12 February 2016

Dr Ron Ben-David
Chairperson, Victorian Essential Services Commission
Essential Services Commission
Level 37 / 2 Lonsdale Street
Melbourne Victoria 3000

Via email: energy.submissions@esc.vic.gov.au

Inquiry into the true value of distributed generation – Response to proposed approach

Dear Dr Ben-David

I am writing to you following the release of the Essential Service Commission's report *Inquiry into the true value of distributed generation – Proposed Approach Paper* (Approach Paper) in December 2015.

The ENA welcomes the transparent and staged approach the Commission has proposed in the Approach Paper for the conduct of this important review process. The ENA and its members recognise the economically efficient integration of distributed generation is a critical means of providing new services, value and benefits to individual customers as well as wider benefits to other network customers.

Providing a sequenced national approach to efficient distributed energy incentives

As outlined in our previous input into the inquiry, energy network businesses consider the Commission's review will be one of a number of important opportunities occurring through 2016 to ensure promotion of the efficient integration of increasing levels of distributed generation within electricity distribution networks in Australia.

ENA also recognises that the Commission's review will occur in the context of a series of separate but directly related initiatives, including the Queensland Productivity Commission inquiry into the value of distributed solar generation, and the proposed introduction of a local generation network credit scheme under a current *National Electricity Rules* change application soon to be considered by the Australian Energy Market Commission.

The ENA notes these developments occur within a national electricity market. ENA strongly supports a coordinated national regulatory and pricing framework that promotes efficient investment and usage decisions throughout the energy chain, including electricity transmission and distribution networks, gas networks and embedded generation. The efficient investment, in and use of, embedded generation has material benefits to both consumers and energy networks.

ENA has been active in publicly promoting the consumer benefits of a sequenced approach to network pricing reforms, including through the recent distribution network pricing rule change. ENA members are currently in the process of developing, refining, consulting upon, and seeking approval of a 'first wave' of reformed network pricing structures (for example, through the AEMC's Tariff Structure Statements processes).

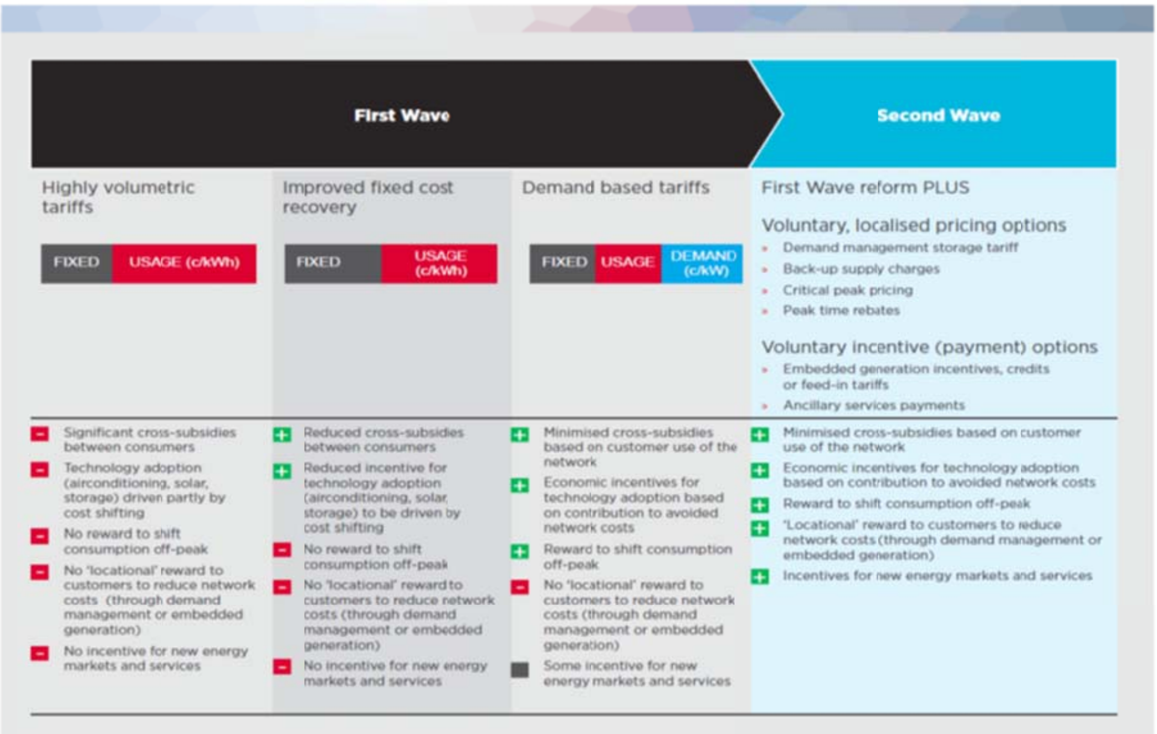
In this 'first wave' the timely implementation of more cost-reflective network tariffs with close customer engagement can make electricity bills fairer by removing inequitable cross-subsidies among customers. It can also provide more efficient signals for efficient investment in network infrastructure and distributed energy resources, such as embedded generation, storage and demand management.

It has been widely recognised by the AEMC and other experts that without more cost-reflective network tariffs, there are effectively distorted incentives to install some forms of distributed generation (among other technologies). Clearly, such existing distortions should be recognised ***prior*** to considering further changes to incentives for distributed generation.

As the Commonwealth Government's *Smart Grid, Smart City* project identified, one of the key risks of incomplete or distorted investment and usage signals is the potential for costly outcomes for consumers broadly, and the promotion of inefficient and inequitable subsidies between network customers or customer classes. The network sector encourages close analysis by the Commission of these issues in its work program.

As reflected in the Interim report of the ENA and CSIRO Network Transformation Roadmap (see Figure 1 below) these factors support a sequenced approach to pricing incentive reform where opportunities for additional distributed energy resource incentives are evaluated after achieving the prerequisite 'first wave' tariff reform that addresses existing distortions to incentives.

Figure 1 – Sequencing of tariff and related reforms



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Proposed multi-phased review process

Network businesses strongly support the proposed phasing and timing of the review, and its extension as proposed in the Approach Paper. The issues of approaches to determining wholesale and network values are each material analytical and empirical tasks that warrant careful review, iterative approaches and a staged testing of developing views through the review. The original proposed review timeline would not have fully permitted this approach.

The issue of approaches to valuing the network benefits is a complex one on which a range of national and international processes are focusing over 2016. These processes will be helpful in informing and shaping all review participants' understanding of the issues, and will also likely be of assistance to the Commission. This longer timeframe should, for example, provide a better opportunity for early outcomes and considerations of the AEMC *Local Generation Network Credit* rule change process to inform Commission findings. ENA looks forward to engaging in detail with the Commission on the issue of network benefits and costs around the proposed Discussion Paper phase, and ahead of the draft report in October.

Reaching an appropriate conceptual valuation framework – Frontier analysis

ENA supports the proposed overarching framework for assessing costs and benefits set out in the Approach Paper. The approach put forward by the Commission appears to be consistent with practice adopted by a range of government agencies and policy assessment bodies carrying out reviews of this nature. The approach provides a transparent framework for any parties to suggest and evidence the full range of costs and benefits outlined in the review Terms of Reference. This framework will support the identification of net public benefits.

The Approach Paper appropriately highlights that the nature of network costs and benefits from increased distributed generation are highly localised in nature, and have a dynamic component through time. This dynamic component includes both intra-day variations in the value of distributed generation services, and also a variation across multi-decade asset lives (i.e. a distributed generator offering network services may deliver widely different levels of value or impose highly varying costs based on when it occurs in an individual assets' particular life and utilisation profile).

ENA has recently commissioned Frontier Economics, in the context of the AEMC local generation network credit rule change to:

- Identify and review relevant Australian and international regulatory practice and published papers on valuation frameworks for measuring the network benefits of embedded generation;
- Set out a high level systematic economic framework for assessing and valuing the full range of benefits and costs of services and flows of value between embedded generators connected to the distribution network ; and
- Set out in a structured conceptual approach a framework which provides for the recognition of all relevant economic costs and benefits arising from the operation of embedded generation facilities within the distribution network, including the potential for local generation facilities to impose additional costs which should be recognised and recoverable under an economically efficient pricing approach.

Frontier also conducted indicative modelling around the potential impacts of any local generation network credit scheme. This modelling highlights that significant additional further investment in, and use of distributed generation – such as solar PV and battery storage and other technologies – is expected to occur in Australian energy markets in the absence of further changes to the existing national regulatory framework.

This is a result of current policy settings around retail price tariffs, feed in tariffs, distributed generation costs, and further influenced by a range of existing policy and regulatory settings across the market.

As noted above in the context of tariffs the existing incentives for distributed generation and the expected consequence for uptake would appear to be an important threshold consideration in the Commission's current inquiry.

The modelling highlights that the additional up-take of distributed generation as a result of any network credit is highly dependent upon the shape of customers' consumption (or load profile), retail tariffs in terms of both structure and price level, the level and structure of any network credit (in addition to the SRES and jurisdictional Feed-in-Tariffs), and current and future distributed generation costs.

ENA considers Frontiers' modelling analysis surrounding these three elements of the report will have significant value to the Commission and this report is attached (Attachment A).

Should you wish to discuss any of these issues further, please feel free to contact either myself or Garth Crawford, Executive Director, Economic Regulation

Yours sincerely,

John Bradley
Chief Executive Officer

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Valuing the impact of local generation on electricity networks

A REPORT PREPARED FOR THE ENERGY NETWORKS ASSOCATION (ENA)

February 2015

Valuing the impact of local generation on electricity networks

Valuing the impact of local generation on electricity networks

Boxes

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Executive summary

The City of Sydney, Total Environment Centre and the Property Council of Australia (the Proponents) have requested a change to the National Electricity Rules (NER) to include a requirement for DNSPs to offer a Local Generation Network Credit (network credit) to eligible Embedded Generation (EG) for electricity exported to the network.[1] By setting up a new payment relationship between DNSPs and EGs, this Rule change requests note that the network credit will allow EGs to monetise the benefits they provide to network businesses. By setting the network credit with reference to the net benefits provided by EGs exporting electricity to the network, the Rule change request purports to provide incentives for efficient investment in EG.[2]

In recent years there have been changes to the NER to provide additional incentives for DNSPs and others to invest in EG. The Rule change request represents one potential response to further reform of the treatment of EGs, particularly small scale EG, under the NER.

There are a range of factors that influence the supply and demand of EG, and continued investment in, and use of, EG – such as solar photo-voltaic (PV) panels, co/tri-generation, battery storage and other technologies – is expected to occur in our electricity market in the absence of further changes to the NER. In this context this report highlights that evaluating the costs and benefits of the Rule change request requires consideration of:

- the costs and benefits that different forms of EG can provide to network businesses, and the variability in these costs and benefits across different EG technologies as a result of their operating characteristics
- the experiences and 'lessons learnt' from other jurisdictions that have implemented network credits for EG
- the key issues that would need to be resolved if any regulated and mandated set of network credits (and potentially charges) is to facilitate efficient investment in and use of EG
- interaction between any network credit and the other market, policy and regulatory settings that influence the supply and demand of EG and have the potential to amplify or weaken the impact of any network credit, and the associated costs and benefits of additional investment in, and use of, EG.

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1 Oakley Greenwood, Local Generation Network Credit Rule Change Proposal – Submission to Australian Energy Market Commission: Proposed by City of Sydney, Total Environment Centre, and the Property Council of Australia, July 2015.

2 Any network credit would operate in addition to any jurisdictional Feed-in-Tariffs that EGs may receive.

In our view, it is not clear that the Rule change request has considered and resolved these issues in a way that is likely to promote the NEO.

The costs and benefits of EG are likely to be highly dynamic and locational

As outlined in the AEMC's Consultation Paper, EG can potentially reduce stress on network infrastructure during peak times, and may defer or avoid the need for network expenditure to meet customers' demand. However, EG can also create additional costs to DNSPs and the broader energy market as market participants and the Australian Energy Market Operator (AEMO) seek to accommodate increasing levels of (and potentially volatility in output from) EG.

We have developed a framework for considering the costs and benefits of EG. The framework shows that the costs and benefits are likely to be:

- Dynamic and locational, dependent upon the shape of aggregate consumption (or load profile) at the relevant feeder or substation, the level or take-up of EG (relative to aggregate consumption), and the extent to which given network elements are currently close to capacity.
- Technology specific given the material differences in the operating characteristics of EG. For example, it is less likely for there to be material long-term benefits in the form of deferred or avoided network capital expenditure from EG that may be intermittent and/or unreliable during periods of peak network demand.
- Dependent on wider market outcomes including relevant policy and regulatory settings. The uptake of EG by different stakeholders will reflect numerous factors including customers' load profile, the structure and level of retail electricity prices, any relevant feed in tariffs and EG technology costs. The assessment of the Rule change request needs to account for outcomes and interactions across the wholesale, retail and network levels of the market and wider regulatory and policy settings.

Establishing where these costs and benefits occur, and the level and duration of these costs and benefits is ultimately an empirical exercise.

The international experience highlights that a range of network efficiency and broader policy goals have underpinned the development of EG network credits

Policy-makers and regulators across a number of jurisdictions have implemented export credit arrangements and these have been driven by a range of network efficiency and broader policy objectives.[3] However to date, there has not been significant analysis of the extent of any net benefits that EG provides to networks (and their customers). For example, in Great Britain Ofgem assumed that EG would not cause additional reinforcement costs given the assumption that there will be even dispersion of EG across the network[4]. As such policy-makers and regulators are in the process of (or have indicated the benefits from) undertaking further work to understand and quantify the benefits more robustly.[5]

The experiences in the UK and US where policy makers and/or regulators have introduced uniform charging methodologies across distribution networks, as well as experiences in NZ that rely on commercially negotiated outcomes, suggests that establishing pricing principles and managing some of the inherent trade-offs or tensions in implementing a set of network credits – such as between efficiency, simplicity and predictability – when setting the structure and level of any network credit is challenging, yet critical, if signals are to be provided for efficient investment in, and use of, EG in locations and times where it is of value to networks (and all energy consumers).

However unlike in the UK[6], the existing (and potential future) market, regulatory and policy settings in Australia makes generator-dominated network nodes a more likely possibility. This suggests that a regulated and mandated set of uniform and highly averaged network credits – as proposed in the Rule change request – may risk:

- incentivising inefficient investment in, and use of, EG in locations, quantities or technologies where it may create *little benefit* to networks (i.e. does not materially reduce long-run costs for DNSPs) or
- incentivising inefficient investment in, and use of, EG in locations, quantities or technologies where it imposes *net costs* on networks or the broader energy

3 For example, in its 2008 Decision to proceed with a common charging method, Ofgem said that: "Delivery of this project is vital in facilitating progress towards meeting government targets on climate change, in ensuring that economic signals are provided to existing and potential users of electricity distribution networks and in enabling the efficient development of the network." It said the common method would "further enable DNOs' role as facilitators in tackling climate change" Ofgem, 22nd July 2008, 104/08 "Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements".

4 Ibid. p.60

5 For example, Ofgem is seeking to better understand the extent to which the assumption that EG is likely to offset some network reinforcement requirements is applicable at all network locations and therefore whether generator credits should vary by location.

6 In choosing to err on the side of simplicity and customer understanding in setting a uniform 'postage stamp' network charging methodology at the HV/LV level, Ofgem decided has to some extent benefited from there being relatively low probabilities in the foreseeable future of any generator-dominated network nodes in the UK (partly the result of other market policy settings that do not drive significant up-take in small scale EG).

market, (i.e. materially increases long-run costs for DNSPs or market participates), and may ultimately lead to higher electricity prices for consumers

- disincentivising efficient investment in and use of EG in locations, quantities and technologies where it has the potential to create material net benefits to networks and/or energy market participants (i.e. where it could lead to lower electricity prices for consumers).

There are numerous issues that need to be resolved if any set of regulated and mandated network credits (and charges) is to promote efficient investment in and use of EG

There are a range of factors that influence the supply and demand of EG, and continued investment in, and use of, EG is expected to occur in our energy market in the absence of further changes to the NER.

While network pricing reform to date has primarily focused on electricity imported from the network[7], and in theory encouraging efficient investment in and use of EG requires some form of price signal to be provided to EG investors and users for electricity exported to the network (as well as other regulatory mechanisms to provide 'signals' to DNSPs), it is not clear that a regulated and mandated set of uniform and highly averaged network credits – as proposed in the Rule change request – will necessarily facilitate efficient investment in and use of EG in Australia given that:

- if efficient investment is to occur in EG in locations, quantities or technologies where it provides net benefits to DNSPs, then any set of network credits (and charges) should reflect the nature of the costs and benefits to DNSPs that different forms of EG may provide,[8] should account for material locational differences, be dynamic and allow for payments to and/or from DNSPs (i.e. be symmetrical)[9]
- the international experience in implementing EG network pricing would suggest that introducing a regulated and mandated set of uniform and highly averaged network credits – as proposed in the Rule change request – in Australia, in addition to the existing regulatory and policy settings, requires careful consideration of a number of implementation issues including:
  - the appropriate categories (and sharing) of costs and benefits within the network credits (and charges), the appropriate price structure for providing

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7 Changes to the National Electricity Rules (NER) made in 2014 pursuant to the Distribution Network Pricing Arrangements Rule change

8 i.e. the level and structure of any network credit is cost reflective

9 With a positive credit determined where there are clear long term net benefits to networks from additional investment in, and use of, EG and a negative credit (or charge) where there are clear long term net costs to networks from additional investment in, and use of, EG.

cost reflective signals to EG customers[10], and the appropriate balance between flexibility and predictability[11]

- the risks associated with potentially implementing a highly dynamic, locational and technology specific set of regulated network credits (and charges) for exported electricity that may be more cost reflective than the corresponding set of regulated network tariffs for imported electricity
- the interaction with the existing (and potential) mechanisms in the NER[12] and other policy settings that may also encourage investment in and use of EG.

In our view it is not clear to what extent the Rule change request for a set of regulated and mandated network credits has been developed with a set of clear pricing principles[13] nor considered and resolved these issues in a way that is likely to promote the NEO. As highlighted earlier, the Rule change request represents but one potential response to further reform of the treatment of EGs, particularly small scale EG, under the NER.

Quantifying the potential interaction of any network credit with other market, regulatory and policy settings is crucial

There are a range of factors that influence the supply and demand of EG and the AEMC Consultation Paper highlights the importance of understanding the *additional* up-take of EG as a result of any network credit.[14]

Australia's energy markets have witnessed a significant up-take of EG (primarily solar PV) driven by the interaction between market[15], policy[16] and regulatory

10 Which involves a trade-off between a highly dynamic and locational approach – which is more likely to reflect the nature of the costs and benefits and therefore send efficient signals for investment in and use of EG – and a simpler approach that maximises customer understanding, but with less ability to capture any net benefits and may risk discouraging investment and use of EG in locations, quantities or technologies where there may be net benefits, and/or encourage investment where there may be net costs to networks and ultimately on customers.

11 In terms of allowing network businesses to respond to changing market conditions by updating the level of any network credit (and charge) and customers' preference for predictability and simplicity

12 For example, the NER provides some mechanisms for providing price signals to small scale EGs (such as through the small generation aggregator framework).

13 Nor considered to what extent any pricing principles should mirror, draw from, or depart from the existing distribution network pricing objectives and principles.

14 As the AEMC's Consultation Paper notes, the Rule change request may promote the NEO if it incentivises efficient investment in, and use of, EG that would otherwise not have occurred. AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, Sydney, p.19.

15 Such as increasing household choice and awareness of energy supply options such as small scale EG, increasing affordability of small scale EG and the structure of and level of retail electricity prices.

16 Such as the Small Scale Renewable Energy Scheme (SRES) and jurisdictional Feed-in-Tariffs

settings. (See **Appendix A** for information on solar PV uptake and the policy settings that support investment in solar PV).

This Rule change request occurs in the context of significant change in these settings, and uncertainty in terms of their impact on the supply and demand of EG. For example, the impact on the supply and demand of small scale EG resulting from new cost reflective distribution network pricing obligations[17] and other mechanisms in the NER relating to incentivising least cost non-network solutions are still uncertain.[18] Likewise, there is uncertainty relating to future policy settings such as the SRES, jurisdictional Feed-in-Tariffs and jurisdictional energy efficient schemes[19].

These regulatory and policy settings have the potential to amplify or weaken the impact of any network credit, and the associated costs and benefits of additional investment in, and use of, EG. Any consideration of the costs and benefits of the Rule change request needs to account for these interactions and this is ultimately an empirical exercise.

Our indicative modelling highlights that further investment in, and use of, EG – such as solar PV and battery storage and other technologies – is expected to occur in our energy market in the absence of further changes to the NER. This is a result of current policy settings around retail price tariffs, feed in tariffs, EG costs and is influenced by a range of policy and regulatory settings across the market.

Our indicative modelling highlights that the *additional* up-take of EG as a result of any network credit is highly dependent upon:

- The shape of customers' consumption (or load profile). Further assessment of likely market outcomes across a robust set of load profiles, where EG uptake may be more or less influenced by any distribution credit, would be important in further assessing the impacts of the proposed rule change.
- Retail tariffs in terms of both structure and price level. These prices reflect outcomes across the wholesale and network sides of the market and strongly influence customer's perceived value of EG.
- The level and structure of any network credit (in addition to the SRES and jurisdictional Feed-in-Tariffs)
- Current and future EG costs.

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17 Which may alter customers' consumption patterns, in turn, influencing the supply and demand of EG.

18 Not to mention other potential changes to the NER and the market arrangements (such as potential introduction of virtual net metering) that may facilitate local electricity trading if implemented.

19 For example the Victorian Minister for Energy and Resources has asked the Essential Service Commission of Victoria (ESC) to examine the "true value of distributed generation to Victorian Consumers." http://www.esc.vic.gov.au/Energy/Inquiry-into-the-true-value-of-distributed-generat/publications

The Rule change request does not provide empirical evidence about the relationship between any network credit and other market, policy and regulatory settings that are likely to continue to encourage continued investment in, and use of, EG. Further modelling and quantification of these interactions would be crucial to understanding the *additional* up-take of EG from any network credit and the potential costs and benefits of the Rule change request.

Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
CHP	Combined Heat and Power (cogeneration, new residential developments with district heating/cooling)
EG	Embedded generation
DNSP	Distribution Network Service Provider
DSR	Demand side response
DER	Distributed Energy Resource (EG + DSR + smart grids)
ESS	Energy Savings Scheme
FiT	Feed in tariff
LGC	Large-scale Generation Certificates
LRET	Large-scale Renewable Energy Target
LGNC	Local Generation Network Credit
NEO	National Electricity Objective
NEM	National Electricity Market
NER	National Electricity Rules
NEO	National Electricity Objective
RET	Renewable Energy Target
PV	Photovoltaic
SRES	Small-scale Renewable Energy Scheme

2 Background

We have prepared this report for the Energy Networks Association (ENA) in the context of Australia's electricity markets currently undergoing a period of significant change. Increasing household choice and awareness of (increasingly affordable) energy supply options has focused attention on the demand for, and the economics of, grid supplied electricity and the costs and benefits of future investment in networks relative to other alternatives.

These developments have sparked a national discussion on the importance of "putting consumers at the centre of future decision-making"[20] with reforms to the way customers pay for electricity being at the forefront of this discussion. Changes to the National Electricity Rules (NER) made in 2014 pursuant to the Distribution Network Pricing Arrangements Rule change[21] now require DNSPs to structure their prices to ensure they better reflect the costs of providing electricity to consumers with different patterns of consumption. It also follows a number of other changes made to the NER to facilitate and incentivise DNSPs to invest in efficient non-network solutions and to empower small scale EGs to sell their output through a third party.[22]

However, some stakeholders have observed that cost reflective pricing arrangements for customers 'exporting' energy back to the network are also important in providing signals for efficient investment in and use of the energy supply chain.[23] This is because investment in embedded generation (EG) – such as solar photo-voltaic (PV) panels, co/tri-generation, potentially battery storage and other technologies that can generate and/or export energy to the network – is increasingly becoming a key part of Australia's energy mix.

Customers with EG that export energy to the network are users of the network and can drive both costs and benefits for networks, as well as broader economic costs and benefits. In theory, a cost reflective set of network credits (and charges) could facilitate efficient investment in, and efficient operation and use of electricity services.

The Rule change proposal submitted to the AEMC in July 2015 by the City of Sydney, Total Environment Centre and the Property Council of Australia (the

20 John Pearce, Chair – Australian Energy Market Commission, *New rules for cost-reflective network prices,* 27 November 2014. http://www.aemc.gov.au/News-Center/What-s-New/Announcements/New-rules-for-cost-reflective-network-prices

21 AEMC, Final Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, November 2014 (Distribution pricing Rule change).

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

23 http://arena.gov.au/project/investigating-local-network-charges-and-local-electricity-trading/

Proponents) offers one suggested approach to further reform of the treatment of EGs under the NER.

The AEMC recently published a Consultation Paper on the Rule change request.[24] The Consultation Paper notes that the Rule change request follows a number of other changes made to the NER to facilitate and incentivise DNSPs to invest in non-network solutions if they are more efficient than alternative network solutions.[25] The Rule change request also coincides with considerable uncertainty relating to policy settings that support renewable energy and small scale EG in Australia, as offered through the Small Scale Renewable Energy Scheme (SRES)[26] and jurisdictional Feed-in-Tariffs (FiTs)[27], as well as other potential changes to the NER and the market arrangements. For example, the potential introduction of virtual net metering would facilitate local electricity trading if implemented.[28] These policy measures have the potential to amplify or weaken the impact of any network credit.

Understanding the interaction between any network credit and the support provided to EG through the SRES, jurisdictional FiTs and other market arrangements is critical to evaluating how any network credit may influence the take-up of EG, the costs and benefits for networks, as well as broader economic costs and benefits that are relevant to examining whether the Rule change request promotes the NEO.

2.1 Scope of our task

The ENA is seeking advice in responding to the proposed Rule. In particular, the ENA has requested Frontier:

- Identify and review relevant Australian and international regulatory practice and published papers on valuation frameworks for measuring the network benefits of embedded generation; and
- Set out a high level systematic economic framework for assessing and valuing the full range of benefits and costs of services and flows of value between embedded generators connected to the distribution network and set out in a

24 AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, Sydney.

25 See Section 2.2.

26 http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/How-the-scheme-works/Small-scale-Renewable-Energy-Scheme

27 For example the Victorian Minister for Energy and Resources has asked the Essential Service Commission of Victoria (ESC) to examine the "true value of distributed generation to Victorian Consumers."

http://www.esc.vic.gov.au/Energy/Inquiry-into-the-true-value-of-distributed-generat/publications

28 http://arena.gov.au/project/investigating-local-network-charges-and-local-electricity-trading/

structured conceptual approach a framework which provides for the recognition of all relevant economic costs and benefits arising from the operation of embedded generation facilities within the distribution network, including the potential for local generation facilities to impose additional costs which should be recognised and recoverable under an economically efficient pricing approach(for example, reflecting a 'causer pays' principle), as required by the network pricing objective in the National Electricity Rules.

- Assist in assessing the merits of the proposed Rule and others changes to the NER relating to charges for EGs' use of the network.

2.2 Structure of the report

The remainder of this report is structured as follows:

- Chapter 3 provides an overview of the Rule change request
- Chapter 4 highlights the international experience in providing price signals for EG and some of the lessons from these arrangements
- Chapter 5 discusses sending efficient EG price signals that reflect the costs and benefits to networks
- Chapter 5 presents our indicative modelling of the customer responses to different types of network credits and resulting up-take of EG
- Chapter 8 provides our observations on the costs and benefits of the Rule change request
- Appendix A provides an overview of the types of EG that currently and are likely to form part of Australia's energy mix over the foreseeable future.
- Appendix B provides detail on the network credit arrangements in Great Britain.
- Appendix C provides detail on the methods used to quantify the impacts of indicative EG credits on customers and networks.

We consider our analysis and this report to be of use to the ENA and AEMC in understanding the potential network (and broader economic) costs and benefits of increased up-take of EG and the merits of the Rule change request.

3 Overview of proposed changes to the National Electricity Rules

In July 2015, the City of Sydney, Total Environment Centre, and the Property Council of Australia submitted a proposal to the AEMC to amend the NER.[29] The proposal (summarised in Box 1) principally seeks to oblige DNSPs to offer EGs a Local Generation Network Credit (LGNC) for energy that is exported to the grid. The credit would reflect the long-term economic benefits of EG exports to DNSPs.

In broad terms the proposed Rule is predicated on the view that:

- The electricity supply chain is undergoing significant long-term change and the NER does not sufficiently incentivise efficient uptake of small-scale EG[30]
- The AEMC's 2014 distribution pricing Rule change only addressed the cost-reflectivity of network pricing signals for electricity consumption, and as such will not encourage the efficient sizing, location and operation of local generation that can be used to export energy to the grid.
- There is precedent in other jurisdictions for credits being provided to local embedded generators. The submission notes that the UK Office of Gas and Electricity Markets (Ofgem) requires each distribution network to provide a credit tariff that is payable to 'decentralised generators' (varying by classes of generator including size, intermittency and time of operation) based on a standard methodology provided by Ofgem.[31]

Box 1: Overview of proposed Rule change for a Local Generation Network Credit

The key features of the proposed Rule change are as follows:

- The credit is a price signal for exported energy that reflects the long-term economic benefits that the export of energy from a local generator provides to a distribution business
- The credit would be available to local generators of any size but be optional
- The credit could vary by voltage level (and potentially by location)

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29 Oakley Greenwood, Local Generation Network Credit Rule Change Proposal – Submission to Australian Energy Market Commission: Proposed by City of Sydney, Total Environment Centre, and the Property Council of Australia, July 2015.

30 The submission notes that the NER do not provide adequate recognition of the benefits that local generation can provide, and/or may not be readily accessible to small-scale local generators. Oakley Greenwood, Local Generation Network Credit Rule Change Proposal, July 2015, p1.

31 Oakley Greenwood, Local Generation Network Credit Rule Change Proposal, July 2015, p3.

- The credit would be adjusted yearly as part of the DNSP's broader Annual Pricing Submission process, prepared by network businesses, under Australian Energy Regulator guidelines.
- The credit should not be negative (i.e. a charge) even in situations where the cost of catering for bi-directional flows is deemed to exceed the benefits of the exported electricity to the network.

The proposed changes are to be made to Chapter 6 and 10 of the NER.

Source: Rule change proposal

The submission also notes that the LGNC is consistent with the NER and the National Electricity Objective in that:

- It advances cost-reflectivity in network pricing by providing a price signal for exported energy where and to the extent that the exported energy serves to defer or avoid augmentation, reduce the cost of replacement assets, or reduce load at risk.
- Allows local generators who export energy to the grid to monetise the benefits that they collectively provide to the grid
- It will put downward pressure on prices and provide benefits to consumers in the long run
- It will better facilitate non-dispatchable generation being integrated into network planning. [32]

[32] Oakley Greenwood, Local Generation Network Credit Rule Change Proposal, July 2015, p2-3.

4 Costs and benefits of EG to electricity networks in Australia

Australia's energy markets are currently undergoing a period of significant change with increasing household choice and awareness of (increasingly affordable) energy supply options, such as small scale EG. **Appendix A** provides an overview of the types of EG that currently and are likely to form part of Australia's energy mix over the foreseeable future.

Localised EG, including small scale EG, can reduce stress on network infrastructure during peak times, and may defer or avoid the need for network expenditure to meet customers' demand. However, EG can also create additional costs on the network, both in terms of upfront costs associated with facilitating EG connections, as well as costs associated with accommodating potentially highly dynamic EG output and customer demand.[33]

This chapter sets out our framework for considering the costs and benefits of EG and shows that the costs and benefits are likely to be:

- Dynamic and locational, dependent upon the shape of aggregate consumption (or load profile) at the relevant feeder or substation, the level or take-up of EG (relative to aggregate consumption), and the extent to which given network elements are currently close to capacity.
- Technology specific given the material differences in the operating characteristics of EG. For example, it is less likely for there to be any material long-term benefits in the form of deferred or avoided network capital expenditure from EG that may be intermittent and/or unreliable during periods of peak network demand.
- Dependent on wider market outcomes including relevant policy and regulatory settings. The uptake of EG, which will influence any network costs and benefits, will reflect numerous factors including customers' load profile, the structure and level of retail electricity prices, any relevant feed in tariffs and EG technology costs.

4.1 Potential benefits of embedded generation

In principle, the benefits of EG to distribution networks arise from the way in which EG can help avoid the same costs that electricity consumption imposes on the network. Specifically, incremental electricity consumption at peak network

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33 For example, increased penetration of intermittent EG (including solar PV) may necessitate investment in voltage control systems and high levels of localised EG uptake may lead to situations where network elements peak on an export basis requiring investment in protection systems.

loading times can bring forward the need for costly augmentation of the network, or bring forward the need to replace or maintain existing network assets. Conversely, the injection of power into the distribution network at peak network loading times can defer or avoid the need for DNSPs to incur augmentation, replacement or maintenance expenditure.

More broadly, the potential benefits of EG include:

- Avoided capital expenditure. Benefits may arise via delayed investment in (or complete avoidance of) upgrades to the network as a result of a reduction in the rate of growth (or level) of local peak demand for grid energy due to EG uptake.
- Avoided operating expenditure. Benefits may arise to the extent that some assets are used less frequently and/or at lower loadings, leading to reduced time between failures and lower maintenance requirements.
- Losses. Locally exported energy from EG may offset distribution and, potentially, transmission losses to some extent. Such effects are likely to be more material on long rural lines with high distribution loss factors.
- Secondary effects at the transmission level. It is likely that a significant incremental uptake of EG would be required before material capital and operating savings arose at the transmission level.

This section discusses each of these categories.

Deferred or avoided capital augmentation expenditure

On a large-scale basis, the adoption of EG can potentially substitute for network capital expenditure and in some sense EG help defer or avoid the same costs that electricity consumption imposes on the network.

Any deferred or avoided capital augmentation expenditure necessarily requires any localised EG in aggregate, to provide sufficient capacity at times of peak network demand to enable DNSPs to utilise EG as an alternative to traditional network augmentation to meet customer demand. The localised capacity provided by EG must meet DNSPs (and customers') need in terms of quantity (i.e. output) as well as quality (i.e. reliability). As noted in the AEMC's Consultation Paper, where localised EG in aggregate is not able to provide sufficient capacity, both in terms of quantity and quality, the benefits in terms of deferred or avoided capital augmentation expenditure reduce considerably.[34]

For example, in 2012, AusNet Services forecast a requirement for additional capacity at its Traralgon zone substation. Rather than replace two transformers,

[34] AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, Sydney, p.5.

AusNet replaced just one transformer and commissioned Nova Power to supply 10 MW from a gas generator. In this instance, it was possible to defer capital expenditure of $2.9m.[35] Importantly, this would have required the capacity (both in terms of quantity and quality) and the cost (relative to other network and non-network solutions) of the EG solution to meet AusNet Services (and their customers') needs and is consistent with the intent of the Regulatory Investment Test for Distribution (RIT-D) under the NER.[36] As the AEMC's Consultation Paper highlights[37], the NER may already facilitate the recognition of these benefits.

Any benefit in the form of deferred or avoided augmentation expenditure is likely to be highly localised and dynamic.

Section 4.3 discusses the types of EG that may be likely (or not likely) to provide network benefits in the form of deferred or avoided capital augmentation expenditure.

Avoided capital replacement expenditure

EG may also offer benefits by deferring the need to replace distribution networks assets.

Asset life, particularly for assets like transformers, is heavily influenced by the amount of "cycling" (frequency of moving between different load levels) that those assets experience over time. If network loading levels are reduced due to EG, it could offer some small whole-of-life savings by deferring the timing of asset replacements. For example, a transformer operating at a lower average loading could potentially last an additional 5 years in the context of an anticipated life of 50 years.

However, providing robust estimates of any potential replacement capital expenditure is challenging – partly because the relationship between network loading and asset life is far from deterministic and partly because technological change may render such operating life extensions redundant. For example, the CSIRO/ENA report, "Electricity Network Transformation Map" envisages such profound change to the technology of the network by 2065 that assets such transformers could be obsolete.

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35 Grattan Institute, *Sundown, sunrise*, May 2015, p38.

36 Where a DNSP has identified the need for a network augmentation and the cost is expected to exceed $5 million, the DNSP is obliged to undertake the Regulatory Investment Test for Distribution (RIT-D). This test requires the DNSP to compare its proposed network option against suitable network and non-network alternatives. The DNSP may only proceed with the option that offers the highest net economic benefits, taking account of a range of scenarios regarding external conditions (e.g. demand growth and potential load profiles, the value of unserved energy and option costs).

37 AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, Sydney, p.7.

Avoided operating costs

EG may also provide benefits in the form of deferred or avoided operating expenditure. These benefits may arise to the extent that some assets are used less frequently and/or at lower loadings, which leads to reduced time between failures and potentially lower maintenance requirements.

However, providing robust estimates of any potential avoided operating expenditure is also challenging given that some EG may reduce overall loadings but result in increased volatility of loadings which can create stress on assets.

Electricity losses

Electricity is 'lost' as it is transported along a distribution or transmission network as a result of electrical resistance. These electricity losses result in retailers (and customers) needing to purchase more electricity from the NEM than is actually consumed by the end-customer.

Localised EG is likely to reduce electricity losses on the distribution network up to the point when the reverse power flow is equal to the original demand (e.g. equivalent power flowing in the opposite direction). These losses are a factor of the electricity consumed, so EG would be expected to reduce electricity losses, particularly at peak times however the exact benefit would be challenging to estimate particularly given electricity losses calculations can be highly dynamic.

Impacts on Transmission Network

Transmission assets are generally installed in capacity increments that are substantially larger than distribution assets. This means that finding reliable EG projects of sufficient capacity to defer or avoid a discrete transmission augmentation or replacement project would not be a trivial exercise. Successfully deferring or avoiding a transmission project would probably require aggregation services to combine a number of EG project, and potentially also small-scale demand-side response arrangements.

A study conducted in the USA by the Maine Public Utilities Commission on the value of solar generation to their network drew the conclusion that:

> The challenge is finding the cost of future transmission that is either avoidable or deferrable.[38]

If sufficient reliable EG projects can be found to avoid or defer a transmission project, a TNSP may contract for EG to provide network support services under

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38 See Maine Distributed Solar Valuation Study, March 2015 http://web.colby.edu/joules-to-dollars/files/2015/03/MEDistributedSolarValuationStudy.pdf.

the auspices of the Regulatory Investment Test for Transmission (RIT-T). Like the RIT-D, the RIT-T requires TNSPs to consider non-network alternatives where appropriate when a network augmentation option has been proposed.

Regarding transmission losses, it does not necessarily follow that reductions in losses on the distribution network automatically result in a corresponding reduction in transmission losses. This is because the extent of transmission losses would largely be determined by the geographic location of the transmission-connected centrally-despatched generation displaced by the EG.

4.2 Potential costs of embedded generation

EG can also create additional costs on the network, both in terms of upfront costs associated with facilitating EG connections, as well as costs to DNSPs and broader energy market participants (including AEMO) in accommodating potentially highly dynamic EG output.

Connection and other facilitation costs

Network businesses may incur costs associated with connecting EG to their network, including negotiating connection agreements and establishing and administering any network support payments (for those larger than 5MW). These costs are likely to vary across networks and will depend on the specifics of the EG and potentially on the up-take of different technologies.

Network management costs

There are may be several incremental network reliability and security costs as networks as accommodate EG. While relatively small amounts of EG in a network do not usually give rise to material operational issues, appearing as just a small reduction in the overall demand, as EG levels increase, the materiality of a number of technical issues relating to power quality and security also increases.[39] The expenditure required to manage these issues can be material.

Some of the issues highlighted by DNSPs in Australia include:

- Voltage Control – highly intermittent EG sources (particularly solar PV) can cause voltage deviations that can have a detrimental impact on consumer devices. To manage this issue (and meet their license obligations[40]) some DNSPs have already had to install additional fast-acting voltage control

[39] Mazumder, Sumit, Ghosh, Arindam, & Zare, Firuz, Improving power quality in low-voltage containing distributed energy resources, *International Journal of Emerging Electric Power Systems*, vol 14, N.1, pp. 67-78.

[40] Relating to power quality, AS61000.3.100.

equipment. Inverter tripping due to over-voltage was noted as a common occurrence by Essential Energy and Endeavour in submissions to the IPART solar feed-in tariff review.[41] Essential Energy indicated that in 2011, 60 to 70% of the power quality issues on the network were related to voltage rise caused by solar PV systems and inverter tripping.[42]

- Protection – configuring protection systems for distribution networks is notoriously difficult. This is because such systems need to strike a balance between providing sufficient protection for safety, but not too much as would lead to unnecessary "nuisance tripping" of customer supplies. Any significant changes to the network (such as installation of substantial EG) would require changes to protection systems. At one end of the scale, this could be a simple change to the settings of an existing protection scheme; but at the other extreme, it would mean a completely new system which would result in significant cost.
- Reverse Power Flow – reverse power flows to those for which the distribution network has been developed have the potential to damage certain types of equipment and in some networks, schemes will have to be installed to limit the degree of reverse flows.
- Fault Level Issues – with more energy available to feed into a fault (since the EV is also contributing), bigger circuit breakers are required to safely interrupt the fault current.

Broader energy market costs

The operating characteristics and up-take of EG can also result in broader energy market costs. As the AEMC Consultation Paper notes, EG has the potential to result in an 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.[43]

4.3 Understanding the differences in costs and benefits across EG

The preceding section discussed the costs and benefits that localised EG can provide to network businesses, however there may be signification variation that

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41 IPART, *Solar feed-in tariffs*, October 2015, Appendix F.

42 Essential Energy, 2011, cited in "PV Integration On Australian Distribution Networks", The Australian PV Association, Sept 2013.

43 AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, Sydney, p.6.

specific investment in and use of EG contributes towards any overall aggregative costs or benefits. This results from the:

- Dynamic and locational nature of any costs and benefits, which is dependent upon the shape of aggregate consumption (or load profile) at the relevant feeder or substation, the level or take-up of EG (relative to aggregate consumption), and the extent to which given network elements are currently close to capacity
- Variability in operating characteristics of EG technologies, which leads to differences in the reliability and intermittency of EG output.

This section discusses the variability in the costs and benefits of several key EG types, and how these may vary over time as up-take changes.

Solar PV

Smaller-scale EG installations can create network benefits in the form of avoided or deferred capital expenditure. However relative to other forms of EG, the operating characteristics of solar PV combined with the typical shape of customer demand mean that solar PV is less likely to be able to provide sufficient capacity (primarily in terms of quality of output) at times of peak network demand for there to be any material long-term benefits in the form of deferred or avoided network capital expenditure.

As can be seen in a residential feeder example in Queensland in Figure 1, solar PV output and its contribution to meeting demand during the peak period is typically small as a result of:

- Solar PV panels being typically orientated towards the north to maximise energy capture across the day (and maximise FiT payments) but by late afternoon, the sun is well to the west and much less power is produced.[44]
- The majority of DNSPs have peak demands during the summer, usually late afternoon on very hot days when air conditioning is likely to be operating.

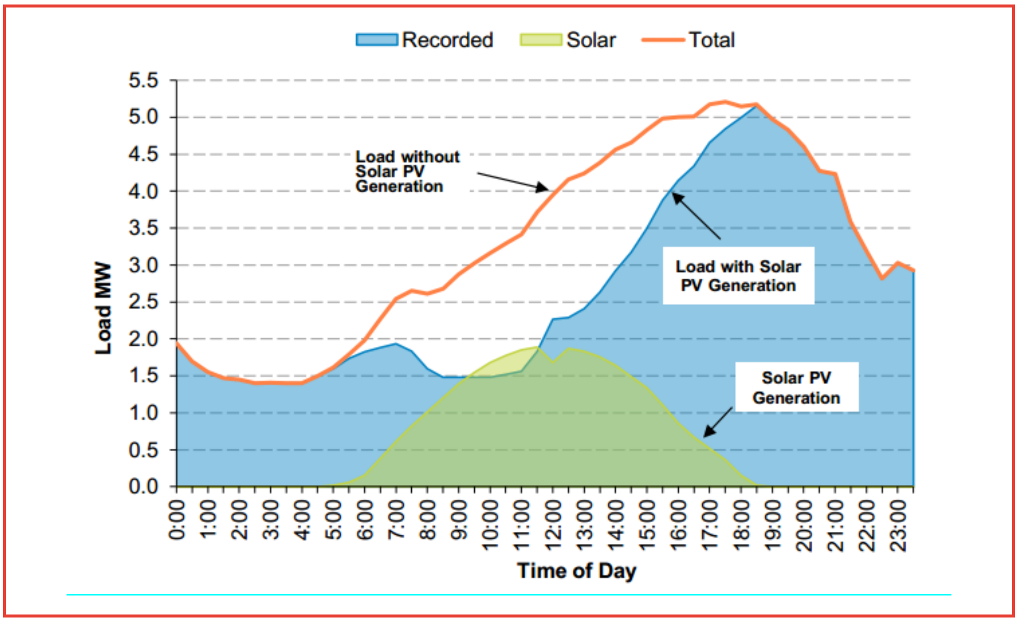
While there can be variation over the year, this suggests that on the extent to which solar PV can defer or avoid network reinforcement is small.[45] As noted in the AEMC's Consultation Paper, where localised EG in aggregate is not able to

44 Further solar PV panels are most efficient on cool, sunny days and on hot days efficiency may drop by more than 10%.

45 A report recently prepared by the Grattan Institute highlighted this issue noting that because the use of solar PV does not usually coincide with periods of peak demand, it will not necessarily reduce the size of the grid we need". Grattan Institute (2015), p.27.

provide sufficient capacity the benefits in terms of deferred or avoided capital augmentation expenditure reduce considerably.[46]

Figure 1: Solar PV impact on a typical Queensland residential feeder loading on a peak demand day



Source: Energex, Distribution Annual Planning Report – 2015/16-2019/20 Volume 1, 2015, figure 8 (p38)

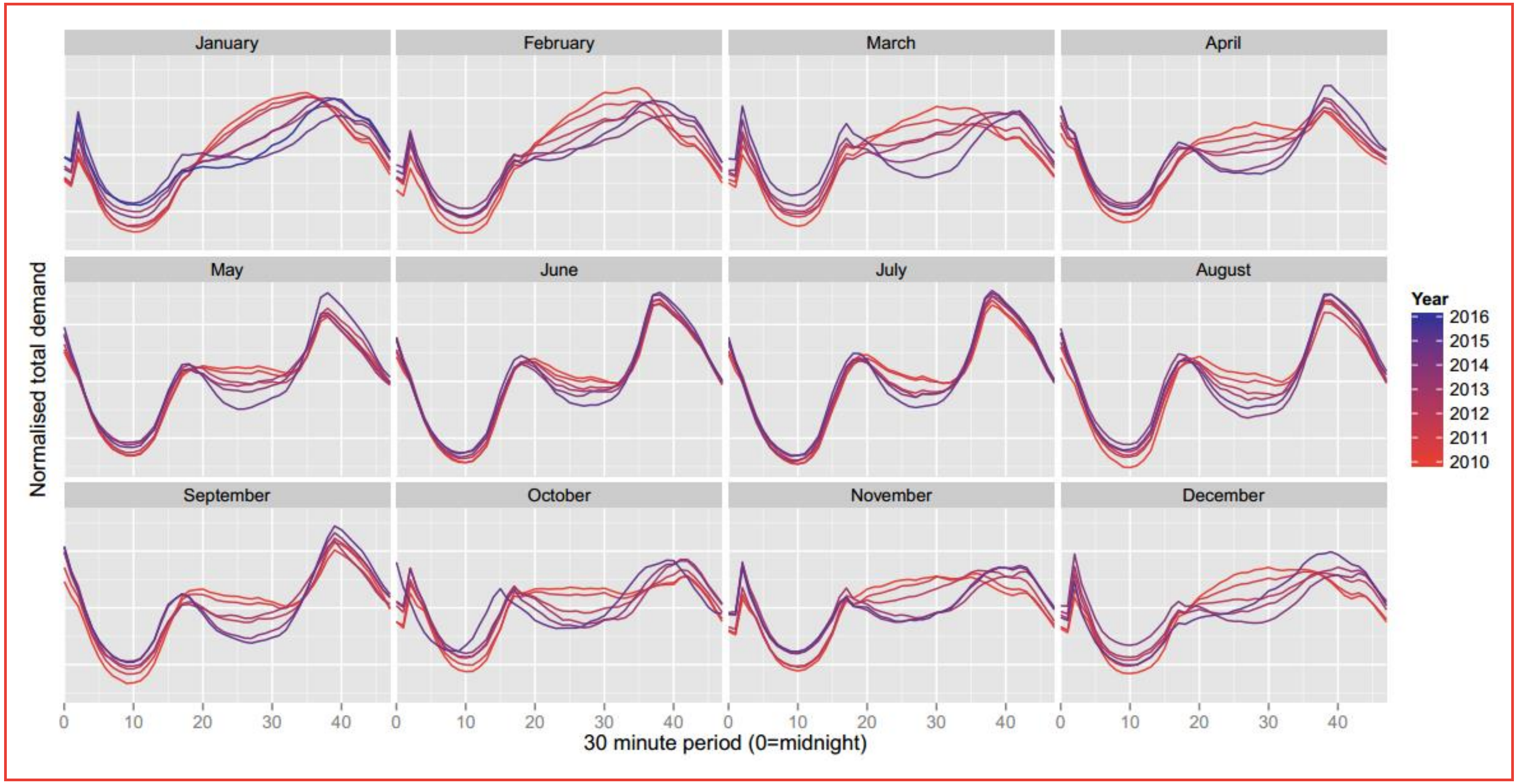
However, the costs to DNSPs and the broader market of facilitating high levels of solar PV may be material. As more customers take up solar PV, the resulting demand from the network and NEM during daylight hours generally decreases, but the overall level of peak demand occurring in the evening remains broadly unchanged. This can result in:

- Increasingly peaky demand profiles where average or total energy demand decreases relative to peak demand (known as a decreasing load factor), as shown in Figure 2 in South Australia
- 'Peak shifting' where levels of peak demand become increasingly concentrated in the evening (as opposed to occurring throughout daytime and evening hours) as shown in Figure 3[47] in South Australia and Queensland - the regions with the highest solar PV penetration. AEMO are forecasting peak-shifting to occur in the future due to the increasing presence of residential solar PV generation.

46 AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, Sydney, p.5.

47 Figure 3 presents histograms showing the daily five minute period in which demand was highest for Queensland and South Australia (total demand is normalised across the years). In the earlier years, daily peaks occur throughout daytime and evening hours. In the latest years, as solar PV penetration increases, we see fewer peaks occurring during the middle of the day, when solar PV generation is at its highest, with peak instances becoming highly concentrated in the evening.

Figure 2: South Australian average monthly load shape with PV 'carve out' showing deteriorating load shape and minimal peak impact – 2010 to 2016.



Source: Frontier Economics

Figure 3: Peak shifting in Queensland and South Australia (net of solar PV)

Source: Frontier analysis of AEMO data

These phenomena can create incremental costs for DNSPs and the broader energy market and/or lead to higher average costs in supplying consumers.[48] As shown in the following section solar PV combined with battery storage has the potential to lead to peak shifting in a way that reduces costs for DNSPs and the broader energy market (i.e. away from the evening peak).

Table 1 summarises the potential costs and benefits associated with solar PV.

Table 1: Overview of potential costs and benefits of solar PV

	Low Uptake	High Uptake	Comments
Potential benefits			
Avoided augmentation expenditure	X	X	Intermittency and timing of output unlikely to assist meeting localised peak demand, therefore unlikely to defer or avoid augmentation expenditure
Avoided replacement expenditure	X	?	Potentially, but high uptake could lead to increased variability in loading of assets
Avoided operating costs	X	?	Potentially, but high uptake could lead to increased variability in loading of assets
Avoided electricity losses	?	✔	Material changes may occur under high uptake
Impacts on Transmission Network	X	?	Unlikely but will depend on specifics of EG
Potential Costs			

48 As noted by the Queensland Productivity Commission, "Business and residential electricity consumers have responded to increased prices, through energy efficiency, demand management and the installation of solar PV. As a result average electricity demand is falling, which presents challenges for electricity prices with costs being spread across a smaller demand base. At the same time, Queensland's peak electricity demand continues to grow, although not at the rates experienced in the late 2000s." Queensland Productivity Commission, Electricity Pricing Inquiry – Draft Report, 2016, pviii.

	Low Uptake	High Uptake	Comments
Connection and other facilitation costs	?	?	Connection costs are likely to vary across DNSPs
Network management costs	?	✓	Intermittency and day-time output mean costs associated with managing voltage deviations, protection and reverse control issues could be material with high solar PV uptake
Broader energy market costs	X	✓	Can lead to significant peak shifting under higher solar PV uptake

Solar PV + battery

While battery storage can come in many forms (see **Appendix A**) this section discusses the potential costs and benefits from combining solar PV with battery storage.

In contrast to solar PV in insolation, solar PV combined with battery storage could fundamentally alter the above narrative. For example combining solar PV with battery storage could enable the energy produced by solar PV units during the day to be stored (rather than outputted during daylight hours) and drawn down over the peak period and in doing so could:

- greatly enhance the potential for solar PV (or other small scale EG) to create network benefits in the form of deferred or avoided network capital expenditure of small-scale EG
- provide broader energy market benefits from 'flattening' customers' load profile (and increasing the load factor)
- minimise or avoid network and/or broader energy market costs that might typically arise with a high uptake of solar PV alone.

Table 2 summarises the potential costs and benefits associated with solar PV combined with battery storage.

Table 2: Overview of potential costs and benefits of solar PV + battery

	Low Uptake	High Uptake	Comments
Potential benefits			
Avoided augmentation expenditure	X	?	Battery could assist in managing solar PV intermittency and timing of output issues, therefore potential to assist meeting peak demand, and to defer or avoid augmentation expenditure
Avoided replacement expenditure	X	?	Higher uptake of Solar PV + battery could lead to avoided expenditure if batteries reduced variability in loading of assets
Avoided operating costs	?	?	Higher uptake Solar PV + battery could lead to avoided expenditure if batteries reduced variability in loading of assets
Avoided electricity losses	?	✓	Material changes may occur under high uptake
Impacts on Transmission Network	X	?	Unlikely but will depend on specifics of EG
Potential Costs			
Connection and other facilitation costs	?	✓	Incremental connection costs are likely to vary across DNSPs, but higher uptake of solar PV + battery could create material costs
Network management costs	X	?	Reduced intermittency and day-time output potentially means less need for measures to manage voltage deviations and reverse control issues
Broader energy market costs	X	?	Batteries could minimise costly peak shifting

Thermal EG (Co/tri-generation or gas fired generation)

To date, a significant proportion of larger scale EG has taken the form of thermal EG, primarily gas fired generation technologies including cogeneration (combined with heating) and/or trigeneration (combined with heating and cooling).

Given thermal EG is dispatchable, output can be produced on demand meaning that it has a high potential for responding to peak network loading conditions (by offsetting local consumption or exporting to the network), and can defer or avoid network augmentation. The extent to which thermal EG may create network management costs or broader energy market costs will depend on the specifics of the thermal EG.

Table 3 summarises the potential costs and benefits associated with thermal EG

Table 3: Overview of potential costs and benefits of thermal EG

	Low Uptake	High Uptake	Comments
Potential benefits			
Avoided augmentation expenditure	✓	✓	Depending on specifics of thermal EG, it could lead to deferred or avoided augmentation expenditure
Avoided replacement expenditure	?	?	Higher uptake of thermal EG could lead to avoided expenditure if reduced variability in loading of assets.
Avoided operating costs	?	?	Higher uptake of thermal EG could lead to avoided expenditure if reduced variability in loading of assets.
Avoided electricity losses	?	✓	Material changes may occur under high uptake
Impacts on Transmission Network	X	?	Unlikely but will depend on specifics of EG
Potential Costs			
Connection and other facilitation costs	✓	✓	Connection costs likely to be material, particularly for larger EG

Network management costs	**?**	**?**	Depending on specifics of thermal EG, it could create network management costs
Broader energy market costs	**X**	**?**	Depending on specifics of thermal EG, but unlikely to create broader market issues given relatively small aggregate load

5 International experience in providing network credits for EG

Policy-makers across a number of jurisdictions have implemented export credit arrangements that seek in part to incentivise investment in and use of EG. The Rule change request is predicated on these precedents, particularly Great Britain.

This chapter provides an outline of EG network price signals in other mature electricity markets around the world, and discusses the importance contextual, including broader policy objectives, underpinning their development. Most attention is focused on Great Britain, which has traditionally imposed negative transmission charges (i.e. credits) on generators located in the south of England. We go on to briefly discuss arrangements in New Zealand and the United States.

5.1 Lessons from the international experience in providing network credits for EG

Policy-makers across a number of jurisdictions have implemented export credit arrangements that seek in part to incentivise investment in and use of EG. Many of these arrangements have been introduced in the context of a range of network and non-network objectives.

Interestingly, to date, there has not been significant analysis of the extent of any net benefits that EG provides to networks (and their customers), nor the interactions with other regulatory and policy settings. As such policy-makers and regulators are in the process of undertaking (or have indicated the need for) further work to understand and quantify the network benefits of EG more robustly, alongside any interactions with other regulatory and policy settings.[49]

The experiences in the UK and US where policy makers and/or regulators have introduced uniform charging methodologies across distribution networks, as well as experiences in NZ that rely on commercially negotiated outcomes, suggests that establishing pricing principles and managing some of the inherent trade-offs or tensions in implementing a set of network credits – such as between efficiency, simplicity and predictability – alongside the interactions with other regulatory and policy settings is challenging, yet critical, if signals are to be provided for efficient investment in, and use of, EG in locations and times where it is of value to networks (and all energy consumers).

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49 For example Ofgem has stated that EG should not continue receiving network credits if they drive the need for network reinforcement and appears to be open to re-visiting if this issue, and the related issue of the need for locational network credits, if generator-dominated nodes became prevalent.

Unlike in the UK[50], the existing (and future) market, regulatory and policy settings in Australia makes generator-dominated network nodes a more likely possibility. This suggests that a regulated and mandated set of uniform and highly averaged network credits – as proposed in the Rule change request – may not necessarily facilitate efficient investment in and use of EG in Australia given that:

- if efficient investment is to occur in EG in locations, quantities or technologies where it provides net benefits to DNSPs, then any set of network credits (and charges) should reflect the nature of the costs and benefits to DNSPs that different forms of EG may provide,[51] should account for material locational differences, be dynamic and allow for payments to and/or from DNSPs (i.e. be symmetrical)[52]
- the international experience in implementing EG network pricing would suggest that introducing a regulated and mandated set of uniform and highly averaged network credits – as proposed in the Rule change request – in Australia, in addition to the existing regulatory and policy settings, requires careful consideration of a number of implementation issues including:
  - the appropriate categories (and sharing) of costs and benefits within the network credits (and charges), the appropriate price structure for providing cost reflective signals to EG customers[53], and the appropriate balance between flexibility and predictability[54]
  - the risks associated with potentially implementing a highly dynamic, locational and technology specific set of regulated network credits (and charges) for exported electricity that may be more cost reflective than the corresponding set of regulated network tariffs for imported electricity

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50 In choosing to err on the side of simplicity and customer understanding in setting a uniform 'postage stamp' network charging methodology at the HV/LV level, Ofgem decided has to some extent benefited from there being relatively low probabilities in the foreseeable future of any generator-dominated network nodes in the UK (partly the result of other market policy settings that do not drive significant up-take in small scale EG).

51 i.e. the level and structure of any network credit is cost reflective

52 With a positive credit determined where there are clear long term net benefits to networks from additional investment in, and use of, EG and a negative credit (or charge) where there are clear long term net costs to networks from additional investment in, and use of, EG.

53 Which involves a trade-off between a highly dynamic and locational approach – which is more likely to reflect the nature of the costs and benefits and therefore send efficient signals for investment in and use of EG – and a simpler approach that maximises customer understanding, but with less ability to capture any net benefits and may risk discouraging investment and use of EG in locations, quantities or technologies where there may be net benefits, and/or encourage investment where there may be net costs to networks and ultimately on customers.

54 In terms of allowing network businesses to respond to changing market conditions by updating the level of any network credit (and charge) and customers' preference for predictability and simplicity

- the interaction with the existing (and potential) mechanisms in the NER[55] and other policy settings that may also encourage investment in and use of EG.

5.2 Great Britain

5.2.1 Overview of network credit arrangements in Great Britain

Ofgem has introduced a uniform charging methodology across the distribution networks in Great Britain. Ofgem's rationale for introducing generator credits is that it expects locally connected generators will offset some network reinforcement requirements.

In Great Britain, all distribution network operators (DNOs) are required to adhere to the common charging methodology. This methodology consists of two parts:

- The **Common Distribution Charging Methodology (CDCM)**. The CDCM covers all low voltage (LV) and most high voltage (HV) connections, for both demand and generation. It was introduced on 1 April 2010.
- The **extra-high voltage (EHV) Distribution Charging Methodology (EDCM)**. The EDCM for demand customers was introduced in April 2012; and for generation customers in April 2013.

Both the EDCM and the CDCM incorporate a credit for generators, which is essentially the negative of the charge for demand customers. However, there are some conditions and restrictions on these generator credits:

- Under the CDCM, non-intermittent generators receive a credit which varies according to times of peak load. Intermittent generators only receive a single (albeit lower) uniform credit.
- Under the EDCM, intermittent generators receive no credit at all, while non-intermittent generators only receive a credit at so-called "super-red" peak times.

Figure 4 shows schematically the boundaries for the different charging methodologies.

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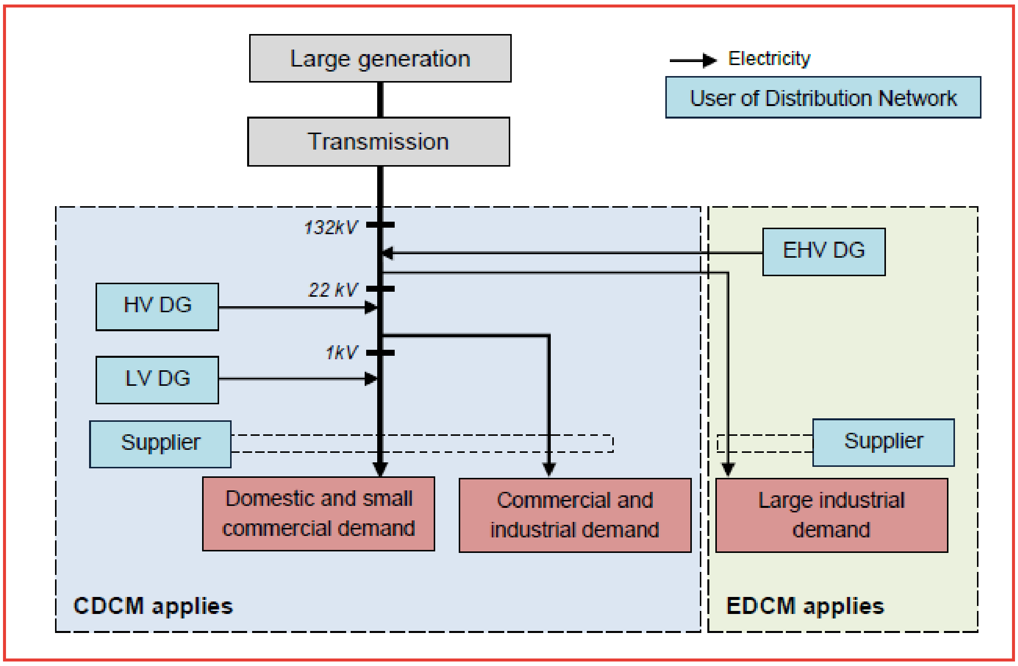
55 For example, the NER may provide some mechanisms for providing price signals to small scale EGs (such as through the small generation aggregator framework).

Figure 4: Boundaries for application of DUoS charging methodologies.



Source: Element Energy, Customer-Led Network Revolution Commercial Arrangements Study. Review of existing commercial arrangements and emerging best practice. 13th June 2013.

Under the CDCM, EGs receive a credit unit rate (in p/kWh), which is equal to the negative of the charge for demand customers, multiplied by an "F Factor". The F Factor varies for intermittent and non-intermittent generation. Non-intermittent generators have a 3-part tariff corresponding to three different times of the day, referred to as 'green', 'amber' and 'red'[56]. Intermittent generators are assigned an F-factor based on the period of continuous generation. The CDCM utilises a so-called Distribution Reinforcement Model (DRM) to establish charges for demand customers. The model is forward-looking – i.e. it produces charges based on the future cost of providing incremental network capacity[57]. There are no locational signals currently within the CDCM.

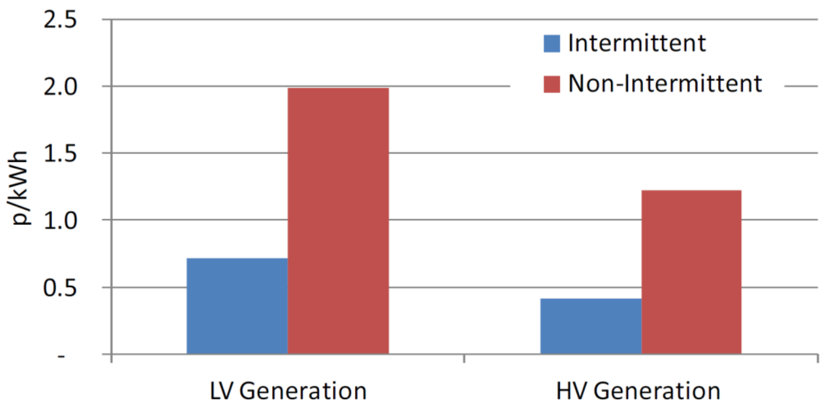
The EDCM offers "super-red" credits to generators that help to meet local peak demand. The super-red charge is the charge applied for consumption at the time of the DNO peak, for example 16h-19h30 Monday to Friday, November to February. For some generators, the super-red credit would be larger than the network charges they incur, and they would receive a net credit.

56 This mirrors the 3-part time rates paid by suppliers. Examples of time bands: Red 16:00 – 19:30 (Monday to Friday); Amber 08:00 – 16:00 and 19:30 – 22:00 (Monday to Friday); Green – All other times. Each DNO can choose the time band for its network and must give 15 months' notice for amendments. For demand customers, the green unit rate is typically <1p/kWh, while the red rate is much higher, up to 20p/kWh.

57 Ofgem considered and rejected alternative models which were based on historical costs.

Figure 5 illustrates generator credit in 2013 calculated by Element Energy.

Figure 5; Average unit charge paid to suppliers for DG, based on CDCM calculations for 2012-13



Source: Element Energy, Customer-Led Network Revolution Commercial Arrangements Study. Review of existing commercial arrangements and emerging best practice. 13th June 2013.

5.2.2 Background and policy intent for network credit arrangements in Great Britain

Ofgem appears to have had two broad objectives when implementing these generator credits.

- First, in line with the principle of cost-reflectivity, Ofgem considered that where generation can reasonably be assumed to defer or avoid future reinforcement costs, these benefits should be reflected in generator charges, so as to deliver appropriate economic incentives.
- Second, Ofgem has also made several references to the broader policy objectives of encouraging take-up of low carbon technologies. For example, in its 2008 Decision to proceed with a common charging method, Ofgem said that: *'Delivery of this project is vital in facilitating progress towards meeting government targets on climate change, in ensuring that economic signals are provided to existing and potential users of electricity distribution networks and in enabling the efficient development of*

the network." It said the common method would *"further enable DNOs' role as facilitators in tackling climate change"*[58].

Ofgem's rationale for introducing the generator credit at HV/LV level was based on two broad assumptions.

- First, Ofgem assumed that DG can give rise to long run negative costs because it is expected to reduce upstream network costs. The underlying assumption is that HV/LV nodes are demand dominated – generators connecting to these nodes therefore impose a net benefit on DNO networks by diverting upstream power flows and contributing to system security[59].
- Second, Ofgem assumed that generators will not cause additional reinforcement costs. Ofgem considers that this is a reasonable assumption because, in its view, there will be even dispersion of generation across the network[60].

However, the extent to which these broad assumptions hold in the future is not clear. If an EG connects to a part of the network where there was very little local demand and/or a significant amount of existing generation capacity, the output from these generators could in theory lead to reverse power flows (from low voltage to high voltage) across the local substation. Such reverse flows could bring forward the need for reinforcement of local network assets. In such a scenario, it would be efficient to impose charges on EG customers to reflect the fact that they are accelerating rather than reducing network investment costs.

In February 2015, Ofgem rejected the proposal to implement locational charging for generators at the HV level due to concerns about cost-reflectivity, complexity and administrative burden.[61] However, Ofgem did support the underlying principle that if generation drives reinforcement, those generators should not continue receiving credits. This would appear to be an area which Ofgem may revisit if it became apparent that generator-dominated nodes were becoming a more significant problem. For now, the CDCM continues to offer a p/KWh credit[62] to generation customers, irrespective of where they are located on the network.

However, one of the key questions Ofgem has grappled with is whether this assumption is applicable at all network locations – and therefore whether generator

58 Ofgem, 22nd July 2008, 104/08 "Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements".

59 E.g. See Ofgem Decision Document: Delivering the electricity distribution structure of charges project, 1st October 2008, p. 2, 26, and 60.

60 Ibid. p.60

61 https://www.ofgem.gov.uk/sites/default/files/docs/2015/02/dcp137_d_0.pdf

62 In addition to this credit, the CDCM levies a fixed charge (p/MPAN/day) on generators where appropriate. A reactive charge (p/kVArh) is also levied where the charge band is exceeded.

credits should vary by location (essentially by network node). In considering this question, Ofgem seems to have accepted that there may be an economic argument for introducing locational variation in generation credits – namely that generators should not be encouraged to connect in nodes which are already "generator dominated". However, Ofgem has sought to balance this economic efficiency argument against the additional complexity associated with introducing locational variation into generator credits.

Ultimately, Ofgem has decided that at the EHV level, it is feasible to develop network charges (and therefore generator credits) based on network reinforcement models specified for each individual node. In contrast, at the HV/LV level Ofgem has noted that locational charging would imply significantly more complexity compared to EHV; and has not seen evidence that there are a sufficient number of generator-dominated nodes that would merit introducing this complexity. Ofgem therefore incorporates locational variation in the EDCM, but not the CDCM.

Appendix B provides further detail on the arrangements in Great Britain.

5.3 New Zealand

Part 6 of the *Electricity Industry Participation Code* 2010 governs pricing arrangements for EG. In general, the Code requires charges for connection of EGs to be based for incremental costs, or the generator's share of generation-driven costs. If incremental costs are negative, the EG is deemed to provide network support to the distributor and may invoice the distributor for that service.

There are no specific regulatory provisions governing the setting of export credits for avoided distribution network costs. A number of DNSPs have considered the merits of providing network credits to EGs.

Orion (around Christchurch), offers export credits for EGs in recognition of the benefits exports provide to its network.[63] Credits are based on the amount of electricity injected into the network during peak loading periods. The cost of delivery during peak loading is represented by Orion's assessment of its long run average incremental cost (LRAIC), which is estimated as $101/kW per annum. However, Orion notes that some of the costs represented in this LRAIC are not alleviated via export: For example, the required size for distribution transformers and low voltage systems is usually unchanged when generation is installed. Consequently, it sets the export credit price below the full LRAIC. Orion sets a lower credit price for export that includes solar PV and where the customer does not have half-hour metering. The lower price reflects the average coincidence

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63 Orion, *Methodology for deriving delivery prices, For prices applying from 1 April 2015*, 18 February 2015, section 8.

between export from solar PV generation and network peak demands (usually occurring on cold winter days and evenings). The credit provided to exporting generators also includes a component reflecting avoided transmission charges.

Customers have a choice of two types of rebates for small-scale EG (<30 kW):

- A lower anytime credit rate for all kWh of energy export or
- A higher credit rate for exports at peak times (requiring appropriate time-of-use metering).

The anytime credit for solar PV exports is lower than for other types of EG, reflecting the fact that export contribution from solar PV generation is generally very low during Orion's peak load periods, which occur during cold winter days and especially evenings. However, solar PV owners can still elect to apply for the higher peak time credit rate if they install appropriate time-of-use metering. By way of comparison, Orion's current export credit rates for EG under 30 kW are:

- 1.082c/kWh for anytime exports (without solar PV)
- 0.038c/kWh for anytime exports (with solar PV)
- 75.86c/kWh for peak period exports (with or without solar PV).

Different rates apply for exports from larger EGs.

In addition, Orion offers generation credits for EG output during times it exercises ripple control load management, even if the EG is not exported. For EGs between 500kW and 1.2MW, the rate is 60c/kWh, representing half a network credit and half a transmission credit.

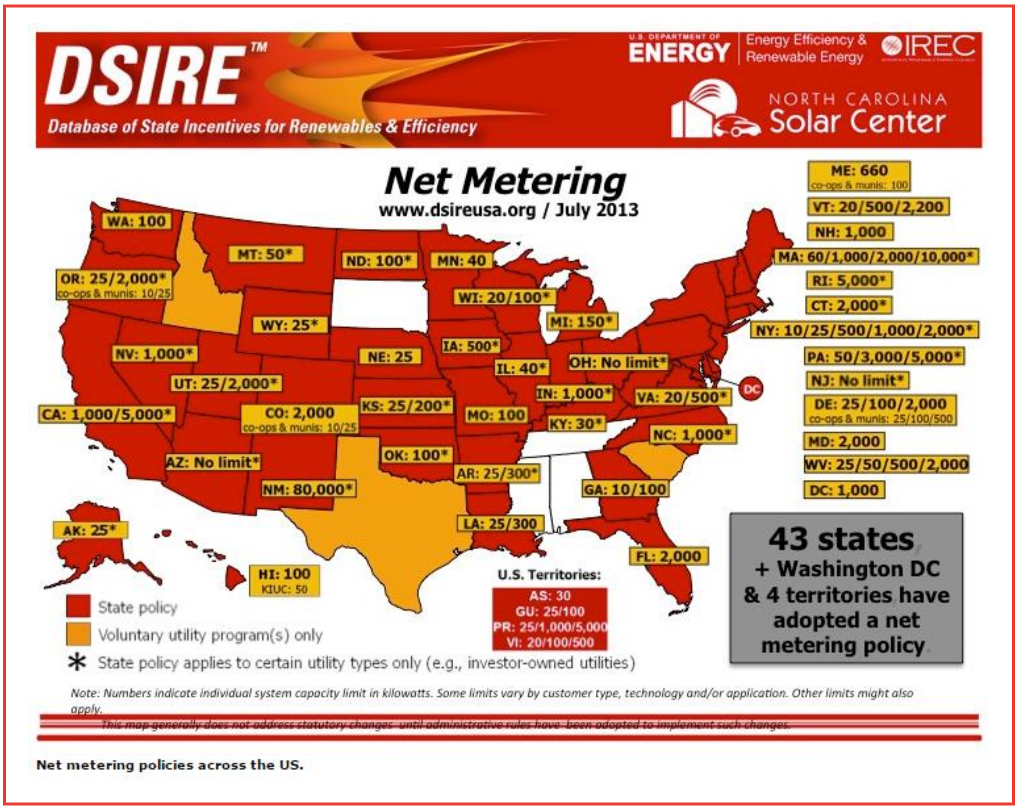
Similarly, Unison acknowledges the potential benefits associated with allowing EG customers to 'return' any excess energy they have produced with the potential for this to reduce peak demand. While Unison has elected to provide EG credits, they have stressed the challenge they face managing power quality when a sufficiently large number of consumers elect to return energy to their network.[64]

5.4 United States

In the US, export credits for EGs are largely based around the concept of 'net metering', whereby EG exports reduce the customer's bill for energy consumed at other times. Almost all States have developed net metering rules for at least some utilities, with the 'credit' rate generally at the retail tariff. **Error! Reference source ot found.** below is from the website of the Solar Energy Industries Association and summarises net metering policies across the United States.

64 Unison, *Distributed Generation*, <http://www.unison.co.nz/tell-me-about/electricity/solar-energy/distributed-generation>

Figure 6: Net metering policies across the United States



Net metering policies across the US.

Source: http://www.seia.org/policy/distributed-solar/net-metering

Most net metering programs allow a customer to reduce their monthly bill to zero at best. However, some States, such as California and Vermont, allow group or 'virtual' net metering, which allows credits for EG exports to be allocated to customer accounts beyond the physically net metered accounts. Many utilities are now seeking to reduce the rate at which EG exports are valued or to increase daily demand charges on EG customers. For example, the Arizona Public Service (APS) has made an application to the Arizona Corporation Commission (ACC) to cut the rate it pays solar PV customers for their exports, In 2013, ACC agreed to impose a 'lost fixed cost recovery' charge of 70c/kW on solar PV installations. However, APS wants that rate increase to $3/kW and the ACC has postponed its decision until the next full rate case in 2016. Another Arizona utility, Tucson Electricity Power (TEP) believes the reimbursement rate should be changed to the rate the utility pays for wholesale solar generation from utility-scale projects.

The North Carolina Clean Energy Technology Center (NCCETC) and Meister Consultants recently reported that a number of US states are considering changes to policies concerning EG tariffs. The changes being considered include:[65]

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65 North Carolina Clean Energy Technology Center and Meister Consultants Group, *The 50 States of Solar*, Q2, 2015.

- Reviewing the valuation of solar under net metering policies
- Raising or lowering net metering caps across the state
- Raising fixed charges to help ensure sunk cost recovery in light of increases in EG connections and outputs.
- Increases in charges only to solar PV or net metered customers.

6 Sending efficient EG price signals that reflect the costs and benefits to networks

Network pricing reform to date has primarily focused on electricity imported from the network[66], and the Rule change request notes while these reforms encourage efficient price signals for electricity consumption, they may not lead to efficient investment in and use of EG in terms of efficient size and location.[67] By setting up a new payment relationship between DNSPs and EGs, the Rule change request submits that the network credit will allow EGs to monetise the benefits they provide to network businesses, providing incentives for efficient investment in EG.[68]

Our indicative modelling (Quantifying the impacts of indicative EG credits on customers and networksshows that up-take of EG is sensitive to the level and structure of any network credit. However it is not clear to what extent the Rule change request for a set of regulated and mandated network credits has been developed with a set of clear pricing principles, nor considered to what extent any pricing principles should mirror, draw from, or depart from the existing distribution network pricing objectives and principles.

This chapter highlights that there are a number of key issues that would need to be resolved if any regulated and mandated set of network credits (and potentially charges) is to facilitate efficient investment in and use of EG, including

- the pricing objective and pricing principles that should guide the development of any network credits (and charges)
- a number of key (but inevitable) implementation issues.

It is not clear that the Rule change request has considered and resolved these issues in a way that is likely to promote the NEO.

66 AEMC, Final Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, November 2014.

67 Oakley Greenwood, Local Generation Network Credit Rule Change Proposal – Submission to Australian Energy Market Commission: Proposed by City of Sydney, Total Environment Centre, and the Property Council of Australia, July 2015, p1.

68 Any network credit would operate in addition to any jurisdictional Feed-in-Tariffs that EGs may receive.

6.1 Providing efficient price signals to EG

The Rule change request notes while recent distribution network pricing reforms encourage efficient price signals for electricity consumption, they may not lead to efficient investment in and use of EG in terms of efficient size and location.[69]

While in theory encouraging efficient investment in and use of EG requires some form of price signal to be provided to EG investors and users for electricity exported to the network (as well as other regulatory mechanisms to provide 'signals' to DNSPs), as the AEMC Consultation Paper highlights, the extent of any under (or over) investment in EG, and the need for further reform of the treatment of EG (with the Rule change request being one option) will depend on the operation of other elements of the NER (refer Box 2).

Box 2: Encouraging efficient investment in and use of EG

Where customers are contemplating investment in EG that may lead to them becoming net exporters into the distribution network, the distribution network pricing reforms alone does not ensure that they will face efficient price signals.

This is be illustrated by comparing two adjacent households contemplating an EG investment – one household that would remain a net consumer following the investment and the other that would become a net exporter of power following the investment. At the margin, both customers should face the same incremental signals to invest in EG. However, in light of the recent distribution network pricing reforms:

- The household that would remain a net consumer following the investment would face broadly efficient signals to invest in EG. This is because the customer would benefit from reduced network charges attributable to the operation of the EG. Those reduced charges would (in principle) reflect the value of network expenditure avoided by the operation of the EG; But
- The household that would become a net exporter of power following the investment would not necessarily receive any benefits from those exports beyond the reduction in its usage-related network charges to zero. If the customer was considering becoming a substantial exporter, and was not able to access some form of network support payment or any payment through some form of small aggregator framework, it might forgo a large proportion of the benefits that would be available to a higher-consuming customer that invested in the same EG plant.

As the AEMC Consultation Paper highlights, the extent of any under (or over) investment in EG will depend on the operation of other elements of the NER, rather than simply the recent distribution network pricing reforms in insolation.

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69 Oakley Greenwood, Local Generation Network Credit Rule Change Proposal – Submission to Australian Energy Market Commission: Proposed by City of Sydney, Total Environment Centre, and the Property Council of Australia, July 2015, p1.

6.2 Pricing objective and pricing principles for use of the network

In making its distribution network pricing Rule change in 2014[70], the AEMC concluded that network prices had not evolved in line with the way customers were using the network. This meant that there were significant benefits to DNSPs and customers from reforming the design, consultation and transparency of network prices.

As electricity consumers and EG investors/operators are both users of the electricity network, to some extent, the Rule change request has sought to 'borrow' from these distribution network pricing principles and processes. For example, one of the key drivers of the 2014 Rule change was ensuring that network tariffs reflect the fact that consumers with different patterns of consumption impose different costs on the network[71] and the Rule change request highlights the importance of efficient pricing signals in encouraging efficient investment in and use of EG. The Rule change request acknowledges that economic efficiency may be enhanced by having a network credit that varies by voltage level and location.

However, Rule change request also differs in some key areas. For example, the Rule change request stipulates that the credit should not be cost reflective at all times. For example, in situations where the cost of catering for bi-directional flows is deemed to exceed the benefits of the exported electricity to the network, the Rule change request is that the credit should not be negative, such that the costs should be recovered from all network users. That is, the Rule change request does not involve providing an efficient pricing signal to EG investors and operators at these times.

Given this, it is not clear to what extent the Rule change request for a set of regulated and mandated network credits has been developed with a set of clear pricing principles, nor considered to what extent any pricing principles should mirror, draw from, or depart from the existing distribution network pricing objectives and principles[72].

As discussed in Chapter 4, the costs and benefits of EG are likely to be:

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70 AEMC, Final Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, November 2014.

71 As the AEMC recognised, while customers "might look the same…because of the appliances they have and the different lifestyles they lead they may have very different load profiles" which in turn can impose different costs on the network. AEMC, Final Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, November 2014, p3.

72 AEMC, Final Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, November 2014.

- Dynamic and locational, dependent upon the shape of aggregate consumption (or load profile) at the relevant feeder or substation, the level or take-up of EG (relative to aggregate consumption), and the extent to which given network elements are currently close to capacity.
- Technology specific given the material differences in the operating characteristics of EG. For example, it is less likely for there to be any material long-term benefits in the form of deferred or avoided network capital expenditure from EG that may be intermittent and/or unreliable during periods of peak network demand.
- Dependent on wider market outcomes including relevant policy and regulatory settings. The uptake of EG, which will influence any network costs and benefits, will reflect numerous factors including customers' load profile, the structure and level of retail electricity prices, any relevant feed in tariffs and EG technology costs.

This suggests that if any viable set of regulated and mandated network credits (and charges) is to provide signals for efficient investment in, and use of, EG they need to be guided by a pricing objective, and underpinned by clear pricing principles. We have considered a number of key principles that might guide any set of network credits (and charges) if they are to encourage efficient investment in and use of EG (see Box 3 and Table 1).

Box 3: Key principles that might be considered if any set of network credits (and charges) is to encourage efficient investment in and use of EG

Given the nature of the costs and benefits that EG provides, we have developed a number of key principles that might guide any set of network credits (and charges). These principles include that any set of network credits (and charges) should:

- Reflect the nature of the costs and benefits to networks that different forms of EG may provide (i.e. the level and structure of any network credit is cost reflective) recognising that the contribution towards any system benefits or costs from any individual EG will depend on the operating characteristics and use of the EG, including firmness and reliability of any generation
- Reflect locational differences to ensure investment in and use of EG occurs where it can potentially defer or avoid network constraints and the need for expenditure
- Reflect the dynamic nature of the costs and benefits that EG may provide to networks to ensure investment in and use of EG occurs when it can potentially defer or avoid network constraints and the need for expenditure
- Be symmetrical, with a positive credit determined where there are clear long term net benefits to networks from additional investment in, and use of, EG and a negative credit (or charge) where there are clear long term net costs to

networks from additional investment in, and use of, EG. (i.e. this may involve payments to and/or from DNSPs)[73]

- Be designed with recognition of any risks associated with implementing a highly dynamic, locational and technology specific set of regulated network credits (and charges) for exported electricity that may be more cost reflective than the corresponding set of regulated network tariffs for imported electricity
- Where possible, be predictable and understood by both networks and investors (and potential investors) of EG, which likely requires a comprehensive consultative process on symmetrical estimation and charging methodologies.

Source: Frontier Economics

6.3 Implementation issues

Implementing a set of regulated and mandated network credits (and charges) that sought to promote efficient investment in and use of EG principles would inevitably involve resolving a number of key issues, some of which are similar to issues that the AEMC considered and consulted upon with market participants as part of the 2014 Rule change.[74]

The experiences in the UK and US where policy makers and/or regulators have introduced uniform charging methodologies across distribution networks, as well as experiences in NZ that rely on commercially negotiated outcomes, suggests that managing some of the inherent trade-offs or tensions in implementing a set of network credits – such as between efficiency, simplicity and predictability – alongside the interactions with other regulatory and policy settings is challenging, yet critical, if signals are to be provided for efficient investment in, and use of, EG in locations and times where it is of value to networks (and all energy consumers).

For example, it is not clear whether the Rule change request has considered:

- How to manage any risks associated with implementing a highly dynamic, locational and technology specific set of regulated network credits (and charges) for exported electricity that may be more cost reflective than the corresponding set of regulated network tariffs for imported electricity
- How in practice any symmetrical set of regulated network credits (and charges) would work when the Rule change request is that the network credit be optional.

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73 This may require other changes to the NER given that EGs that only use the network for exporting electricity do not pay DNSPs for providing the infrastructure to transport this energy. Clause 6.1.4(a) of the NER prevents a DNSP from charging users distribution use of system charges for exporting electricity to the distribution network.

74 Changes to the National Electricity Rules (NER) made in 2014 pursuant to the Distribution Network Pricing Arrangements Rule change

Box 4 outlines some of the key implementation issues that would need to be resolved if any set of network credits (and charges) is to encourage efficient investment in and use of EG. Table 4 then explores some of these implementation issues and considers to what extent application of any pricing principles should mirror, draw from, or depart from the existing distribution network pricing principles and processes.

Box 4: Key implementation issues that would need to be resolved if any set of network credits (and charges) is to encourage efficient investment in and use of EG

There are likely to be a number of key implementation issues that would need to be resolved if any set of network credits (and charges) is to encourage efficient investment in and use of EG, including:

- The appropriate categories[75] (and sharing[76]) of costs and benefits within the network credits (and charges), as well as methodology for estimating these costs and benefits (including a forward-looking cost based methodology)
- Whether and to what extent residual costs should be recovered from EG customers who are or are not already paying a fixed charge, and on what basis (including any contribution that these EG customers may already have made as load customers)
- The appropriate balance between flexibility and predictability in terms of allowing network businesses to respond to changing market conditions by updating the level of any network credit (and charge) and customers' preference for predictability and simplicity
- The appropriate price structure for providing cost reflective signals to EG customers,[77] which involves a trade-off between the efficiency benefits of a highly dynamic and locational approach, and a simpler approach that maximises customer understanding but may discourage investment and use of EG in locations, quantities or technologies where there may be net benefits, and/or

75 For example, commercially negotiated export credits provided by Orion in NZ for EGs involves credits priced below the assessment of its long run average incremental cost (LRAIC) given that some of the costs represented in this LRAIC are not alleviated as a result of EG exporting electricity to the network. For example, the required size for distribution transformers and low voltage systems is usually unchanged when EG is installed. Further, it is not clear whether other benefits such as reduced electricity losses should be included in any network credit given the benefit primarily accrues to retailers (and their customers) in the form of reduced energy purchase requirements from the NEM.

76 By setting the network credit to reflect the entire expected reduction in long-run network and operating costs brought about by EG, the Rule change request implies that EGs receive (or monetise) all the network benefits of EG, leaving customers no better off. The AEMC's Consultation Paper recognises that for the proposed Rule to promote the long term interests of customers, any network credit may need to be less than 100% of the forecast network benefits. AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, Sydney, p29.

77 Assessing different pricing structures involves considering the benefits in terms of efficient investment that may result from cost reflective price signals and the costs in terms of implementation and administration costs, advanced metering requirements and reduced customer understanding.

encourage investment where there may be net costs to networks and ultimately on customers

- How in practice any symmetrical set of regulated network credits (and charges) would work when the Rule change request is that the network credit be optional
- The likely impact on networks and the energy market of over-or under-stating the true value of the benefits or costs of EG in any network credit, including the interaction with other regulatory and policy settings[78]
- The risk associated with a set of network credits (and charges) for exported electricity that may be more or less cost reflective that the corresponding set of network tariffs for imported electricity, and the impact this may have on customers' incentives to invest in, and use, EG.

Table 4: Key implementation issues that need to be considered and resolved if any set of regulated and mandated network credits (and charges) is to promote efficient investment in and use of EG.

Pricing principles	Interpretations of Rules by DNSPs for 'imported' electricity	Implementation issues that would need to be addressed for 'exported' electricity
Efficient price signals		
Tariff class - Establish tariff classes on an economically efficient basis and to minimise transaction costs	Grouping of customers with similar characteristics together so that similar customers pay similar prices. JEN has proposed 5 tariff classes. [79]	Factors to consider when 'grouping' EG customers together into tariff classes: • What makes EG customers similar/different? Is it worthwhile to establish more tariff classes for customers with EG who are frequent exporters? • What factors are most likely to influence scale and scope of network savings (Voltage level, generator type, location, size, time)? To what extent would a single tariff class have the effect of inefficiently deterring or encouraging investment and usage of EG? • What factors are likely to be identifiable to DNSPs to assign EG customers to a tariff class?

78 For example, understanding to what extent a single tariff class for EG have the effect of inefficiently deterring or encouraging investment and usage of EG.

79 Jemena Electricity Networks, Tariff Structure Statement, September 2015, p8.

Pricing principles	Interpretations of Rules by DNSPs for 'imported' electricity	Implementation issues that would need to be addressed for 'exported' electricity
Tariff structure and level - each network tariff must be based on the long run marginal cost of providing the service.	Where technology exists, signals are provided through a capacity charge or demand charge ($/kW) using LRMC to provide a signal to reflect the cost of consumption during peak periods [80]	Factors to consider when establishing appropriate structure and level of network credit: • What is the appropriate tariff structure to provide efficient price signals ($/kW, $/kWh during specified times, or $/pa with conditions) • To what extent (if any) should the credit (or negative charge) be tailored to reflect long term benefits from EG at times and in locations where additional network investment may or may not soon be required? • Should EG supply need to be 'firm' (if even on aggregate/ portfolio basis) to receive any or a higher credit? • To what extent should a negative credit (or charge) be imposed at times or in locations where the costs of exports exceed the benefits?
Recovery of total revenue requirement		
Recovery of residual costs	Residual costs (total revenue requirement minus revenue from usage/ demand tariffs) to be recovered through fixed charge ($/ pa) and some usage (c/kWh) charges	Is there a need for a fixed charge for those EG customers not paying the 'traditional' fixed charge (i.e. EG customers that do not off-take energy)?[81]
Minimising distortions to efficient use of the network	Recovery of total revenue in a way that minimises distortions to price signals	What factors would assist DNSPs in deciding upon/recovering any residual costs from EG customers in a way that minimises distortions to use of network?

80 Jemena Electricity Network (JEN) has proposed to levy a demand charge tariff component—a charge that applies to either a customer's electricity capacity requirement (in dollars per kilovolt-ampere (kVA)) or their maximum demand level (in dollars per kilowatt (kW)) depending on the type of customer. Jemena Electricity Networks, Tariff Structure Statement, September 2015, p8.

81 Most likely large scale EG.

Pricing principles	Interpretations of Rules by DNSPs for 'imported' electricity	Implementation issues that would need to be addressed for 'exported' electricity
	that encourage use of the network	
Impacts on consumers		
Predictability and stability in network pricing	• Tariff Structure Statement sets out medium to long-term view on likely movement in network tariffs • Tariff structures 'locked in' for regulatory period, with DNSPs consulting with customers and stakeholders before making changes to the TSS	Potential swings in network savings as result of movements in network capacity (say leading up to vs after major network investment) could result in volatility in network credit and barriers to investment in EG
Customers being able to understand and respond to network prices	Extensive consultation relating to structure and transition to new tariffs (particularly demand based charges)	Bespoke network credits (location, time etc.) likely to promote efficient investment but create greater challenges for customer understanding[82]
Jurisdictional obligations		
Network tariffs must comply with jurisdictional pricing obligations imposed by state or territory governments	Some jurisdictions have states have state-wide uniform pricing requirements.	Risks associated with seeking to implement a highly dynamic, locational and technology specific set of regulated network credits (and charges) for exported electricity that may be more cost reflective than the corresponding set of regulated network tariffs for imported electricity. Likely that any jurisdictional pricing obligations on imported energy (like state-wide uniform pricing requirements) would then be imposed on charges for exported energy

82 A useful case study is customer understanding relating to the different tiers of FiTs available in various jurisdictions, including whether customers installed solar PV before or after the closure of the subsidised schemes.

7 Quantifying the impacts of indicative EG credits on customers and networks

As noted earlier in the report, the market, regulatory and policy settings have the potential to amplify or weaken the impact of any network credit, and the associated costs and benefits of additional investment in, and use of, EG.

This chapter summarises our modelling approach and provides the results of our indicative customer modelling. The scenarios and modelling presented here:

- Demonstrate the sensitivity of EG uptake to both the level and structure of any network credit
- Illustrate the interdependencies of network credits with other market prices and wider outcomes
- Highlight the importance of further quantifying the potential range of interactions and outcomes in considering the costs and benefits of the Rule change request.

7.1 Summary of modelling results

Summary of modelling results: Quantifying the impacts of indicative EG credits on customers and networks

Our modelling indicates three key findings:

- **EG uptake occurs in the absence of any network credit (the reference case).** Our analysis, consistent with other market forecasts, estimates that there will be continued uptake of solar PV and storage under current arrangements. Primarily, this is a function of high and increasing retail electricity prices relative to declining EG technology costs and in some cases policy settings supporting EG (for example PV feed-in-tariffs). The introduction of any network credit arrangement would be likely to lead to incremental investment relative to the reference case. It is critical that any full cost benefit assessment account for the current and future impact of regulatory settings and likely market outcomes to avoid any double counting of any EG uptake.

- **The level of the credit is important.** Our analysis demonstrates that increasing the level of the credit, other things equal, would be likely to increase uptake of EG and potentially alter the mix of technologies, potentially skewing the mix of EG towards specific technologies or locations given it's likely that any broadly available network credit will over compensate or undercompensate different types/locations of EG.

- **The structure of the credit is also important**. Relative to a simple volumetric subsidy (c/kWh), a demand based credit (c/kW) will tend to provide stronger incentives for investment and use of EG that is able to contribute at peak times. Our analysis demonstrates that a demand based credit results in a greater battery storage uptake.

- **Other factors will amplify or weaken the impact of any network credit**. This includes customers' usage patterns (or load profile), tructure and level of the customers' electricity tariff, costs of different EG technologies, and other subsidies that may apply such as feed-in-tariffs and/or distribution credits.

7.2 Our modelling scenarios

We examined two forms of potential network credits structures, both with varying network credit levels.

- A **volumetric structure**, where electricity consumers are paid a c/kWh return on energy exported to the grid. For practical purposes, this is equivalent to increasing the FiT.
- An **upfront** or **deemed** structure, where electricity consumers are given a rebate on EG based on its ability to contribute at peak times. For practical purposes, this is similar to an additional SRES rebate, only also applicable to storage.

These network credits structures have different incentive properties, which we test under different tariffs structures. Table 5 outlines the tariff and network credit combinations that make up the scenarios considered in our modelling. We have included:

- two volumetric network credits at 3c/kWh and 6c/kWh, and
- an upfront network credit with equivalent value to the 6c/kWh for the average consumer in our sample, pro-rated between solar PV and batteries by contribution at time of peak.

Table 5: Scenarios for modelling the impact of network credits

Tariff	Network Credit structure	Network Credit level
Declining block	None (reference case)	NA
Declining block	Volumetric	3 c/kWh
Declining block	Volumetric	6 c/kWh
Declining block	Upfront (deemed)	Upfront equivalent of 3 c/kWh volumetric credit for average customer, pro-rated to solar PV/battery by contribution at time of peak
Time of use	None (reference case)	NA

Time of use	Volumetric	3 c/kWh
Time of use	Volumetric	6 c/kWh
Time of use	Upfront (deemed)	Upfront equivalent of 3 c/kWh volumetric credit for average customer, pro-rated to solar PV/battery by contribution at time of peak

Source: Frontier Economics

In anticipation of new TSSs, we have altered the time-of-use tariff modelled by doubling the fixed charge and reducing the peak rate, such that the tariff is revenue neutral for an average customer (calibrated to the Ausgrid NSLP). [83]

Detail on our modelling approach is provided at **Appendix C.**

7.3 Scenario modelling results

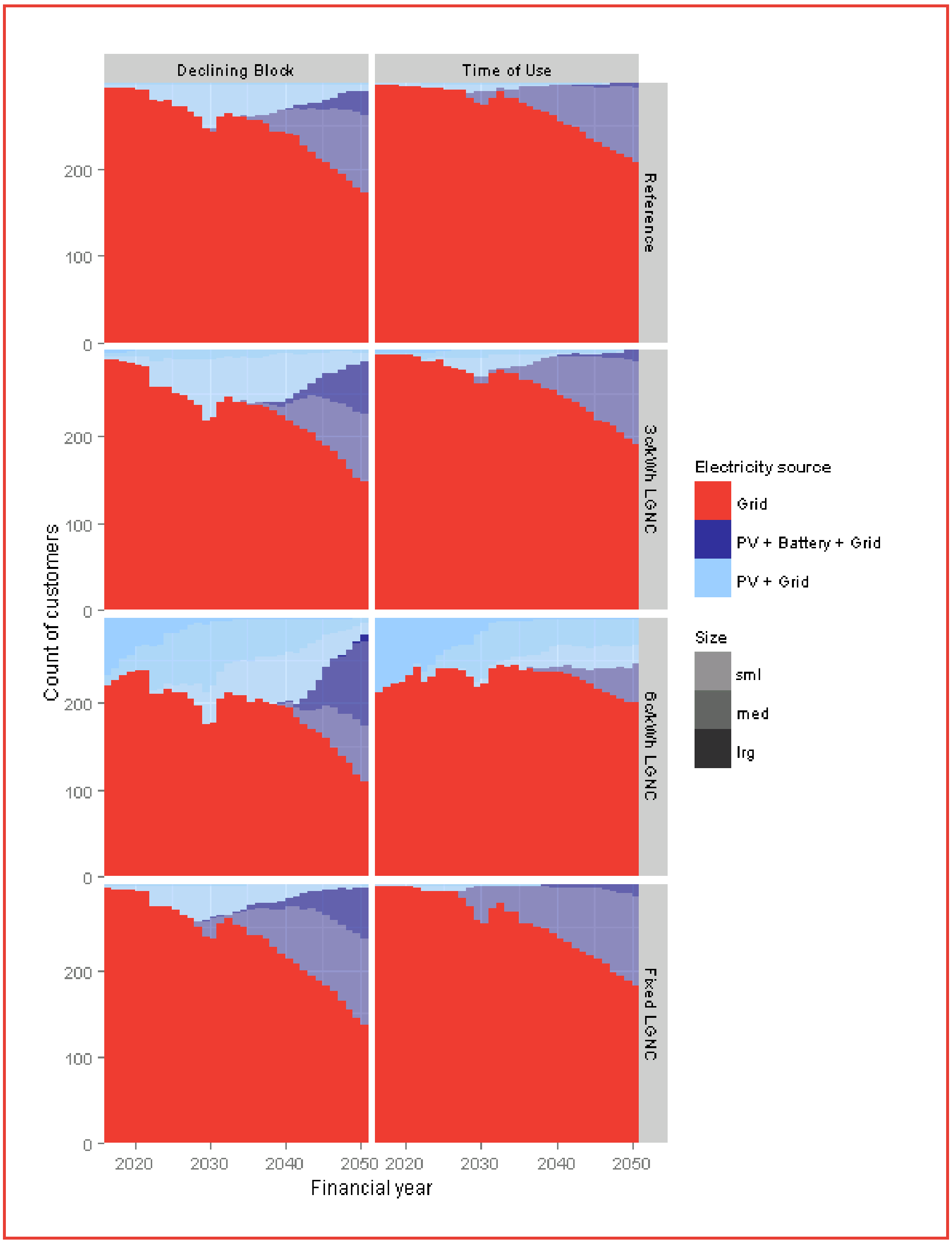
Figure 7 presents our forecasts of EG uptake for each of our customers under each scenario outlined in Table 5. EG investment incentives are stronger overall under our declining block tariff, as we've modified the time-of-use tariff such that the average variable rate for electricity is lower.

In all scenarios, batteries do not become economical under the implicit 10 year payback period[84] assumed for at least 10 years. Solar PV fares especially badly under our modified time of use tariff, due to the low average variable cost of electricity resulting in a lower benefit to offsetting consumption with EG. Batteries fare relatively better under the time of use tariff reference case, as under dynamic tariffs batteries have the additional value of being able to time-shift consumption. The declining block reference scenario sees steady growth in solar PV uptake, mirroring retail price increases which outweigh comparatively small reductions in the FiT. As battery costs fall, almost all EG systems eventually become combined solar PV and battery systems, allowing customers to forego retail charges by capturing any excess generation.

83 Our reasoning for altering a current time-of-use tariff is that a large differential between off-peak and peak rates and off-peak and shoulder rates means that there is high value in time-shifting consumption, i.e. charging batteries during off-peak times and consuming during peak times. With a peak rate of 50c/kWh and an off-peak rate of 10c/kWh, each time-shifted kWh of consumption is worth slightly less than 40c/kWh (slightly less due to battery losses). A high differential strongly incentivises battery-only investment, which is unsustainable as DNSPs would have strong incentives to reduce these rates as storage uptake increased.

84 We use 10 years as this is the warranty period of the Tesla Powerwall. Payback periods for combined solar PV and battery systems are complicated as the expected life span of solar PV panels are significantly higher than currently available batteries.

Figure 7: Customer decision-making under indicative modelling

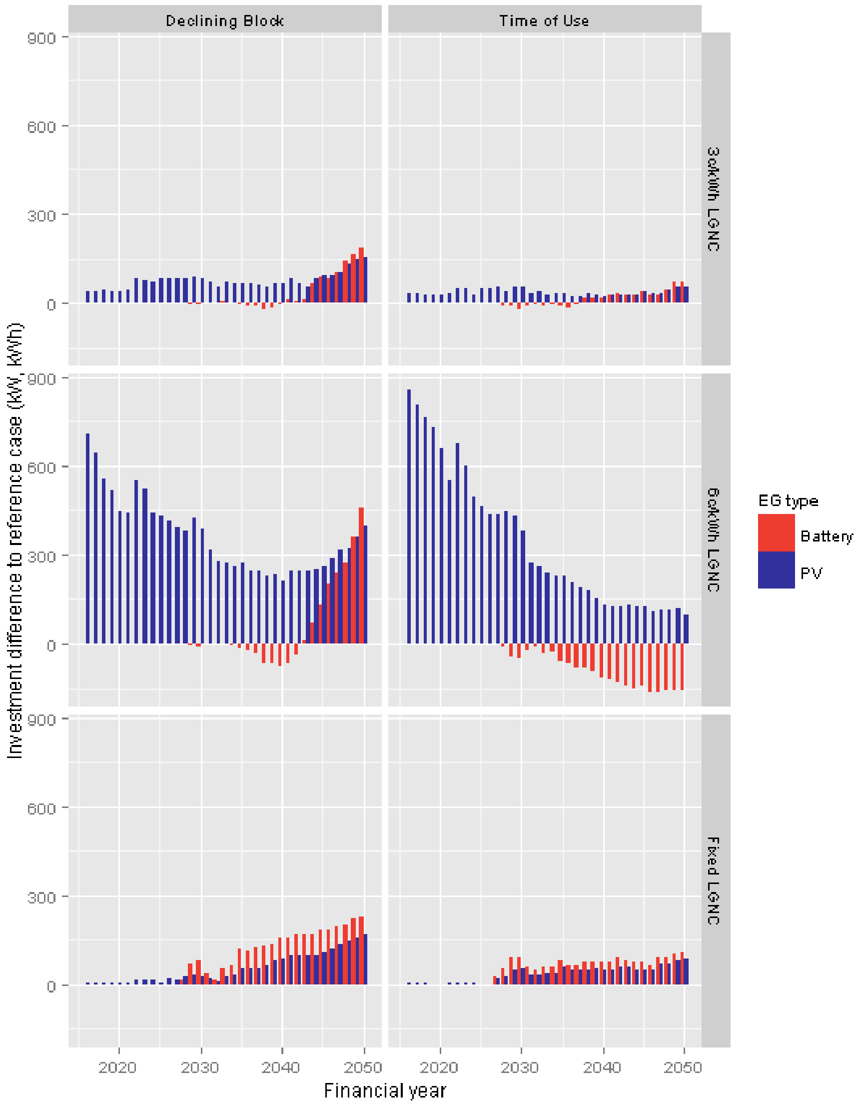


Source: Frontier Economics

Figure 8 shows the kW (PV)/kWh (storage) differences in EG investment compared to the relevant reference case for each tariff and network credit scenario. The effects of each assumed network credit structure and level are similar regardless of the tariff, although are more pronounced in the declining block cases due to the higher average variable cost of electricity. Likewise, the 6c/kWh volumetric network credit has a similar but more pronounced effect than the 3c/kWh network credit, in that:

- PV is, in all modelled years, more attractive in the reference case; and
- batteries are initially less attractive than in the reference case, but at a certain point, become more attractive.

Figure 8: Investment level differences to reference case out to 2050



Source: Frontier Economics

Unsurprisingly, increasing the value of exported energy initially decreases the value storing excess energy resulting in lower investment incentives. In the latter modelled years, reductions in battery costs mean virtually all solar PV systems are eventually paired with batteries. In the volumetric network credit scenarios, the increase in export price means that (some) rational customers should invest in panels larger than they would in the reference case. With lower battery costs, however, the increase in panel size is matched with an incremental network credit scenarios in the latter years.

An upfront network credit, on the other hand, unilaterally increases the incentive to acquire both solar PV and storage as it provides an upfront discount, regardless of future price changes or usage incentives, to both forms of EG. This discount is substantially larger for storage (as the likelihood of peak contribution is a lot higher), although both forms of EG see substantial increase in adoption.

7.4 Implications of the modelling

While limited, we believe that the analysis presented in this chapter serves to illustrate a number of important issues that need to be considered in any evaluation of the costs and benefits of the Rule change request.

Importance of individual load data

Outcomes, in terms of uptake of EG, vary considerably across different customer usage profiles in the sample of data used for the analysis. This is intuitive in that any given customer may have a usage profile that is substantially different to the average profile and decisions around investing in solar PV and/or storage are heavily influenced by a given customer's pattern of consumption across the day relative to the output profile of solar PV.

In our view, any evaluation of the costs and benefits of the Rule change request would be assisted via the inclusion of a large set of individual customer profiles in each region.

Disconnection

Our analysis has not focused on the extent to which customers may wish to disconnect from the grid entirely. We have not considered the extent to which a specific customer in the sample would have access to sufficient roof space to facilitate disconnection. We have focused on the pure economics of the problem. In some cases the large solar PV and storage systems considered in the modelling would not be sufficient to allow a customer with a high level of consumption to disconnect entirely across periods in the modelling where solar output is low for an extended sequence of days.

However, it is clear from our results that for the sample customers considered in our analysis, there is virtually no complete disconnection from the grid even out to 2050, despite the assumption of falling storage costs and rising retail prices over the period. This is not to say that there would not be a material reduction in overall consumption or an impact on peak demand due to increased uptake of EG, rather the value to customers is maximised by maintaining connection to the grid. This is consistent with other analyses we have performed recently that has included an explicit focus on the economics of disconnection.

EG uptake occurs in the absence of any network credit (the reference case).

Our analysis, consistent with other market forecasts, estimates that there will be continued uptake of solar PV and storage under current arrangements. That is to say, the introduction of a distribution credit scheme would be likely to lead to *incremental* investment relative to the reference case. As outlined in our wider cost benefit framework, any complete cost benefit analysis would need to consider only the incremental costs and benefits over and above the baseline uptake levels observed in the reference case. Such baseline uptake is likely to be material given the many forms of direct and indirect support in the regulatory settings of the NEM and the likely continuation of reductions in EG costs.

Level and structure of the credit is important

As is the case with prices, tariffs and subsidies more generally, both the form of the credit and the level of subsidy influence decisions around uptake.

Our analysis clearly demonstrates, as would be expected, that increasing the level of the tariff, other things equal, would be likely to increase uptake of EG and potentially alter the mix of technologies. This is most clearly demonstrated in the increased level of uptake under a 6 c/kWh volumetric credit relative to a 3 c/kWh credit. This outcome illustrates an important point. It is likely that any distribution credit will overcompensate and undercompensate specific customers (i.e. the value of the credit will be more or less than the net economic benefits created by that specific customers' EG system). This outcome will occur given the complexity of having more accurate pricing down to the individual customer level. Given this, over-subsidisation to some EG in particular presents a risk to policy makers in that the higher the subsidy, the more likely that the level of the uptake response is larger and occurs more rapidly than is efficient, heightening the risk that the overall impact is a net detriment as costs overwhelm benefits.

The structure of the credit is also important. Relative to a simple volumetric subsidy, a demand based credit will tend to provide stronger incentives to EG that is able to contribute at peak times, as would be expected. In our analysis, this is observed in a shift towards greater storage uptake relative to solar PV.

Wider conclusions

Our analysis is static in the sense that we have considered customer responses in a single distribution area and assumed static trends in retail prices, solar FiTs and EG costs. Despite this, the analysis illustrates the importance of interactions across the supply chain and the feedback loop between demand, prices and customer responses as the driver of overall economic costs and benefits from the Rule change request.

The extent to which net benefits are likely to be exist as a result of the Rule change or alternative distribution credit schemes is an empirical question and needs to be further quantified in considering the costs and benefits of the Rule change request.

8 Observations on the costs and benefits of the Rule change request

To assist the ENA and the AEMC consider the proposed Rule change, this report highlights that evaluating the costs and benefits of the Rule change request requires consideration of:

- the costs and benefits that different forms of EG can provide to network businesses, and the variability in these costs and benefits across different EG technologies as a result of their operating characteristics
- the experiences and 'lessons learnt' from other jurisdictions that have implemented network credits for EG
- the key issues that would need to be resolved if any regulated and mandated set of network credits (and potentially charges) is to facilitate efficient investment in and use of EG
- interaction between any network credit and the other market, policy and regulatory settings that influence the supply and demand of EG.

In our view, it is not clear that the Rule change request has considered and resolved these issues in a way that is likely to promote the NEO.

The costs and benefits of EG are likely to be highly dynamic and locational

While EG can potentially reduce stress on network infrastructure during peak times, it can also lead to additional costs on the network. Our analysis highlights that the costs and benefits of EG are likely to be highly dynamic and locational (dependent upon the shape of aggregate consumption at the relevant feeder or substation, the level or take-up of EG (relative to aggregate consumption), and the extent to which given network elements are currently close to capacity), technology specific (given material differences in the operating characteristics of EG) and influenced by wider market outcomes (including relevant policy and regulatory settings).

The existence of any net benefits and their and the variability across different EG technologies is ultimately an empirical issue. To date, there has not been significant analysis of the extent of any net benefits that EG provides to networks (and their customers).

The international experience highlights that a range of network efficiency and broader policy goals have underpinned the development of EG network credits

Policy-makers and regulators across a number of jurisdictions have implemented export credit arrangements and these have been driven by a range of network efficiency and broader policy objectives.[85] However to date, there has not been significant analysis of the extent of any net benefits that EG provides to networks (and their customers). For example, in Great Britain Ofgem assumed that EG would not cause additional reinforcement costs given the assumption that there will be even dispersion of EG across the network[86]. As such policy-makers and regulators are in the process of (or have indicated the benefits from) undertaking further work to understand and quantify the benefits more robustly.[87]

The experiences in the UK and US where policy makers and/or regulators have introduced uniform charging methodologies across distribution networks, as well as experiences in NZ that rely on commercially negotiated outcomes, suggests that establishing pricing principles and managing some of the inherent trade-offs or tensions in implementing a set of network credits – such as between efficiency, simplicity and predictability – when setting the structure and level of any network credit is challenging, yet critical, if signals are to be provided for efficient investment in, and use of, EG in locations and times where it is of value to networks (and all energy consumers).

However unlike in the UK[88], the existing (and potential future) market, regulatory and policy settings in Australia makes generator-dominated network nodes a more likely possibility. This suggests that a regulated and mandated set of uniform and

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85 For example, in its 2008 Decision to proceed with a common charging method, Ofgem said that: "Delivery of this project is vital in facilitating progress towards meeting government targets on climate change, in ensuring that economic signals are provided to existing and potential users of electricity distribution networks and in enabling the efficient development of the network." It said the common method would "further enable DNOs' role as facilitators in tackling climate change" Ofgem, 22nd July 2008, 104/08 "Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements".

86 Ibid. p.60

87 For example, Ofgem is seeking to better understand the extent to which the assumption that EG is likely to offset some network reinforcement requirements is applicable at all network locations and therefore whether generator credits should vary by location.

88 In choosing to err on the side of simplicity and customer understanding in setting a uniform 'postage stamp' network charging methodology at the HV/LV level, Ofgem decided has to some extent benefited from there being relatively low probabilities in the foreseeable future of any generator-dominated network nodes in the UK (partly the result of other market policy settings that do not drive significant up-take in small scale EG).

highly averaged network credits – as proposed in the Rule change request – may risk:

- incentivising inefficient investment in, and use of, EG in locations, quantities or technologies where it may create *little benefit* to networks (i.e. does not materially reduce long-run costs for DNSPs) or
- incentivising inefficient investment in, and use of, EG in locations, quantities or technologies where it imposes *net costs* on networks or the broader energy market, (i.e. materially increases long-run costs for DNSPs or market participates), and may ultimately lead to higher electricity prices for consumers
- disincentivising efficient investment in and use of EG in locations, quantities and technologies where it has the potential to create material net benefits to networks and/or energy market participants (i.e. where it could lead to lower electricity prices for consumers).

There are numerous issues that need to be resolved if any set of regulated and mandated network credits (and charges) is to promote efficient investment in and use of EG

There are a range of factors that influence the supply and demand of EG, and continued investment in, and use of, EG is expected to occur in our energy market in the absence of further changes to the NER.

While network pricing reform to date has primarily focused on electricity imported from the network[89], and in theory encouraging efficient investment in and use of EG requires some form of price signal to be provided to EG investors and users for electricity exported to the network (as well as other regulatory mechanisms to provide 'signals' to DNSPs), it is not clear that a regulated and mandated set of uniform and highly averaged network credits – as proposed in the Rule change request – will necessarily facilitate efficient investment in and use of EG in Australia given that:

- if efficient investment is to occur in EG in locations, quantities or technologies where it provides net benefits to DNSPs, then any set of network credits (and charges) should reflect the nature of the costs and benefits to DNSPs that different forms of EG may provide,[90] should account for material locational

89 Changes to the National Electricity Rules (NER) made in 2014 pursuant to the Distribution Network Pricing Arrangements Rule change

90 i.e. the level and structure of any network credit is cost reflective

differences, be dynamic and allow for payments to and/or from DNSPs (i.e. be symmetrical)[91]

- the international experience in implementing EG network pricing would suggest that introducing a regulated and mandated set of uniform and highly averaged network credits – as proposed in the Rule change request – in Australia, in addition to the existing regulatory and policy settings, requires careful consideration of a number of implementation issues including:
  - the appropriate categories (and sharing) of costs and benefits within the network credits (and charges), the appropriate price structure for providing cost reflective signals to EG customers[92], and the appropriate balance between flexibility and predictability[93]
  - the risks associated with potentially implementing a highly dynamic, locational and technology specific set of regulated network credits (and charges) for exported electricity that may be more cost reflective than the corresponding set of regulated network tariffs for imported electricity
  - the interaction with the existing (and potential) mechanisms in the NER[94] and other policy settings that may also encourage investment in and use of EG.

In our view it is not clear to what extent the Rule change request for a set of regulated and mandated network credits has been developed with a set of clear pricing principles[95] nor considered and resolved these issues in a way that is likely to promote the NEO. As highlighted earlier, the Rule change request represents but one potential response to further reform of the treatment of EGs, particularly small scale EG, under the NER.

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91 With a positive credit determined where there are clear long term net benefits to networks from additional investment in, and use of, EG and a negative credit (or charge) where there are clear long term net costs to networks from additional investment in, and use of, EG.

92 Which involves a trade-off between a highly dynamic and locational approach – which is more likely to reflect the nature of the costs and benefits and therefore send efficient signals for investment in and use of EG – and a simpler approach that maximises customer understanding, but with less ability to capture any net benefits and may risk discouraging investment and use of EG in locations, quantities or technologies where there may be net benefits, and/or encourage investment where there may be net costs to networks and ultimately on customers.

93 In terms of allowing network businesses to respond to changing market conditions by updating the level of any network credit (and charge) and customers' preference for predictability and simplicity

94 For example, the NER provides some mechanisms for providing price signals to small scale EGs (such as through the small generation aggregator framework).

95 Nor considered to what extent any pricing principles should mirror, draw from, or depart from the existing distribution network pricing objectives and principles.

Quantifying the potential interaction of any network credit with other market, regulatory and policy settings is crucial

There are a range of factors that influence the supply and demand of EG and the AEMC Consultation Paper highlights the importance of understanding the *additional* up-take of EG as a result of any network credit.[96]

Australia's energy markets have witnessed a significant up-take of EG (primarily solar PV) driven by the interaction between market[97], policy[98] and regulatory settings. (See **Appendix A** for information on solar PV uptake in Australia).

This Rule change request occurs in the context of significant change in these settings, and uncertainty in terms of their impact on the supply and demand of EG. For example, the impact on the supply and demand of small scale EG resulting from new cost reflective distribution network pricing obligations[99] and other mechanisms in the NER relating to incentivising least cost non-network solutions are still uncertain. [100] Likewise, there is uncertainty relating to future policy settings such as the SRES and jurisdictional Feed-in-Tariffs[101].

These regulatory and policy settings have the potential to amplify or weaken the impact of any network credit, and the associated costs and benefits of additional investment in, and use of, EG. Any consideration of the costs and benefits of the Rule change request needs to account for these interactions and this is ultimately an empirical exercise.

Our indicative modelling highlights that further investment in, and use of, EG – such as solar PV and battery storage and other technologies – is expected to occur in our energy market in the absence of further changes to the NER. This is a result of current policy settings around retail price tariffs, feed in tariffs, EG costs and is influence by a range of policy and regulatory settings across the market.

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96 As the AEMC's Consultation Paper notes, the Rule change request may promote the NEO if it incentivises efficient investment in, and use of, EG that would otherwise not have occurred AEMC 2015, Local Generation Network Credits, consultation Paper, 10 December 2015, Sydney, p19.

97 Such as increasing household choice and awareness of energy supply options such as small scale EG, increasing affordability of small scale EG and the structure of and level of retail electricity prices.

98 Such as the Small Scale Renewable Energy Scheme (SRES) and jurisdictional Feed-in-Tariffs (See **Appendix A** for information on solar PV uptake and the policy settings that support investment in solar PV).

99 Which may alter customers' consumption patterns, in turn, influencing the supply and demand of EG.

100 Not to mention other potential changes to the NER and the market arrangements (such as potential introduction of virtual net metering) that may facilitate local electricity trading if implemented.

101 For example the Victorian Minister for Energy and Resources has asked the Essential Service Commission of Victoria (ESC) to examine the "true value of distributed generation to Victorian Consumers." http://www.esc.vic.gov.au/Energy/Inquiry-into-the-true-value-of-distributed-generat/publications

Our indicative modelling highlights that the *additional* up-take of EG as a result of any network credit is highly dependent upon:

- **The level and structure of any network credit** (in addition to the SRES and jurisdictional Feed-in-Tariffs). Our analysis demonstrates that:
  - increasing the level of the tariff (all else being equal) is likely to increase uptake of EG and may alter the mix of EG technologies (potentially skewing the mix to specific forms of EG given it is likely any broadly available network credit will overcompensate or undercompensate any different types of form of EG)
  - a demand based network credit (c/kW), as opposed to a simple volumetric network credit (c/kWh), is likely to drive greater investment in EG such as battery storage) that is able to contribute at peak times (where net benefits are likely to be higher).
- **The shape of customers' consumption (or load profile).** Further assessment of likely market outcomes across a robust set of load profiles (including consideration of the impact of new cost reflective distribution network pricing obligations on load profiles), where EG uptake may be more or less influenced by any network credit, is important.
- **Retail tariffs in terms of both structure and price level.** These prices reflect outcomes across the wholesale, network and retail (including obligations on retailers relating to the SRES, LRET and other jurisdictional energy efficiency schemes) sides of the market and strongly influence customer's perceived value of EG.
- **Current and future EG costs**, which is influenced by a range of market and policy settings (such as subsidies under the SRES).

The Rule change request does not provide empirical evidence about the relationship between any network credit and other market, policy and regulatory settings that are likely to continue to encourage continued investment in, and use of, EG. Further modelling and quantification of these interactions is crucial to understanding the *additional* up-take of EG from any network credit and the costs and benefits of the Rule change request.

Appendix A: Understanding embedded generation in Australia

Australia's energy markets are currently undergoing a period of significant change with increasing household choice and awareness of (increasingly affordable) energy supply options. This section provides an overview of the types of EG that currently and are likely to form part of Australia's energy mix over the foreseeable future.

Embedded generation technologies

The term embedded generation refers to 'any form of generation which is connected to (or embedded in) an electrical distribution network'[102]. References to EG in this report includes the following technologies (where connected to a distribution network):

- open and closed cycle gas turbines;
- reciprocating engines (diesel, oil);
- hydro and mini-hydro schemes;
- wind turbines;
- photovoltaic generation (solar);
- fuel cells;
- cogeneration or tri/polygeneration (combined cooling, heat and power); and
- batteries.

We take a broad view of EG that includes residential and commercial electricity storage. While technically not 'generation', we include batteries here as they can be used to discharge power on demand for limited periods of time.

Each EG technology is classified as one of the following four categories:

- **Continuous** generation is a consistent and reliable of energy injections into the grid. This facilitates a high likelihood of timely response to peak network loading conditions at any given point in time.
- **Dispatchable** generation can be produced on demand and typically relies on a processed energy fuel source, such as diesel. The on-demand property of dispatchable generation means that it has a high potential for responding to peak network loading conditions.

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102 See http://www.ena.asn.au/embedded-generation.

- **Intermittent** generation is does not provide a consistent or controllable flow of power. Rather, energy output is determined by the availability of a naturally occurring energy source and ranges from relatively predictable (in the case of solar PV) to unpredictable (in the case of wind). The unpredictability and/or limited windows of production mean these technologies have a lower likelihood of contributing to meeting peak demand. In some cases, power production may be anti-correlated to demand and network loading.
- Electricity supplied by **storage** is technically dispatchable (i.e. available on demand), but is limited by the storage capacity of the unit in question. Storage units must be recharged between discharging periods. The dispatchable nature of storage means it has a high potential for meeting peak demand, but for limited durations.

The following sections take a closer look at the established and up-and-coming technologies: solar PV, batteries, and co/trigeneration.

Table 6: Overview of EG technologies

Technology	Type of customer	Nature of generation	Comments
Open and closed gas cycle turbines	Commercial	Dispatchable	Scale prohibits residential adoption;
Reciprocating engine	Residential/Commercial	Dispatchable	
Hydro/mini hydro schemes	Residential/Commercial	Continuous	Reliance on natural circumstance resulting in few viable sites; may be eligible for SRES
Wind turbines	Residential/Commercial	Intermittent	Uncommon and largely physically and economically unviable in urban areas; requires average wind speed of around 4.5m/s; may be eligible for SRES
Solar photovoltaic	Residential/Commercial	Intermittent	Substantial adoption in recent times, aided by the SRES and feed-in tariffs.
Fuel cells	Residential/Commercial	Dispatchable	Interest remains as a source of energy for vehicles and niche uses (e.g. telecommunications backup source) but evidently a loser as a source of residential or commercial generation
Co/poly generation	Residential/Commercial	Dispatchable	Technically not a source of generation but a system encompassing some of the above (thermal) generation sources;
Batteries	Residential/Commercial	Storage	Recent announcements of cost falls have spurred considerable interest in both residential and commercial scale systems; a small number of systems currently deployed and active in Australia

Source: Frontier Economics

Photovoltaic generation (solar)

Residential and commercial solar PV has boomed in recent years Australia due to falling technology costs and targeted and implicit subsidies. Figure 9 provides a brief history of the average installed cost of solar PV in Australia and one of the available subsidies – the SRES – from 2010 until today. Due in part to these subsidies and our favourable sunshine conditions, Australia now has the highest penetration of rooftop solar PV in the world[103]. Since 2010, solar PV has enjoyed a relatively small payback period, aided by the following three subsidies.

- Both large scale and small scale renewable generators[104] receive subsidies under the Renewable Energy Target (RET):
  - The Small Scale Renewable Energy Scheme (**SRES**) provides an upfront discount on solar PV systems for residential customers, based on the size of the system being installed and the expected lifetime yield of solar energy generation given the climatic 'zone' of installation. Importantly, all production over the life of the asset is deemed such that customers receive a lump sum discount when purchasing the generation system.
  - For larger commercial systems, the Large Scale Renewable Energy Target (**LRET**) makes large scale renewable generators eligible to create Large scale Generation Certificates (LGCs), which can be sold to liable entities (retailers) to generate revenue over and above spot sales of energy.
- **Feed-in tariffs**, offered by electricity retailers, pay residential and small-scale commercial customers for electricity generated by their solar PV units. Some FiTs provide a payment in respect of all electricity generated by a solar PV installation – these are known as 'gross' FiTs. However, most FiTs provide a payment for energy generated but not consumed by the customer and exported into the grid – these are known as 'net' FiTs. 'Premium' or subsidised FiTs of around 40-60 c/kWh that are typically funded by all network customers are no longer available for new installations and will be phased out in the coming years[105]. Current FiTs – applicable to panels installed today – are much closer

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103 http://www.esaa.com.au/Library/PageContentFiles/14251626-ae50-48a1-8fb0-70841eae409f/ESA002_factsheet_renewables.pdf

104 Small scale systems are defined by technology type, see http://www.climatechangeauthority.gov.au/chapter-5-small-scale-renewable-energy-scheme.

105 In some cases, these generous schemes have run into the long term, for example the South Australian 44c/kWh distributor-paid feed-in tariff (D-FiT) runs to 2028.

to an output-weighted price of wholesale generation; typically around 5-6 c/kWh.[106]

- The current state of **network tariffs** means that a significant portion of networks' fixed and sunk costs are recovered through variable charges on electricity consumption. Moreover, such variable charges commonly exceed the costs imposed on the network as a result of such consumption. This means that customers see a lower supply (fixed) charge and higher variable charges than is efficient. For this reason, reducing overvalued grid-sourced consumption via self-generating with solar PV is more attractive than it should be, with other consumers making up the difference. As the AEMC puts it[107]: "*A consumer using an average-size north-facing solar PV system will save themselves about $200 a year in network charges compared with a similar consumer without solar. Because most of the solar energy is generated at non-peak periods during the day, it reduces the network's costs by $80, leaving other consumers to make up the $120 shortfall through higher charges.*"

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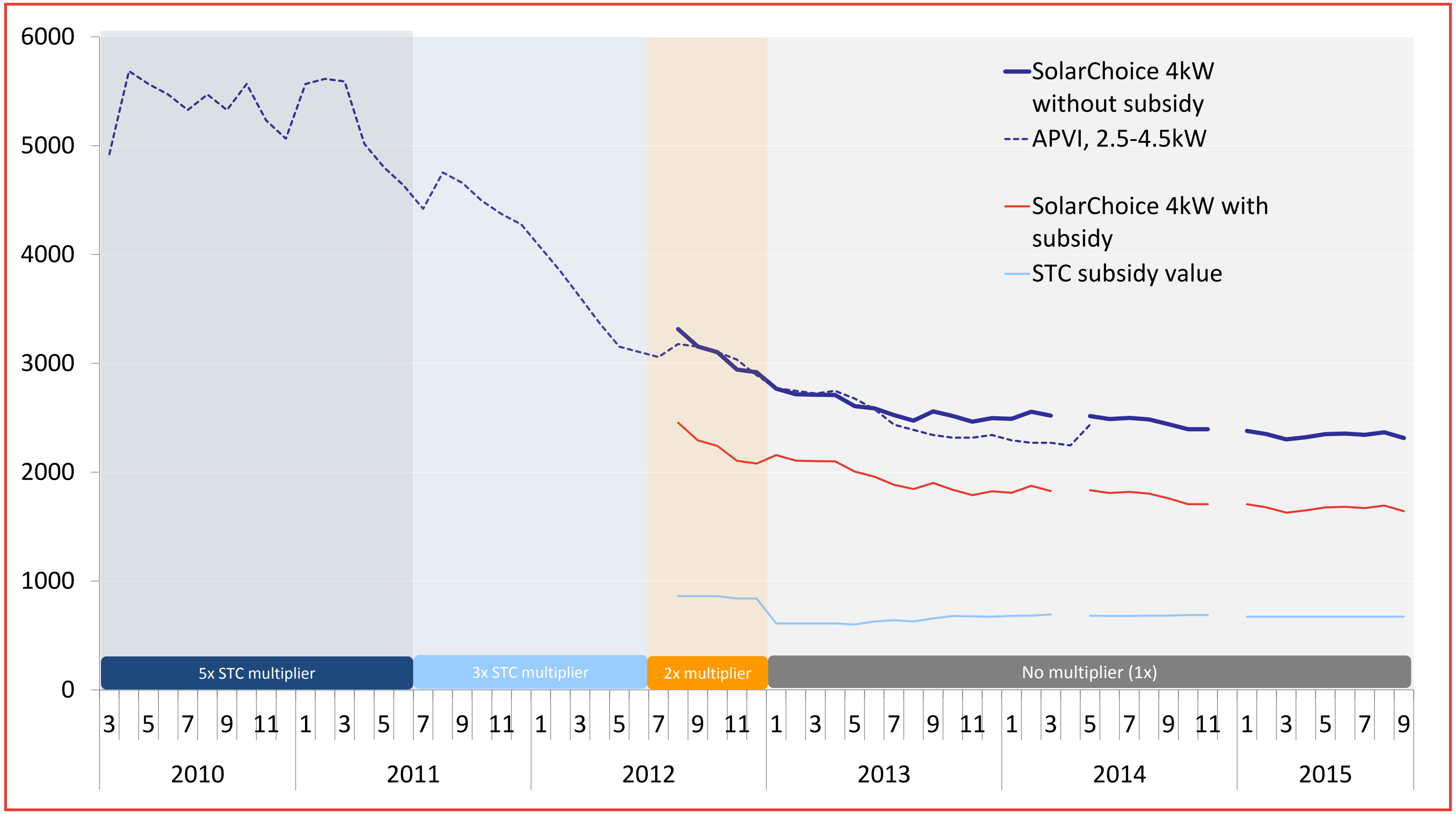
106 IPART has determined a range of 2015-16 is 4.7 to 6.1 c/kWh for 2015/16, see http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Review_of_Solar_feed-in_tariffs_2015-16/News/Final_Report_for_Solar_feed_in_tariffs_for_2015_released.

107 http://www.aemc.gov.au/News-Center/What-s-New/Announcements/New-rules-proposed-for-distribution-network-prices

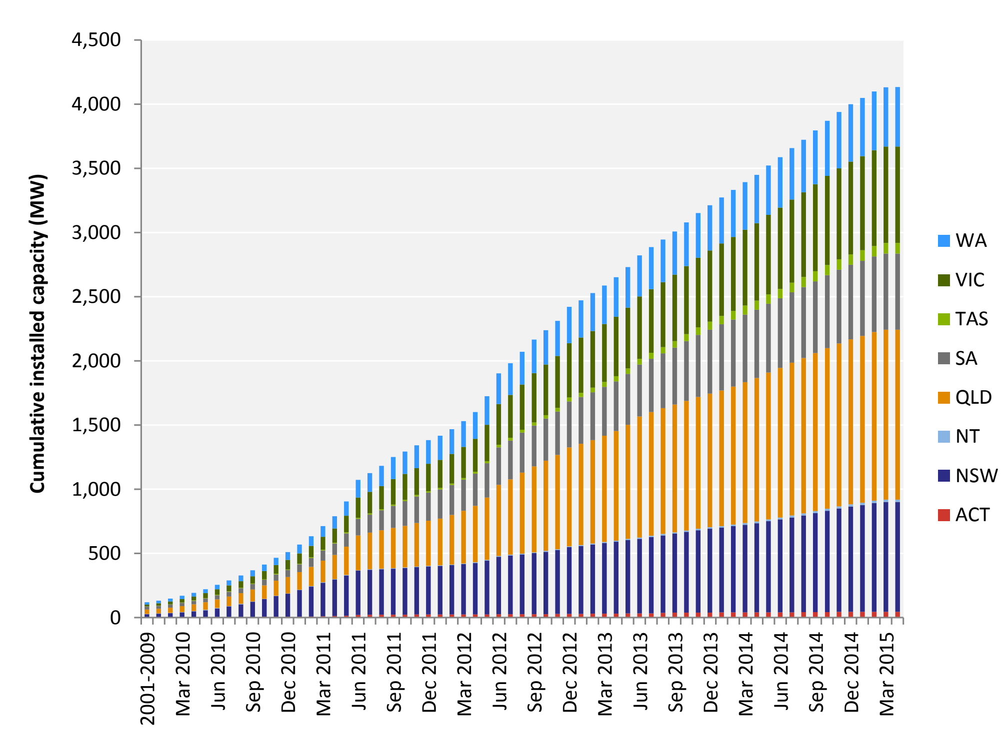
Figure 9 Cost of residential installed solar PV ($/kW) and associated subsidies since 2010



Source: SolarChoice, APVI

Figure 10 provides a history of residential solar PV uptake by state. Since 2010, uptake has been consistent, and especially strong in South Australia and Queensland, which boast the highest penetration rates in the world.

Figure 10: Residential solar PV uptake



Source: Frontier analysis of Clean Energy Regulator STC data

http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

Cogeneration or tri/polygeneration (combined cooling, heat and power)

CHP encompasses a number of distinct but related thermal technologies including cogeneration and heating along with trigeneration (or polygeneration), heating and cooling. Trigeneration systems are typically larger.[108]

These systems are usually gas-fired, produce electricity, involve heat recovery stages that improve electrical efficiency and allow heat to be utilised for heating and, in the case of trigeneration, cooling onsite, further increasing overall efficiency.

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108 For example, the Sydney Central Park residential development include 2.2 MW of gas-fired trigeneration plant, see https://www.clarke-energy.com/2015/sydney-central-park-district-energy-scheme-reduces-carbon-emissions-using-tri-generation.

Battery storage

Residential and commercial scale batteries are not a new phenomenon but have garnered a lot of interest in recent times given:

- Costs have fallen significantly; and
- New offerings are 'mass-market' oriented, including smaller footprints, sleeker designs, and an emphasis on simple connectivity and control.

Batteries come in many forms as illustrated in Figure 11.[109] Batteries are potentially valuable to residential and commercial electricity consumers for three reasons. They enable:

- The capture of excess solar PV generation – if the sum of available FiTs is less than the volume electricity charge, harnessing excess solar PV generation is a valuable activity.
- Time-shifting consumption – grid-tied batteries can be used to purchase energy when prices are low, e.g. at off-peak or controlled load rates, and to consume energy when prices are high, e.g. during peak times.
- Blackouts – a grid-independent system can provide power for consumption during blackouts.

No method of tracking battery installations in presently in place in Australia and there is no quality data on residential or commercial battery uptake. The CEC suggests approximately 500 residential systems installed Australia-wide at the end of 2014[110].

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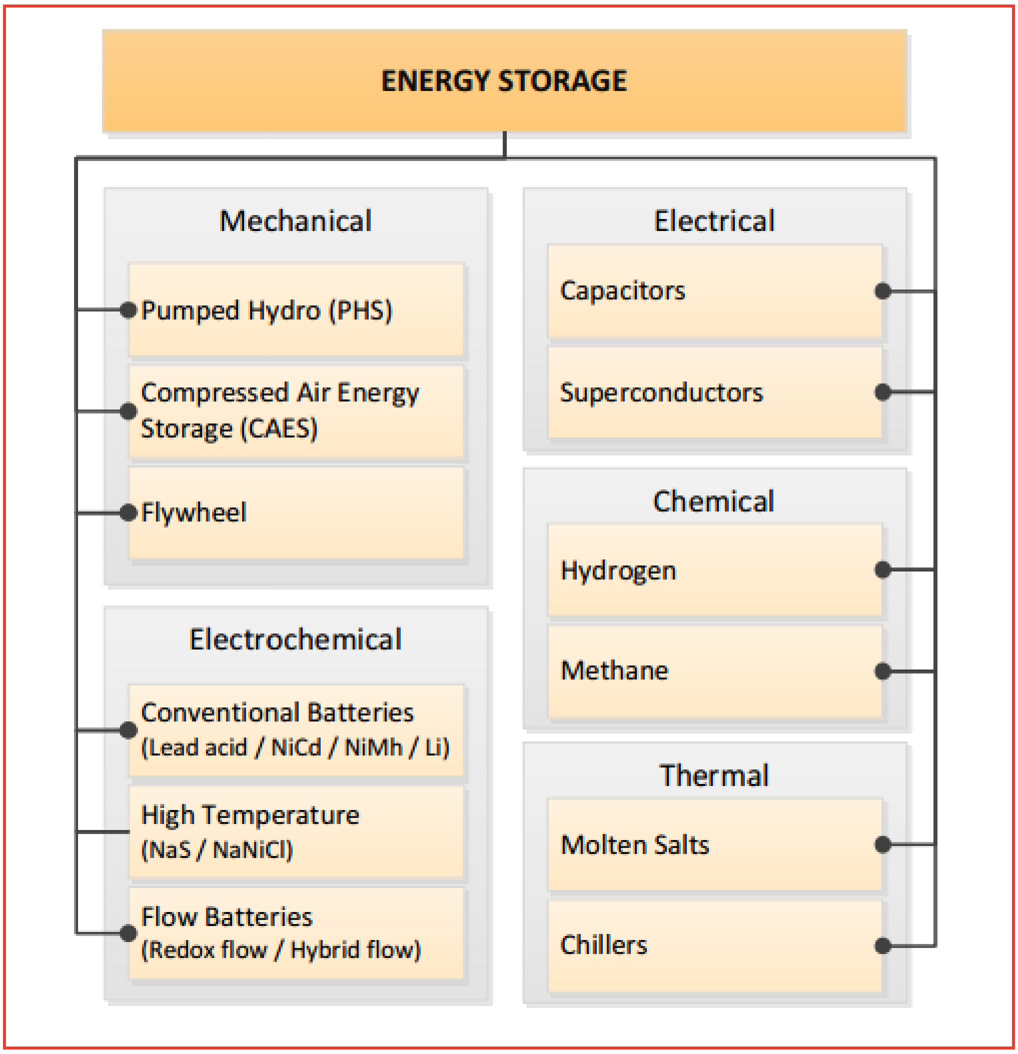
109 Lithium ion batteries are currently receiving a lot of attention due to the wide media publicity surrounding the Tesla 'Powerwall', but lead acid and flow batteries are examples of established technologies already in use by Australian households.

110 https://www.cleanenergycouncil.org.au/dam/cec/policy-and-advocacy/reports/2015/150429-Australia-storage-industry-roadmapFINAL/150429%20Australia%20energy%20storage%20roadmap%20FINAL.pdf

Figure 11: Types of energy storage



Source: AECOM

Appendix B: Network credits for EG in Great Britain

Ofgem has introduced a uniform charging methodology across the distribution networks in GB. There are different methodologies for customers connected at the EHV level – governed by the EHV Distribution Charging Methodology (EDCM); and those connected at the HV/LV level – governed by the Common Distribution Charging Methodology (CDCM).

Both the EDCM and the CDCM incorporate a credit for generators, which is essentially the negative of the charge for demand customers. However, there are some conditions and restrictions on these generator credits:

- Under the CDCM, non-intermittent generators receive a credit which varies according to times of peak load. Intermittent generators only receive a single uniform credit.
- Under the EDCM, intermittent generators receive no credit at all, while non-intermittent generators only receive a credit at so-called "super-red" peak times.

Ofgem's rationale for introducing generator credits is that it expects locally connected generators will offset some network reinforcement requirements. However, one of the key questions Ofgem has grappled with is whether this assumption is applicable at all network locations – and therefore whether generator credits should vary by location (essentially by network node).

In considering this question, Ofgem seems to have accepted that there may be an economic argument for introducing locational variation in generation credits – namely that generators should not be encouraged to connect in nodes which are already "generator dominated". However, Ofgem has sought to balance this economic efficiency argument against the additional complexity associated with introducing locational variation into generator credits.

Ultimately, Ofgem has decided that at the EHV level, it is feasible to develop network charges (and therefore generator credits) based on network reinforcement models specified for each individual node. In contrast, at the HV/LV level Ofgem has noted that locational charging would imply significantly more complexity compared to EHV; and has not seen evidence that there are a sufficient number of generator-dominated nodes that would merit introducing this complexity. Ofgem therefore incorporates locational variation in the EDCM, but not the CDCM.

Introduction

The Proponents of the proposed rule change in Australia noted that there is precedent in other jurisdictions for credits being provided to local embedded generators. Their submission notes the UK Office of Gas and Electricity Markets (Ofgem) requires each distribution network to provide a credit tariff that is payable to 'decentralised generators' (varying by classes of generator including size, intermittency and time of operation), based on a standard methodology provided by Ofgem[111].

We review the experience from the UK in more detail in this Chapter. We provide in turn:

- A description of the UK charging methodology, focussing on the structure and rationale for generator credits.
- An evaluation of the rationale for introducing generator credits; and consideration of possible future developments in the UK in relation to locational incentives for generators.

Description of the charging methodology

In 2000 Ofgem launched its "Structure of Charges" project to improve the charging methodologies employed by the Distribution Network Operators (DNOs). In 2008 Ofgem decided that, having achieved little success thus far with a DNO-led approach, Ofgem itself would need to develop a common charging methodology to be applied across all 14 networks.

In GB, all DNOs are now required to adhere to the common charging methodology. This methodology consists of two parts:

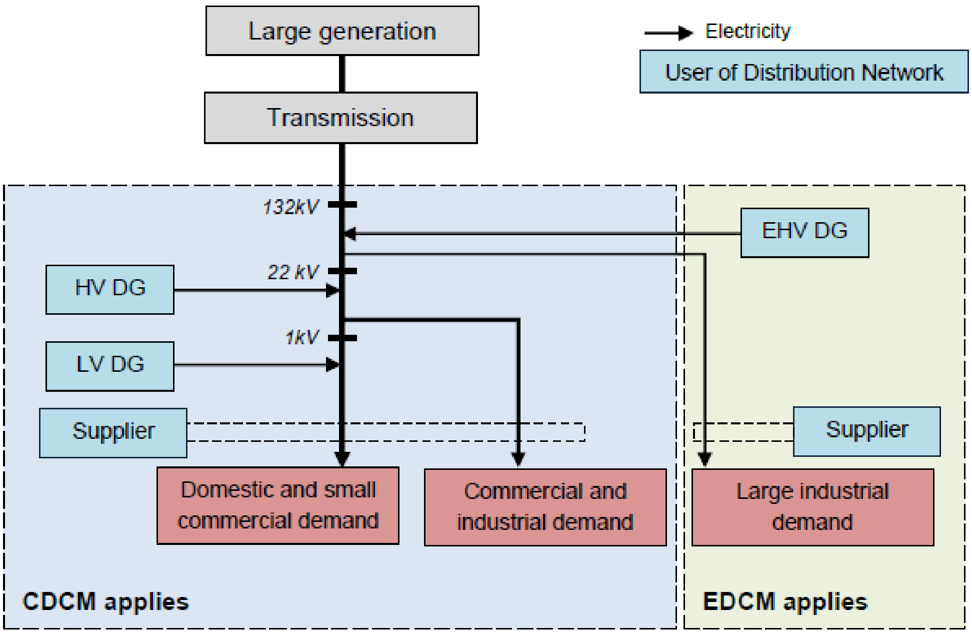
- The **Common Distribution Charging Methodology (CDCM)**. The CDCM covers all low voltage (LV) and most high voltage (HV) connections, for both demand and generation. It was introduced on 1 April 2010.
- The **extra-high voltage (EHV) Distribution Charging Methodology (EDCM)**. The EDCM for demand customers was introduced in April 2012; and for generation customers in April 2013.

111 Oakley Greenwood, Local Generation Network Credit Rule Change Proposal – Submission to Australian Energy Market Commission: Proposed by City of Sydney, Total Environment Centre, and the Property Council of Australia, July 2015, p3.

In addition, the networks were also required to develop a common methodology for calculating connections charges - the Common Connections Charging Methodology (CCCM) – which was introduced in October 2010.

Figure 12 shows schematically the boundaries for the different charging methodologies.

Figure 12: Boundaries for application of Distribution Use of System (DUoS) charging methodologies



Source: Element Energy, Customer-Led Network Revolution Commercial Arrangements Study. Review of existing commercial arrangements and emerging best practice. 13th June 2013.

The common charging methodologies are set out in the Distribution Connection and Use of System Agreement (DCUSA) document[112]. The relevant parts of the DCUSA agreement are as follows:

- Schedule 16 describes the CDCM.
- Schedules 17 and 18 describe the EDCM.

112 The Distribution Connection and Use of System Agreement (DCUSA) was established in October 2006 as a multi-party contract between the licensed electricity distributors, suppliers and generators of Great Britain. It is concerned with the use of the electricity distribution systems to transport electricity to or from connections to them. The DCUSA replaced numerous bi-lateral contracts, giving a common and consistent approach to the relationships between these parties in the electricity industry. http://www.dcusa.co.uk/SitePages/Home.aspx

- Schedule 22 contains the CCCM.

Both the CDCM and the EDCM provide a credit in respect of locally connected generation. We set out the structure of tariff-setting and the methodology for the generator credit under each methodology below.

CDCM

The principle of the CDCM is to calculate the costs incurred by DNOs to install, maintain and operate assets and determine tariffs for different users, based on predicted load volume and use of assets. Estimated tariffs are adjusted to ensure the predicted derived revenue matches the allowed revenue, as defined by the price control regime. We describe in turn below:

- the tariff structure; and
- the methodology for determining tariffs.

Tariff structure for generators

The use of the distribution system by generators incurs the following charges[113]:

- A fixed charge in p/MPAN[114]/day. This applies only to HV[115] half-hourly (HH) settled metered generation. The same tariff applies to all generators (intermittent and non-intermittent), but can vary greatly across DNOs[116].
- A reactive power charge in p/kVArh – this applies only to HH-settled metered generation. This typically costs under 1p/kVArh.
- A payment unit rate in p/kWh. For Distributed Generators (DG) the unit rate is negative. The rate varies for intermittent and non-intermittent generation (see below). Non-intermittent generators have a 3-part tariff corresponding to three different times of the day, referred to as 'green', 'amber' and 'red'[117].

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113 http://www.element-energy.co.uk/wordpress/wp-content/uploads/2013/07/CLNR-Commercial-Arrangements-Study_2013.pdf

114 A Meter Point Administration Number, also known as MPAN, Supply Number or S-Number, is a 21-digit reference used in Great Britain to uniquely identify electricity supply points such as individual domestic residences.

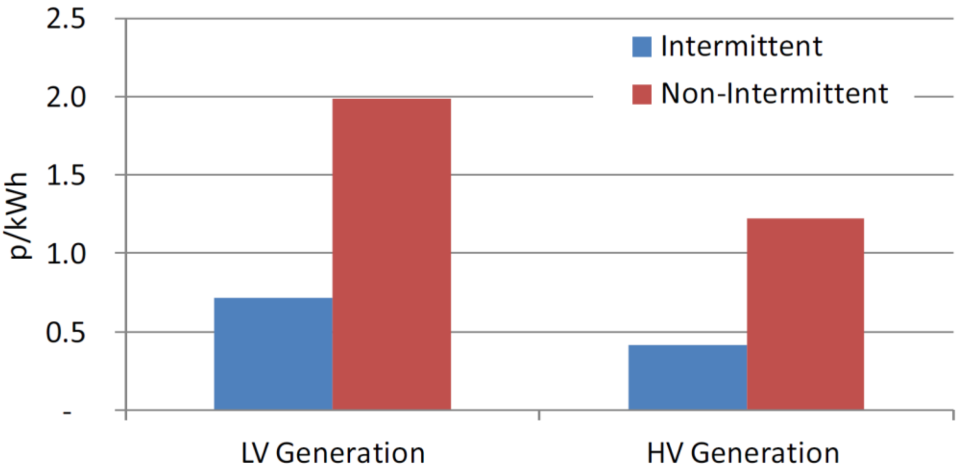
115 LV generators are generally also users and therefore suppliers already pay their corresponding fixed charge for delivering electricity to them.

116 In 2013 Element Energy estimated this charge varied from 6p to 230 p/MPAN/day.

117 This mirrors the 3-part time rates paid by suppliers. Examples of time bands: Red 16:00 – 19:30 (Monday to Friday); Amber 08:00 – 16:00 and 19:30 – 22:00 (Monday to Friday); Green – All other times. Each DNO can choose the time band for its network and must give 15 months' notice for amendments. For demand customers, the green unit rate is typically <1p/kWh, while the red rate is much higher, up to 20p/kWh.

Figure 13 illustrates generator credit in 2013 calculated by Element Energy.

Figure 13; Average unit charge paid to suppliers for DG, based on CDCM calculations for 2012-13



Source: Element Energy, Customer-Led Network Revolution Commercial Arrangements Study. Review of existing commercial arrangements and emerging best practice. 13th June 2013.

Element Energy calculated that payments to DG tend to outstrip charges: in the 2012-13 CDCM, DNOs forecasted DGs on low and high voltage networks were expected to produce 7.5TWh (<3% of LV and HV demand), giving rise to £34million in payments while paying under £0.5million in charges.

Methodology for determining tariffs

The CDCM utilises a so-called Distribution Reinforcement Model (DRM) to establish charges for demand customers. DRM was first implemented by DNOs in the 1980s. The model is forward-looking – i.e. it produces charges based on the future cost of providing incremental network capacity[118]. In deciding to implement DRM in the CDCM, Ofgem explained that the model was well understood, simple, practical, and sent appropriate economic signals to demand customers.

For generation customers, the CDCM specifies a generator credit equal to the negative of the charge for demand customers (the box below describes how

118 Ofgem considered and rejected alternative models which were based on historical costs.

demand charges are calculated in more detail). Generators are classified as non-intermittent or intermittent (according to the P2/6 engineering standards[119]).

- *Intermittent generation* is defined under P2/6 as a generation plant where the energy source of the prime mover cannot be made available on demand. A single-rate tariff (based on a uniform probability of operations across the year) is applied to intermittent generation, because the operator has little control over operating times. Intermittent generators include wind, tidal, wave, photovoltaic and small hydro.
- In contrast, *Non-intermittent generation* benefits from the three-part tariff as described above. This is because the generator can choose when to operate, and potentially bring more benefits to the network if it runs at times of high load (i.e. amber or red times). Non-intermittent generators include combined cycle gas turbine (CCGT), gas generators, landfill, sewage, biomass, biogas, energy crop, waste incineration and combined heat and power (CHP).

119 Electricity distribution networks are designed to meet security standard P2/6. Ofgem determined that P2/6 should be used in the common methodology power flow model both to determine reinforcement needs and identify the generator types.

Methodology for calculating demand charges

HV/LV demand charges are calculated using a DRM which calculates costs associated with a modelled or "representative" network capacity expansion.

- **Step 1**: Identify MEAV for assets required to accommodate a 500 MW increment to each distribution service area (DSA).
  - Model based on topography and demographics of the expected network and how this is likely to develop over time.
  - Costs exclude such connection costs as are remunerated directly by connecting customers; and replacement costs which are remunerated through "scaling" (see below).
  - MEAV is calculated for three different transformation and voltage levels, namely HV circuits; 11kV/LV substations; and LV circuits.
- **Step 2**: Add Operation and Maintenance (O&M) costs. The rate for O&M is calculated as a percentage of total MEAV asset cost based on forecast O&M costs for the upcoming charging year.
- **Step 3**: Allocate these costs to customer classes[120]. Allocation rule is based on estimating the peak load driven by each customer class at each of the voltage levels above, based on the following formula:

  $$Customer\ class\ System\ Max\ Demand\ (kW)$$
  $$= \frac{1000\ \times Annual\ Consumption\ (MWh)\ \times Coincidence\ Factor\ \times [1 + Losses]}{Load\ Factor}$$

  Where:
  - Annual consumption = the average consumption of an individual customer in each customer class, multiplied by the number of customers in each customer class at each voltage level.
  - Coincidence factor = the contribution each customer class makes to overall network peak demand.
  - Loss adjustment factor = scalar to convert the load at the voltage of connection to the load on transformer/voltage level above.
  - Load factor = network load factor.
- **Step 4**: Annuitize costs over a 40-year period using the latest network price control cost of capital to produce a "yardstick" unit cost in p/kWh. A single yardstick unit charge is calculated across all tariffs, irrespective of time-of-day patterns.[121]

- **Step 5**: Allocate the "yardstick" price to both the unit charge (p/kWh) and the fixed charge (p/MPAN/day). The allocation between these is based on a 'standing charge factor' which is assumed for each asset type.[122]

- **Step 6**: Divide the resulting £/kW/year charge by assumed power factor of 0.95 to produce a £/kVA/year charge[123].

- **Step 7**: Apply a "scaling" adjustment to ensure that total revenues based on yardstick prices described above align to total allowed revenue determined in price control. This is based on a fixed additive term (a "fixed adder" in Ofgem's terminology) to scale up the revenue recovered through charges to allowed revenue. At a high level this works by splitting total revenue by the MEAV of the HV/LV assets to obtain a target recovery for HV/LV. The difference between allowed revenue and expected recovered revenue is then allocated to customers on a kWh or p/MPAN basis.

All DNOs use the same Excel-based model to carry out the calculation of tariffs and populated models for each distribution area are publically available[124].

There are no locational signals currently within the CDCM. The adopted approach is based solely on aggregated/probabilistic analysis, reflecting the complexity of trying to model specific HV/LV nodes individually (in contrast to EHV – see further below).

Ofgem's rationale for introducing the generator credit at HV/LV level was based on two broad-brush assumptions.

- First, Ofgem assumed that DG can give rise to long run negative costs because it is expected to reduce upstream network costs. The underlying assumption is that HV/LV nodes are demand dominated – generators connecting to these

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120 As of 2008 there were eight such customer classes, namely NHH Domestic Unrestricted; NHH Domestic Restricted; NHH Non Domestic Unrestricted; NHH Non Domestic Restricted; NHH Unmetered Supplies; NHH LV; HH LV; HH HV.

121 2013-02-01 - CDCM model user manual (v102) - Feb 2013, p.37

122 http://dcmf.co.uk/8a40281d69ddabe00386e14e67643b01772e0e0b.pdf

123 Further calculations are then undertaken to estimate the reactive power charge for those customers with a power factor of less than 0.95 – see Ofgem Decision Document: Delivering the electricity distribution structure of charges project, 1st October 2008, p. 58-59.

124 http://www.energynetworks.org/electricity/regulation/commercial-operations-group/charging-structure/use-ofsystem/development/structure-of-charges-cdcm/common-distribution-charging-methodology.html

nodes therefore impose a net benefit on DNO networks by diverting upstream power flows and contributing to system security[125].

- Second, Ofgem assumed that generators will not cause additional reinforcement costs. Ofgem considers that this is a reasonable assumption because, in its view, there will be even dispersion of generation across the network[126].

Both of these assumptions are potentially problematic, as we discuss further in evaluating the generator credit later in this chapter.

EDCM

The objective of EDCM is to produce cost reflective charges to encourage existing and new customers to help DNOs to use existing network capacity efficiently, and avoid prompting inefficient and costly network reinforcement.

The EDCM incorporates locational variation in demand charges reflecting the level of local network capacity congestion. It also incorporates higher credits for generation in areas where there is little spare capacity. However, there is no credit for intermittent generation at the EHV level.

As with the CDCM, we describe in turn below:

- the tariff structure under EDCM; and
- the methodology for determining tariffs under EDCM.

Tariff structure

Table 7: UK tariff structure for generation customers at EHV level shows the tariff structure charged to generation connectees at EHV level.

Table 7: UK tariff structure for generation customers at EHV level

Charge component	Unit	Comment
Export fixed charge	p/day	Reflects sole use asset charges for direct operating costs and network rates.
Export capacity charge	p/kVA/day	Takes into account both local and remote elements of the asset cost.
Exceeded export capacity charge	p/kVA/day	Applied only if the agreed export capacity has been exceeded, at the same rate as the export capacity charge.

125 E.g. See Ofgem Decision Document: Delivering the electricity distribution structure of charges project, 1st October 2008, p. 2, 26, and 60.

126 Ibid. p.60

Export super-red unit rate	p/kWh	For non-intermittent generators only, applied during the seasonal 'super-red time band' (see further discussion below)

Source: DCUSA, EDCM Schedule 18.

Methodology

The EDCM is based on a power flow model and is linked to the asset costs detailed in the CDCM. Eight of the fourteen GB DNOs employ a Long-Run Incremental Cost (LRIC) model to determine EDCM charges; while the remaining DNOs use a Forward Cost Pricing (FCP) model (see further discussion in box below).

- **Step 1** is the application of load flow techniques and the LRIC or FCP methodologies to determine an EDCM tariff element, known as "Charge 1", which represents costs associated with demand-led reinforcement, estimated by reference to power flows in the maximum demand scenario.
- **Step 2** involves the allocation of DNO Party costs to Connectees using appropriate cost drivers.
- **Step 3** adds a scaling element to charges to ensure expected revenues match Allowed Revenue.
- **Step 4** uses CDCM charges to determine the element of portfolio charges to be applied in the case of IDNO[127] Parties who are supplied from the DNO Party's network at voltages higher than the scope of CDCM charges.

Ofgem made its final decision on the EDCM for generators in November[128] and December[129] 2012, following a consultation process it launched in August 2012 which set out full details of the EDCM methodology for generation[130].

For each generation customer, the key inputs to the EDCM are:

- its export capacity;
- the value of the assets that are exclusively for its use; and
- if it is eligible for super-red credits, the amount that it exports during times of peak demand.

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127 Independent Distribution Network Operators.

128 Ofgem, 16 November 2012: "Electricity distribution charging: Direction by the Authority to approve the charging methodology for higher voltage distributed generation; notice of intention to impose a condition on approval pursuant to Part D of the Electricity Distribution Licence"

129 Ofgem, 5th December 2012: "Electricity distribution charging: decision to impose a condition on our approval of the "EDCM for export"; and decision that this condition has been satisfied"

130 Ofgem, 17th August 2012: "Consultation on charging methodology for higher voltage distributed generation". See web page here: https://www.ofgem.gov.uk/publications-and-updates/consultation-charging-methodology-higher-voltage-distributed-generation?docid=854&refer=Networks/ElecDist/Policy/DistChrgs

We focus on the generator credits in this section. The EDCM offers "super-red" credits to generators that help to meet local peak demand. The super-red charge is the charge applied for consumption at the time of the DNO peak, for example 16h-19h30 Monday to Friday, November to February.

The super-red credit for export is calculated as the negative of "Charge 1" for import (see box below for modelling approach used to calculate "Charge 1"). For import, the two components of Charge 1 are given by the following formula[131]:

- p/kWh super-red rate = (([remote charge 1 £/kVA/year] / PF[132]) / [number of hours in the super-red time band in a year]) * 100
- p/kVA/day capacity charge = ([local charge 1 £/kVA/year] / [days in Charging Year])*100

The generator credit is expressed as a negative charge rate in p/kWh and is applied in respect of active power units exported during the DNO's super-red time band.

The identification of eligible generators is based on P2/6, which identifies the contribution that different types of generators make to security of supply. It specifies that some forms of generation can be more fully relied upon to generate when required, and so can help to meet demand at peak times. Ofgem's decision of 05/12/2012 confirmed that intermittent generators are not eligible for super credits, as their output time cannot be controlled (i.e. there is no generator credit for intermittent generators).

For some generators, the super-red credit would be larger than the network charges they incur, and they would receive a net credit. The super-red credits are paid through demand customers' charges. Ofgem considers this is reasonable, since the alternative is that demand customers would pay higher charges in order to fund reinforcement works.

Two types of credit are calculated:

- a local credit if investment is deferred at the voltage level of the generator's connection; and
- a remote credit if investment is deferred at voltage levels above the generator's connection.

Credits are paid after the event, based on actual output (i.e. p/kWh) during peak periods. The DNOs' indicative charges include estimates of the likely credits for the coming year based on load factor, expected generator behaviour, etc.

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131 See DCUSA, EDCM Schedule 18.

132 PF is the power factor of the flow at the point at which the customer is attached in the maximum demand scenario. This is calculated as - [Active power flow] / (SQRT([Active power flow]^2 + [Reactive power flow]^2). If either the numerator or denominator in calculation of the power factor is zero, the PF is replaced with 1. If the active power flow is generation-dominated, then PF is replaced with 1.

Ofgem introduced an option for generators which had connected prior to 2005 to either opt-in or opt-out of being charged under EDCM. This was because, prior to 2005, distributed generators were exposed to “deep” connection charging arrangements – i.e. their connection charge incorporated the cost of any necessary network reinforcement that was required as a result of their connection. These generators therefore did not pay DUoS charges, but imposing DUoS charges now might result in some double-charging of these customers.

As a result, generators who connected before April 2005 can choose to be exempt from DUoS charges for a period of 25 years from the date of connection. However, some of these generators may choose to opt-in in the expectation of receiving a super-red credits that would exceed their potential charge.

LRIC model vs. FCP model

This box sets out a description of each model at a high level. More detail can be found in DCUSA Schedule 17 (FCP) and Schedule 18 (LRIC).

LRIC model

The LRIC model calculates Nodal incremental costs. These costs represent the brought forward (or deferred) reinforcement costs caused by the addition of an increment of demand or generation at each network Node.

The model is based on AC power flow analysis, which enables the calculation of the time needed before reinforcement is required as a result of an increment in demand/generation. The incremental cost is equal to the difference in the Net Present Value (NPV) of reinforcing under existing conditions vs. the NPV of reinforcing when an increment of new demand or generation is added. The level of investment triggered by additional demand/generation is modelled according to the industry P2/6 engineering standards.

The LRIC model approach has the following steps:

- **Step 1**: Run LRIC model consisting of:
  - AC power flow analysis, summarised as follows:
    - Build a model of the DNO's entire EHV network (the "Authorised Network Model") at each node/branch combination.
    - Identify reinforcement requirements in 'baseline' scenario, based on background assumptions including a general 1% p.a. growth rate; and system security of supply consistent with P2/6.
    - Test reinforcement impact of an incremental 0.1MW generation capacity.
  - Calculation of Branch incremental costs (in £/annum) on the basis of the results of the power flow analysis.
  - Calculation of Nodal incremental costs (based on a Maximum Demand Scenario and a Minimum Demand Scenario) in £/annum.
  - Calculation of Charge 1 (by taking account of the magnitude of the increment in demand which drives the incremental costs) in £/kVA/annum.
- **Step 2**: derive site-specific Use of System Charges (including the consideration of sole use asset charges, transmission exit charges and operating and maintenance costs).
- **Step 3**: scaling charges to derive the final EHV Use of System Charges (similar to CDCM described above to ensure price control revenues are met).

FCP model

The fundamental principle of the FCP model is that the revenue recovery generated from its incremental charges is equal to the expected cost of reinforcement. These incremental charges provide cost signals relative to the available capacity in a Network Group, the expected cost of reinforcement of the Network Group and the time before the reinforcement is expected to be necessary. Load and generation incremental charges are derived separately.

The key FCP modelling steps are as follows:

- **Step 1**: configuration of the Authorised Network Model;
- **Step 2**: development of demand data sets;
- **Step 3:** definition of Network Groups;
- **Step 4**: power flow analyses, comprising of:
  - assessment of network security requirements (load); and
  - assessment of network security requirements (generation).
- **Step 5**: calculation of reinforcement costs;
- **Step 6**: calculation of FCP load incremental charges (£/kVA/annum).

Evaluation of rationale and potential developments

In this section we discuss:

- Ofgem's general objectives and principles for tariff-setting;
- The rationale provided by Ofgem for including generator credits;
- Developments in relation to locational charging in the CDCM.

Ofgem's general objectives for tariff setting

The DNOs are required by their licence to ensure that tariff methodologies:

- are cost reflective as far as possible;
- facilitate competition in generation and supply as well as not distorting, preventing or restricting competition in the transmission or distribution of electricity;
- take account of developments in DNO's distribution businesses as far as is reasonably practicable; and
- facilitate the discharge by DNOs of obligations under the Energy Act and distribution licence.

As part of its Structure of Charges project Ofgem established some key principles for charges, including:

- cost reflectivity;
- simplicity (at point of use);
- transparency;
- predictability; and
- facilitation of competition.

Ofgem also required that a charging methodology should:

- include all relevant information;
- apply to both demand and generation;
- reflect all significant cost drivers;
- minimise distortion of price signals where any adjustment or scaling of charges is necessary to ensure recovery of allowed revenue;
- recognise incremental costs and benefits on a forward-looking basis by virtue of users' use if the distribution system;
- ensure that charges for EHV users vary by location and utilise power-flow modelling at the EHV level; and
- be transparent and predictable to allow network users to estimate future charges.

Ofgem noted there were some tensions between these principles and the common methodology would need to strike a balance – in particular between the need for cost-reflectivity and simplicity/transparency.

Ofgem's objectives for the generator credit

Ofgem appears to have had two broad objectives in mind when implementing generator credits.

- First, in line with the principle of cost-reflectivity, Ofgem considered that where generation can reasonably be assumed to defer or avoid future reinforcement costs, these benefits should be reflected in generator charges, so as to deliver appropriate economic incentives.
- Second, Ofgem has also made several references to the broader policy objectives of encouraging take-up of low carbon technologies. For example, in its 2008 Decision to proceed with a common charging method, Ofgem said that: *"Delivery of this project is vital in facilitating progress towards meeting government targets on climate change, in ensuring that economic signals are provided to existing and potential users of electricity distribution networks and in enabling the efficient development of the network."* It said the common method would *"further enable DNOs' role as*

facilitators in tackling climate change"[133]. Ofgem also considered that the EDCM generator credit would have the benefit of reducing losses if it encouraged non-intermittent generators to locate closer to demand.[134]

Future developments – locational charging in CDCM

Subsequent to the development of the CDCM, some modifications have been proposed and further potential issues and developments of the methodologies discussed. A key issue has been around the assumptions Ofgem made in respect of the CDCM generator credit, as described above, that HV/LV nodes are demand dominated; and that generation will be broadly evenly dispersed, so as to avoid incremental reinforcement costs. When Ofgem approved the CDCM in 2009, one of the conditions for its approval was that the DCUSA parties should consider the principles that should apply when charging generators in situations where incremental generation would trigger network reinforcement.[135]

The DNOs were required to develop, where appropriate, a charging method that would apply to generators that are covered by the CDCM and are identified as being in so-called "generation-dominated" areas. Ofgem stressed that, while this did not necessarily mean that generation charges should end up being locational, it was nonetheless "keen that the DNOs think through the issue and available options … more fully".

Ofgem's call for DNOs to develop a distinct charging method for generation-dominated areas was motivated by its wish to ensure that charges are appropriately cost reflective. This could entail that DUoS charges need to vary by location, since generation customers could impose higher costs on the network by siting in one area vs another.

- If new generation capacity were to connect to a part of the distribution network where there was significant local demand but little existing generation capacity, these generators could under some circumstances help to prevent, or at least defer, the need for reinforcement of local network assets by reducing growth in net demand. In this scenario, a cost reflective DUoS charging methodology should offer credits (i.e., negative charges) to generation customers who site in

133 Ofgem, 22nd July 2008, 104/08 "Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements".

134 Ofgem, 17th August 2012: "Consultation on charging methodology for higher voltage distributed generation". Appendix 1 – Impact Assessment.

135 See Ofgem decision document 140/09, "Electricity distribution structure of charges: the common distribution charging methodology at lower voltages", November 2009:

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/CDCM%20decision%20doc%20201109%20(2).pdf this area, to reflect the fact that they are helping to reduce network investment costs.

- By contrast, if new generation capacity were to connect to a part of the distribution network where there was very little local demand and/or a significant amount of existing generation capacity, the output from these generators could in theory lead to reverse power flows (from low voltage to high voltage) across the local substation. Such reverse flows could in principle trigger, or at least bring forward, the need for reinforcement of local network assets. In such a scenario, a perfectly forward looking, cost-reflective DUoS charging methodology should charge generation customers who site in this area, to reflect the fact that they are accelerating, rather than reducing, network investment costs.

At present, the CDCM offers a p/KWh credit to all HV and LV generation customers, irrespective of where they are located on the network. This may be an appropriate signal to send to generators in areas where local generation can reduce the need for costly network reinforcement by offsetting any local growth in demand. However, a simple credit will not always be cost reflective and, following the logic set out above, could conceivably send generators the wrong signal altogether on parts of the distribution network where modest growth in generation capacity could trigger costly network reinforcement.

The DNOs commissioned Frontier Economics to undertake a CBA study into the extent of generation-dominated areas and the viability of developing a tariff methodology to reflect this at HV level[136]. The key findings of our report were as follows:

- there is a strong case not to introduce a highly complex locational charging regime to address generation dominance;
- there may be a case for a simpler charging regime limited to the impact made by HV generation; and
- careful consideration needs to be paid to the advantages and disadvantages that are more difficult to quantify, namely:
  - whether suppliers would pass the costs on to generation customers;
  - the potentially negative effect that locational charging could have on the simplicity, transparency and predictability of charges; and
  - the interaction of locational charges with other energy policies (eg. reducing generation growth, even in demand-led areas).

136 See Frontier Report, June 2011: https://www.ofgem.gov.uk/ofgem-publications/91106/frontier-enafinalreport-01-04-11-stc.pdf

Subsequent to this report, the DNOs developed some options to modify the CDCM to incorporate locational charging for generators at the HV level[137]. Three charging options were considered.

- Option 1 represents the introduction of a simple locationally varying charging regime for HV generators. Under this option every HV generator would be assigned a set of generation charges based on the primary substation that they are electrically connected to. Each primary substation would be set to one of four probabilities of generation dominance based on the number of years to when it would be deemed generation dominated. The level of generation dominance would determine how much generation credit is removed from these sites.
- Option 2 would introduce a simple arrangement for reducing the amount of credit paid to all HV generators in a DNO wide area. The reduction of the credit would reflect the percentage of primary substations that are generation dominated.
- Option 3 would remove credits from any HV generator that was electrically connected to a Primary substation where that substation was deemed to be generation dominated within 7.5 years.

In February 2015, Ofgem rejected the proposal to implement locational charging[138]. Its concerns included the following:

- The working group did not sufficiently demonstrate that its proposal did lead to cost-reflective tariffs. In particular, Ofgem was concerned that existing generators might start seeing credits reduced up to 7.5 years in advance of when the primary substation is expected to become generation-dominated.
- The proposals would lead to increased complexity and additional administrative burden on the DNOs and suppliers, but the potential gain from incurring this cost was not that large – since there were not many nodes expected to be generator-dominated in the next 10 years.

Other observers pointed to the risk of price volatility; the prospect that the change might discourage further RES roll out; and the prospect that the change might entail a wider review of charges.

Interestingly, Ofgem stated that it did support the underlying principle that if generation drives reinforcement, those generators should not continue receiving credits. This would therefore appear to be an area which Ofgem would be open to re-visiting if it became apparent that generator-dominated nodes were becoming a

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137 https://www.ofgem.gov.uk/sites/default/files/docs/2014/11/dcp_137_change_report_attachment_3_mig_gda_report.pdf

138 https://www.ofgem.gov.uk/sites/default/files/docs/2015/02/dcp137_d_0.pdf

more significant problem in future. For now, the CDCM continues to offer a p/KWh credit[139] to generation customers, irrespective of where they are located on the network.

139 In addition to this credit, the CDCM levies a fixed charge (p/MPAN/day) on generators where appropriate. A reactive charge (p/kVArh) is also levied where the charge band is exceeded.

Appendix C Quantifying the impacts of indicative EG credits on customers and networks: Our modelling approach

As noted earlier in the report, the market, regulatory and policy settings have the potential to amplify or weaken the impact of any network credit, and the associated costs and benefits of additional investment in, and use of, EG.

This appendix details our modelling approach to quantifying the impacts of indicative EG credits on customers and networks.

Objective of our modelling

The objective of our modelling is to:

- Demonstrate EG uptake occurs in the absence of any network credit (the reference case)
- Understand the *additional* EG uptake that might occur with a network credit by endogenously capturing the EG investment response by customers to changes in supply costs, tariff structures, FiTs, and – most importantly – the network credit.
- Highlight the interdependencies of any network credit with other policy and regulatory settings and market outcomes
- Highlight the importance of undertaking further modelling to evaluate the costs and benefits of the Rule change request.

Our modelling approach

Any network credits could potentially alter the economics of various forms of EG and alter the level and mix of EG uptake. Our analysis is focused on capturing customers' responses to investment in EG using our customer response model, *SWITCH*.

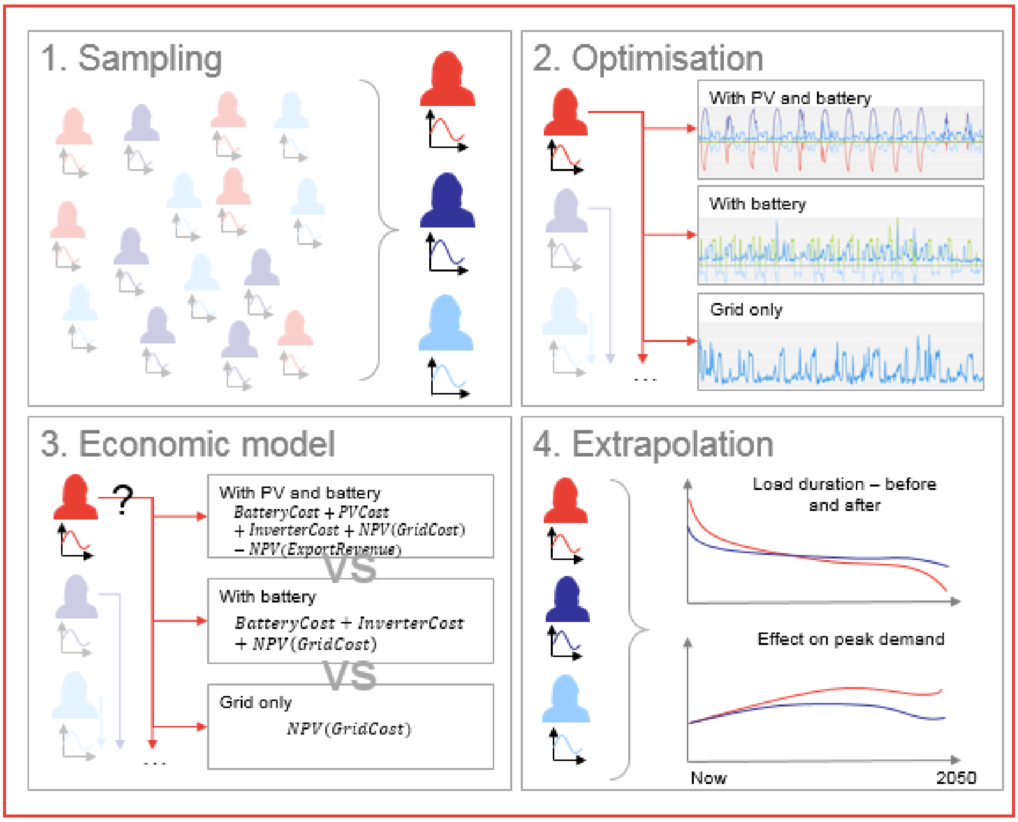
SWITCH optimises energy purchase decisions for individual customers, calculating the mix of supply options that provide the lowest long-term energy supply costs. The model can consider all energy supply options available to customers, different tariffs options and EG options. By modelling decisions for a number of representative customers, with different load shapes and other characteristics, *SWITCH* forecasts rates of adoption for various tariffs or technologies available to customers.

SWITCH looks at the half-hourly consumption and potential generation patterns of a large number of individual customers and projects future EG uptake under assumed scenarios.

SWITCH has four key stages, as illustrated in Figure 14: Switch modelling process

- The **sampling stage** involves deriving a representative sample of the load and potential generation traces of the target population. The model can use individual customers or weighted groups of 'representative' customers that have been clustered appropriately and averaged.
- The **optimisation stage** involves calculating optimal EG usage for each customer and possible combination of relevant inputs – namely investment options (e.g. solar PV and/or batteries) and tariff levels and structures. We have developed a mixed-integer linear programming (MILP) model to determine optimal battery usage and solar PV export decisions.
- The **economic model stage** involves translating these optimal behaviour patterns into economic outcomes. For each customer, we calculate economic outcomes over the modelling period for each scenario, and chose the lowest cost under an assumed decision rule (e.g. payback period of a battery is below 7 years).
- The **extrapolation stage** involves translating sample outcomes into population-level outcomes. This stage accounts for population growth and any saturation assumptions, if not already accounted for in the sampling stage.

Figure 14: Switch modelling process



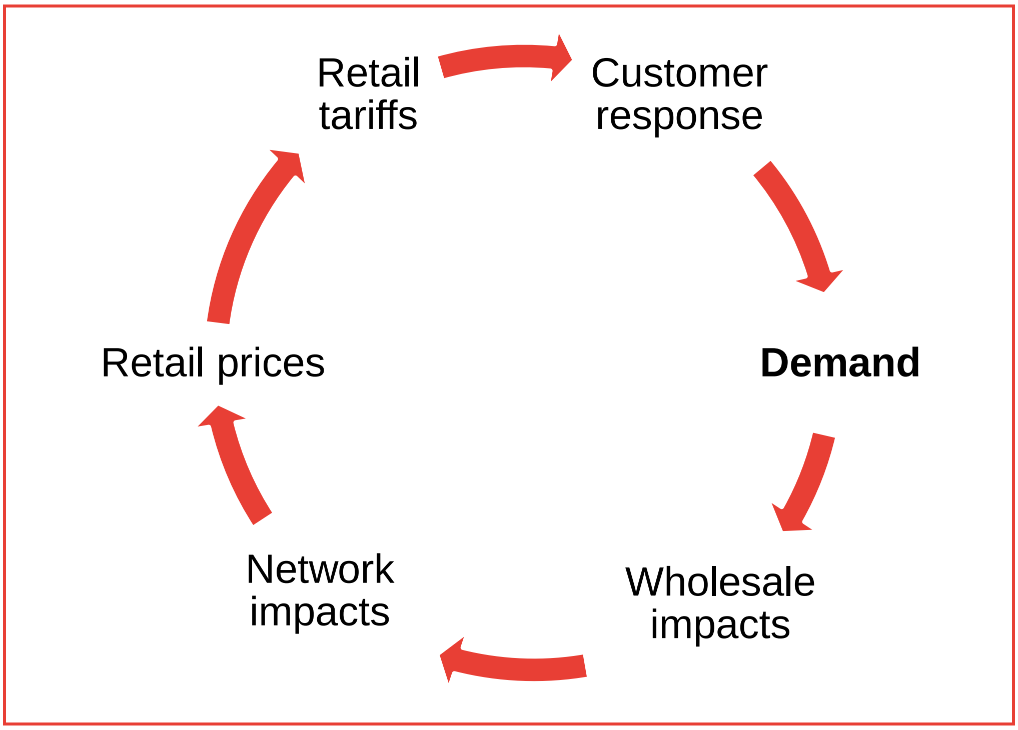
Source: Frontier Economics

Our modelling for this report is static in the sense it does not account for any feedback loop from customer investment in EG to demand and the resulting impact on the wholesale, network and retail parts of the supply chain. A robust evaluation of the costs and benefits of the Rule change request should seek to understand this feedback loop (as outlined in Figure 15: Dynamic supply chain modelling is necessary to understand the costs and benefits of the Rule change request) given that as EG uptake increases there are likely to be one of two outcomes, either:

- EG's impact on local peak demand becomes significant and longer term benefits associated with reduced capital outweigh longer term costs to networks(and broader energy market)
- EG imposes increasing costs on the network (and broader energy market) such that any incremental benefits are outweighed by the incremental costs.

Ultimately this is an empirical exercise.

Figure 15: Dynamic supply chain modelling is necessary to understand the costs and benefits of the Rule change request

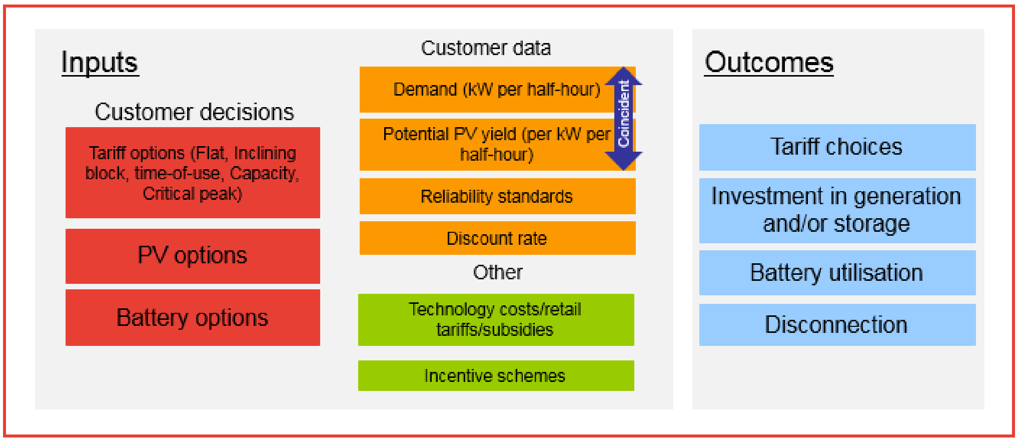


Source: Frontier Economics

Key modelling assumptions

The inputs and outcomes produced by the optimisation stage of *SWITCH* are summarised in Figure 16.

Figure 16: *SWITCH* MILP inputs and outputs



Source: Frontier Economics

We calculated the economically optimal EG investment decision with and without various forms of network credits for 300 customers on the Ausgrid network from today until 2050.

For each of the scenarios, we calculate, for each year from now to 2050, the 10 year NPV (with 5% discount rate) of:

- Remaining on grid
- Purchasing and operating a small, medium or large solar PV array
- Purchasing and operating a small, medium or large battery setup
- Purchasing and operating both a small, medium or large solar PV array and battery setup

Our input data – 300 residential customers from Ausgrid's 'Data to Share'[140] for financial year 2013[141] – contains household consumption and solar PV generation traces. To be able to calculate long term costs of each of the technology combinations listed above, we need battery usage profiles to properly account for all costs. We use an optimisation model to obtain annual optimal battery usage for each customer and technology combination, which we replicate over the modelling period. This stage is discussed in detail in Appendix A.

Table 8: Technology cost assumptions presents starting technology cost assumptions. Solar PV costs are sourced from Solar Choice's monthly index for November 2015[142], and battery costs are estimated from information in recent announcements on Tesla Powerwall authorised installers[143].

140 See http://www.ausgrid.com.au/Common/About-us/Corporate-information/Data-to-share/Solar-household-data.aspx.

141 Note this is not a representative sample; the analysis presented here focuses just on these 300 customers.

142 See http://www.solarchoice.net.au/blog/solar-pv-system-prices-november-2015.

143 See http://www.theaustralian.com.au/business/technology/tesla-flicks-the-switch-on-powerwall-sales/news-story/ce87cb33129937c7eab808f3a8fe4215.

Table 8: Technology cost assumptions

Technology	Rating/Capacity	Cost
Solar PV (includes SRES rebate, installation and inverter)	2.5kW	$4,772
Solar PV (includes SRES rebate, installation and inverter)	5kW	$7,903
Solar PV (includes SRES rebate, installation and inverter)	10kW	$14,303
Battery (includes installation)	3.2kWh, 1.65kW	$4,000
Battery (includes installation)	6.4kWh, 3.3kW	$8,000
Battery (includes installation)	12.8kWh, 6.6kW	$16,000

Source: Frontier Economics, Solar Choice

Figure 17 outlines our assumptions about learning curves for each of the model's input prices Retail prices increase as in the AEMC's Price Trends report, medium scenario[144]. We assume:

- Solar PV costs are subject to both upward pressure, due to SRES incentives abating over time, and downward pressure, due to technological cost improvements. The net effect of these pressures is no change in the current solar PV prices.
- Residential battery storage production costs will fall over time and have adopted AEMO's battery cost curve from their recent Emerging Technologies Information Paper[145].
- FiTs in the NSW jurisdiction will decline as solar PV adoption increases, such that a 6c/kWh tariff today becomes 2c/kWh by 2040.

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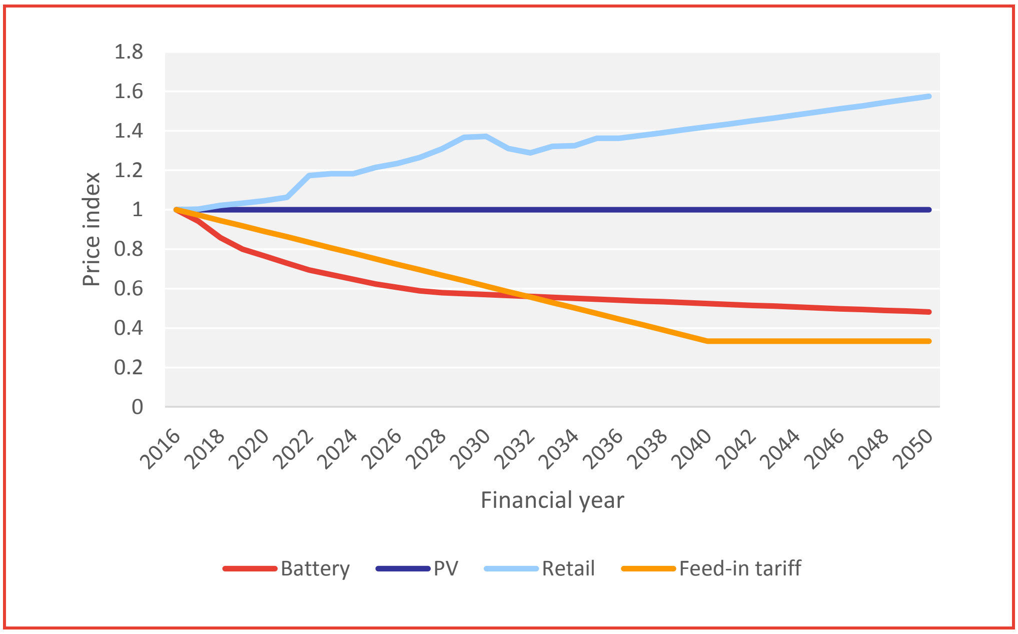
144 See http://www.aemc.gov.au/Major-Pages/Price-trends.

145 See http://www.aemo.com.au/News-and-Events/News/News/2015-Emerging-Technologies-Information-Paper.

Figure 17: Price indices used in modelling



Source: Frontier Economics

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