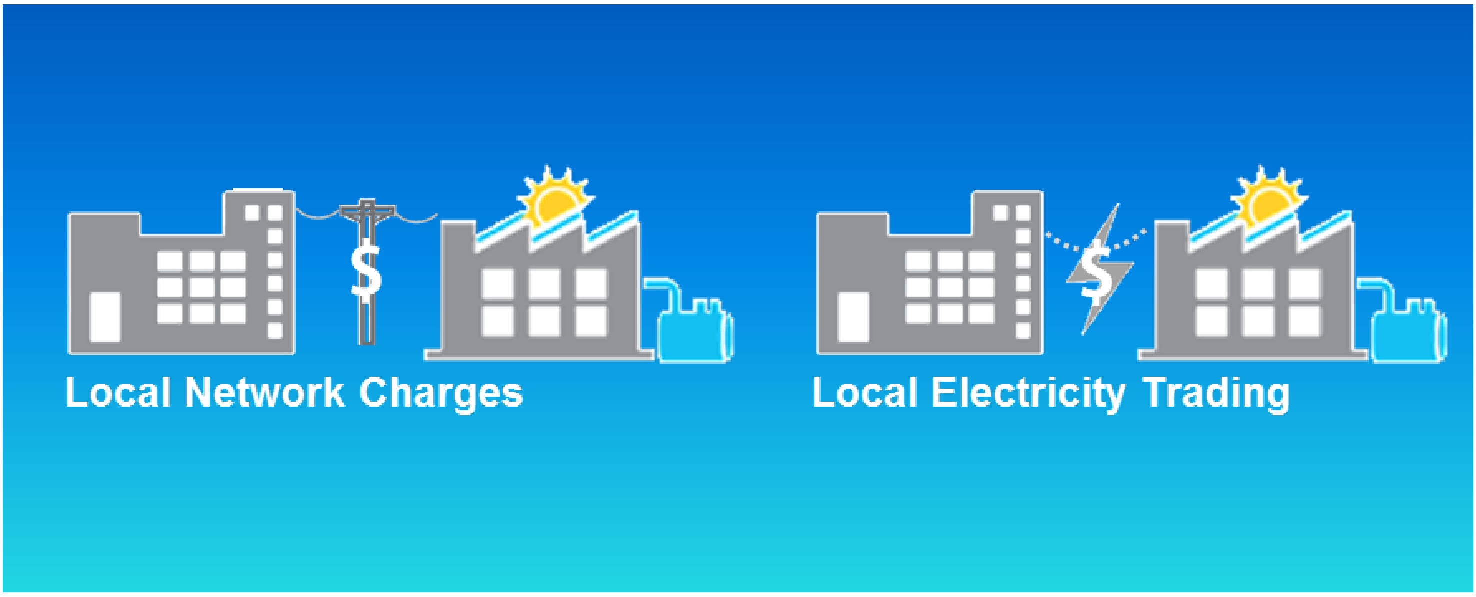

UTS: INSTITUTE FOR SUSTAINABLE FUTURES

VIRTUAL TRIALS OF LOCAL NETWORK CHARGES AND LOCAL ELECTRICITY TRADING

Summary report

July 2016

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2016

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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We would like to acknowledge the great contribution made to this research by our trial partners; however, the analysis and conclusions are the responsibility of the authors alone.

DISCLAIMER

FURTHER INFORMATION

This paper is prepared as part of the ARENA funded project 'Facilitating Local Network Charges and Virtual Net Metering'. The project is due to be completed by August 2016 and results will be publicly available on the project webpage: http://bit.do/Local-Energy

For further information visit: **www.isf.uts.edu.au**

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EXECUTIVE SUMMARY

This work forms part of the *Facilitating Local Network Charges and Virtual Net Metering* research project, led by the Institute for Sustainable Futures (ISF) and funded by the Australian Renewable Energy Agency (ARENA) and other partners. The project is investigating two measures aimed at making local energy more economically viable, Local Network Charges for partial use of the electricity network, and Local Electricity Trading (LET) (previously referred to as Virtual Net Metering or VNM) between associated local generators and customers. This report summarises four of five 'virtual trials' of the two measures.

Local Network Charges: are tariffs for electricity generation used within a defined local network area, to recognise that only part of the network is used. These have been applied as a credit to the generator in these trials. In most cases, this would reduce the network portion of the electricity bill.

Local Electricity Trading (LET): is an arrangement whereby generation at one site is "netted off" at another site on a time-of-use basis, so that Site 1 can 'sell' or assign generation to nearby Site 2. This would reduce the combined energy and retail portion of electricity bills for local energy transactions.

The trials

The trials described here are virtual, so all outputs and netting off transactions are modelled, and proponents' energy bills did not change. However, all of the projects (see table below) are under serious consideration and data inputs are real where possible, including actual consumption profiles, current energy tariffs, and network tariffs from the project proponents. The costs to network businesses and retailers of implementing the measures are not accounted for in this report.

Trial key facts

Proponent	Winton Shire Council	Byron Shire Council	Willoughby Council	Wannon Water
State	QLD	NSW	NSW	VIC
Network provider	Ergon Energy	Essential Energy	Ausgrid	Powercor
Retailer	Ergon Energy	Origin Energy	Energy Australia	AGL
Technology	Geothermal	Solar PV	Cogen	Wind
Size	310 kW	150kW	173 kW	800 kW
Generation site	New plant	Sports Centre	Leisure Centre	Waste Water Treatment Plant
Netting off sites	29 Winton Council sites	Waste Water Treatment Plant	Concourse	17 Wannon Water & 4 Glenelg Shire Council
LET model	1-to-1 transfer	1-to-1 transfer	1-to-1 transfer	1-to-2 transfer

Methodology

An excel-based model was constructed to compare the business case for local generation projects under the current market conditions, and with combinations of the two measures under investigation in the trials. The trials examine the business case for the new generation by comparing eight scenarios:

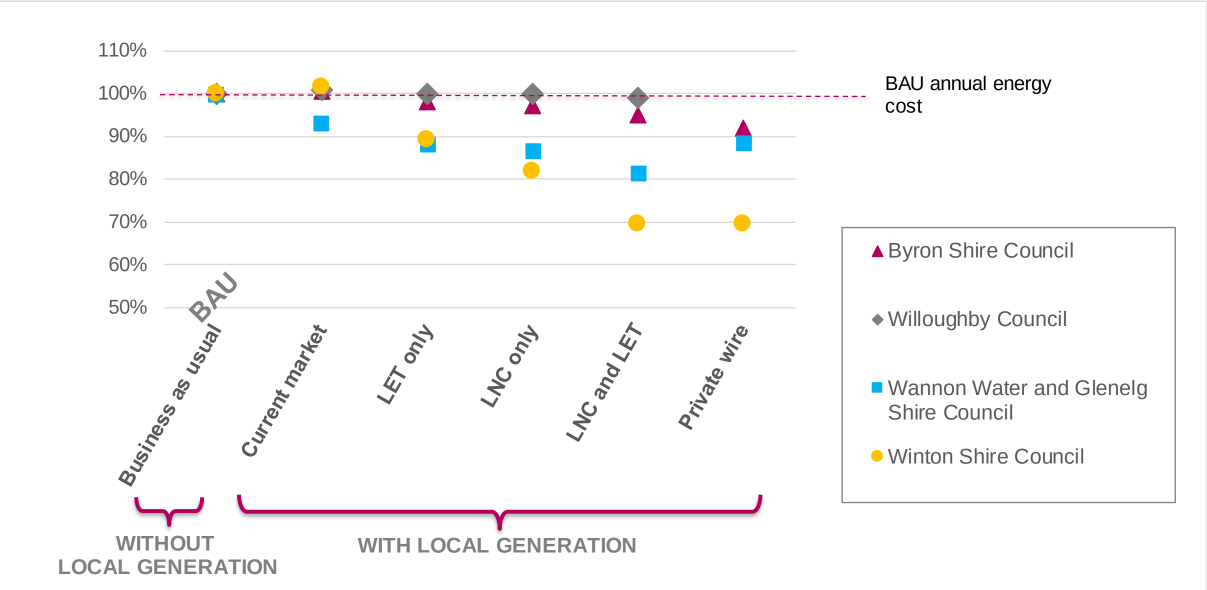
- **Business as usual (BAU)** – current energy charges, with no (new) local generation
- **Current market**: new generation, with the market as it is now.
- **LNC (M1) only**: new generation, with payment of a Local Network Credit calculated using the volumetric method (Method 1).
- **LNC (M2) only**: as above, using combined volumetric and capacity method (Method 2).
- **LET only:** new generation, with Local Electricity Trading in place.
- **LET and LNC (M1):** both measures in place, using methodology 1 for the LNC
- **LET and LNC (M2):** both measures in place, using methodology 2 for the LNC
- **Private wire**: project sites connected via a private wire where feasible, with generation for those sites 'behind-the-meter' on a single meter point. No LNC or LET.

Key results – impact on proponents

The impact on annual energy costs is shown for all trials below. The annual savings (or losses) are the net effect on the energy costs for all the sites included in the trial. Any costs and any income associated with the local generation are included, for example capital repayments, or operations and maintenance (O&M). Income includes Large-scale Generation Certificates (LGCs), any income from energy sales to the retailer, and the new Local Network Credit. The LNC is calculated two different ways, which is why there is LNC (M1) and an LNC (M2).

Under **current market** conditions, i.e. without either LET or an LNC, energy costs are higher after installation of local generation (compared to BAU) in all cases except Wannon, where the modelled buy back rate of 5c/kWh (an assumed rate supplied by Wannon Water) and low cost of generation makes export worthwhile. As such, three of the four projects would not be financially viable under current market conditions.

Proponent total energy costs under each scenario



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 LNC (M2) method for Byron, where the impact of the LET is slightly greater.

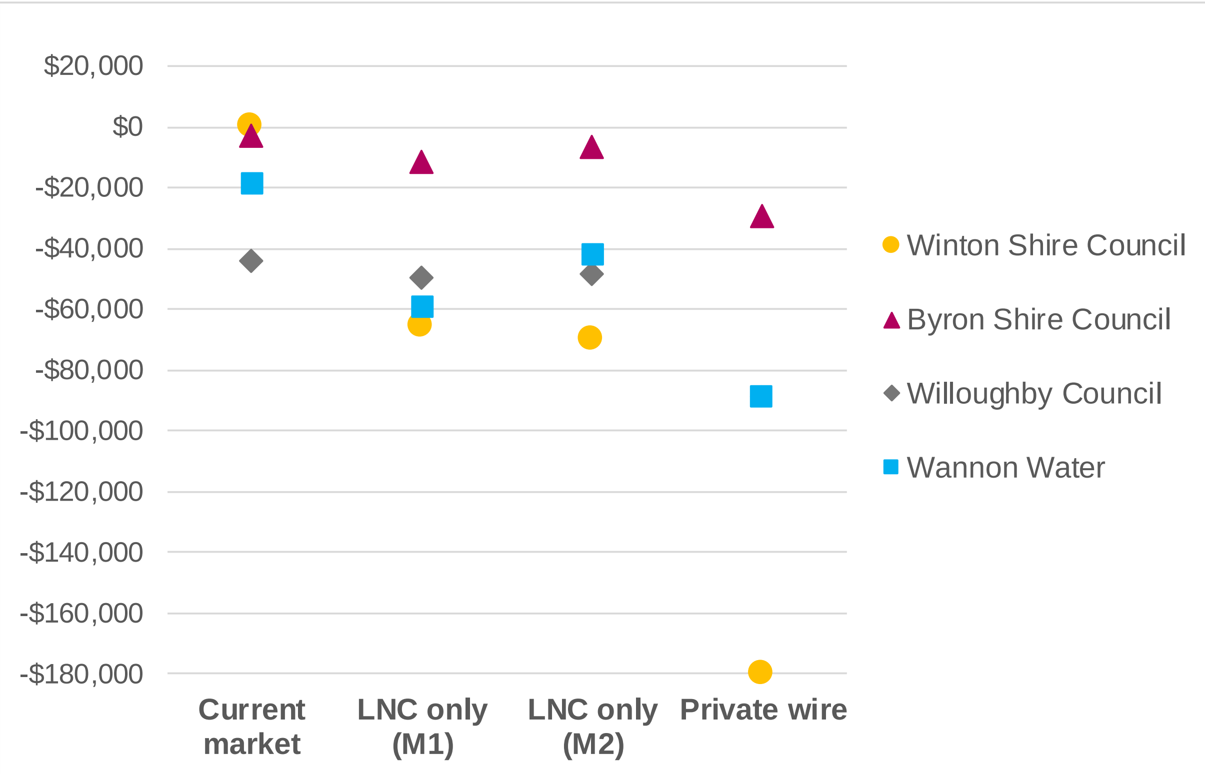
The private wire has a positive effect in all cases where it is an option, but is not as beneficial for the proponent as the scenarios with both the new measures. This indicates that the combination of LNC and LET could remove some of the current perverse incentive to duplicate infrastructure via private wires.

Key results – 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 below. Note that from the network business point of view, the **LET only** scenario (not shown) 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[1]

Net effect on Network Service Provider charges by trial



Note: As of 1 January 2016, all NSPs in trial jurisdictions are operating under revenue caps. As such, revenue shortfalls will be recouped from all customers in the subsequent periods

It is important to note that potential network cost reductions from reduced augmentation will be the same in all the modelled scenarios with local generation, as we have modelled identical generation profiles in each. The amount of energy generated within the distribution

[1] A core principle of the LNC is 'cost and value reflectivity', and as such any LNC payment should reflect reduced system costs in the long term.

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 overall 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 LGNC was in place, but we have not modelled this effect.

In all cases, the current market scenario results in the lowest reduction in network charges, 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 by far 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 immediate revenue than if those customers were incentivised to export to the grid through the use of a LNC.

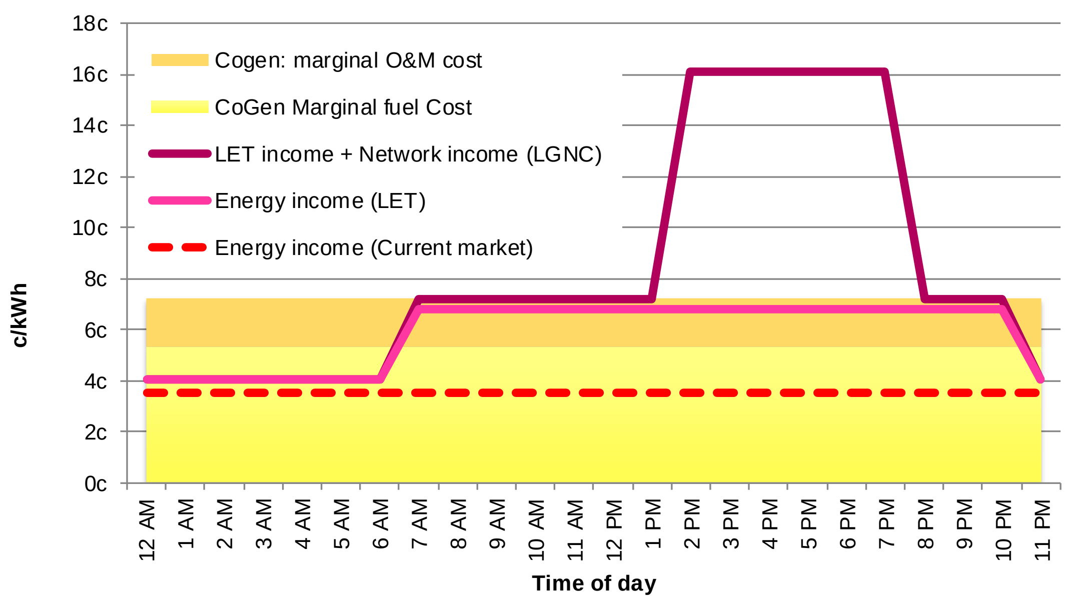
As networks operate under revenue cap regulation, revenue shortfalls in one year are recovered via customer tariffs over the following years. Further, if the removal of a customer/load from the network does not decrease the network's costs to the same degree as the associated revenue reduction from that customer, those residual costs will be recouped as increased charges from all customers.

Key results – marginal operation of cogeneration

The marginal case for export from cogeneration, as modelled in the Willoughby trial, is shown below. The marginal cost of operation is just over 7 c/kWh, provided the cogen is also supplying useful heat. As can be seen, export is not economic under current market conditions, even at peak demand times, when such export would presumably be useful to the network business. The payment of an LNC alone would make peak exports worthwhile, and the combination with LET would make exports worthwhile at shoulder periods.

The implication is that current market conditions result in suboptimal 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 could be remedied through the combination of the LET and LNC value for cogen operators.

CoGen marginal costs vs income



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. So in effect, the payment of a small LNC (helped by the associated LET value) could incentivise a significant improvement in design and operation of cogen systems.

Key inputs – impacts on costs and benefits

We tested an increase and decrease of 20% in the cost of the generator, the price obtained for LGCs, the retailer buy back rate, the gas cost, and the rate paid for the LNC. In all cases except Willoughby, the cost of the generator had by far the greatest impact, followed by the price obtained for LGCs. In general, those scenarios with a positive outcome in the modelled case are still positive with the variation. The key variable for the cogen trial is the gas price, which at a 20% variation renders all scenarios either positive (with a lower gas price) or negative (with a higher gas price).

Discussion and conclusions

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

- Inefficient sizing and operation of distributed generators,
- Lack of incentive for dispatchable[2] generators to operate at required (peak) times,
- Potential 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 we consider the introduction of an LNC to be 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. Cogeneration in particular is likely to be undersized without incentives to export, even when such exports would be most beneficial to the grid. The marginal cost of 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.

Offering an LNC for the cases investigated would keep kWh on the grid in an era of increasingly locally derived supply. An LNC would maintain the network charges paid by the proponent, relative to a significant increase in behind the meter consumption using a private wire approach, even taking into account payment of the LNC itself. The proponent and other customers are better off, as money is not wasted on infrastructure duplication.

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[3]. While not specifically trialled, battery storage plus generation shares many parallels with the private wire cases, 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.

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

[3] For example, a current ARENA project “Moreland micro-grid investigation” is examining the feasibility of microgrids connecting metropolitan suburban dwellings to share PV and batteries.

CONTENTS

FIGURES AND TABLES

List of abbreviations

AEMO	Australian energy market operator
ARENA	Australian Renewable Energy Agency
DNSP	Distribution Network Service Provider
ISF	Institute for Sustainable Futures
kW	Kilowatt
kWh	kilowatt hour
LET	Local Electricity Trading
LG site	Local Generation Site
LGC	Large-scale Generation Certificate
LGNC	Local Generation Network Credit (note this is the term used in the rule change proposal discussed in Section 4)
LNC	Local network credit
LNC (M1)	Local Network Credit (methodology 1)
LNC (M2)	Local Network Credit (methodology 2)
LRMC	Long Run Marginal Cost
NEM	National Electricity Market
NSP	Network Service Provider
NSW EES	NSW Energy Efficiency Scheme
MJ	Megajoule
PV	(Solar) Photovoltaic
RET	Renewable Energy Target
SRES	Small-scale Renewable Energy Scheme
TEC	Total Environment Centre
TNSP	Transmission Network Service Provider
TOU	Time of use
UTS	University of Technology Sydney
VEET	Victorian Energy Efficiency Target
VNM	Virtual Net Metering
WWTP	Waste Water Treatment Plant

1. INTRODUCTION

This report summarises four of the five 'virtual trials' of two measures aimed at making local energy more economically viable. The measures are:

- Local Network Charges (LNC) for partial use of the electricity network.
- Local Electricity Trading (LET) (previously referred to as Virtual Net Metering or VNM) between associated customers and generators in the same local distribution area.

The fifth trial, of the 1-many model (for Moira and Swan Hill Councils), will be covered in a separate report.

The work is part of a one year research project, *Facilitating Local Network Charges and Virtual Net Metering.* The project is led by the Institute for Sustainable Futures (ISF) and funded by the Australian Renewable Energy Agency (ARENA) and other partners.

Local Network Charges (LNC)

Local network charges are reduced network tariffs for electricity generation used within a defined local network area. This recognises that the generator is using only part of the electricity network and may reduce the network charge according to the calculated long-term benefit to the network. The rationale for a local network charge is to address some aspects of inequitable network charges levied on a generator/consumer pair; dis-incentivise duplication of infrastructure (private wires) set up to avoid network charges altogether; and maintain use of the electricity network.

Local Electricity Trading (LET)

LET is an arrangement whereby generation at one site is "netted off" at another site on a time-of-use basis, so that Site 1 can 'sell' or transfer generation to nearby Site 2. The exported electricity is sold or assigned to another site for billing purposes. LET can be applied in a number of different ways:

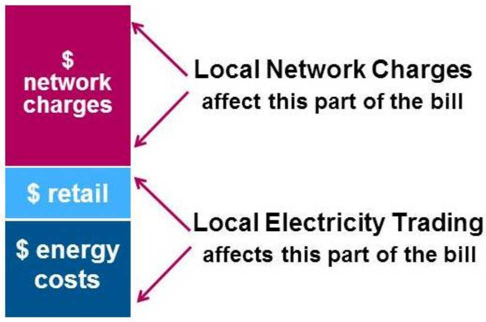
- A single generator-customer can transfer generation to another meter(s) owned by the same entity (e.g. a Council has space for solar PV at one site and demand for renewable energy at a nearby facility);
- A generator-customer can transfer or sell exported generation to another nearby site;
- Community-owned renewable energy generators can transfer generation to local community member shareholders; and
- Community retailers can aggregate exported electricity generation from generator-customers within a local area and resell it to local customers.

The interaction of local network charges and local electricity trading

Local Network Charges and LET are independent but complementary concepts with different effects on a consumer's energy bills. In most cases, the Local Network Charge will reduce the network charge portion of electricity bills, while Local Electricity Trading may reduce the combined energy and retail portion of bills for local generation.

About the project

The objective of the project is to create a level playing field for local energy, by facilitating the introduction of Local Network Charges and Local Electricity Trading. The key outputs are:



a. Improved stakeholder understanding of the concepts of local network charges and Local Electricity Trading;

b. Five 'virtual trials' of local network charges and Local Electricity Trading in New South Wales, Victoria, and Queensland (see Figure 1);

c. Economic modelling of the benefits and impacts of local network charges and Local Electricity Trading;

d. A recommended methodology for calculating local network charges;

e. An assessment of the metering requirements and indicative costs for the introduction of Local Electricity Trading, and consideration of whether a second rule change proposal is required to facilitate its introduction; and

f. Support for the rule change proposal for the introduction of a Local Generation Network Credit submitted by the City of Sydney, the Total Environment Centre, and the Property Council of Australia.

The virtual trials aim to test the impact of Local Network Charges and Local Electricity Trading on local distributed energy projects, particularly the economic impacts, and to assess the real-world requirements for the measures to operate.

2. TRIAL KEY FACTS AND INPUTS

The project includes five virtual trials of the two measures, LET and the LNC. The trials were undertaken from October 2015 to April 2016, with input and in frequent consultation with the trial participants. The map in Figure 1 shows the locations of the trials, and Table 1 summarises key features of the four trials reported here, which include 1-1 and 1-2 models for commercial customers. The 1-many trial undertaken with Moira and Swan Hill Councils will include residential customers, and will be reported separately.

The project compares the business case for the installations with and without a LET arrangement, and with and without an LNC, using an excel model. A private wire is considered where it would be a practical option for the proponent.

The trials are virtual, so outputs are all modelled – no actual netting off has taken place, and proponents' energy bills remain unchanged.

Figure 1 The virtual trials

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	Cavanbah Sports Centre	Leisure Centre	Portland WWTP & Water Treatment Plant (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 150kW 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 173kW cogen is operated with a 15kW 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	1-to-1 transfer	1-to-1 transfer	1-to-1 transfer	1-to-2 transfer

Key variables are summarised in Table 2. Wherever possible, actual figures from the proposed project have been used, incuding actual or derived consumption profiles, current energy tariffs, and proponent network tariffs. In most cases, the proponents are in the process of considering project development, and their figures for capital and operational costs, and the projected generation profiles, have been used wherever possible.

The costs to network businesses and retailers of implementing the measures are not accounted for in the business case.

Table 2 Trial key inputs: Winton, Byron, Willoughby and Wannon[8]

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 / KW	$/kW	6,129	1,888	4,335	3,000
Gas cost	c/MJ	n/a	n/a	1.66 c/MJ	n/a
Generator O+M (variable)	c/kWh	n/a	n/a	1.9 c/kWh	n/a
Generator O+M (fixed)	$/a	50,000	1,500	3,600	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	8,900	2,000	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[1]	c/kWh	n/a [2]	1.20	1.35	1.33
LGCs	$/MWh	50	50	50	50
LGCs credited until	Year	2030	2030	2030	2030
Retailer buy back rate[3]	c/kWh	4.5	Calculated[3]	3.5	5.00[4]
Retailer margin[5]	%	Calculated directly[6]	7.0%	7.0%	7.0%
Network connection level[7]		3 (HV line)	1 (LV Line)	2 (LV sub)	2 (LV sub)

Note 1: AEMO, RET, SRES, NSW EES, VEET

Note 2: Other charges are included in the energy volume charges.

Note 3: Calculated from pool price less $5/MWh

Note 4: Assumed buy back rate supplied by Wannon Water

Note 5: the retailer margin has been assumed for all trials, 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 6: Ergon Energy retail prices are regulated, so the retail margin is specified.

Note 7: The network connection level refers to which voltage level the new generator is connected, and feeds into the calculation of the LNC.

Note 8: Some inputs have been altered to protect commercial confidentiality

3. METHODOLOGY

An excel business case model was constructed to compare local generation projects under the current market conditions with the same generator installed with the two measures under investigation in the trials, namely Local Electricity Trading (LET) and a Local Network Credit (LNC) using two methodologies. The measures are considered together and separately. In order to see the effect of these measures, eight different scenarios were defined.

The model calculates the changes in costs for the proponent sites as a result of the new generation, 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 network business and the retailer (this does not include implementation costs).

The projects were generally at various stages of development, but all the installations are under serious consideration by the proponents, and it was expected that the trial would assist with decisions on whether to go ahead, as well as with project sizing. Table 1 gives summary information about each trial, including the project status.

The model

Figure 2 provides an overview of the excel model which was developed for this project. The model is divided into sub categories in order to organise the input and calculation in a logical flow to reflect the interaction between generation and demand across various locations, in regards to both the physical flow and the financial flow. Standardised input sheets were developed to facilitate data input.

In a first step, all input data for the local generation side (LG) has been arranged in one sheet, so specific parameters such as payback time or interest rate can be changed easily to test the influence on trial results.

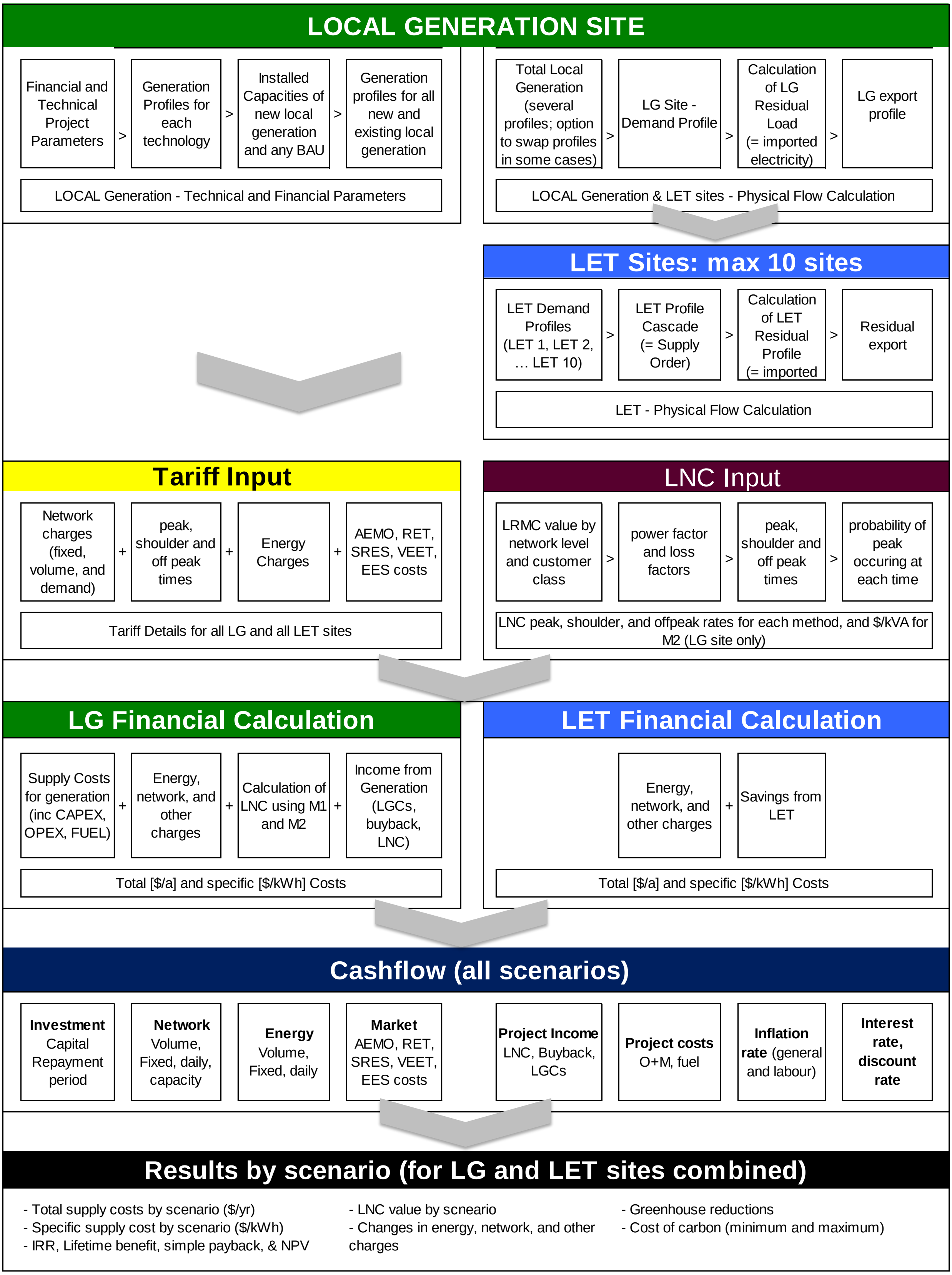
In a second step, both the generation profile(s) and all demand profiles – from the local generation site (LG) as well as the LET "netting off" sites are uploaded in hourly steps. A cascade – which has been developed especially for this project – can calculate up to 10 different demand profiles. Due to "time-of-use" dependent tariffs and LNCs, the shape of generation and demand profiles have a significant impact on the trial results and whether or not a project is profitable.

The third step of the calculation involves detailed input of consumption tariffs and the Local Network Credit (LNC) tariff. The LNC tariffs were calculated from each network partner's data, using the methodology developed for this project. Besides the exact times for shoulder, peak and off peak, the specific energy and network volume and fixed charges are covered in a standardised input template as well.

Steps four and five process all inputs of LG and LET sites in sub calculations, which are summarized in a comprehensive result overview for each scenario. Each calculation step can be traced and checked separately and assumptions can be changed. A specific module for cash flow calculations is connected to the above-described modules.

Finally, a standardised report sheet provides an overview to key results in the form of tables, texts and figures.

Figure 2 Excel model overview



The scenarios

The trial compares the business case for the new generation in current conditions, and with and without the new measures. Costs are calculated for the LG site and any netting off sites included in the trial in all scenarios. All scenarios except BAU (no 1) include the new local generation.

The different scenarios are:

1. **BAU**: Business as usual – current electricity and network charges, without any new generation.
2. **Current market**: installation of new generation, with the market as it is now. (exported electricity is valued according to the retailer buy-back rate).
3. **LET only**: 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 remaining residual exports are valued according to the retailer buy-back rate.
4. **LNC (M1)**: includes new generation, with payment of a Local Network Credit using methodology 1 (volumetric only).
5. **LNC (M2)**: includes new generation, with payment of a Local Network Credit using methodology 2 (combined volumetric and capacity payment)
6. **LET and LNC (M1)**: new generation with both measures in place, using the LNC methodology 1.
7. **LET and LNC (M2)**: new generation with both measures in place, using the LNC methodology 2
8. **Private wire**: some of the project sites could be connected via a private wire, so that all generation would be 'behind-the-meter' on a single metering point.

The Local Network Credit methodology was developed as part of this project, and is explained below (page 18).

Virtual trials - calculating the scenarios

The following sections describe the calculations we performed for the various scenarios. All calculations were performed using the excel model.

Scenario 1. Business as usual – no new local generation (baseline)

- We obtained the electricity consumption profiles for every trial site for 365 days x 24 hours for the 2014/15 financial year. The trial proponent or the trial NSP provided this data.
- We obtained or constructed a generation profile for each trial partner's local generation project for 365 days, for financial year 2014/15 where possible. Where actual data was not available, we constructed the profile using, for example, data for nearby solar arrays or data on wind resources and wind turbine generation.
- We obtained electricity network and energy tariffs from either the proponent, the retailer, or the NSP (and sometimes all three). Tariff details include customer type, the network and energy rates for peak, off-peak and shoulder, network demand

charges, day rates etc. We used 2015/16 FY tariffs as these best incorporate cost-reflectivity, and in some cases used the tariffs that were due to come in rather than the present tariff.

- We applied the consumption profile to the tariff to arrive at the annual cost of BAU. 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. In the cogeneration trial it includes the fuel cost for the heating boiler at the LG site.

Scenario 2. Local generation (LG) in Current Market

- We calculated net consumption at the local generation site (site A) by netting off the generation profile against the site A consumption profile on hourly time intervals and we calculated how much generation could be exported based on the generation and consumption profiles. We applied the tariff for the LG site to the net consumption to arrive at the $ cost of energy at the LG site.
- All costs associated with generation are included, such as capital repayments, O&M, fuel costs.
- Any income is calculated: net export is valued according to the buy-back rate for that trial, and any income from LGCs is calculated.
- Costs for the LET sites are unchanged.

Scenario 3. LG + LET scenario

- As per scenario 2 above, we calculated net consumption at the LG site after the new generation. Any excess generation was then netted off against consumption at the first nominated netting off site (LET site 1) at hourly time intervals. Any remaining generation was then netted off at the next nominated netting off site (LET site 2), and so on, until no excess generation remained. In most cases some exports remain, which attract the same rates as in Scenario 2.
- The reduced consumption from netting off primarily reduces the energy volume charges, which are only charged on the residual load at the LET sites; however, the retail margin is charged on the full load prior to netting off. Note that in Victoria and NSW the retail margin was assumed, as it is commercially confidential information.
- RET charges are only netted off at those LET sites within 1 km of the LG site.
- AEMO charges are netted off, that is only charged on the residual load at LET sites.
- Network charges and any fixed charges remain the same at the LET sites.

Scenarios 4 & 5. LG + Local Network Credit: LNC (M1) and LNC (M2)

For scenarios 4 and 5, we assume that electricity exported by the LG site receives the LNC; LNC (M1) and LNC (M2) use methodology 1 and 2 respectively for calculating 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. We used two different methods of calculating the LNC (M1 & M2).

Scenarios 6 & 7. LG + LET + LNC (M1) and LNC (M2)

In these scenarios we netted off exported energy at the LET site or sites, and credited an LNC to the exported energy from the LG site (as described in scenarios 3, 4 and 5 above). Once again, we calculated results for LNC (M1) and LNC (M2).

Scenario 8. LG + Private wire scenario

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.

We calculated the net consumption of electricity imported from the grid at the private wire connected sites and applied the relevant tariff to arrive at the cost of net grid electricity consumption. 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 buy back income 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.

Calculation of the LNC

This section describes the application of the two different methods we used to calculate the LNC. The calculation of the LNC has two parts:

1. Value setting (the base value of the LNC). We used the same value setting methodology that network businesses use for regular tariffs i.e. the Long Run Marginal Cost (LRMC) of the network.
2. Tariff setting (the application of a tariff structure to the base LRMC value). We applied two different tariffs:
    - Volumetric tariff
    - Combined volumetric and capacity tariff.

1. Value setting

We used the Long Run Marginal Cost of the network (LRMC) in $/kVA/year as the basic input to the value of the LNC. The LRMC is the annual cost of providing one unit of new capacity to the network to carry electricity, and was calculated by the Distribution and Transmission Network Service Providers (DNSPs and TNSPs). The NSPs identified up to five connection levels in network, and the assigned the LRMC value to each of them.

When the LNC is calculated for a particular connection level, only the network levels above that level are included. 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). Power factors and loss factors were provided by the DNSPs. Transmission LRMC was also added and adjusted for power factor and loss factor (from publicly available data).

The combination of the above calculations gave us the total annual value of the network upstream of the generator in $/kW.

2. Tariff setting

The LNC tariff is intended to provide a price signal to generators about when to generate and export electricity. We looked at two different tariff-setting methods:

a) Volumetric

To get the kWh value of the LRMC, we divided the annual kW value by 8,760 (total hours in the year). Each hour was weighted according to its value to the network i.e. according to the probability of network load peaking within the hour e.g. 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:

During peak hours the tariff would be:

$$LNC\ \$/kWh = \frac{LRMC\ for\ network\ levels\ above\ connection\ \ x\ 90\%}{600}$$

During off peak hours the tariff would be:

$$LNC\ \$/kWh = \frac{LRMC\ for\ network\ levels\ above\ connection\ \ x\ 10\%}{8160}$$

b) 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 for in their network usage tariffs. This varied from 45:55 to 76:24 (volume:capacity). 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:

$$\boldsymbol{capacity\ payment}\ \$/\mathbf{kW/day} = \frac{\boldsymbol{Value\ of\ capacity}\ (\$)}{[\boldsymbol{number\ of\ days\ peak\ may\ occur}]}$$

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 value ($/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. 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 divided the $32 by 365 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 capacity payment.

4. TRIAL RESULTS SUMMARY

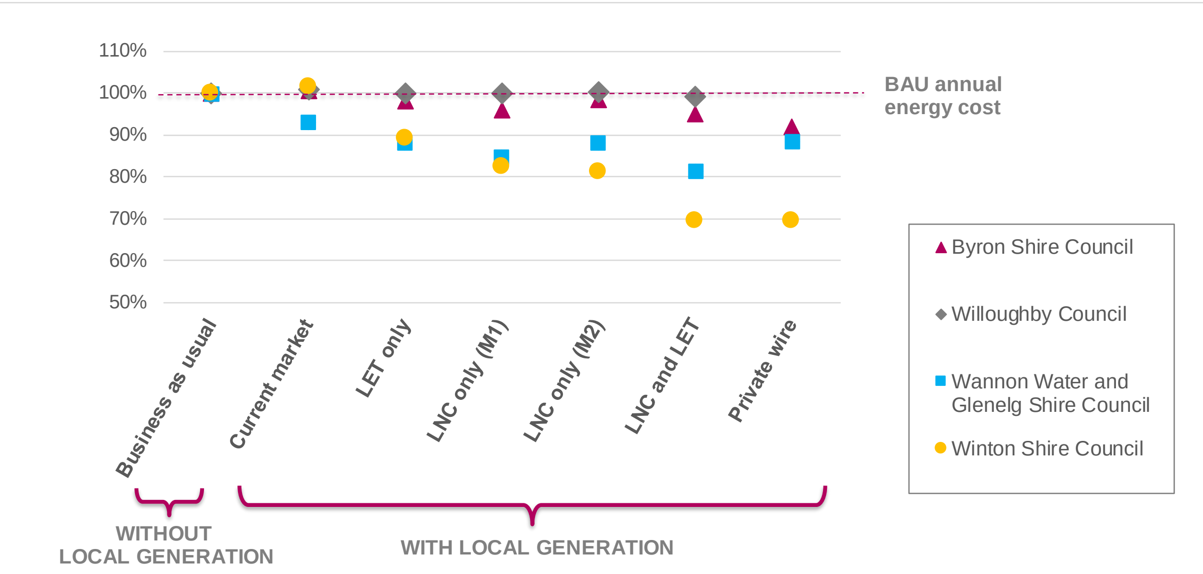
Impact on new generation proponents

The results for the proponents in each trial are shown in Figure 3, Figure 4**Error! Reference source not found.**, and Table 3, and the carbon benefit and associated carbon cost is shown in Table 4.

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

The impact on annual energy costs is shown for all trials in Figure 3. Under **current market** conditions, i.e. without either LET or an LNC, the net effect on energy costs is marginally worse after installation of local generation (compared to BAU) in all cases except Wannon, where the modelled buy back rate of 5c/kWh makes the export worthwhile. There is sometimes still a positive effect in terms of lifetime benefit (which includes the effects of inflation) for Byron and Willoughby, as shown in Table 3, although it is small relative to the investment.

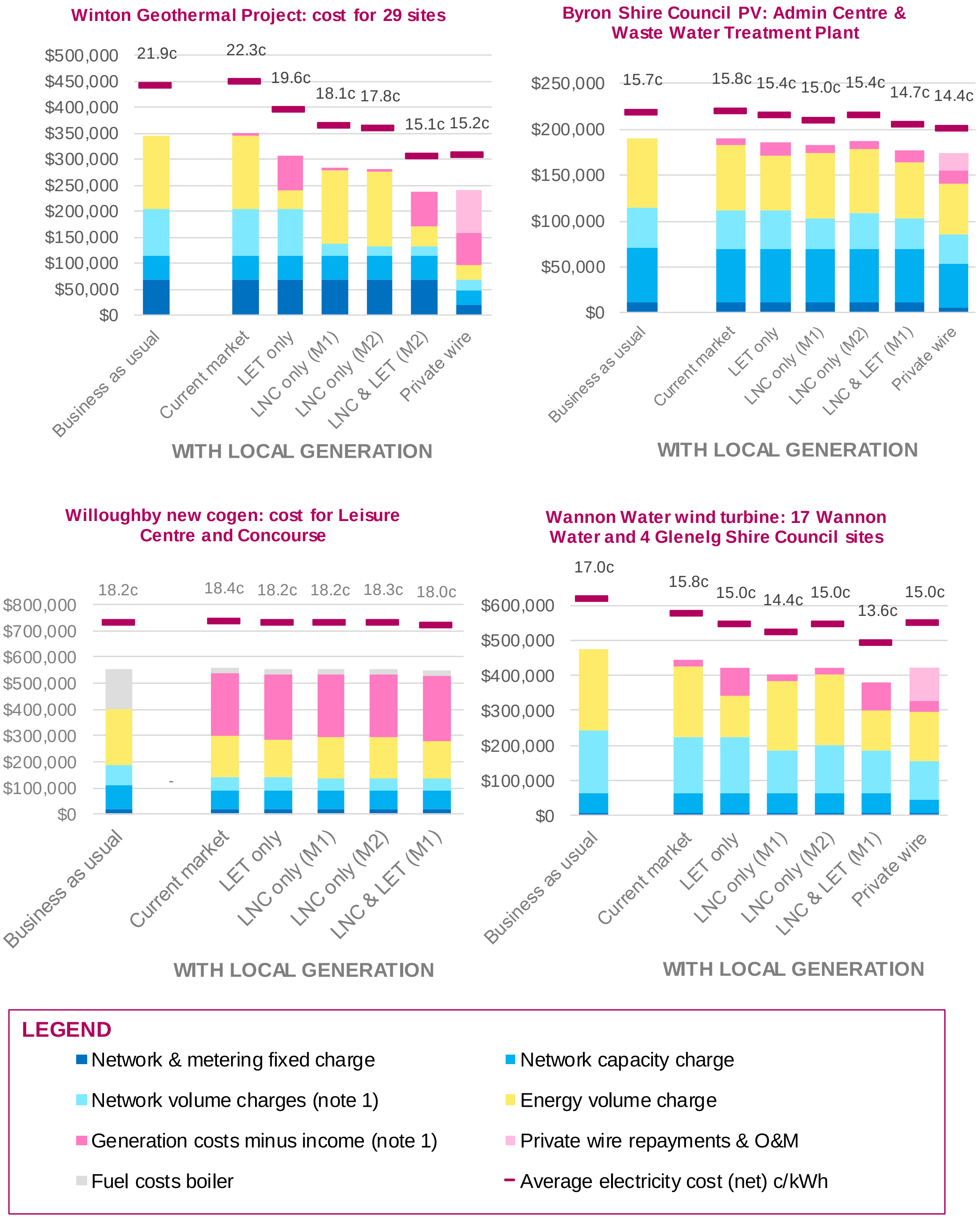
Figure 3 Impact on proponents (total energy costs)



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.

Figure 4 Results - annual 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.

Note 2: costs are modelled, and actual project outcomes may differ.

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. The lifetime benefit includes all the same costs and income, but includes the effect of inflation[4]. The Internal Rate of Return includes both inflation and discounting of income in future years. In Table 3, savings are shown as positive and losses are shown as negative.

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.

Table 3 Net effect on proponent energy costs by scenario

	Current market	LET only	LNC only (M1)	LNC only (M2)	LNC and LET [1]	Private wire
Byron Shire Council						
Annual savings	-$1,200	$3,300	$7,400	$2,700	$9,500	$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						
Annual savings	-$5,500	$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						
Annual savings	$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						
Annual savings	-$6,000	-$300	-$100	-$1,500	$4,900	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

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).

Carbon benefit and cost

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

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

achieved in the third Emissions Reduction Fund Auction in April 2016, where the average price of abatement is $10.23/tonne[5].

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 low emission technologies such as cogen, as the associated carbon savings are not currently credited at all.

Table 4 Carbon benefit (including exports)

	Carbon reduction	Cost of carbon	
	Tons per year	maximum	minimum
Winton Shire Council	1,768	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	3,411	zero cost	No cost [1]

Note 1 no cost in the table is where the measures result in savings, so in fact the carbon "cost" may be a significant saving

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 Figure 5. 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.[6]

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 overall 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 LGNC was in place, but we have not modelled this effect.

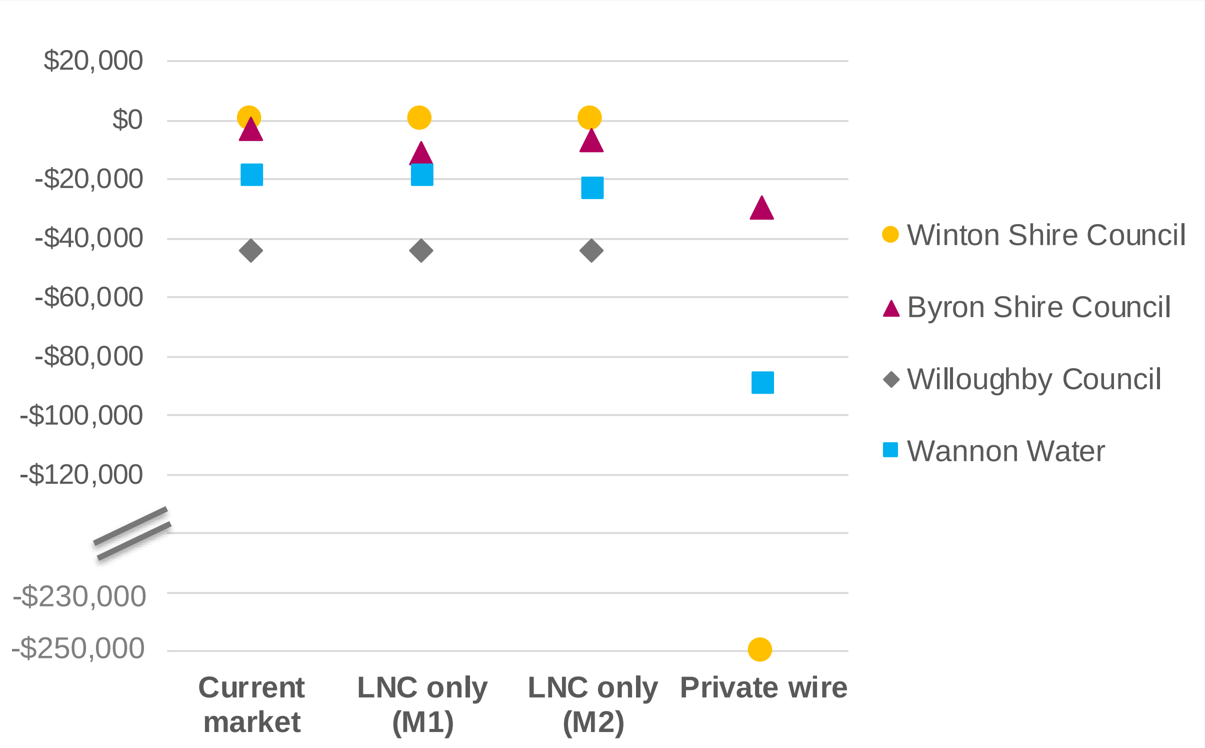
In all cases, the current market scenario results in the lowest reduction in network charges, as the only change in charges is the effect of the behind the meter consumption at the local generation site. The private wire case results in by far the greatest loss of immediate income for the network business, 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

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

[6] It is debated whether the LNC savings will materialise or not. However, the agreed purpose of the LNC methodology is to calculate the incremental cost of augmentation.

businesses will receive less immediate revenue than if those customers were incentivised to export to the grid through the use of a LNC.

Figure 5 Net effect on network charges by trial



Note: As of 1 January 2016, all NSPs in trial jurisdictions are operating under revenue caps. As such, revenue shortfalls will be recouped from all customers in the next regulatory period.

As networks operate under revenue cap regulation, revenue shortfalls in one year are recovered via customer tariffs over the following years. Further, if the removal of a customer/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.

The scenarios including LNC payments come somewhere in between 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 Byron's PV generator and 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 value in each trial per kW for a generator operating constantly, 8760 hours per year, and gives the 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.

The calculated LNC values for each trial in c/kWh for peak, shoulder, and off peak for both methods, and per kVA are shown in Appendix 1.

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)	-$2,700	-$2,700	-$2,700	-$29,400
Local network credit	-	-$8,600	-$3,900	-
Net effect on NSP charges	**-$2,700**	**-$11,300**	**-$6,600**	**-$29,400**
Willoughby Council				
Revenue effect (excluding LNC)	-$43,900	-$43,900	-$43,900	n/a
Local network credit	-	-$5,900	-$4,500	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**

Note 1) Ergon's reduction in immediate income is greater than the loss of network charges, as these are adjusted to take account of the Queensland Community Service Obligation.

Table 6 LNC results for each trial

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

The LNC method

Overall, the volume-capacity method (#2) benefits variable DG less than volumetric only method (#1). This is driven by two factors. Firstly, the volumetric method was intended to be used with quite narrowly defined peak periods, to act as an 'availability adjustment' on the credit value. However, all network businesses selected quite broad peak periods, which effectively meant this adjustment was not applied. This means that the volumetric method LNC payment calculations may be higher than the true value of variable DG to the network. Secondly, networks generally applied a quite 'deterministic' method to rewarding of the capacity credit. That is, if local generation was *ever* not available during a very broadly defined period, it received no credit. However, there is evidence to suggest variable solar PV generation has an impact on network peak demand, for example, from a portfolio of generators located in commercially dominated distribution zones with air-conditioning driven peaks, or upstream in transmission networks[7]. This means that the combined volume-capacity method as used in the trials probably under-rewarded the value of DG. In practice, the true value of variable DG may be somewhere in between the results for Methods 1 and 2.

Cogeneration – marginal results (Willoughby trial)

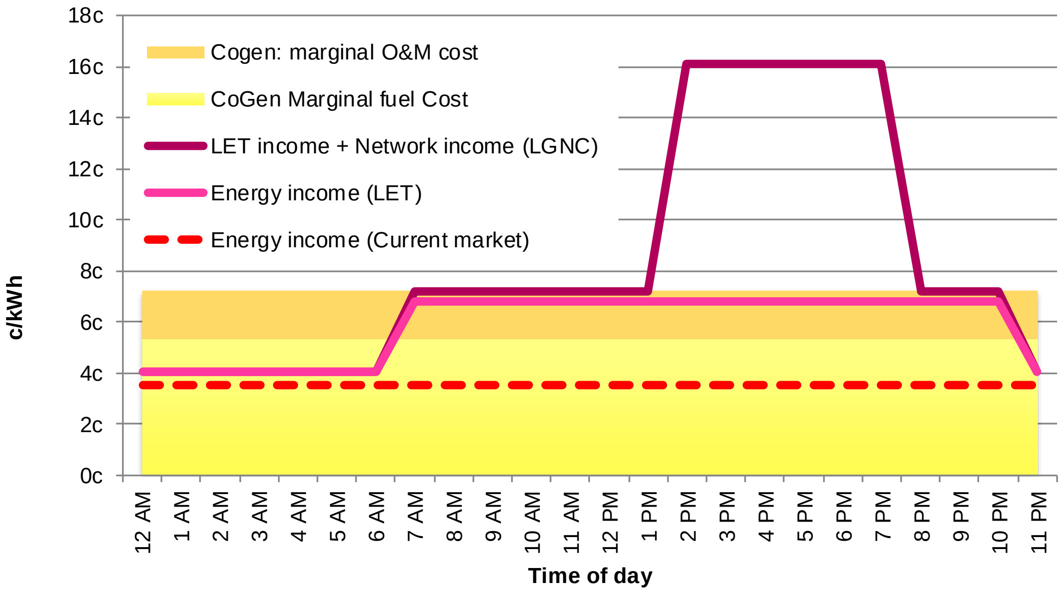
The marginal cost of operation for cogeneration as modelled in the Willoughby trial is just over 7 c/kWh, provided the cogen is also supplying useful heat. The cost for fuel and O&M is 18.6 c/kWh, with a value of heat supplied equal to 11.4c/kWh (electrical).

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 13.5 c/kWh peak to 7.5 c/kWh off peak[8].

Figure 6 shows the marginal case for export. As 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 periods.

The implication is that current market conditions result in suboptimal 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 avoided through the combination of LET and LNC value for cogen operators.

Figure 6 CoGen marginal costs vs income



[7] APVI (2015), APVI Discussion Paper on SA Power Network's Pricing Proposal, working paper for the Australian PV Institute.

[8] This includes all volumetric charges: energy, network, AEMO, RET, SRES, and EES.

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. So 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 peak *exports*, and may result in additional reductions in peak grid consumption from demand at local generation sites because of in better sizing of plant.

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

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

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

Impact on electricity retailers

Table 8 shows the impact on retailers by scenario. Note that the LNC only scenarios are the same as Current Market from the retailer's point of view as the LNC affects does not affect energy volume charges. Results are considerably different by trial, but this is more a function of the different practical arrangements, and the different calculation methods. Specifically:

- The generator at Winton is stand alone, so there is no behind the meter generation. This means the current market has no effect on current energy purchase.
- The Wannon trial uses a different method to calculate the effect of netting off on the retailer, and assumes that the only effect will be to lose the retailer margin on the reduced consumption. As the retailer margin is still charged on netted off electricity, there should be no difference between the LET scenarios and the current market. The private wire scenario results in greater losses to the retailer simply because energy purchase is further reduced.

Table 8 Retailer - net impact

	Current market	LET only	Private wire
Winton Shire Council			
Energy volume charges (change)	-	-$105,500	-$115,600
Net effect on retailer	**-**	**-$15,600**	**-$19,300**
Byron Shire Council			
Energy volume charges (change)	-$4,300	-$14,300	-$15,000
Net effect on retailer	**-$2,800**	**-$6,100**	**-$6,900**
Willoughby Council			
Energy volume charges (change)	-$48,800	-$61,800	n/a
Net effect on retailer	**-$21,200**	**-$26,300**	n/a
Wannon Water and Glenelg Shire Council			
Energy volume charges (change)	-$27,200	-$106,800	-$77,400
Net effect on retailer	**-$1900**	**-$1900**	**-$5400**

Key inputs – impact on costs and benefits

The impact of key variables on the outcome by scenario is summarised in Table 9. We tested an increase and decrease of 20% in the cost of the generator, the price obtained for LGCs, the retailer buy back 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 retailer buy back rate had a large impact in the case of Wannon Water, probably because of the high level of export.

Table 9 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 $50)	+/- 1.2%	+/- 6.6%	+/- 5.3%	n/a
Retailer buy back rate	80% and 120%	+/- 0.6%	+/- 5.0%	+/- 4.5%	+/- 0.3%
Gas cost ($/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%

The impact of variation in the generator cost is shown in Figure 7 for three of the trials. In general, those scenarios with a positive outcome in the modelled case are still positive with the variation. The same graph is shown in Appendix 2 for the impact of the LGC price, which is less significant in all cases.

The key variables for the Willoughby cogen trial are the gas price and the generator cost, which are shown in Figure 8. The gas price has by far the greater impact, and could make all scenarios positive or negative.

Figure 7 Impact of +/- 20% generator cost on annual energy spend by scenario

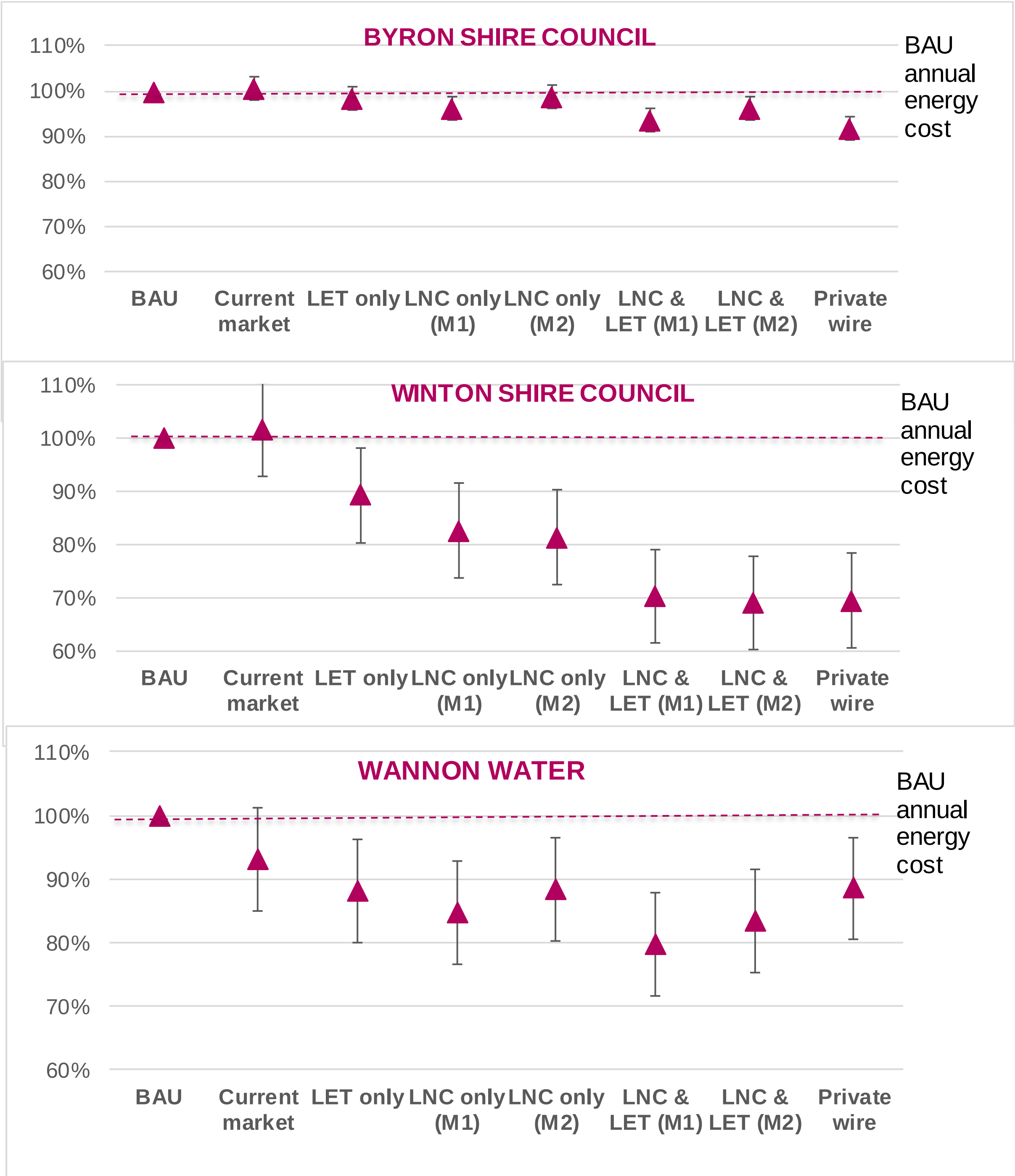
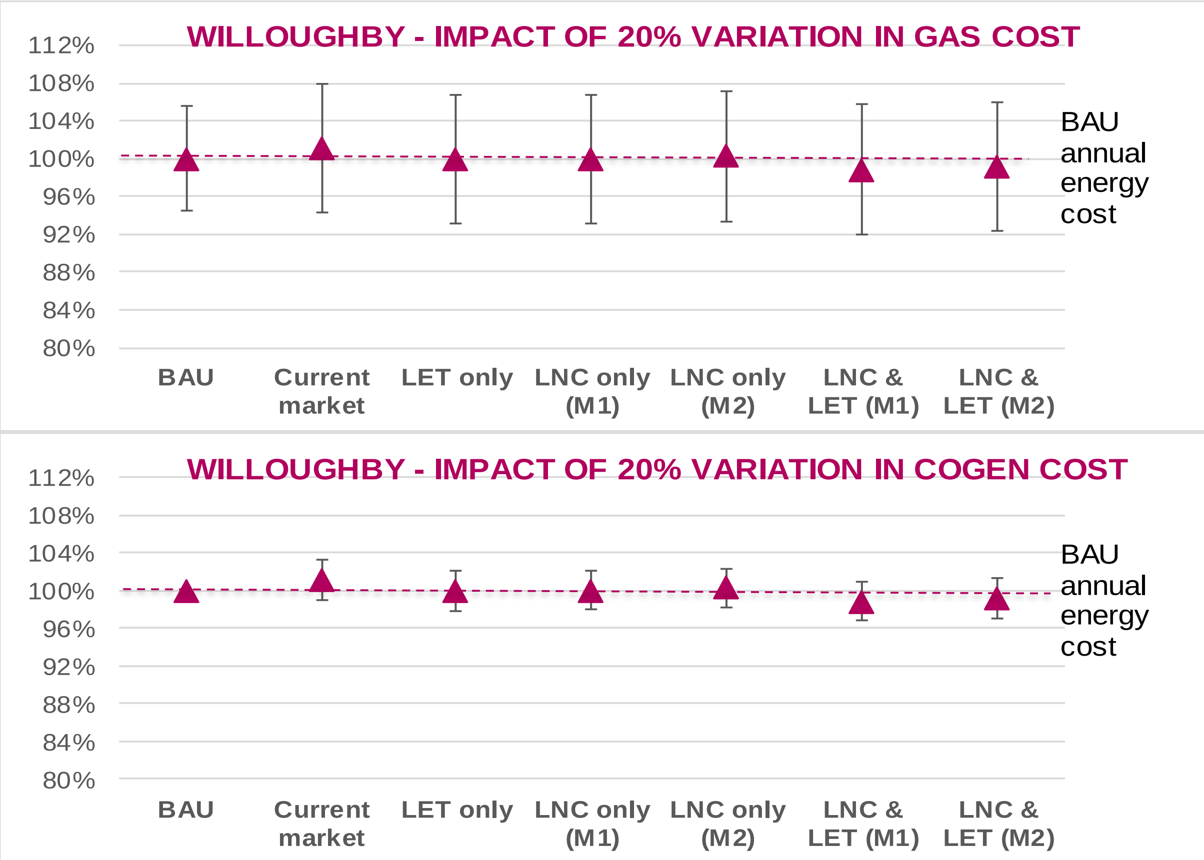


Figure 8 Willoughby – impact of +/- 20% of gas price and generator cost on outcomes



The impact of the LNC and LRMC

The primary effect of a change in the LRMC in the trial is to change the LNC value. The impact of a 20% variation in the LNC rate is small in all cases except Winton, as shown in Table 9. However, some additional modelling of the LRMC value for this project by Energeia[9,10], using publicly available information, allowed us to examine the effect of standardising the inclusions and exclusions for the LRMC calculation between the different networks. The variations in settings are shown in Table 10.

Table 10 Network assumptions and assumptions for standard outputs

	Assumptions used for alternative value	Essential	Ergon	Powercor	Ausgrid
System demand POE	10%	50%	10%	10%	10%
Time horizon	25	10	25	25	15
Connections expenditure included	Associated Augex and Repex only[1]	No	Yes	No	Yes
Capital contributions included	No	no	yes	no	No

Note 1: Direct connections expenditure is excluded, but the associated Augex and Repex are included

[9] Energeia 2016, AIC Calculator.
[10] Energeia. 2016. LRMC Methodology Paper Prepared for the Institute for Sustainable Futures.

Table 11 shows the correlation between the DNSP value for LRMC used in the trial and the Energeia values if the inclusions and other settings match those used by the DNSP. As may be seen, the values are close, with a maximum variation of only 12%.

The variation with settings standardised is also shown, and varies from -11% (Ergon) to +110% (Powercor), and is only significant for Powercor. However, Energeia's value may include some non-demand driven augmentation expenditure that cannot be differentiated from RIN data, but is excluded from Powercor's LRMC trial calculation, such as bush fire related works.

We have tested the effect of these variations on the overall energy costs in the LNC cases, and found the variation to be very small in all cases except Wannon Water. The variation there is significant, and would improve outcomes by 5%-9%. This is similar to the impact of a variation in generator costs of -20%, or an increase in LGCs value from the modelled rate of $50/MWh to $60/MWh.

Table 11 Impact of alternative values for the LRMC

	Byron	Winton	Wannon	Willoughby
Inclusions and setting match DNSP's: Energeia value/ DNSP value	1.12	1.06	0.98	1.03
Standardised inclusions/ settings: Energeia value/ DNSP value	0.94	0.89	2.1	1.04
Reduction in overall energy costs with standardised inclusions	-0.3% - -0.1%	-2.2%	5% - 9%	0.0%

5. DISCUSSION AND CONCLUSION

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

- Inefficient sizing and operation of distributed generators,
- Lack of incentive for dispatchable[11] generators to operate at required (peak) times,
- Potential 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 would be most beneficial to networks. The Winton trial demonstrates that some projects that are inherently cost effective may not be realised under current market conditions.

The marginal cost of 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[12]. 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.

Overall, the result of offering an LNC would be to keep kWh **on the grid,** and maintain utilisation in an increasingly locally derived supply.

Offering an LNC for the cases investigated would keep kWh on the grid in an era of increasingly locally derived supply. An LNC would maintain the network charges paid by the proponent, relative to a significant increase in behind the meter consumption using a private wire approach, even taking into account payment of the LNC itself. The proponent and other customers are better off, as money is not wasted on infrastructure duplication.

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[13]. While not specifically trialled, 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.

[11] Generators that can be switched on at will; in these trials the cogen and the geothermal generators.
[12] 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 hours a year (2-8pm every weekdays year round).
[13] For example, a current ARENA project “Moreland micro-grid investigation” is examining the feasibility of microgrids connecting metropolitan suburban dwellings to share PV and batteries.

APPENDIX 1 LNC VALUES CALCULATED FOR EACH TRIAL

Table 12 LNC values – volumetric method

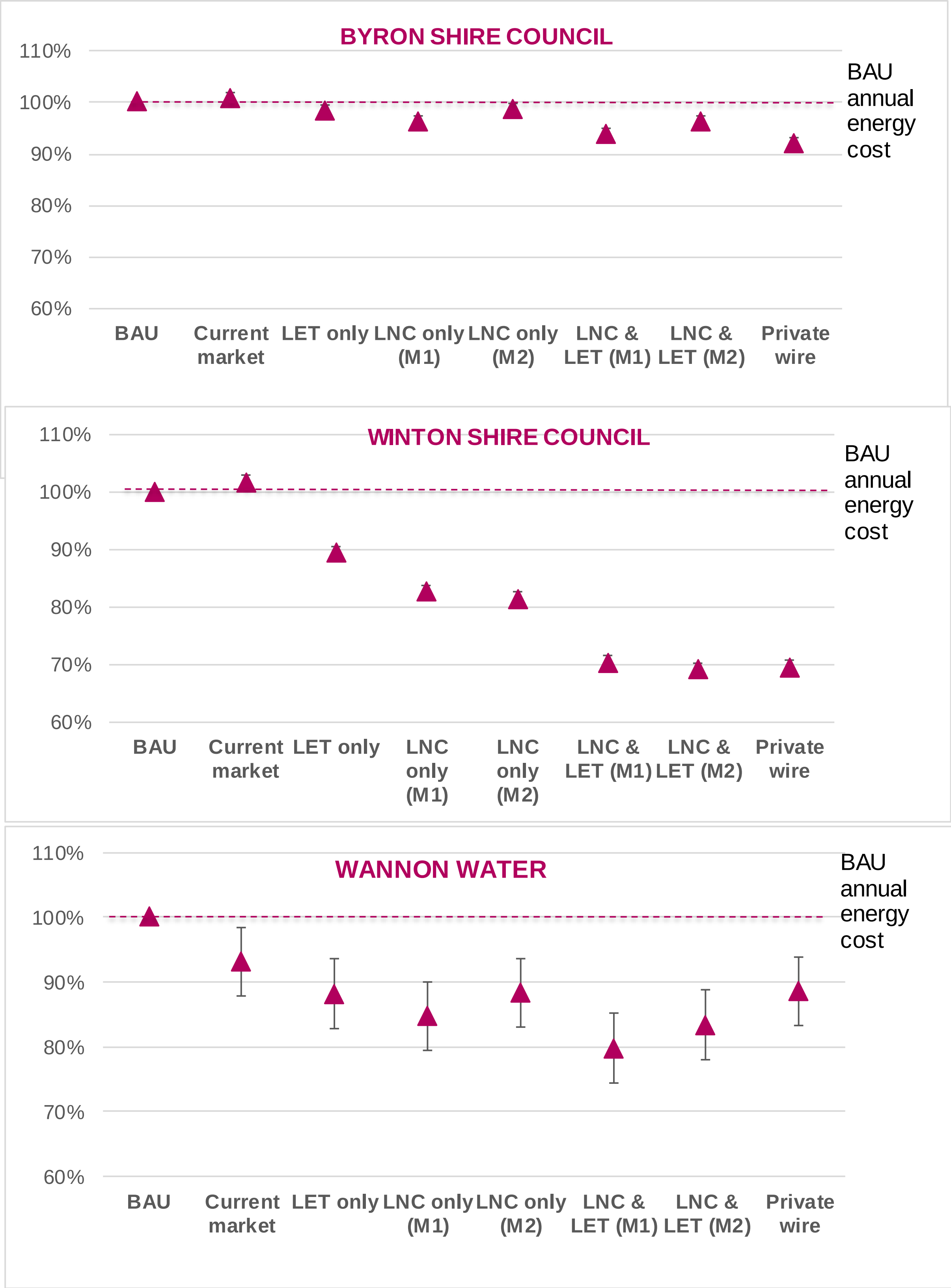
	ERGON			POWERCOR			ESSENTIAL			Ausgrid		
Connection level	1	2	3	1	2	3	1	2	3	1	2	3
	c/kWH			c/kWH			c/kWH			c/kWH		
Peak	32.5	28.3	15.4	22.3	21.8	9.5	6.8	4.6	2.7	12.4	9.3	7.9
Shoulder	n/a	n/a	n/a	n/a	n/a	n/a	5.6	3.8	2.2	0.5	0.4	0.3
Off-peak	4.8	4.2	2.3	0.06	0.06	0.03	1	0.7	0.4	0	0	0

Table 13 LNC values – combined volumetric and capacity payment method

	ERGON			POWERCOR			ESSENTIAL			Ausgrid		
Connection level	1	2	3	1	2	3	1	2	3	1	2	3
VOLUMETRIC PORTION	c/kWH			c/kWH			c/kWH			c/kWH		
Peak	16.2	14.2	7.7	5.6	5.5	3.8	3.1	2.1	1.2	9.4	7.0	6.0
Shoulder	n/a	n/a	n/a	n/a	n/a	n/a	2.5	1.7	1.0	0.4	0.3	0.2
Offpeak	2.4	2.1	1.1	0.1	0.1	0.1	0.5	0.3	0.2	0.0	0.0	0.0
SUPPLY PAYMENT	$/kW/day			$/kW/day			$/kW/day			$/kW/day		
Based on minimum generation in defined period	3.35	2.92	1.59	0.46	0.45	0.31	0.45	0.30	0.18	0.14	0.11	0.09

APPENDIX 2 IMPACT OF LGC PRICE BY SCENARIO

Figure 9 Impact of +/- 20% LGC price on annual energy spend by scenario



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