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Local network credits and local electricity trading: Results of virtual trials and the policy implications

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ABSTRACT

Current charging methods for network infrastructure and recompense for distributed energy may not result in optimum system solutions. Once feed-in tariffs to support the development of renewable generation are phased out, the payment for grid exports is usually based on the wholesale energy value alone. Network charges are generally levied in full, with few attempts to offer a partial charge, or completely waived. Local Electricity Trading (LET) and Local Network Credits (LNCs) offer one approach to reforming charge structures. This paper examines the effects of LET and LNC on different stakeholders in four virtual trials of medium scale distributed generation projects around Australia, and the implications for policy. The trials found the large value gap between behind the meter systems and grid exports may lead to duplication of network assets, inefficient sizing and operation of distributed generators, and a lack of incentive for dispatchable generators to operate at peak times. The trials indicated that in most circumstances, the combination of LNC and LET addresses all four problems identified to some degree.

1. Introduction and background

A number of jurisdictions around the world have seen an extraordinary expansion of distributed generation (DG). Key DG technologies deployed have included distributed photovoltaics (PV), wind turbines and cogeneration units (cogen). The deployment of distributed PV has been particularly remarkable, driven by a dramatic fall in PV system prices combined with strong government support (Bazilian et al., 2013; Candelise et al., 2013; Sunshot, 2015). While there have been challenges associated with high penetrations of distributed PV systems (Deeba et al., 2016), there have been significant benefits in many sectors and PV uptake has made an important contribution towards mitigating the risks of climate change (Akorede et al., 2010; Oliva et al., 2014; Perez et al., 2011)

The most widely implemented commercial arrangement for this DG deployment has been net metering. By the end of 2015, more than 50 countries had implemented some form of net metering policy (REN21, 2017). Under net metering, customers with DG first self-consume the electricity they generate, and any excess generation is exported to the electricity grid. The value of self-consumed generation is the full avoided retail electricity tariff while the value of electricity exported to the grid is typically set at a flat payment per kWh known as a feed-in tariff (FiT).

Australia has the world's highest per capita index of distributed PV systems and currently 18% of households own a PV system.[1] A key driver of this deployment was the highly subsidized FiT rates in place in different Australian states, together with some other capital subsidy programs for PV. Due to the significant costs of these programs, compulsory FiTs were either reduced or stopped altogether rather suddenly, and now most Australian FiTs represent only the wholesale generation value of grid exports (Martin and Rice, 2013; Poruschi et al., 2018). This process coincided with considerable increases of the network component of the electricity bill caused by substantial network investments to manage the electricity peak demand (Productivity Commission, 2012; Simshauser and Nelson, 2013). As a result, today's FiT rates represent less than half of retail rates, so the value of DG self-consumption is far greater than the value of exports to the grid.

However, it has been argued that FiTs that pay only the energy component of the retail tariff are not a suitable reward for generation exported to the distribution grid (Cossent et al., 2009), which is being

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[1] Calculated from Australian Bureau of Statistics 2016 census, total households in Australia 9,901,496 (http://www.censusdata.abs.gov.au/census_services/getproduct/census/2016/quickstat/036?opendocument) and estimated residential installs of 1,794,081 from the Australian Photovoltaic Institute (http://pv-map.apvi.org.au/), downloaded 5th May 2018.

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on-sold to nearby customers at the full retail rate. While DG exports utilise only a very small segment of the distribution grid, their price includes the charge for the entire electricity transmission and distribution network. Thus a reduction of the network charge for distributed generation sales, proportionate to the level of utilisation of the grid, has been proposed in several jurisdictions. Such a network credit was proposed in Australia as a 'Local Generation Network Credit' (LGNC)[2] (AEMC, 2016).

A key commercial arrangement that complements the implementation of Local Network Creditsis Virtual Net Metering, also known as Local Electricity Trading (LET). This type of arrangement allows a generator to assign their exported generation to specific electricity customers on a Time-of-Use basis (Asmus, 2008; Huijben and Verbong, 2013). Whilst an LNC reduces the network component of the electricity bill, LET may offer the opportunity for retailers to reduce the energy and retail components of the bill.

LET and LNC arrangements have already been implemented in a few jurisdictions in different ways. LET – or Virtual Net Metering – has been implemented in many US states for solar programs where customers purchase solar panels from a large array located off-site and receive the benefits of net metering (Asmus, 2008; Huijben and Verbong, 2013). In the UK, LNCs have been systematically applied under the 'Common Distribution Charging Methodology' (DCUSA, 2015). In Australia, a compulsory LNC payment was rejected by the Australian Energy Market Commission (AEMC) (AEMC, 2016). Still, the Australian electricity law does indicate that locational transmission charges should be credited to distributed generation sales (Langham et al., 2013) although in practice is only generally applied to larger generators over 5 MW. The state of Western Australia has regulated what is known as a "prudent discount", which could be regarded as a form of LNC that specifically seeks to avoid the construction of private wires between nearby customers that duplicate existing infrastructure (Government of Western Australia, 2004). In the US, states such as Connecticut and Minnesota have also implemented some form of LNC (Norris et al., 2014; State of Connecticut, 2013).

The financial impacts of DG with net metering and FiTs have been widely studied in the existing literature from both the DG owner perspective (Burns and Kang, 2012; Colmenar-Santos et al., 2012; Darghouth et al., 2011; Liu et al., 2014; McHenry, 2012; Mills et al., 2008; Muhammad-Sukki et al., 2011; Oliva et al., 2016; Radhi, 2011; Rüther and Zilles, 2011) and the utility perspective (Blackburn et al., 2014; Eid et al., 2014; Mayr et al., 2015; Satchwell et al., 2015a, 2015b). However, with no demonstrations or economic assessments of new commercial arrangements for DG such as LET and LNCs, it is still to be tested whether they are effective at creating a level playing field for distributed generation.

In this article we estimate the financial impacts on the DG owners and network service providers (NSPs) of LET and LNC arrangements for four virtual trials in Australia. Key policy implications from the study are discussed and policy recommendations proposed.

The organisation of the paper is as follows: the methodology used for our study is presented in Section 2, and the data inputs summarised in Section 3. Section 4 presents the results and discussion. Finally, Section 5 presents the policy implications and the conclusions of the study, with some suggestions for future research in this area.

2. Methodology

A business case model was constructed to compare local generation projects under current market conditions (that is, a minimal feed-in tariff paid based on the current wholesale price) with the same generator installed with the two measures under investigation, namely Local Electricity Trading (LET), and payment of a Local Network Credit (LNC). The effect of physically connecting the generation site and trading sites by a private wire, effectively combining the sites behind one meter, was also tested where such an installation was a reasonable proposition. Two alternate methodologies were used to calculate the LNC. The measures are considered together and separately.

The model uses hourly data for a full year, and requires yearly profiles for the potential generator output, and for demand at the generation site and any potential trading sites. This is a granular approach that has been previously used in several studies of the economics of distributed generation, including (Borenstein, 2008; Darghouth et al., 2011; Mayr et al., 2015; Mills et al., 2008; Oliva et al., 2016). The method aims to capture the correlations between the DG output, the customer consumption and diverse market outcomes such as the Time-of-Use electricity rates.

The model compares the business case for the new generation in current conditions, and with and without the new measures. The changes in costs for the proponent sites are calculated, including the local generation site (LG site) and whatever trading sites are included in the trial (called the LET sites). The model also calculates the financial impact on the relevant network business.

The total annual electricity cost (AEC) of the LG and LET sites together, for each virtual trial is calculated as in Eq. (1).

$$AEC = FC + \sum_{t=1}^{8760} R_{LG_t} \times imp_{LG_t} + R_{LET_t} \times Vimp_{LET_t} + (R_{LET\,t} - EC_t - RC_t - LNC_t)\times Vbm_{LET\,t} - FiT \times Vexp_{LET\,t} \quad (1)$$

Where at hour t the parameters are:

FC: All fixed charges including generation investment repayments in \$/year
R_{LG_t}: Electricity retail tariff rate at the LG site in \$/kWh
imp_{LG_t}: Electricity imports from the grid at the LG site in kWh
R_{LET_t}: Electricity retail tariff rate at the LET site in \$/kWh
$Vimp_{LET\_t}$: Virtual electricity imports from the grid (after LG netting-off) at the LET site in kWh
EC_t: Energy cost component of retail tariffs in \$/kWh
RC_t: Retailing cost component of retail tariffs in \$/kWh
LNC_t: Local network credit in \$/kWh
Vbm_{LET_t}: Virtual electricity behind the meter (after LG netting-off) at the LET site in kWh
FiT: Current flat feed-in tariff offer for exports to the grid in \$/kWh
$Vexp_{LET\_t}$: Virtual electricity exports to the grid (after LG netting-off) at the LET site in kWh

In order to see the effect of the two measures, eight different scenarios were defined.

1. **BAU**: Business as usual – current electricity and network charges, with the current consumption profiles (without any new generation). We applied the current tariffs to the consumption profiles to arrive at the annual cost of BAU, by summing for each hour of the year the tariff in \$/kWh multiplied by the BAU consumption in kWh for that hour. This is the baseline cost for comparison with all the other scenarios, and includes the costs of both the LG site and the LET sites.
2. **Current market**: Installation of new generation, with the market as it is now (exported electricity receives a FiT). All costs associated with generation are included, such as the annual repayments on purchase, O&M, and any fuel costs (these costs are included in all subsequent scenarios).
3. **LET only**: Includes new generation, with Local Electricity Trading in place for the exported electricity, but no LNC paid. Exports from the LG site are netted off at whatever LET sites are included, and any

[2] The rule change request used the terminology Local Generation Network Credit (LGNC), so that is used whenever the rule change is referred to. It is interchangeable with Local Network Credit (LNC) in this paper.

residual (virtual) exports are valued according to the FiT offered.

4. **LNC (M1)**: Includes new generation, with payment of a Local Network Credit using methodology 1 (volumetric only explained below). No netting off occurs, so all exports from the generation site attract only the LNC and the FiT. The two LNC methodologies are described briefly in Section 2.1.
5. **LNC (M2)**: Includes new generation, with payment of a Local Network Credit using methodology 2 (combined volumetric and capacity payment). As in Scenario 4, no netting off occurs.
6. **LET and LNC (M1)**: Includes new generation with both measures in place, using the first LNC methodology. In this case, exports form the LG site are netted off, and a LNC is paid at the LG site.
7. **LET and LNC (M2)**: Includes new generation with both measures in place, using the second LNC methodology.
8. **Private wire:** Includes new generation. In this scenario we calculated the cost of connecting some of trial sites together with a private distribution wire, effectively converting them to one large site with a single metered connection point to the grid. Costs include the capital and operating costs of the private wire, and the associated repayments or interest payments, in addition to the generator costs. No netting off occurs in this scenario, as the relevant LET sites are effectively connected behind the meter. The net export is calculated for the site, and receives a FiT as per the current market scenario. The net cost of this scenario includes current market costs for any LET sites not included on the private wire, and this scenario is not calculated with either LET or the payment of an LNC.

Data inputs include:

- Electricity consumption profiles for every trial site for the 8760 h of the 2014/15 Australian financial year.
- Generation profile for each trial partner's local generation project for the 8760 h of the Australian financial year 2014/15 where possible.
- Energy tariffs for each trial site. Tariff details include customer type, the network and energy rates for peak, off-peak and shoulder, network demand charges, and any fixed charges. In some cases the installation of local generation, or amalgamation of sites via a private wire, caused network charges to alter, as these tariffs are generally triggered by the maximum demand on the site. The tariff details also include associated charges, such as for the Australian Energy Market Operator and Renewable Energy Target.
- All costs associated with installation of local generation, such as capital repayments, O&M, and fuel.

2.1. Calculation of the LNC

This section describes the application of the two different methods used to calculate the LNC. The LNC depends on the connection level of the generator, and uses the calculated tariff structure, with values varying by time of day and by season. It is always lower than the full network charge, and may be zero in off-peak times. The calculation of the LNC has two parts, value setting (how much the DG is worth to the network) and tariff setting (how that value is credited back to the generator).

2.1.1. Value setting

We used the same value setting methodology that network businesses use for regular tariffs, with the main input the Long Run Marginal Cost (LRMC) of the network in $/kVA/year. The LRMC is the annual cost of providing one unit of new capacity to the network to carry electricity. This is calculated as part of the network business normal tariff setting process, so the existing value calculated by network service providers was an input to this calculation. The NSPs identified up to five connection levels in network and assigned a LRMC value to each of them.

When the LNC is calculated for a particular connection level, network levels down to one level above the level in question are considered not utilized. It is these unutilized levels which form the dollar value basis for the reduction in tariff due to the local generator. We corrected for power factor (to convert from kVA to kW) and loss factor (to account for electricity losses as power is transmitted and distributed), with power factors and loss factors provided by the NSPs. Transmission LRMC was also added and adjusted for power factor and loss factor (from publicly available data). These calculations gave us the combined annualised value of the unutilised portion of the network upstream ($LRMC_{upstream}$) of the generator in $/kW/year. Power factors were subsequently used in the conversion from $/kVA/year values to $/kWh values

2.1.2. Tariff setting

We divided the calculated value of the LNC using two different tariffs, a volumetric only and a combined volumetric and capacity tariff. We tested two types to identify if there were major differences in outcomes, as the volumetric has significant advantages in terms of simplicity and ease of application. The calculations for each are shown below.

2.1.2.1. Volumetric tariff

To get the kWh value of the LRMC, we divided the annual kW value by 8760 (total hours in the year). Each hour was weighted according to its value to the network, that is, according to the probability of network load peaking within the hour. For example, one network advised that the peak was 90% likely during 600 specific hours of the year. The total value for each network level was then split according to this probability to assign a value to each hour. As such, if the probability of network load peaking is P_{Peak} during h_{peak} hours of the year, a TOU LNC structure that, for simplicity, has only a peak and an off-peak period would be as in Eqs. (2) and (3).

$$LNC_{peak} = \frac{LRMC_{above\ conection\ level} \times P_{peak}}{h_{peak} x average\ power\ factor} \tag{2}$$

$$LNC_{off-peak} = \frac{LRMC_{above\ conection\ level} \times (1-P_{peak})}{(8760-h_{peak}) x average\ power\ factor} \tag{3}$$

2.1.2.2. Combined volumetric and capacity tariff

We took the total LRMC value and split it into a volume and capacity component using the same percentages that the NSPs use in their network usage tariffs. This varied from 45:55–76:24 (volume: capacity).[3] For the volume component, we performed the same calculation as in a) above.

For the capacity component, we calculated the number of days in the year the system is expected to have a peak period, and divided the value of the LRMC allocated to capacity by this number of days to get a $/kW/day value. This approach is shown in Eq. (4).

$$\textbf{Capacity payment} = \frac{\textbf{Value of capacity}}{[\textbf{number of days peak may occur}]} \tag{4}$$

We then looked at the minimum performance of the generator on those days, during NSP identified peak periods. Some NSPs chose to look at the average of a few minimums during the billing period, others based the calculation on the single minimum event. This number was used as the level of assured capacity in kW that the generator had provided. This was then multiplied by the number of days in the relevant billing period and by the capacity payment ($/kW/day) to result in a total dollar figure for the billing period.

For example, in the Ausgrid network, the results of the ‘step one: value setting’ for connection levels above the generator distribution substation connection was $130/kW/yr. This was divided 74:24 resulting in $32/kW being allocated to the capacity element. All months contained some of the times identified as peak periods, so we further

[3] Data supplied by network business partners.

Table 1
Trials description.

Trial	Winton Shire Council	Byron Shire Council	Willoughby Council	Wannon Water
State	QLD	NSW	NSW	VIC
Network	Ergon Energy	Essential Energy	Ausgrid	Powercor
Retailer	Ergon Energy	Origin Energy	Energy Australia	AGL
Generation site	New geothermal plant	Council Sports Centre	Leisure Centre	Waste Water & Water Treatment Plant (WWTP & WTP)
Netting off sites	29 Winton Council sites	Byron Waste Water Treatment Plant (WWTP)	Concourse	Wannon Water and Glenelg Shire Council sites
Project status	Winton Council going to tender for geothermal plant and private wire, but would prefer to use existing distribution infrastructure.	25 kW installed, with very small amount of export. Council would like to add 150 kW at the Sports Centre, with most generation exported to the STP.	The business case presented is for new cogen, operated to match the heat load. In reality, an existing 173 kW cogen is operated with a 15 kW minimum import connection agreement.	Wannon Water is at late stage consideration of a wind turbine, and would like to supply multiple sites of their own. The trial included consideration of supply to Glenelg Shire Council.
LET model[a]	1-to− 1 transfer	1-to− 1 transfer	1-to− 1 transfer	1-to− 2 transfer

[a] In this nomenclature the first number refers to the number of LG owners while the second number refers to the number of owners of the LET sites.

divided the $32/kW by 365 days to yield 8.7 cents/kW/day. The assured capacity for the generator was taken as the average of the lowest twelve generating events that occurred during the peak period over the course of twelve months. The twelve lowest events were all zero export events, resulting in a $0 LNC capacity payment in all the trials.

3. Data inputs

Table 1 gives summary information about each of the four trials, with key variables summarised in Table 2. Wherever possible, actual figures from the proposed projects were used, including actual or derived consumption profiles, and proponent energy and network tariffs. In most cases, the proponents were in the process of considering project development, and their figures for capital and operational costs, and the projected generation profiles, were used wherever possible. The costs to network businesses and electricity retailers of implementing the billing systems are not accounted for in the business case.

In our results we dedicated a special analysis to the economic performance of the co-generation technology of the Willoughby trial. This generator is the only dispatchable technology in this study and hence further important insights are found in this scenario.

4. Results and discussion

4.1. Impact on proponents' energy costs

An overview of the impact on proponents' first year annual energy costs is shown for all trials in Fig. 1, with detailed results by bill component shown in Fig. 2 for each trial.

The annual savings (or losses) are the net effect on the energy costs

Table 2
Trial key inputs[1].

Trial	Unit	Winton Shire Council	Byron Shire Council	Willoughby Council	Wannon Water
Technology		Geothermal	Solar PV	Cogen	Wind
Electrical capacity	kW	310	150	173	800
Generator capital cost	$	1,900,000	283,161	750,000	2,400,000
Generator cost per KW	$/kW	6129	1888	4335	3000
Gas cost	c/MJ	n/a	n/a	1.66c/MJ	n/a
Generator O+M (variable)	c/kWh	n/a	n/a	1.9c/kWh	n/a
Generator O+M (fixed)	$/a	50,000	1500	3600	60,000
Interest rate	%	5%	6%	5%	5%
Discount rate	%	5%	6%	5%	5%
Inflation rate	%	2.43%	2.43%	2.43%	2.43%
Private wire capital	$	890,000	200,000	n/a	1,041,250
Private wire OPEX	$/a	8900	2000	n/a	10,413
CO_2 equivalent - replaced power	kg/kWh	0.93	0.97	0.97	1.34
Gas emission factor	kg/GJ	n/a	n/a	51.3	n/a
Other charges[2]	c/kWh	n/a [3]	1.20	1.35	1.33
Large-scale Generation Certificates (LGCs)	$/MWh	50 [4]	50	50	50
LGCs credited until	Year	2030	2030	2030	2030
FiT rate	c/kWh	4.5	Calculated[5]	3.5	5.00[6]
Retailer margin[7]	%	Calculated directly[8]	7.0%	7.0%	7.0%
Network connection level[9]		3 (HV line)	1 (LV Line)	2 (LV sub)	2 (LV sub)

Note 1: Some inputs have been altered to protect commercial confidentiality.
Note 2: Market and environmental charges.
Note 3: Other charges are included in the energy volume charges.
Note 4: The LGC price used is conservative, as LGCs are currently selling on the spot market for more than $85. However, the scheme is set to finish at 2030, so this income will not continue for the lifetime of the schemes, and the LGC Price is likely to reduce as more renewable energy comes on line.
Note 5: Calculated from pool price less $5/MWh.
Note 6: Assumed buy back rate supplied by Wannon Water.
Note 7: the retailer margin has been assumed for all trials as this is commercially sensitive information, and is based on the margins published in Queensland Competition Authority (2015). Regulated retail electricity prices for 2015–16. It has not been supplied by any of the retailers in the trials. Note that the 7% margin is of the energy volume charge only, corresponding to a 5.4% margin on the combined energy and network volume charge.
Note 8: Ergon Energy retail prices are regulated, so the retail margin is specified.
Note 9: The network connection level refers to which voltage level the new generator is connected, and feeds into the calculation of the LNC.

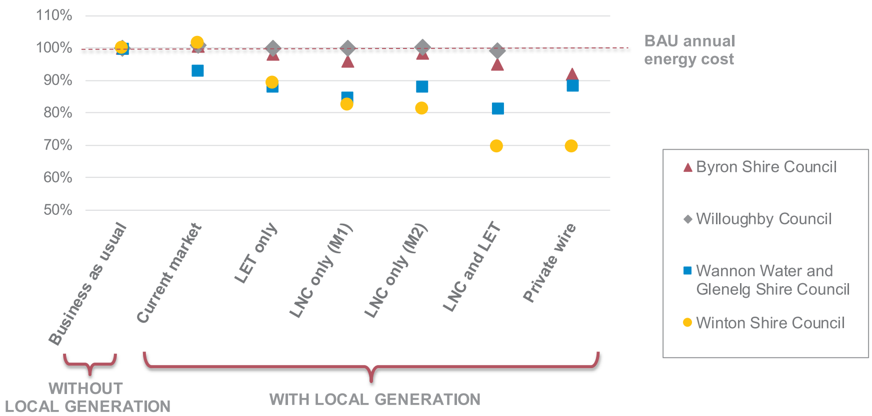

Fig. 1. First year impact on proponents (total energy costs). Note 1: LNC only (M1) uses the volumetric method of calculation for the LNC, while LNC (M2) uses the combined volumetric and capacity payment. The LNC and LET scenario includes the effects of LET and the LNC. In the table the average value of the LNC calculated using method 1 and method 2 has been used for the LNC and LET scenario, as the difference between the two scenarios is simply difference between LNC only (M1) and LNC only (M2).

for all the sites included in the trial, that is the local generation site plus any sites where netting off is occurring. Any costs or income associated with the local generation are included. Costs include capital repayment, annual operations and maintenance (O&M), fuel (for cogeneration), and capital repayment and O&M associated with the private wire where relevant. Income includes Large-scale Generation Certificates (LGCs),[4] any income from energy sales to the retailer, and the new Local Network Credit. The LNC is calculated in two different ways, which is why there is a LNC (M1) and a LNC (M2).

Under current market conditions – that is without either LET or an LNC – the net effect on energy costs to the consumer is marginally worse after installation of local generation (compared to BAU) in all cases except Wannon, (where the modelled FiT of 5c/kWh makes the export worthwhile). There is a small positive lifetime benefit for Byron and Willoughby despite the proponent initially being worse off, as energy prices are subject to inflation in the lifetime benefit calculation, while capital repayments are assumed to be fixed. However, it would be difficult for Local Government to make a case for investments which would initially leave them worse off. The annual, lifetime, and IRR results are shown in Table 3.

The second, third and fourth scenarios, LET only, LNC (M1) and LNC (M2) have a positive impact for the proponent compared to current market conditions. The LNC has a greater impact on the outcome except for Willoughby (the cogen), and the combined method for Byron where the effect of the LET is more beneficial. The LNC and LET scenario is LET plus the average value for LNC (M1) and LNC (M2).

The private wire has a positive effect in all cases where it is an option, but is not as beneficial for the proponent as the scenarios with both the new measures.

Fig. 2 shows that the highest impact of the new LET and LNC arrangements occurs for Winton. This suggests that there is a good match between the geothermal generation and the LNC peak rates. Conversely, the lowest impact is seen for the Willoughby and the Byron case. This is because they have the lowest generation capacity and also a poor generation match with peak rates.

Table 3 shows the lifetime benefit and internal rate of return (IRR) as well as the annual savings for the trial proponents in each case. Savings are shown as positive and losses are shown as negative. The lifetime benefit includes all the same costs and income, but includes the effect of inflation.[5] The IRR includes both inflation and discounting of income in future years.

Combining both measures has the most beneficial effect for the proponent, and gives an increase in IRR of between 2.1% (Willoughby) and 9.3% (Winton), compared to the current market conditions.

4.2. Carbon benefit and cost

The carbon savings are calculated using all of the new generation, including any exports regardless of whether those are netted off at the proponent premises. The carbon cost is calculated by assigning net annual losses to the carbon savings. The calculations have not included a carbon cost/price. In cases where LGCs are generated, this may not be significant, as previous modelling has shown that LGC values may be reduced when a carbon price is available. However, a carbon price could benefit non-renewable low emission technologies such as cogen, as the associated carbon savings are not currently credited at all.

The carbon benefit and associated carbon cost of those savings are shown in Table 4. All the trials show carbon benefit if the local generation was installed, which is unsurprising as the technology is renewable in three cases, and low carbon in the case of Willoughby. The scale of carbon benefit is determined by the size and type of projects.

The maximum cost of carbon is $6.8/tonne, and there is a zero cost in nearly all scenarios with either LET or an LNC in place. This compares favourably with the cost of carbon achieved in the third Australian Emissions Reduction Fund Auction in April 2016, where the average price of abatement was $10.23/tonne.[6]

4.3. Impact on network businesses

The net effect of the new local generation on the charges paid to network businesses by scenarios in the different trials is shown in Fig. 3. Note that from the network business point of view, the LET only scenario is the same as the "current market" scenario, as no LNC is paid, and network charges at the LET sites do not change.

These calculations do not take into account augmentation or replacement savings (if any) as a result of the new generation, which in principle should equal or exceed the LNC payments over time if the LNC methodology is correctly developed.

Table 5 shows the impact on network charges in each case. It is important to note that potential network cost reductions from reduced augmentation will be the same in all the scenarios with local generation, as we have modelled identical generation profiles in each. The amount of energy generated within the distribution area, and consequent reduction in grid imports from higher network levels, is therefore the same in the four scenarios. The only differences are the market arrangements, so the physical effect on network costs should be identical. In practice, different market arrangements would have different outcomes as it is likely that dispatchable generators would choose to export at peak periods if an LNC was in place, but we have not

[4] Large-Scale Generation Certificates are created by eligible renewable generators; under the Australian legislated Renewable Energy Target electricity retailers are required to surrender LGCs each year corresponding to a set percentage of their electricity sales. LGC sales are currently providing two thirds of the total market value of renewable generation.

[5] Inflation is taken as 2.43% in all trials. See Table 2 for details of interest and discount rates.

[6] http://www.cleanenergyregulator.gov.au/ERF/Auctions-results/april-2016.

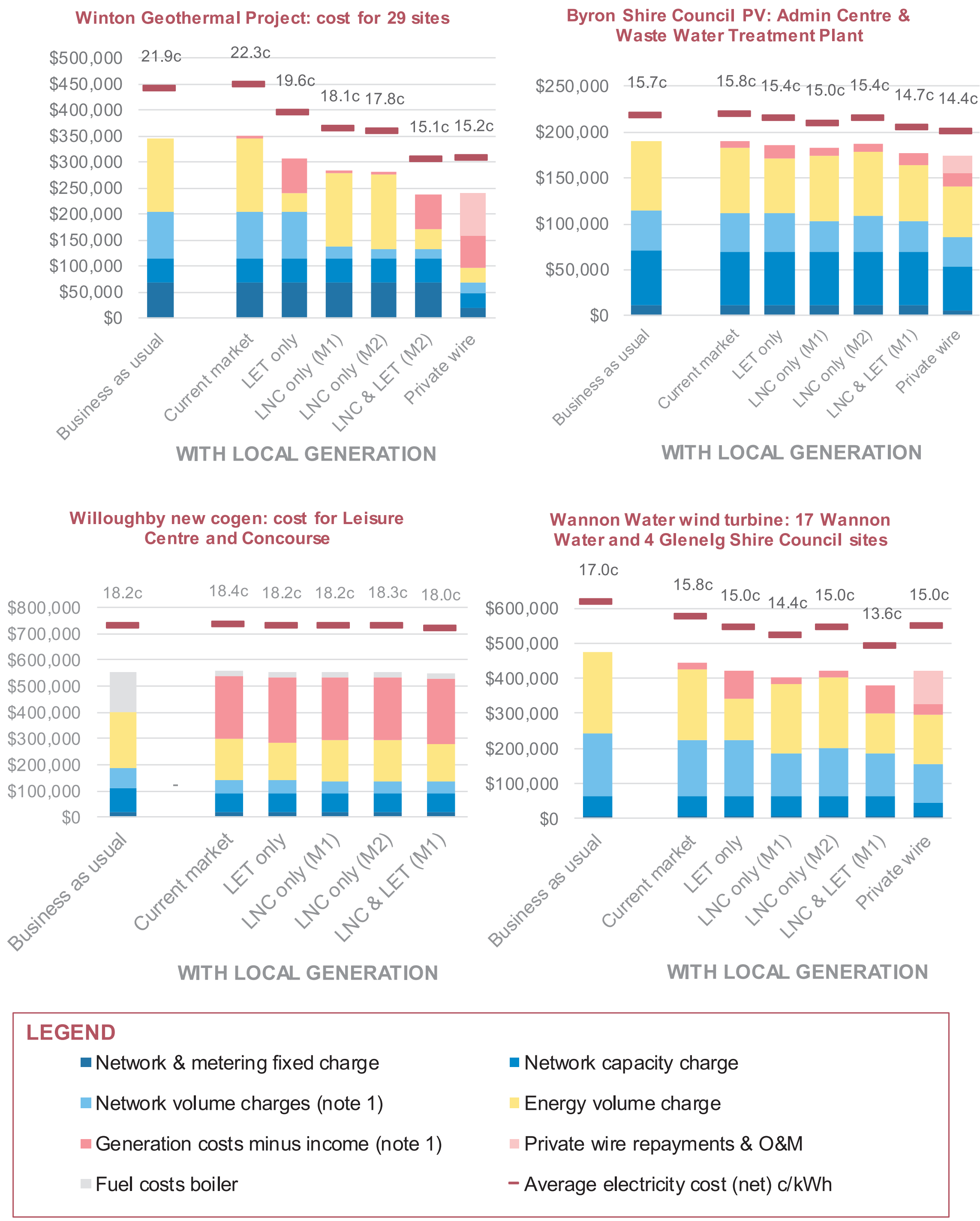

Fig. 2. Results – First year energy costs by scenario for each trial. Note 1: Network volume charges are net of the LNC where applicable. Generation costs are net of income from selling energy and local generation certificates.

modelled this effect.

Also note that PV exports could also drive further costs in order to manage voltage and power quality levels in the distribution grid (Braun et al., 2012). These costs have not been addressed in this article, yet their assessment would be an important complement to this study.

In all cases, the current market scenario results in the least reduction in network income, as the only change in charges is the effect of the behind the meter consumption at the local generation site. The private wire case results in the greatest loss of immediate income for the network business, even compared to the case where the network pays the higher LNC directly. The implication is that if customers opt to build private wires, network businesses will receive less revenue than if those customers were incentivized to export to the grid through the use of a LNC.

As Australian networks operate under revenue caps, revenue shortfalls in one year are recovered via customer tariffs over the following years. Further, if the removal of a customer and/or load from the network does not decrease the network's costs to the same degree as the associated revenue reduction from that customer, those residual costs will be recouped as increased charges from all customers (Satchwell et al., 2015b).

The scenarios including LNC payments come somewhere in between

Table 3
Net effect on proponent energy costs by scenario.

	Current market	LET only	LNC only (M1)	LNC only (M2)	LNC and LET	Private wire
Byron Shire Council						
Cost saving year 1	-$1200	$3300	$7400	$2700	$9500	$15,400
Lifetime benefit	$12,000	$126,000	$230,000	$110,000	$284,000	$578,000
IRR	6.5%	9.0%	11.1%	8.7%	12.1%	12.7%
Winton Shire Council						
Cost saving year 1	-$5500	$36,900	$60,300	$64,600	$104,800	$105,400
Lifetime benefit	-$442,000	$586,000	$1,156,000	$1,261,000	$2,237,000	$2,407,000
IRR	4.0%	8.0%	9.9%	10.3%	13.2%	11.0%
Wannon Water and Glenelg Shire Council						
Cost saving year 1	$32,700	$56,400	$72,900	$55,600	$88,000	$54,800
Lifetime benefit	$814,000	$1,415,000	$1,835,000	$1,396,000	$2,216,500	$2,088,000
IRR	7.8%	9.4%	10.4%	9.3%	11.3%	9.1%
Willoughby Council						
Cost saving year 1	-$6000	-$300	-$100	-$1500	$4900	n/a
Lifetime benefit	$302,000	$447,000	$452,000	$415,000	$578,000	n/a
IRR	6.8%	7.9%	7.9%	7.7%	8.9%	n/a

Table 4
Carbon benefit (including exports).

	Carbon reduction	Cost of carbon	
	Tons per year	Maximum	minimum
Winton Shire Council	1768	3.1 $/tonne	No cost[1]
Byron Shire Council	229	5.4 $/tonne	No cost [1]
Willoughby Council	871	6.8 $/tonne	No cost [1]
Wannon Water / Glenelg Shire Council	3411	zero cost	No cost [1]

Note 1: No cost in the table indicates that the measures result in savings, so in fact the carbon “cost” may be a significant saving.

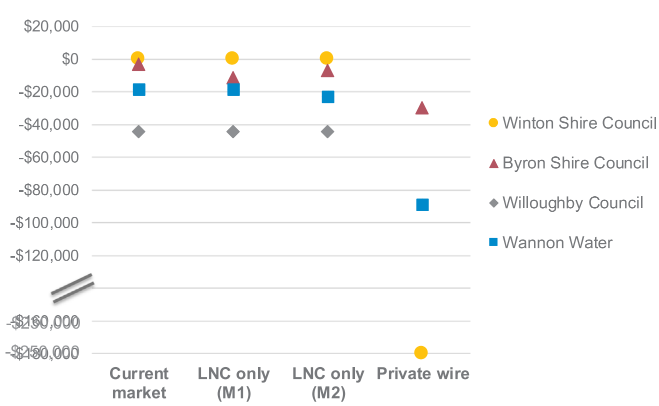

Fig. 3. Net effect on network charges by trial.

the current market and the private wire scenarios. The LNC (M1) methodology (volumetric only) results in a significantly higher payment to the generator than the LNC (M2) combined method for Wannon's wind generator. The calculated LNC payments to the geothermal and the cogeneration plant in Winton and Willoughby respectively are almost identical under the two methods.

Table 6 shows the calculated LNC value in each trial per kW of generation capacity for a generator operating constantly, 8760 h per year, and gives the LNC value calculated for the actual generator in the trial.

The potential value for constant operation ranges from $162 to $297 per kW; the range reflects the location of the trials in the network. The actual value per kW for the generator included in the trial is of course much lower than this, and ranges from $26 per year to $226 per year.

4.4. Cogeneration – marginal results (Willoughby trial)

The net marginal cost of operation for cogeneration as modelled in the Willoughby trial is 7.2c/kWh, provided the cogen is also supplying useful heat. The cost for fuel and O&M is 18.6c/kWh with a value of heat supplied equal to 11.4c/kWh (electrical).[7]

Table 7 shows the key input parameters for the unit. Cogen operation is certainly worthwhile for behind the meter generation, as it displaces both energy and network charges, which vary from about 13.5c/kWh peak to 7.5c/kWh off peak.[8]

Fig. 4 shows the marginal case for export. As it can be seen, export is not economic under current market conditions, even at peak times, when such export would presumably be useful to the network business. The payment of an LNC alone would make such exports worthwhile at peak times, and the combination of an LNC and electricity trading would make exports worthwhile at shoulder tariff periods.

The implication is that current market conditions result in sub-optimal operation of cogeneration, as plants may be undersized in order to avoid export, or simply not operated when operation would result in export. This situation would be potentially avoided through the combination of LET and LNC value for cogen operators.

It is interesting to note that despite the substantial impact on the marginal cost of operation, the measures have a very limited impact on the overall business case for cogen. This is because the LNC and LET are only paid on exports, which represent a small proportion of total generation. In effect, the payment of a small LNC (helped by the associated LET value) could achieve a transformational change in the design and operation of the cogen system. By ensuring the cogen operator does not lose money on every unit of exported power, the system can be sized efficiently to meet the on-site heat load, and does not need to ramp down every time electrical demand is too low to keep all generation behind the meter. Thus, the LNC gives the network business the network support benefit of exports at peak time, and may result in additional reductions in peak grid consumption from demand at local generation sites because of better plant sizing.

The marginal cost of cogeneration case demonstrates that even with a relatively low long run marginal cost (LRMC) value, spread quite widely over 1500 peak hours a year (2–8 pm every weekdays year round), an LNC could send a powerful and meaningful signal to operate dispatchable generation when the network requires support. The more the price signal is targeted to a shorter seasonal peak, the higher the LNC value, and the stronger the generator response.

[7] The cogen case was modelled for Willoughby, where a relatively low long run marginal cost (LRMC) value from Ausgrid is spread quite widely over 1500 h a year (2–8 p.m. every weekdays year round).

[8] This includes all volumetric charges: energy, network and other smaller surcharges.

Table 5
Network businesses – net impact on charges.

	Current market	LNC only (M1)	LNC only (M2)	Private wire
Winton Shire Council				
Revenue effect (excluding LNC)	$400	$400	$400	-$133,900
Local network credit	–	**-$65,700**	**-$70,100**	–
Net effect on NSP charges	**$400**	**-$65,400**	**-$69,700**	**-$282,500** [1]
Byron Shire Council				
Revenue effect (excluding LNC)	-$2700	-$2700	-$2700	-$29,400
Local network credit	–	**-$8600**	**-$3900**	–
Net effect on NSP charges	**-$2700**	**-$11,300**	**-$6600**	**-$29,400**
Willoughby Council				
Revenue effect (excluding LNC)	-$43,900	-$43,900	-$43,900	n/a
Local network credit	–	**-$5900**	**-$4500**	n/a
Net effect on NSP charges	**-$43,900**	**-$49,800**	**-$48,400**	n/a
Wannon Water and Glenelg Shire Council				
Revenue effect (excluding LNC)	-$18,500	-$18,500	-$18,500	-$88,500
Local network credit	–	**-$40,300**	**-$23,000**	–
Net effect on NSP charges	**-$18,500**	**-$58,800**	**-$41,500**	**-$88,500**

Table 6
LNC results for each trial.

Trial	Winton		Byron		Willoughby		Wannon	
Network	Ergon		Essential		Ausgrid		Powercor	
Technology type	Geothermal		Solar		Cogen		Wind	
Size	310 kW		150 kW		173 kW		800 kW	
Connection level	3		1		2		2	
	Method 1	Method 2	Method 1	Method 2	Method 1	Method 2	Method 1	Method 2
Annual LNC value (trial)	$66 k	$70 k	$8.6 k	$3.9 k	$5.9 k	$4.5 k	$40 k	$23 k
Value per kW 100% availability	$286	$286	$297	$297	$162	$162	$192	$192
Value per kW (trial)	$212	$226	$57	$26	$34	$26	$50	$29
Trial income compared to 100% generation	74%	79%	19%	9%	21%	16%	26%	15%

Table 7
Key parameters for cogeneration as modelled in the Willoughby trial.

Gas price	1.7c/MJ
Variable O&M	1.9c/ kWh
Cogen efficiency (electrical)	36% (electrical), 55% (thermal), 90% (total)
Boiler efficiency	80%
Cogen fuel Costs (calculated)	16.7c/kWh (electrical)
Cogen value of heat (calculated)	11.4c/kWh (electrical)
Net marginal cost of operation (calculated)	7.2c/kWh (electrical)

4.5. *Energy cost effects - sensitivity analysis*

The impact of key variables on the outcome by scenario is summarised in Table 8. In order to test the sensitivity of these results we tested an increase and decrease of 20% in the cost of the generator; the price obtained for LGCs; the FiT rate; the gas cost; and the rate paid for the LNC. As may be seen, in all cases except Willoughby, the capital cost of the generator had by far the greatest impact, followed by the price obtained for LGCs. The FiT rate had a large impact in the case of Wannon Water, probably because of the high level of export.

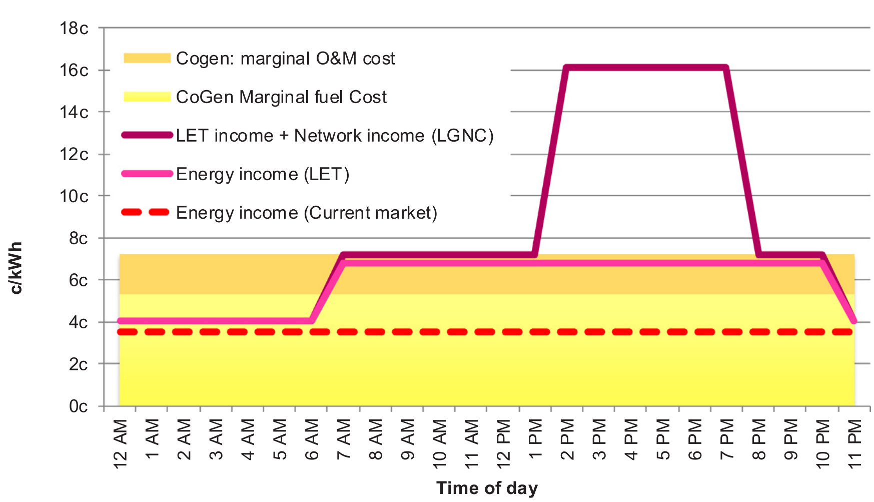

Fig. 4. Cogen marginal export's costs vs income.

The impact of variation on generators cost is shown in Fig. 5 for three of the trials. In general, those scenarios with a positive outcome in

Table 8
Impact of variation in key variables on energy costs.

	Value tested (% of modelled rate)	Byron	Winton	Wannon	Willoughby
Generator cost	80% and 120%	± 2.6%	± 8.9%	± 8.1%	± 2.1%
Large-scale Generation Certificates (LGCs)	$40 and $60 (modelled $50)	± 1.2%	± 6.6%	± 5.3%	n/a
FiT rate	80% and 120%	± 0.6%	± 5.0%	± 4.5%	± 0.3%
Gas cost ($/GJ)	80% and 120%	n/a	n/a	n/a	± 6.8%
LNC	80% and 120%	± 0.4% to ± 0.9%	± 3.8% to ± 4.1%	± 1.0% to ± 1.7%	± 0.2%

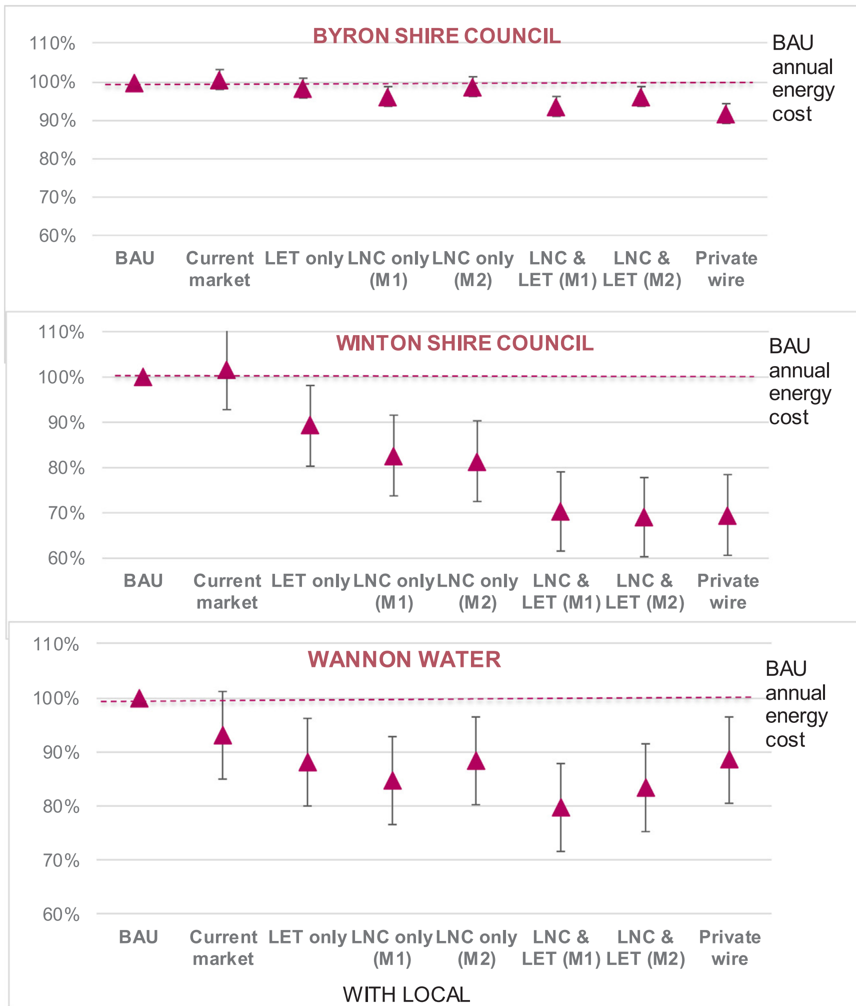

Fig. 5. Impact of ± 20% generator cost on annual energy spend by scenario.

the modelled case are still positive with the sensitivity variations. The key variables for the Willoughby cogen trial are the gas price and the generator cost, which are shown in Fig. 6. The gas price has by far the greater impact, and could make all scenarios positive or negative from a ± 20% deviation from the modelled case.

5. Policy implications and conclusion

The LNC and LET were investigated to further our understanding and help resolve problems identified with the current market, including:

- Inefficient sizing and operation of distributed generators,
- Lack of incentive for dispatchable[9] generators to operate at required (peak) times,
- Potential cases of under-utilisation of the grid, with consequent rise in consumer charges, and
- Perverse incentives to duplicate infrastructure.

The trials indicate that in most circumstances, the combination of LNC and LET address all four problems to some degree. Thus, the introduction of an LNC is a complementary measure to cost-reflective consumption pricing.

All four trials indicate there is potential for distributed generation to meet local consumption, which is unlikely to be realised under current market conditions. Cogen in particular is likely to be undersized without incentives to export, even when such exports could be

[9] Generators that can be switched on at will; in these trials the cogen and the geothermal generators.

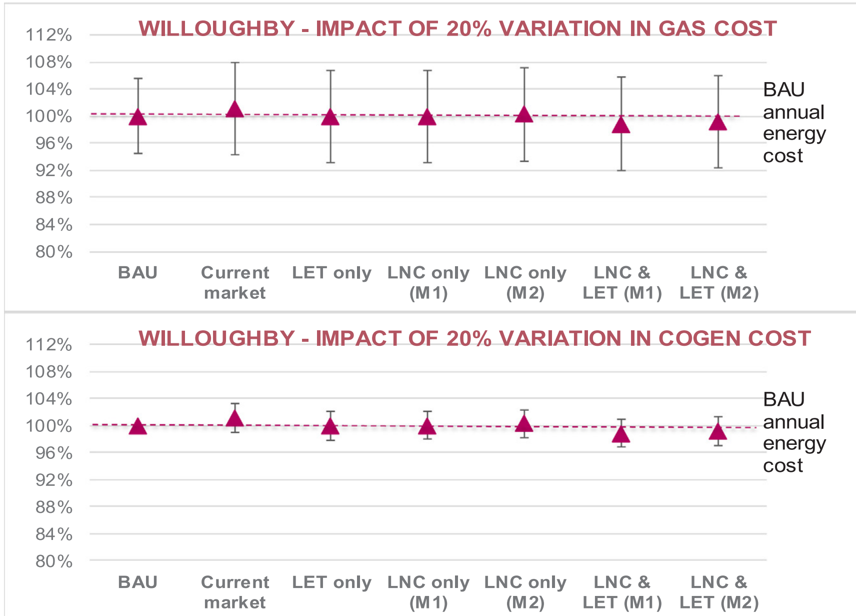

Fig. 6. Willoughby – impact of ± 20% of gas price and generator cost on outcomes.

beneficial to networks. The Winton trial demonstrates that some projects that are inherently cost effective may not be realised under current market conditions. All this shows the need for some market reforms. For example, the proposed Australian National Energy Guarantee presents an opportunity for removing some of these market barriers.

The improved marginal cost of the cogeneration case demonstrates that even a relatively low LNC can send a meaningful signal to operate dispatchable generation when the network is most likely to need support. The more the price signal is targeted to a shorter or more seasonal peak, the higher the LNC value, and the stronger the generator response is likely to be.

Overall, the result of offering an LNC would be to keep kWh on the grid, and maintain utilisation in an increasingly locally derived supply. The introduction of LNC payments could ensure continuance of a proportion of the network charges paid by proponents, relative to a significant increase in behind the meter consumption using a private wire approach, even taking into account payment of the LNC itself. Our results suggest that both the proponent and other customers would be better off with the introduction LNC payments, as money is not wasted on infrastructure duplication. This was further demonstrated in the economic modelling of the effect of introducing an LGNC on the long term network costs in NSW (Kelly et al., 2016).

However, to date there are no regulatory incentives for Australian retailers or NSPs to facilitate LNC and LET arrangements. Unfortunately, the Australian Energy Market Commission (AEMC) recently rejected a proposal for regulating LNC arrangements. One key reason behind this decision was the concern that LNCs may not deliver short term network benefits. However, the AEMC seems to be overlooking two important considerations regarding LNCs. First, LNCs with more targeted location-specific TOU times could effectively shave the network peak in the shorter term. This is a process that could overlap with the design of cost-reflective network pricing, a work already in progress in Australia involving many groups including network businesses, academia, and governments (for example, CSIRO and Energy Networks Australia, 2017, Passey et al., 2017). Second, system-wide LNCs could help reduce long term network expenditure in the same way today's TOU tariffs aim to disincentivise consumption at network peak times. TOU tariffs have continued to grow in many jurisdictions because they have proven to be effective at creating network savings.

The trials specifically examined private wires, which are not currently widely applicable. However, there are several projects underway which are investigating private wires in mass market settings, and the current interest in micro-grids and embedded private networks provides evidence that these situations may not be so exceptional in the future. While not specifically trialed, battery storage plus generation shares many parallels with the private wire case, as the primary driver for individual battery storage is to keep generation behind the meter. We suggest further investigation is warranted of how an LNC might affect the scale and location of battery storage to optimise value for customers and the grid. Another area that would complement this article would be the assessment of potential penalization charges to PV exports that drive costs for managing voltage and power quality levels in the distribution network. These studies could strongly assist policymakers and industry stakeholders in the minimization of the costs of electricity supply.

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