction.

Question 6 Potential costs of design, implementation and administration

1. **What changes would DNSPs and other parties need to make to their existing systems and processes to enable the design, implementation and administration of LGNCs? To what extent does this depend on:**

(a) **To whom LGNCs are applied (ie whether it is applied to all embedded generators or whether there are criteria based on a generator's capacity, availability and/or location)?**

(b) **The degree of specificity in the calculation of avoided network costs (and, in turn, LGNCs) – ie whether separate calculations are made for different voltage levels and/or locations?**

(c) **How often the calculation is updated?**

(d) **How often the LGNCs need to be paid?**

2. **What are the likely costs associated with undertaking the changes described above and how are these likely to vary depending on the factors set out in 1(a) to (d)?**

3. **How do these costs compare to the expected benefits of the proposed rule change?**

At a high level, we suspect there would be a significant upfront cost for DNSPs to investigate and establish a localised price. This would require individual customer load data that is currently unavailable until a large scale roll-out of advanced metering occurs. From a billing perspective there may be additional testing and loading required, an increased number, or complexity of, transactions and an increased number of disputes and errors to manage.

Endeavour Energy would need to undertake a substantive project to understand the changes required and the associated costs to implement an efficient network credit. We consider the design of any credit should be optimised as part of a TSS process which allows time for analysis and consultation. This would be a complex exercise that will result in some level of administrative costs. As discussed earlier we do not consider embedded generation, at this stage, can deliver a network benefit that would justify incurring these costs.

We consider the cost reflective distribution pricing rule change and metering competition rule change will foster an orderly transition to more sophisticated tariffs over time. DNSPs will be incentivised and required to implement more tailored and detailed tariffs whilst considering the demand for such tariffs from customers and their ability to respond to more dynamic price signals.

It would be inappropriate to forgo this process of development and require DNSPs to either develop tariffs and price signals beyond their existing capabilities and their customers' ability to respond to or risk implementing a generic, ill-specified tariff that provides suboptimal price signals which may have significant behavioural and network consequences.