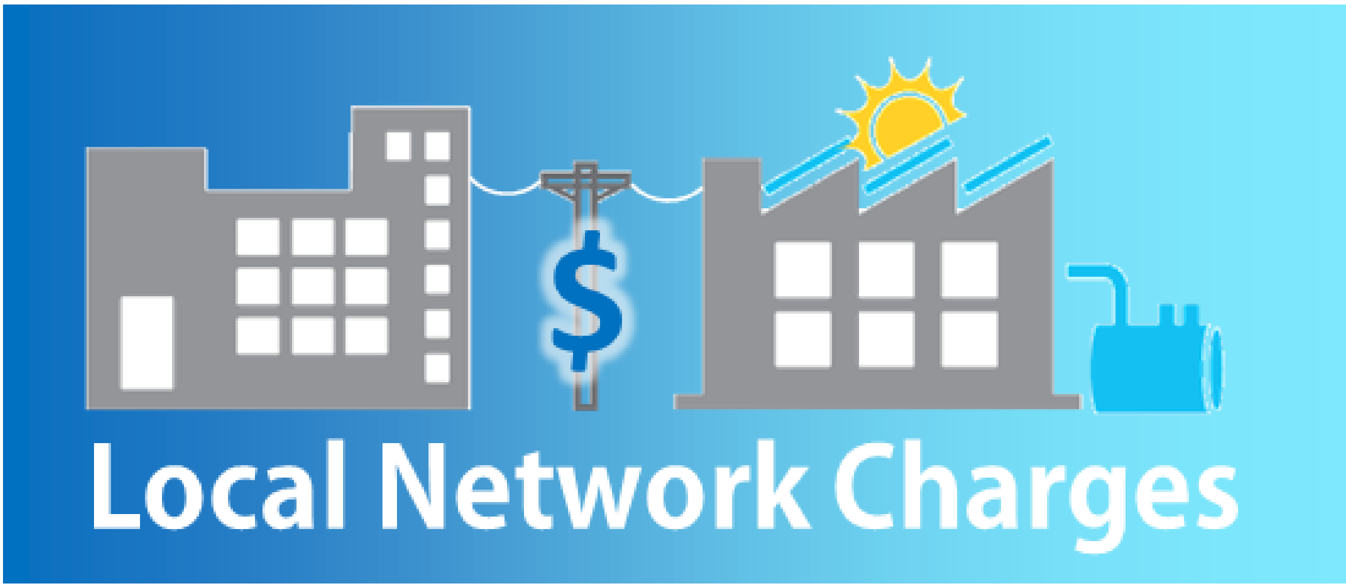

UTS: INSTITUTE FOR SUSTAINABLE FUTURES

TOWARDS A METHOD TO CALCULATE A LOCAL NETWORK CREDIT

Facilitating local network charges and virtual net metering

Workshop Briefing Paper: 13 August 2015

2015

ABOUT THE AUTHORS

The University of Technology Sydney established the Institute for Sustainable Futures (ISF) in 1996, to work with industry, government and the community to develop sustainable futures through research and consultancy. Our mission is to create change toward sustainable futures that protect and enhance the environment, human well-being and social equity. We seek to adopt an inter-disciplinary approach to our work and engage our partner organisations in a collaborative process that emphasises strategic decision-making.

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Authors: Ed Langham, Jay Rutovitz, Lawrence McIntosh,

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DISCLAIMER

The authors have used all due care and skill to ensure the material is accurate as at the date of this report. UTS and the authors do not accept any responsibility for any loss that may arise by anyone relying upon its contents.

Institute for Sustainable Futures
University of Technology, Sydney
PO Box 123
Broadway, NSW, 2007
www.isf.edu.au

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1 INTRODUCTION

This work is being undertaken as part of an ARENA funded project led by the Institute for Sustainable Futures to facilitate the introduction of Local Network Charges (LNC) and Virtual Net Metering. Two key deliverables of the project are the development of a proposed methodology for calculating an LNC, and five virtual trials which include calculating the LNC.

This briefing paper outlines the Institute for Sustainable Futures' (ISF) proposed approach to calculating the value of an LNC, for discussion at a methodology workshop with the project Strategic Reference Group.

The purpose of the workshop process is to:

- Agree on methodologies to apply in five virtual trials of the LNC; and
- Gain better understanding of the issues involved in developing a robust, workable and effective methodology.

The methodology development within this project will assist the consideration of the rule change proposal submitted by the City of Sydney, the Total Environment Centre, and the Property Council of Australia on the introduction of a local generation network credit, and the anticipated development of guidelines by AER.

The LNC methodology and the subsequent virtual trials of the method will feed into economic modelling of the effects of an LNC, in order to gain better understanding of the:

- scale of costs and benefits likely to ensue,
- effect on future rollout of efficient local generation, and
- implication for networks, both distribution and transmission.

The following sections are:

Section 2:	Gives a brief summary of the issues addressed by an LNC, and an overall project description
Section 3:	Presents the principles to be applied in the consideration of alternative LNC methodologies
Section 4:	Gives an overview of the benefits and costs of local generation, and whether these are captured in the proposed methods
Section 5:	Lists the major precedents for an LNC calculation methodology
Section 6:	Puts forward a methodological approach to assigning overall value to the LNC
Section 7	Discusses how this value can be converted to a tariff
Section 8	Covers further methodological issues
Section 7:	Lists all the consultation questions
Appendix 1:	Gives information on each of the precedents

Major consultation questions will be discussed at the methodology workshop on August 24th 2015, and remaining issues will be allocated to project working group(s) if required.

2 BACKGROUND

2.1 The issues

An LNC seeks to address inefficient outcomes in the NEM whereby local generators (LG) that provide or have the capability to provide benefits to the network are not currently incentivised to do so.

LG is currently being deployed at significant scale, and as such an LNC provides the levers to steer its operation and deployment in a manner that has the greatest system benefit. Additionally an LNC increases the visibility of LG to the NSPs, and assists with meeting AER requirements on Demand Management and non-network solutions.

The existing market structure incentivises local generators to maximise the amount of energy being generated and consumed 'behind the meter'. This may result in inefficiently high levels of private sector investment in the equipment to avoid using the grid altogether, or equipment that duplicates network infrastructure (private wires).

The rule change proposal for the introduction presented to the AEMC for inclusion of an LNC in the NEM aims to create a cost reflective way of acknowledging energy exports, and is designed to match the trend towards a cost reflective pricing structure for imports (demand). The proposed introduction of an LNC is to exports what cost reflective pricing is to energy/demand charges.

2.2 The project

The overarching objective of the project is to help facilitate the introduction of Local Network Charges for local generation, and the introduction of Virtual Net Metering (VNM) between local generators (DGs) and associated customers in the same local distribution area. The introduction of VNM and Local Network Charges is expected to unlock substantial new local energy resources, including additional renewable energy potential.

The project will produce supporting documentation for the introduction of VNM, and will draw conclusions on whether a second rule change proposal is required to facilitate its widespread introduction.

Data gathered during the trials will be used in a stakeholder and societal cost benefit analysis on the introduction of Local Network Charges and VNM that will further support the proposed rule change submission on Local Network Charges.

The intended outcomes of the project are:

a) More developed and refined methodologies and improved stakeholder understanding of the concepts of Local Network Charges and VNM.

b) A recommended methodology for calculating Local Network Charges to support the submitted rule change proposal on Local Network Charges.

c) An improved understanding of the metering requirements and indicative costs for the introduction of VNM.

d) An improved evidence base of the potential benefits and impacts of Local Network Charges and VNM, that increases stakeholder understanding and helps support any rule change submissions on these concepts.

e) Increased awareness and understanding by stakeholders of the requirements for the introduction of Local Network Charges and VNM.

2.3 The Rule change proposal for an LGNC

The City of Sydney, Total Environment Centre (TEC) and the Property Council of Australia submitted a rule change request to the AEMC for the Local Generation Network Credit on July 14th 2015. The rule change request was informed by work previously commissioned by the proponents and conducted by ISF in 2014 on the options for calculating the benefits and costs of LG.

The methodologies developed and resulting trials undertaken as part of this project will inform and provide support for the rule change proposal process.

3 PRINCIPLES OF LOCAL NETWORK CREDIT

This section outlines the core principles that should underpin a methodology for calculating Local Network Credits.

According to the rule change submitted to the AEMC on 14th July 2015, two key features of the proposed Local Network Credit (LNC) are that the credit should:

- “[provide] a **price signal** for exported energy”
- “..**reflect the long-term economic benefits** (in the form of capacity support and avoided energy transportation costs) that the export of energy from a local generator provides to a distribution business, including reduced or avoided transmission costs that would otherwise be passed through to end users.” (Hoch et al. 2015)

This is in line with the general economic principles of pricing infrastructure: “ the promotion of efficiency requires the setting of prices that encourage the optimal use of existing infrastructure assets while signalling to users the cost of an additional unit of a good or service.” (Kemp et al. 2014).

These basic principles are listed below, with some secondary principles. Together these principles can be used to test the effectiveness of a particular methodology, which should have the following features:

1. **Provision of a price signal** to incentivise:
   a) **Peak operation:** at the times when LG can provide the most benefit to the network in addressing peaks, and
   b) **Availability and reliability:** of LG units during peak period.
2. **Cost reflectivity:** the methodology should calculate the value of the LNC so that investments in both LG and network expansion meet load in an economically efficient manner.
3. **Stability:** the LNC should be sufficiently predictable to allow for sensible investment decisions.
4. **Transparency and simplicity:** the method should be transparent and easy for LG owners and operators to understand and respond to.
5. **Practicality:** the methodology should be practical for NSPs (both transmission and distribution) and retailers to implement, and fit broadly within existing metering and billing systems.
6. **Neutrality:** the LNC should be technology neutral, which implies:
   - Calculation on performance rather than type of generator
   - Applicability to LG across a range of sizes
   - Allowance for the contributions of many small generators, when considered in aggregate, to be incentivised in the same way as an equivalently sized larger generator with the same performance.
   - Incentivisation of LG exports to reduce system peak in the same manner that load reduction is incentivised (where there is the same impact on system use).

4 BENEFITS AND COSTS OF LG

This section sets out the commonly recognised costs and benefits of local generation (LG) and demonstrates:

- whether or not each cost or benefit will be captured in the calculation of the LNC
- if yes, how the cost or benefit will be captured.

There is reasonable agreement on **categories** of costs and benefits of LG (for example, Hoch & Harris 2015; EY & Clean Energy Council 2015; Nunn et al. 2014). However, the magnitude and how these costs and benefits are calculated is the focus of much debate.

Table 1 classifies each benefit and cost category, and indicates if and how this will be addressed through the proposed local network credit calculation process.

Table 1 How costs and benefits of LG and captured in the LNC

CATEGORY	COST	BENEFIT	CAPTURED IN LNC?	HOW CAPTURED
REDUCTION IN DISTRIBUTION COSTS:		✓		
• Avoided or deferred augmentation capital expenditure			YES	Calculate as LRMC of avoided capital costs
• Progressive downsizing of replacement infrastructure, reducing the Regulated Asset Base			YES	Calculate as LRMC of avoided capital costs
• Reduction of associated operating cost expenditure			YES	Calculate as LRMC of avoided operating costs
REDUCTION IN TRANSMISSION COSTS: • Categories as per distribution above		✓	YES	TBC. Calculate as EITHER: 1) LRMC method as per distribution above, OR 2) Avoided TUOS charge paid by distributor, using existing DNSP avoided TUOS calculation methods. Results reviewed during trial to inform a project recommendation.
AVOIDED LOSSES:		✓		
• Reduced energy generation requirement			NO	Currently addressed in voluntary arrangements for retailer Feed-in Tariff. Trials to check current

CATEGORY	COST	BENEFIT	CAPTURED IN LNC?	HOW CAPTURED
				valuation against ISF calculation of avoided loss value)
• Reduced upstream network capacity requirement			YES	Apply as uplift to capacity impact on LRMC of avoided transmission & distribution capital costs for upstream levels
Network services: voltage & frequency support		✓	NO	Addressed through Frequency Control and Network Control Ancillary Services (FCAS & NCAS) on transmission network. For distribution this is an issue for future consideration
Improving network utilization: retaining long term network revenue in a declining demand environment		✓	NO	Quantified in societal benefit in economic modelling
Billing system changes (where relevant)	✓		NO	Assumed to be negligible as one of a suite of tariff changes to be introduced as part of cost-reflective pricing which is happening regardless of the LNC
LG-driven network augmentation costs, including management of: • Fault levels • Two-way electricity flows • Voltage stability in areas of high LG penetration	✓		YES	Options described for how this can be addressed, either by a "gate" system which with the effect that LNCs are not paid when augmentation costs are imposed by the LG or as netting off LG augmentation costs in LRMC calculation

5 PRECEDENTS INVESTIGATED

This section described six methodologies for LNC calculation. One of these, the UK Common Distribution Charging Methodology (CDCM) was reviewed in the 2014 paper (Langham et al. 2014) and an additional five are considered in this paper.

Table 2 compares different the six different methodologies for calculating LNCs. The comparison includes:

- **Methodology:** the origin of the LNC methodology, whether a country or organisation
- **Value:** The core value captured in the LNC methodology i.e. the basis on which the LNC is calculated
- **Location:** Where/in which part of the electricity network the LNC is applied/available
- **Time:** Time periods within which the LNC is applied
- **Payment structure:** Whether LNC credited as volume (kWh) or capacity (kVA)
- **Additional values:** Any values in addition to the avoided network services value that are captured in the LNC methodology
- **Application of principles:** whether the LNC incorporates the core principles identified in Section 3 above of: peak operation, availability and reliability, cost reflectivity, stability, transparency, and neutrality.

It is useful to consider how aspects of these methods could be adapted to the LNC, although we are not recommending in this paper that any of these precedents be adopted ‘as is’ for LNC calculation. Each precedent has strengths and weaknesses as described below:

Strengths include:

- **Cost/Benefit calculation:** Most precedents contain a method for calculating total benefits of LG to the network. The actual method for calculating benefits varies considerably, including:
    - Estimates, such as in Connecticut and ActewAGL
    - Long term average methods of assessing network benefits, such as in the UK CDCM
    - More thorough calculations such as Minnesota’s conventional and deferred plan method.
- **Stability**: All the precedents demonstrate the principle of stability because they use a volumetric payment structure. None of the precedents vary payments more frequently than annually, and in one case payments are set for the life of the generator.

Weaknesses include:

- **Lack of signalling for operation and availability:** Many of the tariff structures fail to provide meaningful price signals to LG in that availability and peak load / generation coincidence are assumed, (Connecticut, Minnesota), or not signalled in advance (ActewAGL). A combination of both is necessary to allow generators to have incentives to respond to, and assist with, peak load abatement.

- **Locational consideration:** Many precedents lacked a locational consideration of connection point. We note however that the for the methods in use by ActewAGL and Ausnet, the generator size restriction makes it likely that all connections are LV.
- **Neutrality:** Many precedents are not technology neutral as they are only available to particular technologies or have technology specific calculation steps. Where generator performance is estimated in this manner, a generator with a significantly worse or better performance will not be incentivised or rewarded appropriately.

A number of elements from the precedents have influenced the methodologies this paper proposed for consideration in the following sections. In particular, the valuation, locational and Time of Use (TOU) elements of the UK CDCM methodology are seen as easily adaptable to the Australian context as explained below:

- **Average incremental cost approach to LRMC**: The UK CDCM uses an Average Incremental Cost (AIC) approach to assessing LRMC. Many aspects of this are directly applicable to the Australian context and fit within existing cost reflective pricing guidelines.
- **Voltage level of connection:** Allocation of network value by voltage level as used by the UK CDCM once again provides a framework that fits closely with Australian pricing guidelines.
- **Time of Use Signals from DNSPs:** Ausnet and the UK CDCM both incentivise LG operation at particular times based on the probability of generation in those times assisting with meeting peak periods. This approach is necessary in addressing the operation criteria and is similarly easily adapted to the Australian market, where TOU pricing has strong precedents, assisting both with ease of implementation and in generator owner understandability.

A fuller description of the precedents is provided in Appendix A.

Table 2: Methodology Comparisons

Methodology	Value calculation	Location	Time	Payment structure [Additional values]	Operation	Availability	Cost Reflectivity	Stability	Transparency	Implementation	Neutrality
UK CDCM	Marginal Cost based on 500MW increments	By voltage level	Probabilistic: based on peak periods and estimated generation	Volumetric [Losses]	✓	✗	✓ ✗	✓	✓ ✗	✓	✓ ✗
Connecticut	Declining percentage of DUOS and TUOS	Generator and consumer in same distribution territory	Applies to exports not consumed by customers other sites within billing period	Volumetric	✗	✗	✗	✓	✓	✓	✗
Minnesota	NPV of value of generator over its lifetime. Load and generation data for 12 months (hourly basis)	Assumed low voltage (LV) (Solar only)	All	Volumetric, [avoided generation, capacity, ancillary services and environmental benefits]	✗	✗	✓	✓	✓ ✗	✗	✗
ActewAGL	Estimate avoided TUOS	Assume LV (Solar only)	All	Volumetric	✗	✗	✗	✓	✗	✓	✗
Ausnet	Unknown	Assume LV (Solar only)	Summer generation only	Volumetric	✓ ✗	✗	?	✓	✗	✓	✗
Reference service approach[1]	Lowest avoided cost	Very location specific, requires user to be identified			✗	✗	✓	✓	✗	✗	✓ ✗

1 Both Western Australia in the WA Wheeling Method and Trasmission pricing guidelines include a methodology based on this approach

6 METHODOLOGICAL APPROACH: VALUE CREATION

A pragmatic and economically efficient Local Network Credit calculation methodology needs to address the following:

1. VALUE CALCULATION
    a. Framework for network value of LG
    b. Calculation by location, network level and customer class
2. TARIFF CREATION
    a. Allocating value to LG by volume, capacity, or both
    b. Allocating value to LG by time
3. OTHER ISSUES
    a. Treatment of LG costs
    b. Avoided transmission costs
    c. Avoided losses

It is assumed throughout that the general principles for cost reflective network pricing as applied to tariff setting should be followed in the calculation method for the LNC, unless there is a reason why applying these methods will lead to an inefficient or inequitable outcome in a particular instance. These principles are set out in general terms in advice published by the AEMC (Kemp et al. 2014)

Note that there is a methodological barrier in identifying the cost reflectiveness of network pricing because the network is broken up into separate operators for distribution and transmission. Almost all consumers experience a bundled price (except for network losses), because they receive a bundled service. So for the purpose of offering cost reflective tariffs for local generation, a bundling of all network costs makes sense from the customer's perspective. However, for the purposes of this discussion paper, avoided transmission costs are discussed separately in Section 8.1 due to different implementation precedents.

This section addresses two issues, the general approach taken to determining the value of the LG to the network, which by implication is the approach to calculating the LNC, and the specifics of how this can be applied to calculating an LNC. Section 7 addresses how to translate the overall value of the LNC into a tariff, and Section 8 the treatment of LG costs, avoided transmission costs, and avoided losses.

6.1 Framework for network value of LG

Options

The two main alternatives for calculation of the value of LG are:

- **Reference service approach:** The difference between current network charges and the lowest cost of provision of an alternative 'reference' service (i.e. a private wire). This approach is currently allowed for within chapter 7 of the Western Australia Electricity Access Code (see Appendix A), and is the concept of the "prudent discount" mechanism in the NER, which is intended to prevent inefficient bypass of the transmission system.
- **LRMC of network services approach:** the avoided cost of network augmentation and replacement equates to the long run marginal cost (LRMC) of network services, This should include growth-related augmentation which is caused by an increase in demand (and therefore may be avoided as a result of LG or reductions in demand), and in the case of falling demand, any reduced replacement expenditure. Associated operational expenditure should be included. (Note that while this applies to both distribution and transmission, transmission is addressed separately in Section 8.1.)

Proposal

A central tenet of the rule change proposal on cost reflective pricing was to set "cost reflective tariffs in a manner that reflects the LRMC of providing network services". To maintain consistency with this principle, using the LRMC of network services is the preferred approach to calculation of the LNC.

This also recognises a key limitation of the alternative service approach, which requires a defined generator *and* a defined consumer, which is inconsistent with the proposed Rule Change to direct a LNC payment to the local generator, recently submitted by the City of Sydney, Total Environment Centre and Property Council of Australia (see Section 2.3).

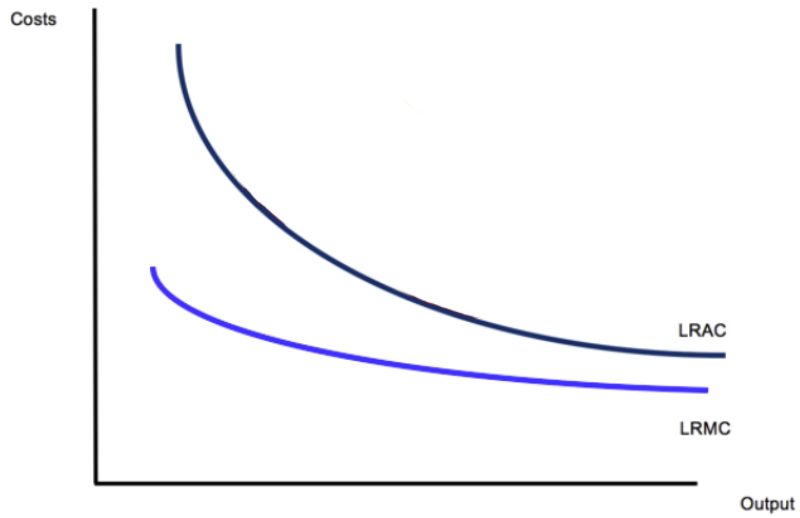
The LRMC in natural monopolies tends to decline with scale, as illustrated in Figure 1. Thus using the LRMC alone as the basis of tariff tends to lead to under-recovery of revenue compared to the overall network costs. The normal practice is to mark up the LRMC based values in order to ensure NSP revenue covers costs (Kemp et al. 2014, pg 8)

It is suggested that an equivalent mark-up is *not* added to the LNC. Rather, we suggest that any potential gap between the actual value of LG and the credited LNC value may be captured by all customers as a societal benefit from the introduction of an LNC.

CONSULTATION QUESTION 1

Is there general agreement that the calculation of the LRMC of network services should be the basis of the local network credit value?

Figure 1: Long Run Marginal Cost in Natural Monopolies (Riley 2015)



6.2 LRMC calculation method

Options

The main alternatives for calculation of the LRMC are the Average Incremental Cost (AIC) and the perturbation method, which can have significantly different outcomes for the actual value calculated in different circumstances (Kemp et al. 2014).

Average incremental cost approach

The average incremental cost approach estimates LRMC as the average change in forward looking operating and capital expenditure resulting from a change in demand. This is represented by the following formula:

$$LRMC\ (AIC) = \frac{\text{Present value (cost of new network capacity + associated operating costs)}}{\text{Additional demand served at future reference year}}$$

The AIC is defined as referring to an increment in demand, but a similar calculation could be undertaken for the reduction in capital expenditure on replacement (and the corresponding reduction in operating costs) resulting from a reduction in demand.

The UK CDCM method uses the AIC method to calculate LRMC to determine both the cost of network services and the avoided costs associated with LG.

The perturbation method

The perturbation method looks at the direct changes in forward looking operating and capital expenditure as a result of a specific change in demand (kWh or kVA). This is represented by the following formula:

$$LRMC\ (perturb) = \frac{\text{Present value ((revised CAPEX + OPEX)} - \text{(original OPEX + CAPEX))}}{\text{Additional demand served at calculation year}}$$

While calculations are usually applied to an increase in demand, it can as easily be applied to a decrease in demand.

The AIC method is widely used for current NSP calculations feeding into tariff settings, as the perturbation method requires detailed information at a granular level.

The AIC method by definition is the average cost of demand increments, and smooths projected expenditure over the entire increase in demand. It will tend to underestimate the LRMC when the network is close to being constrained, as at that point a small increase in demand could trigger a large amount of expenditure. The perturbation method will tend to return very low values when the network is not constrained, and may underestimate the LRMC.

In general, we consider the AIC method to be more suitable for calculating long run averages over customer classes, provided it can be adapted to provide the average LRMC of reductions in demand, as well as increments in demand.

Proposal

Rather than prescribing which method is preferable for LNC calculations, one option would be to stipulate that the same LRMC calculation method should be used as for tariff setting for that network area and customer class. This would meet the principle of equity for the LNC compared to the price signal to reduce demand.

It is important that the LRMC of downsizing assets as a result of long run reduction in peak demand, which is likely to be particularly important for transmission and sub-transmission elements in the future, is incorporated in whichever method is used.

CONSULTATION QUESTION 2

Is it appropriate to stipulate the same method be used to calculate the LRMC for LNC setting as for the tariff setting? Is further guidance needed?

6.3 Calculation by location, network level and tariff class

Local generation will avoid network costs for the network levels upstream of that unit. As such an LNC calculation needs to consider where LRMC is incurred across the different network levels.

Furthermore, different customer classes contribute to the total network LRMC in differing proportions. An LNC set for one customer class based on an LRMC calculation that includes other customer classes may result in cross subsidy and should be avoided. Work for the AEMC by NERA on economic pricing concepts describes allocating LRMC at a network level to each customer grouping (Kemp et al. 2014, pg 16).

This approach of costing by network level and tariff class reflects current tariff setting practice and thus should be familiar to all DNSPs in the NEM.

Proposal

Network Level and Customer Class

It is proposed to calculate LRMC for both customer class and voltage level of the network, resulting in $/kVA/yr figures by network level and customer class. This table would need to be populated by DNSPs as an input to calculating the LNC. An example of this input table can be seen in Table 3, using dummy data. It should be noted that the LRMC of the whole network would be the weighted average of the individual customer class LRMCs.

Table 3: Sample table for LRMC by network level & customer class (dummy data)

LRMC ($/kVA/yr)	Residential customers	Small commercial customers	Large commercial customers
Subtransmission	24	24	25
HV Substation (Zone Substation)	33	33	27
HV Feeder	60	69	57
Distribution Sub	57	48	33
LV	104	93	0
TOTAL	**278**	**257**	**142**

To translate these LRMC values into a LNC for LG connected at a particular part of the network, it is necessary to then allocate the levels of the network being utilised by the LG. This is in effect the same as crediting the LRMC of the parts of the system *not used* by the LG. It is proposed to apply the following principle: LG should pay in full for the transport of power at the level of connection and below (i.e. ‘downstream’). It should not pay for the levels of the network above where it is connected (i.e. ‘upstream’), to the extent that the LG is available during system peak periods. This principle is the approach applied in the UK CDCM precedent.

How this principle is applied to the LRMC components is shown in Table 4.

Table 4 Components of LRMC forming LG local network credit, according to the level of generator connection location (credited components marked with a tick)

	Cost Category							
Generator Situation	Transmission (TransGrid)	Sub-transmission line	HV Substation	HV System	LV Substation	LV System	System-Fixed	Non-System fixed
Co-Located (Same site)	✓	✓	✓	✓	✓	✓	✗	✗
LV System Connected	✓	✓	✓	✓	✓	✗	✗	✗
LV Substation Connected	✓	✓	✓	✓	✗	✗	✗	✗
HV System Connected	✓	✓	✓	✗	✗	✗	✗	✗
HV Substation Connected	✓	✓	✗	✗	✗	✗	✗	✗
Sub-Transmission Connected	✓	✗	✗	✗	✗	✗	✗	✗

Location

Each DNSP applies tariff setting for different regions differently. Typically, distribution networks do not differentiate between regions, although some split their territory down into a small number of pricing zones where there are large differences in the cost of supply. By contrast, transmission networks are highly location specific in their charging structure. It is proposed that Table 3 be produced and applied for each relevant pricing zone, to reflect current tariff setting practice. The LNC should not be more locationally specific than the existing network pricing zone.

CONSULTATION QUESTION 3

Is assessing LRMC based on customer class and network level an acceptable method of delineating parts of the network that particular generators may impact?

6.4 Adjustment for capacity impact of reduced losses

Network capacity upstream needs to meet not just the energy requirements of downstream loads but also the losses incurred in transporting the energy through the various levels of the distribution network. As such, one kVA of generation at a low network level will avoid more than one kVA of network capacity upstream. The difference will be the ratio of the Distribution Loss Factor (DLF) at the generator connection point to the DLF at the upstream network level. It should be noted that Distribution Loss factors apply to the distribution network and Marginal Loss Factors (MLFs) to the transmission network. As this section of the calculation is referring to distribution network *capacity* only and not energy value, the DLF has been applied.

This step begins with locating the generator in the network by both network level of connection and by customer type. Then, the ratio of the loss factors is calculated for each network level above the generator connection point.

$$Adjusted\ LRMC_{upstream\ level} = Base\ LRMC_{upstream\ level} \times \frac{DLF_{Generator\ connection\ point}}{DLF_{Upsteam\ level}}$$

This methodology is not dissimilar to ActewAGL's avoided TUOS methodology (ActewAGL 2013). The key difference it is applied as a ratio to each network level as opposed to only a single ratio back to the transmission connection level.

An example is presented below for the case of a small commercial customer's generator connected at the distribution sub level.

Table 5: Hypothetical example of proposed application of uplift of capacity impact due to reduced losses

LRMC ($/kVA/yr)	Base LRMC $/kVA/yr for customer class	Distribution Loss Factor	Loss factor ratio to generator connection level	Adjusted LRMC per kVA at generator connection level
Subtransmission	24	1.0019	1.0330	24.8
HV Zone Substation	33	1.0052	1.0296	34
HV Feeder	69	1.0293	1.0055	69.4
Distribution Sub	48	1.0350	1	48
LV	93	1.0490	n/a	n/a
TOTAL	257			

Proposal

We propose that the LRMC for each network level be adjusted based on generator connection point to account for the capacity effects as a result of losses as per the above formula, noting that this adjustment will need to be calculated for generator connection level within each customer class.

CONSULTATION QUESTION 4

Is an uplift factor applied to the LRMC calculated value by network level and customer class based on the calculated Distribution Loss Factors (DLFs) reasonable and implementable?

7 METHODOLOGICAL APPROACH: TARIFF CREATION

7.1 Volumetric or capacity or both?

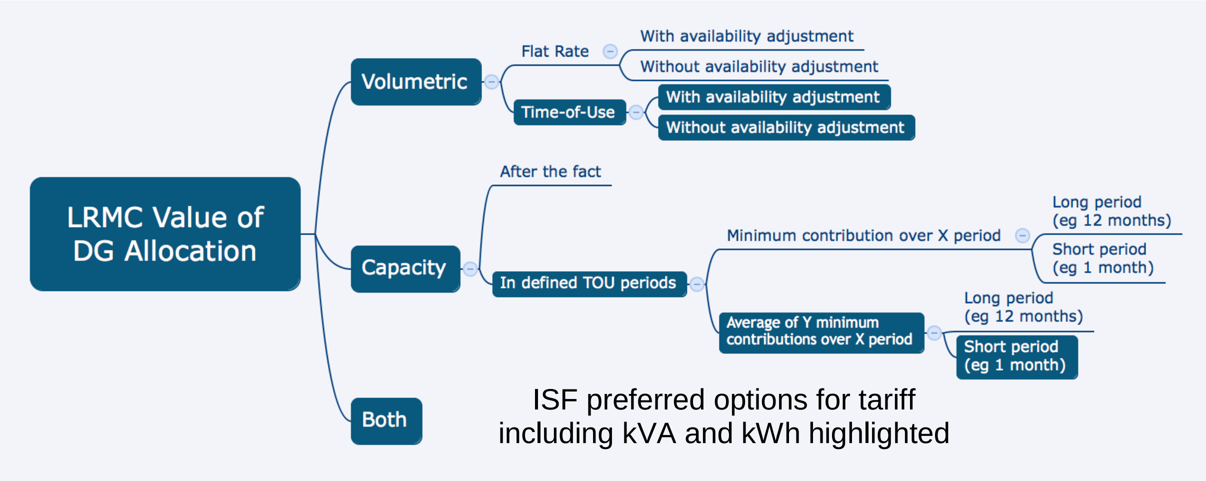
Options

Once the overall value of the LNC has been calculated, the next step is to allocate the value to customer classes via a specific tariff. A fundamental decision is how the tariff is paid, with the three options being volumetric, capacity, and both volumetric and capacity. The main characteristics and pros and cons of the three alternatives are summarised below.

There are subsequent calculation options for how volume and capacity payments are applied, which have a significant impact on the tariff effectiveness. These are summarised here and discussed in more detail in Appendix B.

Figure 2 shows the decision tree associated with volumetric and capacity payments.

Figure 2: Decision tree for volumetric and capacity payments



Option 1: Volumetric payment alone

A volumetric payment may be applied as flat rate or Time of Use (TOU). It is assumed that TOU would be adopted, as flat rate does not meet basic principles of efficiency as it does not incentivise operation at times that reduce network costs.

A TOU payment may include an adjustment for generator availability. For example, the UK's CDCM method applies an "f" factor by generator type, while the Minnesota method attempts a uses actual performance-based aggregate availability in determining the value of the generation unit. [1]

[1] The Minnesota calculation is done according to the generation profile of the class of generators for a full year or set of sequential full years. Where the data is not available the Minnesota method prescribes the simulation methods to be applied.

The main **advantages** of volumetric payments are:

- The only two systematic **precedents** for LNC tariffs are both paid via a volumetric payment (see the UK CDCM method and the Minnesota method in Appendix A)
- **Implementation** is straightforward, as TOU volumetric payments require only an interval export meter
- **Transparency and stability**: once the tariff is calculated it is understandable and provides a stable environment for LG investment decisions
- **Incentivising performance:** volume payments structured on a TOU basis provide a price signal for generators to operate during these pre-identified

Potential **disadvantages** – depending on the detail:

- **Allocative efficiency:** a volumetric payment based on the LRMC should be cost reflective overall, but the distribution of value to particular LGs may be incorrect.

Outstanding issues – depending on the detail:

- **Availability adjustment:** a volumetric payment would be technology neutral. However an availability adjustment is required to incentivise generator availability. To remain this way an Australian LNC would need an availability adjustment based on actual generator availability as a substitute for the UK CDCM “f” factor which estimates this availability (but breaks the Neutrality principle).

Option 2: Capacity payment alone

A capacity payment is given for the provision of capacity during defined periods, with many options for defining the period and other parameters (see Figure 1 and Appendix B).

The main **advantages** of capacity payments are:

- **Cost reflectivity:** Capacity payments are the most obviously **cost reflective** payments, as network capacity peak periods are the main driver of marginal costs.
- **Incentivising future performance:** capacity payments may offer a strong **price signal**, as LG is only paid to generate at those times most useful to the NSP.

Potential **disadvantages** – depending on the detail:

- **Applicability**: Many smaller customer classes do not currently have capacity payment components, and as such metering and billing infrastructure may not be in place to apply capacity payments, and the concept may be more difficult to communicate to residential or small commercial customers.
- **Incentivising performance:** if the time period is very long, or if the allocation to time is *After the event* (in which an event is defined as the top peak day(s) for the year, or the top 30 minutes for the month) the ability to send an effective price signal is greatly compromised, as the DG does not have the information to modify behaviour.
- **Transparency and stability:** the payments will be difficult to understand or use as the basis for investment, as the outcome would be extremely variable according to the design details chosen. As different NSPs apply capacity charges in different ways, it is perhaps less likely that a consistent approach will be agreed. This could lead to considerable variation between NSP areas, and potentially between regulatory periods.
- **Neutrality**: while capacity payments appear to be technology neutral as they reward performance, an ‘all-or-nothing’ approach to capacity charges across a whole peak

period would not, in effect, be technology neutral. For example, requiring capacity across an entire 2-8pm peak period would always result in a zero credit for Solar PV, yet a 4pm critical peak would still have been lowered by the PV contribution. This is an argument for allocating to LG value both capacity and volumetric components.

Option 3: Combined volumetric and capacity payments

Combining both a volume and capacity payment may address many of the concerns that attach to one approach or another, providing the best aspects are taken from each. A proposed combination is shown in dark blue Table 6: Summary of two proposed methods for trial and is:

- A TOU volumetric payment, without an availability adjustment (as availability is addressed through the capacity payment component); and
- A capacity payment according to availability during defined peak periods.

If a combined volumetric and capacity method is used, it is assumed that the LRMC and allocation by customer class and network level would be the same as for the volumetric calculations, with the exception that there would be no need for an availability adjustment.

The allocation of value between volumetric and capacity payment, and the choices regarding how to reward capacity, can be made from the bottom up (Option 3A below), as any tariff is determined, or could use the results of the calculations undertaken for the existing tariff for the LG customer, described as a “mirror” tariff (Option 3B below).

Option 3A “**bottom up”:** this method allocates a percentage of LNC value to capacity and volumetric payments, and then determines how the peak kW should be rewarded, including the periods (for example, monthly, daily, after the fact), and the method (lowest minimum, average of four minimums, etc.). A key unanswered question is how the value should be allocated between volumetric and capacity payments.

The key advantage of this method is that it should be the most cost reflective, while the key disadvantages are that it may duplicate effort with other tariff setting. There is also a risk that it is inequitable, if there is a mismatch between the tariff the customer is paying for their service, and the LNC which is effectively rebating for their locally used generation.

Option 3B “**Mirror”:** The LMRC value combined with the locational and customer class allocation would be used to allocate a percentage value to the network levels for that customer class. This would be applied to the volume and capacity charges that the LG pays, so the appropriate percentage of volume charges would be allocated to the LNC. The capacity payment would simply “mirror” the demand charge, so that the minimum KW availability during the relevant period is rewarded at the same rate as demand payments.

The key advantages of the mirror method are that it reduces the complexity of setting the LNC for each NSP, and avoids duplication of effort. It is also intuitively equitable and easy to understand. The key disadvantage is that it is only as cost-reflective as the LG customer’s tariff, which may not be very cost reflective currently, but will increasingly become so.

Proposal

ISF proposes that two methods of LNC calculation are trialled; a volumetric method and a volumetric and capacity method (Option 1 and either Option 3a or 3b). The three options are summarised inTable 6, and shown against the principles put forward in Table 7.

Table 6: Summary of two proposed methods for trial

	1) VOLUMETRIC	COMBINED VOLUMETRIC + CAPACITY 3a) BOTTOM UP	COMBINED VOLUMETRIC + CAPACITY 3b) MIRROR
Determine LNC value	LRMC of augmentation and replacement CAPEX and OPEX (standard cost reflective tariff approach) with: • AIC / perturbation LRMC chosen as per CC & network level • include LRMC of downsizing	Same as volumetric method	Same as volumetric method
Locational allocation of LNC value	Allocate by network level and customer class, as per standard cost reflective tariff approach	Same as volumetric method	Same as volumetric method
Allocate between volume and capacity	All volumetric	To be determined (working group?)	Mirrors LG customer tariff
Availability adjustment	To be determined (working group?)	Capacity payment rewards availability, adjustment not required	Capacity payment rewards availability, adjustment not required
Time Allocation	Peak, shoulder and off peak by network level (option of 2 tier system with system peak at HV levels & network level/ CC peak at LV levels)	Same as volumetric method	Mirrors LG customer tariff
Include additional values/ costs	**Additional values:** Avoided TUOS payments, volumetric losses	Same as volumetric method	Same as volumetric method

CONSULTATION QUESTION 5

Is trialling a volumetric plus a volumetric/ capacity combined LNC payment a good approach? Which combined method is preferred, "bottom up" or mirroring the LG tariff?

Table 7: Proposed methods for trials against principles

Methodology	Operation	Availability	Cost Reflectivity	Stability	Transparency	Implementation	Neutrality
Volumetric TOU with availability adjustment	✓	?	✓	✓	✓	✓?	✓?
Volumetric TOU without availability adjustment AND Capacity Payment	✓	✓	✓	✓	?	?	✓
Mirror	✓	✓	?	✓	✓	✓✓	✓

7.2 Additional questions

There are a number of additional questions on the split between capacity and volumetric payments, and the specifics of time periods and availability below. Appendix B gives further information on these issues time periods and availability issues.

***We do not expect Questions 6 to 9 to be resolved at the workshop – please bring general suggestions and be ready to volunteer for a working group if you're in interested in these topics.**

CONSULTATION QUESTION 6*

How should LRMC value be split between capacity and volumetric payments in the "bottom up' combined volumetric/capacity approach?

CONSULTATION QUESTION 7*

How do you effectively integrate availability into a volumetric method for setting the LNC?

CONSULTATION QUESTION 8*

Which peak time should be applied to the LNC in a volumetric calculation: system peak(s), local network level peak, or a two-tier system?

CONSULTATION QUESTION 9*

What peak periods and calculation methods (single minimum, average of X minimums, etc.) should be used for capacity payments in the “bottom up’ approach to the LNC?

8 METHODOLOGICAL APPROACH: OTHER ISSUES

8.1 Avoided transmission costs

The value of avoided transmission costs is analogous to avoided distribution costs described in Section 6.2. However, as the LNC only considers LG embedded within the distribution network, no granular understanding of the cost by level of the transmission network is required. Further, as Section 5.5(h) of the NER stipulates that registered (large) generators are eligible to received avoided TUOS rebate, there are existing precedents for the calculation of this value. The value of avoided TUOS is determined by each DNSP, and is intended to reflect reduced augmentation costs of the TNSP. TUOS charges are made up of three components: Usage Charges, General Charges and Common Service Charges. Only the Usage Charge is generally included as being avoidable. This is calculated according to the lower costs incurred by the DNSP at the point of transmission connection, as a result of the LG's existence.

Options

The options for a transmission services avoided cost methodology are:

1. Apply the same **distribution LRMC calculation decisions to the transmission network**. The benefit of this approach would be in creating consistency and transparency of application between DNSPs and for all levels of the network. The negatives of this approach are that it adds administrative complexity as it requires the LRMC to be calculated for transmission, and creates a new transaction involving the TNSP that differs but overlaps with the existing avoided TUOS calculation.
2. **Utilise the existing avoided TUOS methodology of each NSP**, but apply it to all LG as opposed to just registered generators. The benefit of this approach is that there is a well-established method that DNSPs are comfortable with, although this is heavily contested by some local generation proponents. The negatives of this approach are that:
    a. The method is not consistent (in that NSPs have different methodologies);
    b. There is currently not full transparency in how this methodology is applied;
    c. The means of calculation may be more simplistic in how peak demand reductions from LG are treated than some of the options explored by DNSP capacity charges (Appendix B). This may be particularly true for variable output generators, and as such may not be technology neutral.

If Option 2 was applied, it would be important to cross check the effective value of the avoided TUOS value calculation through the trial component of this project, to inform a position of whether the existing avoided TUOS method is satisfactory.

CONSULTATION QUESTION 10

Do you prefer maintaining a consistent LRMC approach to avoided transmission costs, or trialling the application of the existing DNSP avoided TUOS calculation methods?

8.2 Avoided losses

Local generators reduce the losses in delivering energy from the generator to the customer. Combined losses for the transmission and distribution systems are in the order of 6-10% for urban networks and 10-15% for rural networks (Langham *et al.* 2014).

Energy losses must be credited as a volumetric payment as they are inherently related to power flows rather than capacity. Currently, avoided losses from LG are captured as an (uncalculated) benefit to the electricity retailer. As such, the money flows required to correct this issue is from the retailer to the LG. This is currently done through a voluntary (e.g. NSW)[2] or mandatory (e.g. Victoria)[3] retailer-offered Feed-in-Tariff.

Proposal

The calculation of the value of losses is **price x volume** as follows:

- The **volume** of losses is calculated as the sum of the percentage of losses (the 'loss factor') for each level of the network upstream of the LG, multiplied by the annual generation of the LG. This should include both avoided distribution *and* transmission losses.
- The **price** used should be the energy wholesale value for the relevant time-of-use (peak, shoulder or off-peak) period.

As the avoided losses transaction must involve the retailer rather than the DNSP, it is considered that the only option is to exclude avoided losses from the LNC calculation, and recommend that retailers participating in the project trials undertake to offer the above calculated avoided loss value to LG for all exports at a minimum.

Additional Note

Note that the reduction of losses not only has an energy impact, but also has an equivalent capacity impact on the levels of the network upstream of the LG. This is incorporated as an uplift of the capacity impact of the LG on each upstream level of the network (see Section 6.4). The magnitude of the uplift is defined by the loss factor of at each level of the network in relation to the level of the network where the generator is connected.

8.3 Treatment of LG costs

There are a number of other potential cost increases as a result of LG connections to or operation on the network. These include costs associated with:

- The ability of the network to safely handle levels of fault current which may be increased by nearby presence of LG (commonly referred to as "fault levels").
- The management of voltage stability, where a very high penetration of LG exists on a part of the network with low demand (e.g. long residential feeders with large amounts of PV and low daytime demand).
- Power flows in the 'reverse' direction along feeders or other network elements that were not designed to accommodate this type of flow. For example, protection grading.

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[2] http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Solar_feed-in_tariffs_201415/16_Jun_2014_-_Final_Report/Final_Report_-_Solar_feed-in_tariffs_-_The_subsidy-free_value_of_electricity_from_small-scale_solar_PV_units_from_1_July_2014

[3] For renewable energy generators only. http://www.esc.vic.gov.au/Energy/2014-Minimum-Feed-in-Tariff/Final-Decision-Minimum-Feed-in-Tariff-for-2015

Options

There are three possible options to deal with these costs:

1. **Incorporate into avoided LRMC calculation:** compute a LRMC for this cost component, and subtract from the LRMC benefit calculation
2. **LNC Gateway:** Deem that the LNC is no longer payable to LG where any of the above investment triggers is required, and standard deep and shallow augmentation procedures are triggered. This could be applied on a TOU basis, whereby the LNC is not paid during specific periods when certain network conditions are met (for example a reverse flow situation), or on an additional LG basis (first in up to a cap).
3. **Export Gateway:** Deem that no more export from LG is allowed.

Proposal

As these costs are highly variable and specific to the part of the network to which the LG is being connected, it is not considered appropriate to average out these costs using Option 1.

We propose to apply Option 2 the applied on an ‘additional LG’ basis, and only offer the LNC up to the point where LG is still beneficial to the network. This option is preferred to the TOU basis, as it is simpler to administer and more predictable for the LG.

Stability/predictability of LNC offering should be proactively managed by the network to ensure sufficient warning of impending limits is provided. There is some precedent for this in Western Australia where the distributor, Western Power publish as Network Capacity Mapping Tool indicating generator connection capacity at major substations. (Western Power n.d.)

CONSULTATION QUESTION 11

Is the LNC gateway approach, in which the LNC is not payable at the point that LG imposes significant costs on the network, an acceptable compromise to managing LG network costs?

CONSULTATION QUESTION 12

If a gateway approach is taken to deal with LG network costs, should it be applied on the basis of “first in best dressed” up to a cap on a particular feeder or network area?

9 DISCUSSION QUESTIONS

CONSULTATION QUESTION 1 Is there general agreement that the calculation of the LRMC of network services should be the basis of the local network credit value?

CONSULTATION QUESTION 2 Is it appropriate to stipulate the same method be used to calculate the LRMC for LNC setting as for the tariff setting? Is further guidance needed?

CONSULTATION QUESTION 3 Is assessing LRMC based on customer class and network level an acceptable method of delineating parts of the network that particular generators may impact?

CONSULTATION QUESTION 4 Is an uplift factor applied to the LRMC calculated value by network level and customer class based on the calculated Distribution Loss Factors (DLFs) reasonable and implementable?

CONSULTATION QUESTION 5 Is trialling a volumetric plus a volumetric/ capacity combined LNC payment a good approach? Which combined method is preferred, “bottom up” or mirroring the LG tariff?

CONSULTATION QUESTION 6* How should LRMC value be split between capacity and volumetric payments in the “bottom up’ combined volumetric/capacity approach?

CONSULTATION QUESTION 7* How do you effectively integrate availability into a volumetric method for setting the LNC?

CONSULTATION QUESTION 8* Which peak time should be applied to the LNC in a volumetric calculation: system peak(s), local network level peak, or a two-tier system?

CONSULTATION QUESTION 9* What peak periods and calculation methods (single minimum, average of X minimums, etc.) should be used for capacity payments in the “bottom up’ approach to the LNC?

CONSULTATION QUESTION 10 Do you prefer maintaining a consistent LRMC approach to avoided transmission costs, or trialling the application of the existing DNSP avoided TUOS calculation methods?

CONSULTATION QUESTION 11 Is the LNC gateway approach, in which the LNC is not payable at the point that LG imposes significant costs on the network, an acceptable compromise to managing LG network costs?

CONSULTATION QUESTION 12 If a gateway approach is taken to deal with LG network costs, should it be applied on the basis of “first in best dressed” up to a cap on a particular feeder or network area?

***We don’t expect Questions 6, 7, 8 and 9 to be resolved at the workshop - please bring general suggestions and be ready to volunteer for a working group if you’re in interested in this topic.**

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APPENDIX A: PRECEDENTS

UK COMMON DISTRIBUTION CHARGING METHODOLOGY

The UK method for valuing local generation has the following steps:

1. Asset value by network level including opex is adjusted to standard life of the asset and used to determine percentage at each network level.

2. The Average cost of network in $/kW/yr (including capital and operating costs) is allocated to network level by the percentages determined in step 1. The connection level of the generator is identified.

3. The combined value of unused network levels upstream of the generator is then adjusted by a probability factor based on time of generation.

4. A per kWh value is determined based on the number of peak hours in the year

5. Generation during the peak times is considered to have a X% chance of addressing the peak

6. An availability F-factor is applied based on technology type to represent the likelihood of the generation profile of different technologies occurring during the peak period. (Note that UK does not have TOU metering so generation profiles must be estimated and then converted to an F-Factor based on peak load / generation coincidence)

7. Volumetric losses based on the wholesale rate are credited as a separate transaction.

(Distribution Connection and Use of System Agreement Ltd 2015)

The UK method has strengths in its method for breaking down network cost by level and assigning a probabilistic weighting to volumetric payments. The key weakness of the UK method is that actual generation behaviour is not incentivised, a generator with markedly better or worse performance than its f-factor estimate is not penalised or rewarded.

MINNESOTA VALUE OF SOLAR METHODOLOGY

Minnesota's methodology is technology specific to solar power only. It is important to note that Minnesota has a vertically integrated electricity supply regulator context. Calculation steps therefore include the generation units owned by the utilities.

1. Utilities are required to establish synchronised, time stamped datasets of hourly values for a 12 month period of:
   - Utility owned and operated generation
   - Utility distribution load
   - PV Fleet (Distributed Generation) production.

2. The datasets are used to establish actual 'Effective Load Carrying Capacity' (ELCC), 'Peak Load Reduction' (PLR) and avoided loss values through calculating generation requirements, peak loads and losses in scenarios where the PV fleet is present and not present.

3. The values of the benefits to the network are assessed by comparing the two scenarios above and the respective conventional vs deferred expenditure plan.

4. To arrive at a volumetric value, the Minnesota method takes the $/kW/yr value for actual capacity avoided (by considering a conventional and deferred capital expenditure plan). For this reason a UK style f-factor is not required, as the load / generation match has already been assessed in the comparison of capital expansion plans.

   Annual values of deferred augmentation are then divided by estimated annual generation per kW to determine a kWh Value.

$$\frac{\$_{LNC}}{kWh} = \frac{Annual\ cost\ conventional\ plan - Annual\ cost\ deferred\ plan}{Annual\ production}$$

   Where

   - Annual cost of the conventional and defer plan is in units of $/kW/yr
   - Annual production is in units of $kWh/kW_{peak}/year$

   This method is only possible to use in accompaniment to the expenditure plan comparison methodology in assessing network benefit.

   After all values of the generation fleet are determined on a volumetric basis, the total discounted value is then amortised over the 25 expected life span of the PV unit and re-adjusted for inflation over the 25 year period.

5. The utility is permitted to substitute location specific avoided costs where it chooses, based on engineering costs within the planning horizon. The above method is applied to each area. Beyond the planning horizon however the utility must revert to using the system wide method. For areas where engineering cost estimates are not available the system wide method must be used.

6. Each year the process is recalculated, PV systems installed in the previous years *remain* on the VOS tariff set the year they were installed; the recalculated value is applied only to new generation units installed in that year.

The Minnesota method also includes some costs and benefits that are not proposed for the Australian LNC. These include

- Environmental externalities
- Avoided fuel costs for the displaced generation,
- Avoided plant capex and O&M cost for displaced generation

(Norris et al. 2014)

The Minnesota method is very thorough in its before and after calculation of peaks, capacity requirements and local generator contribution. It also has advantages of the stable investment environment it presents to generation. The flexibility awarded to utilities in choosing location specificity also allows utilities to incentivise generation in a location-focussed manner where desired. It has a similar weakness to the UK method in that plant has no price signal to dispatch. A second drawback is that over the years there would be many different levels of the tariff accumulating as different units installed in different years receive differing amounts. Finally, managing expansions to a generation unit would be challenging, as expansions installed in different years would require separate metering.

CONNECTICUT

Connecticut has enacted an LNC methodology applying to surplus generation at a site over a billing period. The credit includes a 'declining percentage of transmission and distribution charges' to be applied against other sites or against the next bill.

The declining percentage is

- 80% to July '14
- 60% from July '14 to July '15
- 40 % from July '15

Any remaining credits at the end of the calendar year are paid out to the customer.

The credits are limited to 'Class I' (Renewables) and 'Class III' (combined heat and power systems) and apply to generation less then 3MW, located in the same distribution territory as the 'customer host and its beneficial accounts' i.e, the accounts to which the energy is being credited under the existing virtual net metering provisions.

(State of Connecticut 2013)

ACTEWAGL

ActewAGL make a volumetric payment applying to Solar PV units up to 30kW in size, as an acknowledgement of the avoided TUOS benefit of local generation. The methodology used in quantifying the payment is unclear.

"The estimated avoided cost of TUOS charges on energy exported into the electricity network is 0.5 cents per kWh." (ActewAGL 2015)

AUSNET

Ausnet (previously SP AusNet) operating in Victoria have implemented a payment in their recent pricing proposal incentivising summer generation during peak periods.

The payment is volumetric and applies only to Solar PV generators. It varies between 4.3824c/kWh and 4.0580c/kWh. The reasons behind the difference in values across different tariff classes are unclear. The methodology used in quantifying the payment is also unclear.

"Photovoltaic cell customers continue to receive an equal offset for electricity generation consumed within their installation, as well as an additional payment for excess generation during summer peak periods (1 November – 31 March) "

(SP AusNet Annual Tariff Proposal 2014)

WA Wheeling charges (Alternative Service Provision)

Where a generator has identified a local customer (point to point) a simple methodology for assessing the use of the network is the lowest avoided cost of separately providing the service for that power flow as a stand-alone service. This method involves pricing a 'reference service' ie, the cost of a new asset that meets the required function for transferring the energy. The total cost of this service is then divided by the expected volumetric throughput from the generator to that local customer. This amount is determined to be the value of network used by the transaction.

No new asset is constructed, however the existing assets of the Distributor are allowed to be used and a credit would be paid to the generator for any difference between the local customer's standard network fees and the network use value determined by the above method.

This calculation methodology would ensure that private wire construction costs and the resultant inefficient duplication of networks by generators would be avoided. As distributors must offer the service at the cost of private wire/stand-alone service equivalent or lower.

This methodology appears to be allowed for within the Chapter 7 of the Western Australian Electricity Network Access Code (WAENAC) where:

> 7.3 (b) the reference tariff applying to a user:
> (i) at the lower bound, is equal to, or exceeds, the incremental cost of service provision; and
> (ii) at the upper bound, is equal to, or is less than, the stand-alone cost of service provision.

Chapter 7 also requires the distributor to provide discounts for distributed generation plant if this results in lower costs to the distributor as discounts for plant which reduces the service provider's capital and non capital related cost as a result of the generator.(Government of Western Australia 2004)

TRANSMISSION SYSTEM PRICING METHODS

The challenge of creating fair pricing mechanisms with correct incentives for partial use of a network is not a new one. Transmission system pricing methodologies have encountered this problem for many years and approaches used are instructive for the LGNC calculation.

1. **Postage Stamp** methods allow for single point tariffs (ie generator or customer only) and may be on a capacity or volumetric basis. Numerous sub methodologies exist within the 'postage stamp' category (Handschin et al. 2000), these include:
    a. Maximum system load share method
    b. Energy based retrieval point tariff
    c. Energy based postage stamp of voltage and transformation levels

    All postage stamp methods provide little incentive for behaviour by generators as each and every kWh or kW incurs a similar charge. The advantages of postage stamp methods however are simplicity in calculation, full cost recovery and investment stability.
2. **Nodal pricing** is the opposite extreme from the postage stamp method. Each location receives pricing on a load flow basis dependent on real time system flows. This method is usually regarded as the most economically efficient, however it suffers the drawbacks of calculation complexity and level of opacity that would apply to local generator operators.
3. **MW.km** this methodology can be load flow based or distance based. Distance is determined 'as the crow flies' or along a particular asset route. The MW.km of the transaction is then determined as a ratio of the total system MW.km and system costs allocated accordingly. This method provides a good balance between nodal pricing and the postage stamp method in that stability and simplicity are maintained while at the same time providing signals to users about their particular. As a point to point method however it is not suitable for the LNC in the Australian context

    (Anon 2012)

APPENDIX B: ADDITIONAL DISCUSSION OF TIME PERIODS AND AVAILABILITY

Volumetric payments: time signals and availability

Volumetric payments can be made without a time signal at all (for example, most solar feed in tariffs have been structured this way). Alternatively, payments can be given a time signal, by structuring as peak, off-peak, and shoulder blocks. The payment can also be made increasingly cost reflective with various adjustments for the likely or actual availability of the LG.

No variation (Flat rate)

The simplest option is to have no variation in the tariff by time, where each unit of generation is considered to be of equal value regardless of when it occurs.

Long run marginal cost for the customer is simply spread across the number of hours in the relevant period. For a simple non-varying tariff the formula is:

$$\frac{\$_{LNC}}{kWh} = LRMC \times \frac{1}{8760 \times Average\ power\ factor}$$

(Where LRMC is in \$/kVA/yr)

While simple to calculate, “no variation” provides no signal of peak times and thus does not meet the conditions for efficient pricing.

Peak/off peak (and shoulder) – which peak to use?

Peak/ off peak rates provide information to LG about when generation is of most value. This information is provided beforehand through the DNSP identifying seasons, day of the week and times when the peak is expected to occur. The DNSP estimates the probability of the peak occurring in each of the periods e.g. 90% probability of peak occurring in peak time, 8% probability of peak occurring in off shoulder times, and 2% probability of peak occurring in off-peak times. This percentage is then applied to the value of the expected benefit from generation during that period. Peaks and their associated time based probabilities can be assessed on:

1. The system peak only, such as Ergon Energy’s Seasonal TOU structure; or
2. Each network level peak with higher cost reflectivity but increased complexity; or
3. A two tier scheme, with one tier reflecting peak conditions above a certain and another reflecting more local peaks at lower levels of the network, which could be defined by generator customer class. That is, a residential customer class assumes the customer is more likely to be within an area with a residential-dominated demand profile.

A basic calculation of the volumetric payment is

$$\frac{\$}{kWh}\,(peak) = LRMC \times P_{peak}\,\frac{1}{hours\ in\ peak\ period \times Average\ power\ factor}$$

$$\frac{\$}{kWh}(off\ peak) = LRMC \times P_{off\ peak} \frac{1}{hours\ in\ off\ peak\ period \times Average\ power\ factor}$$

Noting that

$$P_{off\ peak} + P_{peak} = 1$$

This equation can be adapted to allow for further time periods (e.g., shoulder) through using the same formula and ensuring that the sum of the probability terms P_{peak}, $P_{off\ peak}$, $P_{shoulder}$ etc. is equal to 1. The equation can also be used for peaks at various network levels by using the LRMC attributable to that customer group for each network level and summing the resultant kWh values together for each hour of the day.

Discussion

Option 1 is not overly data intensive and is familiar to many NSPs, while option 2 is likely to be more cost reflective and potentially give better price signals, while being more complex to implement. Option 3 may provide a suitable compromise.

Volumetric payments: adjustment for availability

Volumetric payments may be adjusted to reflect generator availability by estimating the likely generation profiles to determine how likely particular generator types will meet peak events. Both the UK CDCM and Minnesota method use this approach, albeit with very different calculation methods.

The UK CDCM estimates an availability factor (“f” factor) for each generator type to include the likelihood of that generator meeting the peak. The peak is identified through setting of distribution time bands (effectively peak, shoulder and off peak).

The Minnesota method uses a year’s worth of hourly data from generation (estimated if required) and load to determine total impact from the presence of the generation fleet[4]. As such availability is inherently included in the value calculation and is not applicable to the LRMC value calculation proposed in this paper

The UK CDCM employs the first equation from the peak and off peak section for each network level and then an extra f-factor is applied as an estimate of ‘load match’ i.e., of the level of generation from particular generation types that will fall within the peak times. This has the limitation that the method is not technology neutral, and rewards predicted rather than actual performance.

As the preferred LNC approaches includes volumetric and capacity based components, we anticipate that the generator may be required to install interval metering, and as such actual data can be used to assess the level of generation within particular periods as well as peaks and minimums of the generators profile. This is expected to be preferable to estimate based approaches.

Methodologies for calculating an availability factor to be applied to the volumetric payment could be based on:

- A statistical correlation between a flat generation profile and the generator’s actual generation profile during the peak period.

[4] Note that the Minnesota method was developed specifically to assign value to solar PV, so this calculation is done for one generator type only

- A statistical correlation between the generator's average profile and its worst profile during peak period for the cycle. I.e., rewarding consistent behaviour during peak periods from day to day
- The proportion of time within the peak period that the generator generates within the limits of its average level ± a 30% tolerance band We note that this would involve more complex analysis on customer export data than is currently undertaken within billing systems. Thus a weakness of this approach is the ease of implementation.

Capacity payments: calculation and time period

A capacity payment is based on the performance of the generator during the peak period, analogous to the demand charges applied to customers.

Demand charges are typically approached by charging for the maximum level of customer demand in specified periods, and calculated either as a single maximum, or the average of a specified number of events.

A capacity payment could be paid on the minimum export level during a defined period. Some care would be needed to ensure the period and method of payment is appropriate. Demand charges may be set for the maximum event or events, regardless of when the event occurs (peak, off peak, or shoulder). However, a capacity payment should be triggered by capacity within each period, as the benefit offered to the NSP by a generator during the peak period is not affected by whether that generator is operating during the off peak period.

The time frames selected for the peak periods, and for the cycles over which the availability is measured, require careful consideration, in order to both incentivise operator behaviour and maintain cost reflectivity.

There are multiple options for setting the calculation method and the billing period. In the "mirror tariff" option, these choices would all be set to reflect the tariff the LG was paying. In a "bottom up" approach, all these will require determination. Options for consideration are set out below.

Defined time periods – these can be daily, monthly, seasonal, or even yearly, and generally would only apply to peak times within the defined billing period. A key consideration is incentivising behaviour, as too long a period combined with an early outage means that worst performance for the period is set and unchangeable.

"After the fact"
Peak events occur at specific times, so it may be argued that generation is of most benefit at those specific times only. Under an "after the fact" setting, the contribution at the **actual** time of system peak and/or local peak, rather than the pre-advertised peak time, is used to compensate the generator on a per kW or per kVA basis. This is similar to some DNSP's methods for paying avoided TUOS to local generators.

This has a significant drawback, as the effect of the LG on the peak is disregarded. Thus the peak may have occurred at a different time had LG had not been generating, aligned more closely with their availability. This will systematically tend towards a mismatch between actual contribution and credited contribution. A fairer calculation of "after the fact" peak contribution is comparing the observed peak level with that which would have occurred without the fleet of LG, which is undertaken in the Minnesota credit methodology. This is much more complex to administer however.

The **advantage** of an after the fact time setting is its cost reflectiveness (provided it takes into account the effect of the DGs contribution to peak). However there are significant **disadvantages**. No information is provided to generators in advance about when the peak time is expected to occur, so there is no price signal for the generator to ensure operation and availability at this time. This reduces the likelihood that this time setting would lead to benefits for the network.

What capacity value should be credited?

Analogous to demand charges, capacity payments are likely to be set according to the minimum generator output in kVA over a set time period. This can be the average of a specified number of minimums over a set time period (for example, the average of four minimums for each hour during the peak period), the single worst event in a set time period, and so on.