RULE CHANGE

Australian Energy Market Commission

CONSULTATION PAPER

National Electricity Amendment (Local Generation Network Credits) Rule 2015

Rule Proponents

City of Sydney
Total Environment Centre
Property Council of Australia

10 December 2015

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About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Summary

The Australian Energy Market Commission (AEMC or Commission) is consulting on a rule change request by the City of Sydney, Total Environment Centre and the Property Council of Australia (the proponents). The request is to introduce a payment from distribution networks to embedded generators, which reflects any benefits the generators provide to the network.

An embedded generator is any generating unit that connects directly to a distribution network. Embedded generators vary by type (some use renewable sources such as solar or wind, but others are powered by fossil fuels such as gas or diesel), size (from small rooftop solar panels to commercial plants) and their usage and availability to export electricity.

The rule change request – and the discussion in this Consultation Paper – is focussed on the network support benefits potentially offered by embedded generation. It is not concerned with the trading or selling of energy by those embedded generators.[1]

The National Electricity Rules (NER) contain several provisions that are designed to incentivise efficient investment and operation of demand management approaches, including embedded generation, as an alternative to further investment in the network. The proponents state that these provisions may be effective for larger-scale embedded generators, but that they are less attractive for small-scale embedded generators.

The proponents suggest that small-scale embedded generators offer significant benefits for which they are not sufficiently rewarded under the current NER provisions. This is said to risk insufficient investment in small-scale embedded generation, inefficient use of its capacity to export electricity and, ultimately, higher prices for consumers. The proponents' solution is to change the NER so as to require distribution network service providers (DNSPs) to:

- calculate the long-term benefits that embedded generators provide in terms of deferring or down-sizing network investment or reducing operating costs; and
- pay all types of embedded generators a local generation network credit (LGNC) that reflects those estimated long-term benefits (netting off any additional costs).

LGNCs would be a separate negative network tariff, and would create a new payment relationship between DNSPs and embedded generators. Under the proposed rule, any embedded generator would be eligible to receive LGNCs, irrespective of size, availability, and whether or not it was already in place prior to the rule change. However, the payment under these LGNCs could vary depending on the voltage level and/or location of each generator.

1 Note that the energy that is generated by embedded generators can either: offset local consumption, be sold through the NEM as market generation or be sold to a local retailer.

The AEMC has made a number of reforms to the regulatory frameworks for embedded generation in recent times. There are now several aspects of the NER that are designed to promote efficient investment in, and use of, this type of generation and other forms of non-network solutions. An important part of this Consultation Paper is devoted to detailing these aspects of the NER so that stakeholders can provide their views on whether there remains an issue to be addressed in relation to the NER not sufficiently incentivising efficient small-scale embedded generation.

This rule change process will consider whether it is appropriate for the NER to do more to foster efficient investment in, and use of, embedded generation so as to contribute to the achievement of the National Electricity Objective (NEO). Determining whether introducing LGNCs – or an alternative solution that better addresses the issues raised by the proponents – would give rise to benefits is not straightforward. This Consultation Paper examines the design and implementation of LGNCs, or an alternative solution, and how the AEMC intends to assess whether the proposal is likely to contribute to the achievement of the NEO.

The issues and questions set out in this Consultation Paper should be of keen interest to consumers, since they must ultimately pay the costs of network and non-network solutions (including embedded generation) through their electricity tariffs. If it is possible to reduce the costs of delivering electricity by incentivising a more efficient mix of network solutions and embedded generation, there is the potential to pass those cost savings on to consumers as lower prices. Conversely, any proposal that increases costs without delivering benefits, will lead to higher electricity charges.

The AEMC will, of course, consider carefully the changes to the NER specifically suggested by the proponents, but we will not necessarily confine our analysis to their specific solution. If the AEMC determines that the proponents have identified an issue with the current NER provisions, we will also consider whether alternative approaches to resolve that issue would better contribute to the achievement of the NEO. Those options might entail modifications of the proponents' LGNC methodology, or different approaches to address the issues raised by the proponents.

The principal purpose of this Consultation Paper is to facilitate public engagement on the proponents' rule change request and the issues described above. As we continue our assessment of this rule change request, stakeholders will be given further opportunities to comment on any detailed policy proposals. Recognising the complexity and importance of these issues, the AEMC has extended the rule change process so that we can undertake additional consultation through a series of public workshops between February and April 2016.

Contents

1 Introduction

On 14 July 2015, City of Sydney, the Total Environment Centre and the Property Council of Australia (the proponents) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) that would alter the payment arrangements for embedded generators in the National Electricity Market (NEM).[2] If implemented as proposed, the rule change would require distribution network service providers (DNSPs) to:

- calculate the long-term economic benefits that embedded generators provide to distribution and transmission networks; and
- pay embedded generators a local generation network credit (LGNC) that reflects those estimated long-term benefits.

Throughout the rule change request, the proponents use the term 'local generation' as shorthand for small-scale embedded generation. Embedded generation is also commonly known as distributed generation. For consistency, we have used the term 'embedded generation' throughout this Consultation Paper, since it is the term used in the National Electricity Rules (NER).[3]

This Consultation Paper seeks stakeholder feedback on the key issues that the Commission will consider in assessing this rule change request. Given the complexity of the issues (and the solution) raised in the rule change request, the Commission has extended the time for making a draft determination to provide time to engage with stakeholders thoroughly on the issues raised. Stakeholder views on the issues discussed in this paper will inform the timetable and process for further considering this rule change request. We will follow this paper with stakeholder workshops at which we will discuss the proposal in more detail, as well as matters raised in submissions.

Depending on the content of submissions and the feedback received at the workshops we may choose to release an Options Paper in June or July 2016 that seeks views on a number of alternative approaches. That would be followed by a draft determination – the timing of which would be advised at the release of the Options Paper. Alternatively, the Commission may elect to proceed straight to a draft determination following the workshops. If so, the rule change will follow the timetable set out in Table 1.1.

2 Oakley Greenwood, 'Local Generation Network Credit Rule Change Proposal', Submission to: Australian Energy Market Commission, Proposed by: City of Sydney, Total Environment Centre, Property Council of Australia, 14 July 2015 ('rule change request'). The rule change request is available on the AEMC's website: www.aemc.gov.au.

3 Chapter 10 of the NER defines an embedded generator as a generator who owns, operates or controls an embedded generating unit. An embedded generating unit is, in turn, defined as a generating unit connected within a distribution network and not having direct access to the transmission network.

Table 1.1 Indicative project timeline

Milestone	Date
Rule change request received from the proponents	14 July 2015
Publication of Consultation Paper	10 December 2015
Deadline for submissions on Consultation Paper	4 February 2016
Stakeholder workshops	February – April 2016
Publication of Draft Determination (6 week consultation)	14 July 2016
Publication of Final Determination	6 October 2016

The remainder of this Consultation Paper:

- sets out the background to, and provides a summary of, the rule change request;
- describes the assessment framework that we propose to use in assessing the rule change request; and
- identifies a number of questions and issues to facilitate public consultation on this rule change request.

Submissions to this Consultation Paper are due by no later than **4 February 2016**. Chapter 6 explains how to make a submission.

2 Background

At the heart of the rule change request is the role of embedded generation in the NEM. The proponents' chief contention is that the NER do not provide sufficient incentives for the efficient investment in, and use of, *small-scale* embedded generation. This is said to result in DNSPs favouring network solutions over cheaper small-scale embedded generation options, giving rise to unnecessarily high network costs.

The rule change request – and the discussion in this Consultation Paper – is consequently focussed solely on the network support benefits potentially offered by embedded generation. It is not concerned with the trading or selling of energy by those embedded generators.

It is also worth noting at the outset that, although the issues identified in the rule change request focus specifically on small-scale embedded generation, the proposal would apply to *all* types of embedded generation – small or otherwise. For example, it would apply to households that have installed solar panels on their rooftops with a capacity of around 1kW and, equally, to large-scale embedded commercial generators, such as the 160MW gas-fired Somerton power station in Melbourne.

In light of the central role that embedded generation plays in the rule change request, this chapter provides an overview of the many different forms it can take in practice and the effects it may have on the design and operation of the electricity system – both positive and negative. It also summarises the various mechanisms already in place in the NER that have been designed to incentivise efficient investment in, and use of, embedded generation.

2.1 Embedded generation

The vast majority of electrical energy delivered to customers in Australia is generated by power stations that are connected to high voltage transmission lines that are, in turn, connected to low voltage distribution lines and, ultimately, a customer's premises. In contrast, an embedded generating unit is a form of generation that is connected directly to a distribution network and does not have access to the transmission network.[4] The energy that is produced by embedded generators can:

- be used to offset on-site consumption (see further discussion in section 2.1.1);
- be sold through the NEM as market generation or sold to a local retailer; and
- attract other payments from DNSPs and transmission network service providers (TNSPs) for any network support benefits that it provides (see further discussion in section 2.2).

To be connected to the distribution network, an embedded generator must pay a DNSP a connection charge. That connection charge may vary depending on the size of the

4 See: NER chapter 10.

generator (see further discussion in section 2.2) and on whether any investment in the network is required to accommodate the generator (eg if transformers or switchgear need to be upgraded). However, once connected, embedded generators do not pay any other charges to use the distribution network. That is, they do not pay the DNSP for providing the infrastructure to transport any energy that they export.

2.1.1 Types of embedded generation

Not all embedded generation is alike. As noted above, to be considered 'embedded', a generator need only be connected to the distribution network. There are many different types of generator that conform to this broad definition. These generators vary considerably in terms of their:

- **Fuel source**: some embedded generators will harness renewable fuel sources such as wind, water and sunlight; whereas others will be powered by natural gas or diesel fuel.
- **Installed capacity**: embedded generators can vary substantially in size from a small rooftop solar photovoltaic (PV) system with a capacity of around 1kW to facilities that are many magnitudes bigger, such as:
  - large wind-farms and commercial power stations; and
  - diesel generators and gas-fired co- and tri-generation plants located in the basements of commercial buildings.
- **On-site usage**: the proportion of energy generated that is injected into the grid can vary considerably between different types of embedded generators:
  - some embedded generators will have some or all of the electricity that they generate consumed on-site and only export the balance – small-scale household solar PV systems being an example; whereas
  - other types of embedded generators, such as large scale wind-farms and commercial generators, will export nearly all of the power they generate.[5]
- **Availability**: some forms of embedded generation can be reliably called upon to supply a fixed amount of capacity for a set period (for example, diesel- or gas-fired generators can usually be switched on at any time), whereas other sources (such as wind and solar) exhibit two elements of intermittency:[6]
  - their output can be quite *variable* – for example, the production of solar generation is dependent on cloud cover; and

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5 There is often little difference between these types of generators and equivalent transmission-connected generators, aside from the fact that they happen to be connected to the distribution network.

6 Note that electricity storage (such as batteries) can be used to mitigate the intermittency of renewable energy, allowing it to be used or exported at other times.

— their output can be *difficult to predict* – because they are influenced by the elements, there is no guarantee that a particular solar or wind generator will be available at any particular time.

It follows that the advantages that these different types of embedded generation can offer to DNSPs (and potentially TNSPs)[7] at a particular time and place may also vary considerably. Sometimes there will be clear benefits and in other circumstances embedded generation will serve only to increase network costs.

2.1.2 How embedded generation can affect networks

In principle, embedded generation can reduce stress on distribution and transmission network infrastructure during peak times. In the longer term this can mitigate the need to invest in maintaining and upgrading the networks. Specifically, customers with embedded generating units may be able to:

- **reduce their reliance on the grid** during peak periods by meeting a greater proportion of the their requirements from energy they generate (although, this will clearly not apply to those embedded generators that export 100 per cent of the electricity that they generate); and

- **export surplus energy** into the distribution network at peak times, potentially reducing the need to transport electricity from generators located further afield through the centralised network and, in turn, the need to invest in expanding and maintaining that network.

However, the extent to which embedded generation will give rise to these benefits in practice depends on the specific circumstances. If there is an imminent need to invest in new network capacity, and embedded generation of sufficient capacity and reliability is able to defer or down-size that investment and/or reduce operating costs, there is a clear benefit. Where that is not the case, the benefits to network businesses diminish considerably, or there may be no benefits.

For example, there may be circumstances in which embedded generation is built where it is not needed, or where it is too small or unreliable to impact on the need to invest in the network. In those circumstances the result may be a duplication of overall costs since, in addition to the costs of connecting embedded generators, the network business may still have to build the same infrastructure that it would have built in the absence of that generation. That is, there may be no network cost savings at all.

There may also be other incremental costs for network businesses and, potentially, for other market participants. These may include:

- any additional spending on distribution infrastructure that is required to enable a greater amount of embedded generation to be exported throughout the local

7 In the same way that embedded generators may reduce the need to invest in the distribution network, they may reduce the need to invest in the transmission network. This is because a greater proportion of local energy requirements would be met by embedded generation.

network whilst meeting the applicable reliability standards (for example, upgrading transformers or switchgear in order to prevent the risk of higher fault levels);

- network businesses incurring transaction costs interacting with embedded generators, such as costs associated with negotiating connection agreements and network support payments (which we discuss in more detail in section 2.2); and/or
- any increase in the proliferation of intermittent sources of embedded generation that causes existing generation assets to be ramped up or down more often (at potentially significant cost), or requires the Australian Energy Market Operator (AEMO) to procure more ancillary services to manage frequency variations.[8]

Achieving the most efficient mix of network solutions (ie poles and wires) and non-network solutions such as embedded generation is, therefore, a difficult balancing act. There can be no presumption that one type of solution will be superior to the other – the appropriate solution may vary from case to case.

These decisions should be of keen interest to consumers, since they must ultimately pay the costs of network and non-network solutions through their electricity tariffs. Consumers are the ultimate beneficiaries of any efficiency gains that can be achieved but are, equally, the parties from whom any additional costs are eventually recovered.

The Commission has given these matters a great deal of consideration in recent times – and continues to do so. There are now several aspects of the NER that are designed either wholly or in part to promote efficient investment in, and use of, non-network solutions, including embedded generation.

2.2 Mechanisms in the NER

The role of non-network approaches – such as demand-side management and embedded generation – formed a key aspect of several of the recommendations set out in the AEMC's Power of Choice review.[9] The NER now contain a number of mechanisms to incentivise efficient use of non-network solutions. These include:[10]

- **Cost-reflective distribution network tariffs**:[11] This rule change requires DNSPs to develop prices that better reflect the costs of providing services to individual

8 Frequency Control Ancillary Services are used by AEMO to balance, over short intervals, the power supplied by generating units and the power consumed.

9 AEMC 2012, Power of choice review – giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney.

10 Note that several, but not all, of these mechanisms were introduced following recommendations in the Power of Choice review. For example, the network support payment, RIT-D and RIT-T and distribution network planning and expansion arrangements were not Power of Choice recommendations.

11 AEMC 2014, Distribution Network Pricing Arrangements, Rule Determination, 27 November 2014, Sydney.

consumers so that they can make more informed decisions about their electricity use. Cost-reflective network tariffs can incentivise investment in forms of embedded generation that result in increased on-site consumption and/or export during peak times.

- **Network support payments**:[12] Embedded generators with capacity greater than 5MW can negotiate with a TNSP to receive network support payments. These payments must reflect the economic benefits the embedded generator is providing to the TNSP by delaying or avoiding investment in the transmission network. Network support payments can also be negotiated between DNSPs and embedded generators, but their treatment under the NER is different.[13]

- **Avoided Transmission Use of System (TUoS) charges**:[14] DNSPs are required to make payments to embedded generators with a capacity of more than 5MW if the presence of those generators reduces the energy supplied to the distribution network from the transmission network. The avoided TUoS payment reflects transmission charges the DNSP saves (ie the Locational Transmission Use of Service payment).

- The **Regulatory Investment Test for Distribution (RIT-D) and Transmission (RIT-T)**:[15] The RIT-D and RIT-T require DNSPs and TNSPs, respectively, to consider the costs and benefits of all credible network and non-network solutions where an investment need is projected to cost $5 million or more. In some circumstances, the benefits will be maximised, or the costs minimised, by procuring embedded generation capacity.

- The **distribution network planning and expansion framework**:[16] This rule change (which also introduced the RIT-D) introduced obligations on DNSPs to annually plan and report on assets and activities that are expected to have a material impact on the network. The rule also includes a number of demand-side engagement obligations on DNSPs. This provides transparency on DNSPs' planning activities and decision-making, and better enables non-network providers to put forward options – including embedded generation – as credible alternatives to network investment.

- The **Capital Expenditure Sharing Scheme (CESS)** and the **Efficiency Benefit Sharing Scheme (EBSS)**:[17] These schemes provide DNSPs and TNSPs with incentives to invest in and operate their networks efficiently by allowing them to retain a portion of any cost savings, and to share the remaining portion with

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12 See: NER clause 5.4AA.

13 Specifically, the terms upon which such payments must be made are not specified in the rules – they are determined purely by negotiation.

14 See: NER clause 5.5(h).

15 See: NER clauses 5.16 and 5.15, respectively.

16 AEMC 2012, Distribution Network Planning and Expansion Framework, Rule Determination, 11 October 2012, Sydney.

17 See: NER clauses 6.5.8A and 6.5.8, respectively.

customers. This incentivises a DNSP or TNSP to substitute a non-network solution for a previously anticipated investment in the network, if the former is more efficient.

- The **demand management incentive scheme (DMIS)**:[18] The Australian Energy Regulator (AER) is required to publish an incentive scheme for network businesses to implement non-network investments where it is efficient to do so.

- The **demand management innovation allowance (DMIA)**:[19] The DMIA provides DNSPs with funding to undertake research and development in demand management projects. The allowance is used to fund innovative projects that have the potential to deliver ongoing reductions in total demand or peak demand, which could include embedded generation initiatives.

- The **small generation aggregator framework**:[20] This rule change sought to reduce the barriers to small generators participating in the market by enabling them to aggregate and sell their output through a third party (a Market Small Generator Aggregator). This makes it easier for those parties to offer non-network solutions, and for DNSPs to procure those options when it is efficient to do so.

The AEMC has also endeavoured to improve the process by which embedded generators – both large and smaller generators (less than 5MW) – connect to the grid. The 'Connecting Embedded Generators' rule seeks to achieve this through a more transparent connection process, with defined time-frames and requirements on the part of the DNSPs to disclose relevant information.[21] In addition, the 'Connecting Embedded Generators Under Chapter 5A' rule provides proponents of smaller scale embedded generation with a choice of two frameworks (the embedded generator connection process in Chapter 5 of the NER or the connection process in Chapter 5A of the NER) when negotiating connection to a distribution network.[22]

In summary, a number of mechanisms in the NER incentivise market participants to invest efficiently in (or procure) embedded generation. However, the proponents contend that there remains a gap in the NER with regard to *small-scale* embedded generation. This has prompted the rule change request.

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18 See: NER clause 6.6.3 as set out in: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015. Note that this clause is not currently included in the consolidated NER.

19 See: NER clause 6.6.3A as set out in: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015. Note that this clause is not currently included in the consolidated NER.

20 AEMC, 2012, National Electricity Amendment (Small Generator Aggregator Framework) Rule 2012, Rule Determination, 29 November 2012, Sydney.

21 AEMC 2014, Connecting Embedded Generators, Rule Determination, 17 April 2014, Sydney.

22 AEMC 2014, Connecting Embedded Generators Under Chapter 5A, Rule Determination, 13 November 2014, Sydney.

3 Details of the rule change request

The proponents state that the NER do not currently provide adequate recognition of the network benefits that small-scale embedded generation can provide, or contain mechanisms that are not readily accessible to these parties. They contend that this will lead to under-investment in and inefficient use of embedded generation, and to long-term network benefits being foregone. This chapter sets out the issues that the proponents claim to have identified with the NER and their proposed solution.

3.1 Issues the proponents raise in relation to current arrangements

The proponents consider that the NER do not allow small-scale embedded generators to "monetise the benefits that they collectively provide to the grid" in the form of capacity support and avoided transmission costs.[23] The network support payment, avoided TUoS and RIT-D arrangements described in Chapter 2 of this Consultation Paper are said to be less accessible to small-scale embedded generators, because:

- the transaction costs to the network business and embedded generator of negotiating these arrangements will almost always outweigh the potential benefits on offer from a single small-scale embedded generator; and
- the networks generally require the provision of firm capacity, which is difficult for an individual small-scale embedded generator to offer.[24]

The proponents do not claim that the NER provide insufficient recognition of the benefits offered to networks by *larger-scale* embedded generators. Rather, they acknowledge that the current NER provisions "may facilitate efficient investment in larger-scale embedded generation".[25]

The proponents also state that the introduction of cost-reflective distribution pricing only provides signals regarding electricity consumption. It does not explicitly address situations where customers with small-scale embedded generators generate more energy than they consume, and export that additional electricity to the grid.

The gaps the proponents claim to have identified in the NER are said to be problematic because:

- the **aggregate benefits** to the network business offered by a portfolio of small-scale embedded generators may be material; and

23 See: rule change request, p2.

24 A generator offers 'firm capacity' when it is able to guarantee that it will inject a certain amount of electricity (eg 50MW) at a particular time (eg between 4pm and 4.30pm if that is when demand tends to be at its highest in that part of the network). Certain types of generator may be unable to provide firm capacity because their ability to generate is dependent on factors that are outside the generator's control, such as whether the sun is shining or the wind is blowing at that time.

25 See: rule change request, p15.

- it may be less important for an individual small-scale embedded generator to offer firm capacity if it is part of a **broader portfolio** of embedded generators. Such a portfolio may include both generators that offer firm capacity (eg diesel and gas-fired generators) and intermittent generators (eg wind and solar).

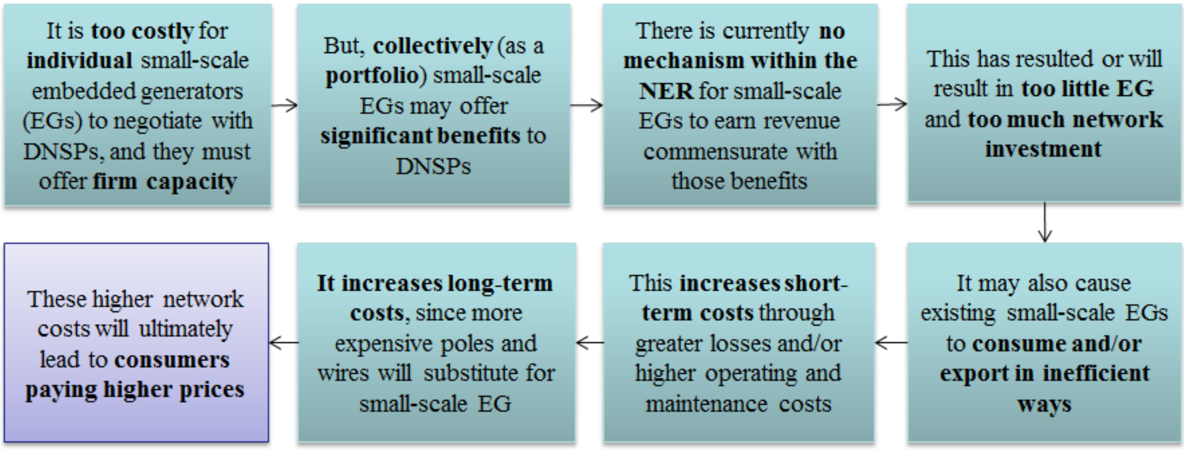
The proponents contend that the gap they identified in the NER has resulted, or will result, in:

- not enough small-scale embedded generation and too much network investment, including when the former would be less costly than the latter; and

- existing small-scale embedded generation being utilised in inefficient ways, with users having an incentive to maximise consumption rather than exporting when it is efficient to do so.

The overall effect is implied to be higher costs in both the short-term (through higher electricity losses due to greater use of the grid) and the long-term (through more expensive network capital costs). These costs are, ultimately, borne by consumers. Figure 3.1 summarises the AEMC's understanding of the issue that has motivated the rule change request.

Figure 3.1 Summary of perceived issue



3.2 Reconciling the rule change request with the proposed NER amendments

The proponents' rule change request consists of a description of the perceived issues and the proposed solution, and marked-up changes to the NER provisions that are intended to give effect to the proposal (in Appendix A of the rule change request). Our initial review has noted at least two inconsistencies between the apparent intention of the rule change request and the marked-up amendments to the NER provisions.

First, it is clear that the proposed rule is intended to produce LGNCs that reflect both distribution and transmission network cost savings. In particular, the proponents state that LGNCs should "capture avoided transmission-use-of-system charges".[26] The proposed amendments to Chapter 6 of the NER would require DNSPs to estimate any reduction in long-term distribution network costs and reflect them in LGNCs, but the proponents have not provided analogous changes for any reduction in long-term transmission network costs (which would require an amendment to Chapter 6A of the NER). Under the proposed amendments, there would be no new obligations on TNSPs. They would continue to levy TUoS charges on DNSPs in the same way as currently. DNSPs, in turn, would continue to pass those costs on to their customers.

Second, the intention of the rule change request is to encourage network businesses to efficiently increase their operating expenditure (in the form of LGNCs) by procuring embedded generation when they expect that this will give rise to long-run savings in network capital expenditure. The simplest way to accomplish this would be to treat LGNCs as an operating expense incurred by DNSPs in providing direct control services. Instead, the proposed rule would classify LGNCs as a new alternative control service.[27] Under the proposal, any savings in a DNSP's capital and operating costs that make up its revenue requirement for standard direct control services would be replaced with an equal and opposite cost that the DNSP would incur designing and paying LGNCs. It is not obvious, therefore, that it is practical – or even possible – to treat LGNCs as a separate service. The feasibility of this feature of the rule change request will need to be considered carefully as part of the rule change process.

The following section provides an overview of the proposed solution to the issues the proponents have identified. In light of the material set out above, and based on our discussions with the proponents, when we encounter an apparent conflict between the approach described in the body of the rule change request and the marked-up amendments to the NER, we have given precedence to the former (ie to the methodology that appears to have been intended by the proponents), while noting any potential complications arising from that inconsistency.

3.3 Overview of the proposed solution

The proponents recommend requiring DNSPs to design and implement a LGNC. The LGNC would be a network price signal for exported energy.[28] Specifically, DNSPs would be required to:

- Develop a credit (a negative network tariff) that reflects any long-term benefits that embedded generators provide in terms of:
  - deferring or down-sizing network investment (capacity support); and
  - reducing operating and maintenance costs (avoided transportation costs).

26 See: rule change request, p8.

27 See proposed clause 6.2.2(f) in the rule change request.

28 The value of the exported energy itself would need to be determined separately. For example, through the price paid if the energy is sold through the NEM as market generation or sold to a retailer.

- Net off any increase in capital and operating costs caused by having to cater for bi-directional/localised energy flow from embedded generators instead of utilising centralised energy generation.

- Pay embedded generators a LGNC equal to that difference between the benefits and costs, which DNSPs would be able to adjust as part of their annual pricing proposals.

It is worth noting that, although the LGNC it is described as a credit, it does not reflect what is generally understood by this term. Specifically, the term *credit* could be taken to mean that the effect of the rule change is to reduce the net amount that embedded generators who consume and export electricity pay for their consumption. Rather, the proposal would set up an entirely new payment relationship – between DNSPs and all embedded generators – that is not linked explicitly to any existing bill. Those payments would not be capped in any way, so there would be no requirement that an LGNC be less than or equal to the sum a customer pays for they energy they consumed. For example, DNSPs would be required to make new payments:

- to large scale wind-farms and commercial generators that are exporting nearly 100 per cent of the energy that they generate (ie to customers who are not consuming any energy); and

- to households with small rooftop solar PV systems that consume some or all of the electricity that they generate on-site, the net effect of which may be that:

    - the LGNC offsets some, but not all, of a household's network charges for consumption; or

    - the household receives a net payment from the DNSP, if the LGNC exceeds network charges for consumption.

The detail of the LGNC would be developed by individual DNSPs, but would be based on a guideline prepared by the AER. The proponents indicate that LGNCs might vary by voltage level and/or location.

However, the proponents state that LGNCs should not vary by the type of embedded generator in question. All embedded generators would be eligible to receive LGNCs, irrespective of size or their availability at particular times.[29] There would also be no distinction between embedded generators already in place at the time any such rule was implemented and those that invested subsequently – both new and existing generators would be eligible to receive LGNCs.

The proposal would let each generator decide whether to receive LGNCs, and incur any incremental metering charges. The proponents also state that the LGNC should not be permitted to become a charge on the generator in those instances where the cost of

29 When an embedded generator is also eligible for network support payments, those payments would be net of any LGNCs.

catering for bi-directional flows exceeds the benefits of the exported energy[30] – for example, because of increased fault levels.[31]

3.3.1 Relationship between LGNCs and a DNSP's revenue allowance

The proposal that LGNCs be paid out as negative network tariffs is significant because existing distribution tariffs are designed to recover each DNSP's total revenue allowance over the regulatory period. A DNSP's revenue allowance would not decrease as a result of the proposed rule because, as we stated above (and explain in more detail in section 5.2.4), the proposal is for the LGNC to match the entire expected reduction in long-run network and operating costs brought about by embedded generation.

In other words, for every forecast reduction in network capital expenditure and/or operating expenditure arising from embedded generation, DNSPs will face an equal and opposite increase in operating expenditure in the form of LGNC payments to eligible generators.[32] As section 5.2.4 explains in more detail, the only difference is that a sum of money that would otherwise have been paid to one group of market participants (eg, engineering and construction firms that build network assets) is instead paid to embedded generators.

3.3.2 Consistency of the proposal with the NEO

The proponents contend that requiring DNSPs to pay LGNCs will contribute to the achievement of the National Electricity Objective (NEO) because it will enable small-scale generators to "monetise the network benefits that they collectively provide to the grid",[33] which will "exert downward pressure on prices and provide benefits to consumers over the long term, because it incentivises investment in alternatives with lower costs than the long run marginal cost (LRMC) of the network."[34] The AEMC's understanding of the claimed benefits of the proposed rule change are summarised in Figure 3.2.

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30 In this respect we note that clause 6.1.4(a) already prevents a DNSP from charging users distribution use of system charges for exporting electricity into the distribution network.

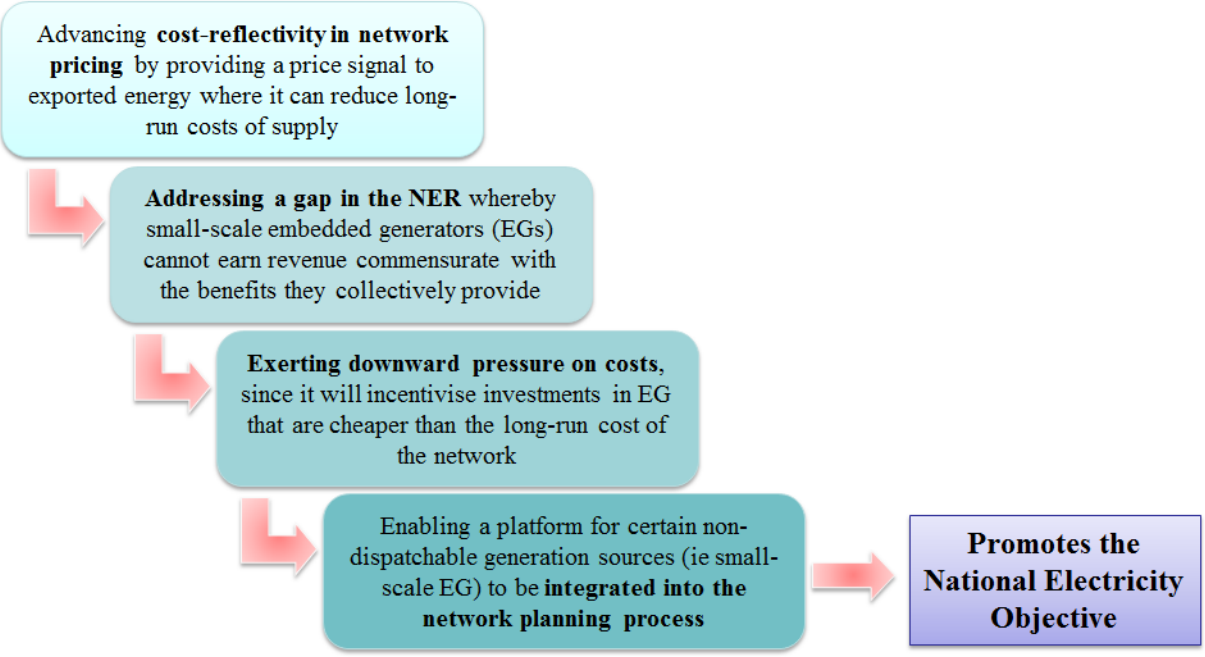
31 The proponents state that the DNSPs can be expected to disallow further connections in an area when this arises, or to allocate any such additional costs across all applicable tariff classes (ie consumers).

32 We note that, in prospective terms, the CESS and EBSS are calibrated so that a DNSP's overall financial position would not change (in net present value terms) if it were to spend less than its capital expenditure allowance and spend an equal amount more than its operating expenditure allowance.

33 See: rule change request, p2.

34 See: rule change request, p3.

Figure 3.2 Summary of purported benefits



4 Assessment framework

This section describes the aspects of the NEO that are relevant to the rule change request and introduces our proposed assessment framework.

4.1 Requirements under the NEL

The AEMC must assess proposed changes to the NER based on whether the proposed rule will, or is likely to, contribute to the achievement of the NEO. The NEO is:[35]

> "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The relevant aspects of the NEO in this instance are the promotion of efficient investment in, and operation of, electricity networks and generation units for the long term interests of consumers with respect to:

- **price** – whether the proposal is likely to decrease or increase the prices paid by consumers for electricity; and
- **reliability and security** of electricity supply experienced by consumers.[36]

The AEMC may make a more preferable rule if it is satisfied that, having regard to the issues raised, it is likely to better contribute to the achievement of the NEO.[37] To determine whether the proposed rule, or a more preferable rule, is likely to contribute to the achievement of the NEO, we propose to apply the assessment framework described in the following section.

In designing the framework we have been mindful of the fact that, although the issues identified in the rule change request focus specifically on small-scale embedded generation, the proposal itself would apply to *all* types of embedded generation – irrespective of its size. As a result, it is important that our framework and the issues we raise for consultation in Chapter 5 reflect that breadth of application.

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35 NEL s.8.

36 We note that the rule change request focuses primarily on the potential effects of the proposed rule on prices. While those effects are plainly relevant, the AEMC is also interested in stakeholders' views on the potential impact of the proposal on reliability and security, including whether there might be adverse consequences for these non-price dimensions of supply.

37 NEL s.91A.

4.2 Proposed assessment framework

Promoting the long-term interests of consumers means that network quality, safety, reliability and security of supply requirements are met at efficient long-term cost, taking into account both network and non-network (including embedded generation) options. This will be achieved if:

- Demand is met at the **lowest total system cost** (given reliability standards): the NER should incentivise DNSPs to provide network services at the lowest total cost by using an efficient combination of network and non-network solutions.

- **Prices reflect those costs**: customers should face tariffs that reflect the underlying costs of supply so that consumption and, subsequently, investment is not inefficiently deterred or encouraged.

- There is **efficient investment in new assets** over time: the NER should provide DNSPs with incentives to make the right investments in network and non-network solutions at the right times and in the right places.

To assess whether the proposed rule (or a more preferable rule) promotes these outcomes and, in turn, contributes to the achievement of the NEO, we will first examine whether the proponents have in fact identified an issue with the existing NER provisions. The key question here is whether the NER provide sufficient incentives for customers to invest efficiently in embedded generation and to operate it efficiently, and for DNSPs to procure it when it is the least cost solution.

If the current NER provisions appropriately incentivise such outcomes, then there is no issue to address. Conversely, if the NER could be improved to better incentivise such outcomes – as argued by the proponents – then there is a potential issue that may warrant change. It would then be necessary to consider whether the proposed rule (or a more preferable rule) would be likely to address those matters and deliver long-term benefits to consumers in the form of reduced prices and/or improved reliability.

Three issues of particular relevance to applying this assessment framework are:

- whether it is feasible to arrive at a sufficiently accurate calculation of the long-run network costs and/or operating costs that will be avoided through embedded generation, bearing in mind that these avoided costs may vary by voltage level, location, the type of generator and generator availability;

- how those long-run cost estimates are then used to determine a LGNC paid to eligible embedded generators; and

- what impact the LGNC is likely to have on electricity prices for consumers – including those who have embedded generation and those who do not.

Finally, we will consider whether any potential benefits of the proposed rule (or a more preferable rule) are likely to outweigh the costs associated with designing, implementing and administering it.[38] If the likely benefits of the rule change outweigh the costs then it should be made. If they do not, then the rule should not be made.

The Commission welcomes stakeholder feedback on our proposed assessment framework.

Question 1 Assessment framework

1. **Would the proposed framework allow the Commission to appropriately assess whether the rule change request can meet the NEO?**
2. **What is the relevance, if any, of reliability and security for the purposes of assessing the proposed rule (or a more preferable rule)?**
3. **What changes, if any, to the proposed assessment framework do you consider appropriate?**

38 As we explain in more detail in section 5.2.3, these costs are likely to vary depending on the degree of specificity in the calculation of the LGNCs; eg the extent to which they vary by voltage level, location and type of generator.

5 Issues for consultation

This chapter identifies a number of issues that the Commission is seeking stakeholder views on, in order to inform its assessment of this rule change request. The issues outlined below are provided for guidance. Stakeholders are encouraged to comment on these issues as well as any other aspect of the rule change request or this Consultation Paper.

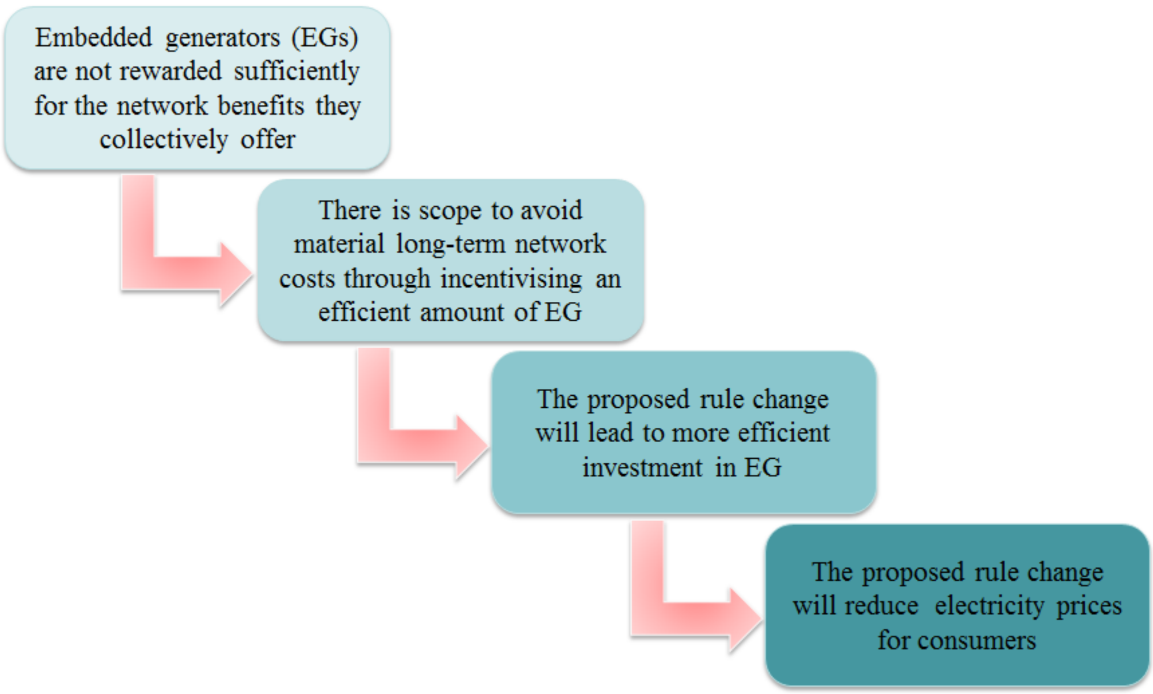
5.1 Is there an issue with the current NER provisions?

Chapter 3 explained that the basic proposition in the rule change request is that DNSPs' costs are higher than they need to be (or will be in the future) because the NER are said not to provide:

- appropriate price signals to customers to invest in embedded generation and to export energy; or
- sufficient incentives to DNSPs to procure such solutions, including when they are lower cost than network investments.

The Commission would like to understand whether the assumptions that underpin the proponents' view hold. The Commission's understanding of these assumptions are summarised in Figure 5.1. If any of those conditions do not hold then there may be no issue with the NER that would warrant change.

Figure 5.1 Assumptions underpinning the rule change request



5.1.1 Investment in embedded generation

The proposed rule change will contribute to the achievement of the NEO if it alters the commercial incentives facing market participants and leads to more efficient investment and/or operational decisions. In this specific instance, the proposed rule change will advance the NEO if it incentivises investment in, and use of, embedded generation that otherwise would not have occurred, which reduces long-run costs for DNSPs and, in turn, the average prices paid by consumers.[39]

The proponents argue that embedded generators are currently not rewarded sufficiently for the benefits that they collectively offer to the networks. If left unchecked, this will lead to inefficient under-investment in, and inefficient operation of, embedded generation. In order to test that claim, we draw a distinction between the issue that the proponents identify in their rule change request (which pertains to small-scale embedded generators) and the solution they offer (which would apply to all embedded generators). The proposed solution:

- Does not differentiate between the small-scale embedded generators that the proponents say are incapable of negotiating with network businesses under the existing NER provisions and the larger-scale generators that can (eg large wind farms).[40] Given that the proponents have acknowledged that the current NER provisions "may facilitate efficient investment in larger-scale embedded generation",[41] it is unclear what efficiency benefits – if any – would arise from compelling DNSPs to make additional payments to these larger generators.
- Offers no distinction between existing embedded generators and new generators – all would be eligible to receive LGNCs. By definition, the absence of a LGNC has not prevented existing embedded generators from investing. Paying those existing generators LGNCs might reward them for investments that they have already made without that inducement. However, it may also incentivise more efficient utilisation of existing embedded generation, eg by providing them with incentives to export energy when it is efficient to do so.[42] This raises the question of whether it is appropriate to draw a distinction between new and existing investments in embedded generation.

The Commission is interested in stakeholders' views on whether the assumptions underpinning the rule change request apply to existing generators and to larger-scale generators. We are also interested in exploring the extent to which those assumptions hold for the small-scale generators that are at the heart of the rule change request.

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39 While maintaining or improving the quality, safety, reliability and security of supply.

40 See: rule change request, p15.

41 *Ibid*.

42 It may also be the case that such outcomes are only possible because of the embedded generation that is already in place. For example, an additional investment in embedded generation capacity may only be capable of deferring a network augmentation when it is added to the embedded generation capacity that already exists. Although it is the new generation that makes the difference at the margin, it may not have that effect in the absence of the prior investments.

For example, the proponents claim that, under the current NER provisions small-scale embedded generators are not sufficiently rewarded for the benefits that they collectively offer to networks. This is predicated on the view that there is insufficient scope for customers to form a portfolio of generators, or for a third-party aggregator to fulfil such a coordination role.[43] However, we note in this respect that:

- the small generation aggregator framework rule change sought to reduce the barriers to small generators participating fully in the market by enabling them to aggregate and sell their output through a third party (a Market Small Generator Aggregator);[44] and
- there are currently firms in the market, such as Reposit Power, that appear to be offering customers these third party aggregation services.[45]

The proponents also claim that providing small-scale embedded generators with LGNCs would lead to more efficient investment and/or operating decisions by those parties. This assumption hinges on whether the absence of such a payment is causing (or will cause) some small-scale embedded generators not to invest when they otherwise would have or to operate their generators in an inefficient way.[46]

To this end, the Commission will seek to understand the reasons new small-scale embedded generators invest and the factors that influence their operating decisions. For example, we will explore whether new investment is likely to be in response to the prospect of receiving LGNCs for the network benefits of exported energy, to sell the energy itself or for other non-price reasons, such as to have a form of back-up power or for environmental reasons. We will also consider whether any additional price signal provided through LGNCs is likely to be large enough to have a material effect on a small embedded generator's investment and/or operating decisions.[47]

5.1.2 Incentives on DNSPs

The rule change request contends that the NER could do more to incentivise DNSPs to procure an efficient amount of network support services from embedded generation. This is based on the view that DNSPs do not currently have the right incentives to invest in non-network solutions as a lower cost alternative to investment in the network.

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43 The role of a small generation aggregator is described in s.2.3A of the NER.

44 AEMC, 2012, National Electricity Amendment (Small Generator Aggregator Framework) Rule 2012, Rule Determination, 29 November 2012, Sydney.

45 See Reposit Power website, viewed on 17 November 2015, http://www.repositpower.com.

46 The absence of such payments has not precluded investment from existing embedded generators (large and small). It should also be noted that LGNCs will only provide a price signal that reflects the avoided network costs. Some embedded generators already receive other payments, such as feed-in tariffs (FITs) that reflect avoided generation costs and renewable energy certificates (RECs) that reflect environmental benefits.

47 For example, the magnitude of a typical LGNC relative to the investment cost.

More specifically, it assumes that there is the potential for DNSPs to avoid significant long-term costs through procuring additional network support services from embedded generation, but that they are either unable or unwilling to do so under the current NER provisions. Section 5.1.1 highlighted the issues with this assumption as far as existing embedded generators and larger-scale embedded generators are concerned. If the assumption holds at all, it may be in relation to small-scale embedded generation. This ultimately turns on the effectiveness of the current NER provisions at facilitating efficient planning and investment by DNSPs – including in non-network solutions. The key issue is whether those mechanisms summarised in section 2.2 sufficiently incentivise DNSPs to procure networks support services from embedded generation – and, particularly, small-scale embedded generation – to minimise long-term costs of supply.

The Commission welcomes stakeholders' views on whether the assumptions underpinning the proposed rule change hold, and whether there is an issue that should potentially be addressed.

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?**
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?**
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?**

5.2 Potential benefits of the proposed rule

The chief potential benefit in the proposed rule change lies in reductions in long-term network costs and ongoing operating costs that, in turn, reduce the prices consumers pay for electricity. The rule change would seek to obtain those benefits by requiring DNSPs to do two things:

- estimate the long-term cost savings that they expect to obtain during a regulatory period through the existence of embedded generation (with guidance from the AER); and
- design LGNCs that reflect those benefits and pay them to qualifying generators.

Several key issues arise in relation to both of these steps.

5.2.1 Factors that influence long-run avoided network costs

Estimating the network costs that will be saved in the long-run due to embedded generation may not be straightforward.[48] As section 5.1.1 explained, long-run network costs that are expected to be incurred in the future can only be avoided through investment in new embedded generation, or through more efficient use of existing generation. However, whether the actions of any particular embedded generator (or a portfolio of generators) will give rise to long-run network cost savings depends on the location, voltage and type of the generator(s). The rest of this section discusses each of these factors in turn.

Location of the generator

The value of an embedded generator (or a portfolio of embedded generators) in reducing the need for investment in the network will depend on whether it is connecting (or connected) in a location where additional network investment will soon be needed, or where there is spare network capacity.[49]

The long-run network cost savings from embedded generation connecting (or connected) where there is sufficient spare capacity to meet current and forecast future electricity demand are likely to be low or zero, because the value of any potential deferral or down-sizing of future network investment is relatively low.[50] Costs may even increase if the additional generation output results in bi-directional flows and increases fault levels.

But as the need to invest in new network capacity approaches in a location, the long-run network cost savings from additional embedded generation output will increase, because the value created through any potential deferral or down-sizing of that imminent network investment is closer in time.

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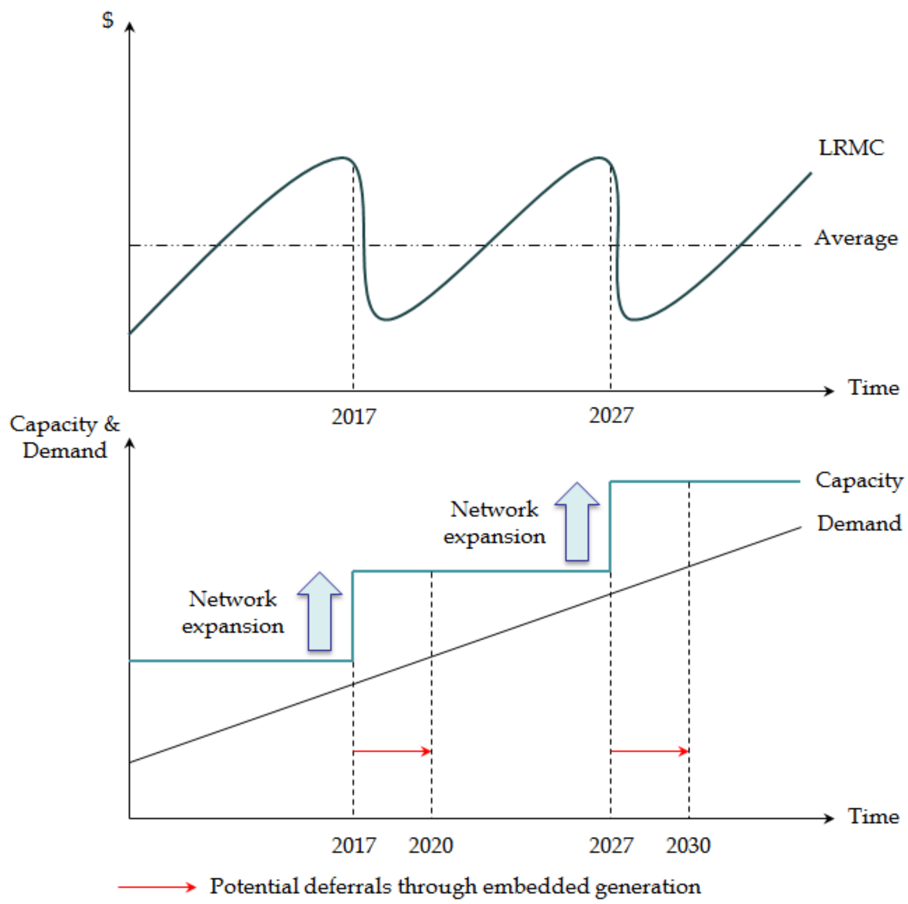
48 The extent to which the proposed rule is likely to give rise to reductions in ongoing operating and maintenance costs is discussed in section 5.2.2.

49 This is acknowledged by the proponents in their rule change request. See: rule change request, p9.

50 Specifically, this is due to discounting: if additional network investment is not going to be needed for, say, another ten years, the saving (in net present value (NPV) terms) associated with pushing that investment need back by, say, another one or two years may be trivial. In contrast, the saving (in NPV terms) associated with deferring imminent network investment by, say, one or two years, is likely to be high.

In other words, the benefits of additional embedded generation in a location will vary substantially over time. Figure 5.2 illustrates that the potential cost savings (measured by long-run marginal cost (LRMC)) that can be made by pushing back an imminent network investment (eg in 2017 in Figure 5.2) are significant. But once an investment in the network has been made, the potential for further savings falls away and efficiency is instead maximised – and the costs for consumers minimised – by utilising that new network capacity rather than encouraging further investment (or additional export from existing embedded generation). That remains the case until the need for new network investment re-emerges.

Figure 5.2 Fluctuations in network cost savings



Voltage level

As the proponents highlight, the network cost savings may vary depending on the voltage level at which an embedded generator connects.[51] Specifically, the more of the network an embedded generator uses to deliver electricity, the more network assets the DNSP will need to continue investing in and maintaining.

51 See: rule change request, p8.

Type of generator

The extent to which network costs can be avoided may depend also on the type of embedded generator in question. A customer may be investing at the right time and in the right place but, if the generation capacity in question is either too small or unreliable to have a material effect on projected system requirements, then there may be no network cost savings.

Although the proponents acknowledge that it may be appropriate to disaggregate LGNCs by location and voltage level, they do not consider that it is appropriate to limit the payment of LGNCs to certain types of generator. That is, they do not support only paying LGNCs to those of a particular size or those that can guarantee capacity support to meet electricity demand at times of peak demand.[52] Rather, they contend that all embedded generators – irrespective of type – can be treated as part of a diversified portfolio of generation and, consequently, be eligible to receive LGNCs.[53] The proposition appears to be that, even if an individual generator is very small or cannot guarantee supply at a particular time, it can be presumed to be part of a larger group of proximately located units that, collectively, will provide a sufficiently large and reliable source of capacity.

This raises a number of issues, including whether:

- it can be safely assumed that there will indeed be other embedded generators in a location that, when aggregated together, provide sufficient capacity to defer or delay network expenditure; and
- it is appropriate for all of the embedded generators in any such portfolio (however defined) to receive the same LGNCs.

It is not obvious that either of these assumptions would hold in practice, since:

- It is conceivable that there will not be a sufficient portfolio of embedded generators in a location to defer or delay network investment in that location. For example, the pool of generators may be too small, or the source of generation may not be sufficiently reliable, even after all of the individual sources are aggregated.

52 The ability of embedded generators to offer firm capacity is particularly important to DNSPs, since they are subject to reliability standards that place limits on the number of times per year that customers' power supply can be unintentionally interrupted, and on the duration of those outages. If a generator is able to guarantee that it will inject a certain amount of electricity (eg 50MW) at the time of peak demand, then the DNSP can rely on that capacity being available and will know that it will not have to transport power through the centralised network. However, if an embedded generator cannot offer firm capacity (eg because its ability to generate at the required time depends on whether the sun is shining) then the DNSP knows that it will need to have sufficient network capacity available to transport energy through the centralised network in the event that the generator cannot supply when it is needed.

53 See: rule change request, p9.

- Even if there is a sufficiently diverse portfolio, it is unclear whether it is appropriate for all of the generators in that collective to be compensated equally if some contribute more than others. For example, if some embedded generators rarely, if ever, export during peak periods they will offer little incremental value to the network.

If the proponents' assumptions do not hold then, either:

- DNSPs will pay LGNCs but will also have to invest in their networks in order to be certain of meeting reliability standards at times of peak demand, which will result in increased electricity prices for consumers;[54] or

- DNSPs will factor the availability of embedded generators into their planning and rely on these portfolio effects and, if those generators turn out not to be available to the extent forecast, consumers will experience poorer reliability.

The Commission is seeking to understand how the above factors influence the extent to which embedded generation can be expected to give rise to network cost savings.

5.2.2 Factors that influence avoided operation and maintenance costs

The previous section focussed solely on the estimation of long-run network cost savings arising from embedded generation.[55] However, the proponents also suggest that the export of energy from embedded generators will result in lower on-going operation and maintenance costs for DNSPs.[56] Specifically, they contend that:

> “where local generation replaces the use of centrally generated electricity, this energy does not flow through the portions of the network infrastructure upstream of that injection, thereby avoiding any variable costs associated with the flows in the upstream portions of the network.[57]”

However, the proponents do not elaborate on what those avoided variable costs might entail in practice. The Commission is interested in stakeholders' views as to whether embedded generation can materially reduce DNSPs' ongoing operating and maintenance expenditure and, if so, how those reductions might be estimated.

54 Put another way, DNSPs would be paying embedded generators LGNCs for long-run network cost savings that did not materialise.

55 The proponents refer to this as "capacity support" in the rule change request. See: rule change request, p12.

56 The proponents refer to this as "avoided transportation costs". See: rule change request, p12.

57 See: rule change request, p14.

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?**

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?**

5.2.3 Trade-off between accuracy and simplicity

When it comes to estimating long-run avoided costs, there is a clear trade-off between accuracy and simplicity. On the one hand, more complex calculations that account extensively for all of the variables described in the previous section (eg by undertaking a large number of highly localised estimates of potential cost savings) can be expected to yield the most accurate answers and, in turn, the most efficient price signals. However, these calculations may be costly to undertake and volatile over time; and potentially difficult for embedded generators to understand and predict when making investment decisions. The costs that DNSPs incur in making these calculations would be recovered through higher network charges for consumers.

On the other hand, calculations that are relatively simple (eg if there is no location-specific element) will be less costly to undertake, less volatile over time and easier for existing and prospective embedded generators to understand and to predict. But these are more likely to send the wrong price signals. This trade-off is best illustrated using a simple example in Box 5.1.

Box 5.1 Illustration of the trade-off between accuracy and simplicity

Suppose that a distribution network is made up of two areas. In location A, there is an imminent need for new network capacity and so the potential long-run cost savings from embedded generators investing in this area are high. In location B, network capacity is ample, and so the potential benefits are minimal.

If the DNSP undertakes two avoided cost calculations – for locations A and B, respectively – and pays a bespoke LGNC in each area, embedded generators in location A will be paid more. Conversely, if the DNSP makes a single calculation for the whole network – ie the average potential savings over both locations – such that customers receive the same credit regardless of where they locate, then:

- the average LGNC paid to customers in location A will be too low and offer a weaker signal of the potential long-run network cost savings, which may lead to too little investment in embedded generation in location A; and
- the credits paid to customers in location B will be too high and offer a stronger signal of the potential long-run network cost savings, which may lead to too much investment in location B.

The overall effect may be that the DNSP cannot defer or downsize the network investment in location A. That is, it would not achieve the savings that a bespoke LGNC would offer. However, embedded generators would still be paid LGNCs as if long-run network cost savings had been achieved. The effect is likely to be that average electricity prices for consumers would increase.

As the example in Box 5.1 demonstrates, one of the key design issues is how to strike the right balance between providing the right investment signals, while ensuring the calculation does not become unduly burdensome.[58]

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?**

58 Analogous issues arose in the context of the rule change review that introduced cost-reflective distribution pricing.

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?**

5.2.4 Allocating forecast long-term cost savings

Assuming that it is possible to arrive at a reasonable estimate of the long-run network and, if relevant, operating and maintenance cost savings expected to be delivered by embedded generation (recognising the above trade-off between complexity and simplicity), the issue then arises as to how to allocate that potential benefit between embedded generators, DNSPs and consumers.

Under the regulatory arrangements that apply to DNSPs' revenues and prices, the AER sets an overall revenue allowance that DNSPs can recover for a period of typically five years. Each DNSP then sets annual distribution network charges across the different groups of consumers that it serves, so as to recover a sum of revenue equal to the allowance determined by the AER.

As we noted earlier, 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.

Moreover, it is conceivable that the allocation methodology in the rule change request may actually increase DNSPs' total costs and average electricity prices for consumers. 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.[59]

59 We note that it is possible that there may be other cost savings throughout the supply chain that are not reflected in LGNC payments. For example, embedded generation might displace more expensive transmission-connected generation, leading to reduced wholesale prices (although some generators may already be receiving a feed-in-tariff from their state government that may reflect – at least in part – these benefits). There may also be benefits through reduced energy losses. However, neither of these factors is relevant to the determination of the LGNC.

As section 5.2.3 explained, 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 (an issue section 5.3 explores in more detail).

Even if LGNCs are designed so as to send efficient price signals to embedded generators, and the forecast long-run network cost savings are achieved,[60] DNSPs' total network costs may still increase, leading to higher network charges for consumers. This is because a DNSP would still have to pay LGNCs that were equal to the long-run network cost and/or operating cost saving (resulting in no reduction in its total costs), plus the additional costs of designing and administering LGNCs.

Indeed, it is important to remember that the efficient costs that DNSPs incur calculating LGNCs and making payments to every eligible embedded generator will, ultimately, be recovered through consumers' network charges. 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.[61]

Even if the proposal would increase total costs, the methodology might still be modified in some way so as to give rise to a more efficient outcome. For example, by paying embedded generators a LGNC worth less than 100 per cent of the estimated network cost savings. There may also be alternative approaches that extend beyond the LGNC methodology that are capable of delivering benefits to consumers.

The Commission welcomes stakeholders' views on the extent to which the proposal addresses the issue that the proponents identify and, if not, whether other solutions might give rise to the identified benefits and contribute to the achievement of the NEO.

60 Note that this may not necessarily be the case, in practice, even if the right price signals are sent.

61 This possibility is acknowledged by the proponents. See: rule change request, pp21-22.

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?**

    (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?**

    (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?**

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

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?**

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

5.3 Potential costs of design, implementation and administration

Even if the proposal (or an alternative approach) is expected to give rise to material benefits, it is necessary to consider whether they will outweigh the costs of designing, implementing and administering the solution. In this instance, the proposal could impose a number of additional costs on market participants.

In the first instance, there are likely to be a number of costs associated with designing the LGNC framework itself, including:

- the costs to the AER of producing a guideline and of stakeholders engaging in the process of developing the guideline;

- the costs that DNSPs and other parties incur designing the methodology for estimating long-run network cost and/or operating cost savings; and
- the costs of translating those estimated cost savings into negative network tariffs.

Once those design elements are in place, further costs may be incurred implementing and administering that framework, such as:

- the transactions costs of the DNSPs and each embedded generator contracting with each other;
- costs incurred by DNSPs to collect and manage information related to the LGNCs;
- the costs to DNSPs of periodically paying LGNCs, which may involve setting up new systems to make new payments; and
- any costs that DNSPs would incur adjusting their other network tariffs so as to ensure that they recover their total revenue requirements in the event that their total costs increase.

These costs are likely to vary significantly depending on the complexity of the design of the LGNC calculations. However, as section 5.2.3 explained, the simpler those calculations became, the less likely it is that the resulting LGNCs would send the right investment signals to embedded generators.

The Commission invites stakeholders' views on the potential costs of designing, implementing and administering the solution set out in the rule change proposal, and how they are likely to compare to the potential benefits.

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?**

6 Lodging a submission

The Commission invites written submission on this rule change request.[62] Submissions are to be lodged online via the Commission's website www.aemc.gov.au, or by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

or by fax to (02) 8296 7899.

Submissions must be clearly marked with the project reference code: **ERC0191**.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions on rule change proposals.[63] The Commission publishes all submissions on its website subject to a claim of confidentiality.

Upon receipt of a submission, the Commission will issue a confirmation email (for electronic submissions) or letter (for submissions by mail or fax). If confirmation is not received within three business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

All enquiries on this project should be directed to Hayden Green on (02) 8296 7800.

62 The Commission published a notice under section 95 of the NEL to commence and assess this rule change request.

63 This guideline is available on the Commission's website.

Abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CESS	Capital Expenditure Sharing Scheme
Commission	See AEMC
DMIA	Demand Management Incentive Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
EG	Embedded Generation
LGNC	Local Generation Network Credit
LRMC	Long Run Marginal Cost
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
TNSP	Transmission Network Service Provider
TUoS	Transmission Use of System