The Business Case for Behind-the-Meter Inverter Control for Regulating Voltage

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About the authors

The Institute for Sustainable Futures (ISF) is an interdisciplinary research and consulting organisation at the University of Technology Sydney. ISF has been setting global benchmarks since 1997 in helping governments, organisations, businesses and communities achieve change towards sustainable futures.

We utilise a unique combination of skills and perspectives to offer long term sustainable solutions that protect and enhance the environment, human wellbeing and social equity.

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Introduction

NETWORKS RENEWED

Networks Renewed is a major project funded by the Australian Renewable Energy Agency (ARENA). It aims to demonstrate how solar PV, battery storage and inverters can support distribution networks in managing power quality. The project is specifically focused on investigating the potential for smart inverters to regulate network voltage. The path to implementation is being established by two commercial-scale demonstrations of controlled solar PV and energy storage – one on the Mid North Coast in regional NSW, and one in rural northern Victoria.

AIM OF THIS REPORT

This report provides a sample business case for demonstrating that the use of behind the meter inverter control can be an economic solution to regulating voltages. For each demonstration, the business cases used are described. The framework for doing this was built around the business model canvas – a method that provides a compact overview regarding all aspects of a business model.

The report outlines how the value of network services can be realised, and this includes a comparison table of the technical requirements, performance, and cost of behind the meter inverter control against traditional voltage regulation options.

It also assesses the market participation value when providing aggregated FCAS, drawing on results from the NSW demonstration.

Relevant findings are references from the Electricity Network Transformation Roadmap in consultation with the Energy Networks Association (ENA).

A final section reviews how behind the meter inverter control could be more rapidly deployed in NSW, including policy measures, knowledge sharing activities for customers, networks and technology providers, accelerated technical development and integration, and advancement of viable business models. This complements a report that was previously delivered to the Victorian government addressing their context.

The Sample Business Case

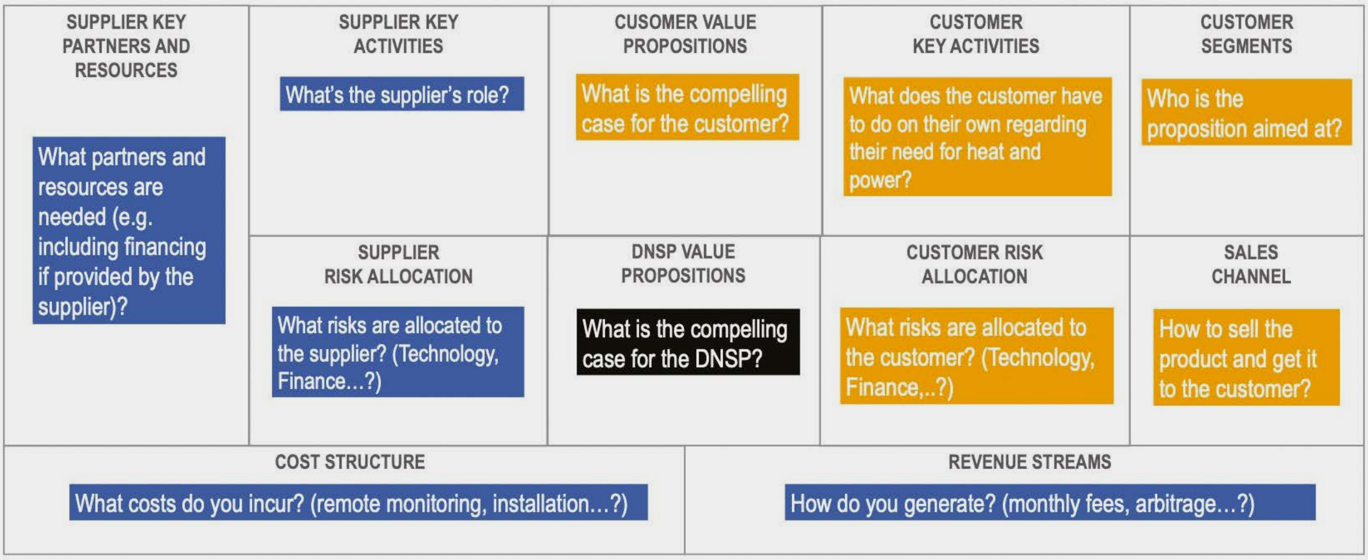
EXPLANATION OF THE BUSINESS MODEL CANVAS

The business model canvas provides a compact overview regarding all aspects of each business model. It helps succinctly characterise the different aspects of the current business models being deployed for behind the meter (BTM) voltage regulation, as well as identify key barriers and risks.

The business model canvas was populated for each of the demonstration projects, using feedback received on telephone calls, teleconferences, and workshops with the different stakeholders.

The business model canvas features eleven key sections as shown in Figure 1. While typically the canvas features ten key section, due to the importance of the DNSP role in this project and in BTM voltage control, an additional section has been added for the DNSP value proposition.

Figure 1: The business model canvas



The canvas is constructed from the point of view of the 'Customer' and the 'Supplier'.

For the 'Customer'

This is the end customer in the case of this project. In the case of this project, it is the person(s) purchasing the hardware (solar PV, battery storage, smart inverter, and smart controls) and providing their system for control by the DNSP to stabilise voltage in their area.

For the 'Supplier

This is the main actor who interfaces with the Customer for the supply of the main goods and services. In the case of this demonstration project, it can mean either the 'Installer' or the 'VPP Aggregator'.

The Current Business Case

Two different demonstration projects were run, each with their own group of stakeholders. The result is two similar but subtly different business cases. The following section describes each of the business cases in turn.

The main commonalities and differences are described in Table 1.

Table 1: Customer business case today – comparison

	NSW Trial	Victoria Trial
Partners	Essential Energy Reposit Power	AusNet Services Mondo Power
Key Commonalities	- Ownership model type - The types of stakeholder involved - The main customer value proposition (energy bill savings)	
Key Differences	- The main financial transaction takes place between the Installer and the Customer - The Customer is remunerated for providing voltage regulation services on an 'Earn as you Go' basis - with the Customer paid $1 per kWh per event	- The main financial transactions takes place between the Customer and Mondo power - The Customer is remunerated for providing voltage regulation services on an 'Upfront Payment' basis - with the Customer paid $200 per year

NSW Demonstration – Business Model

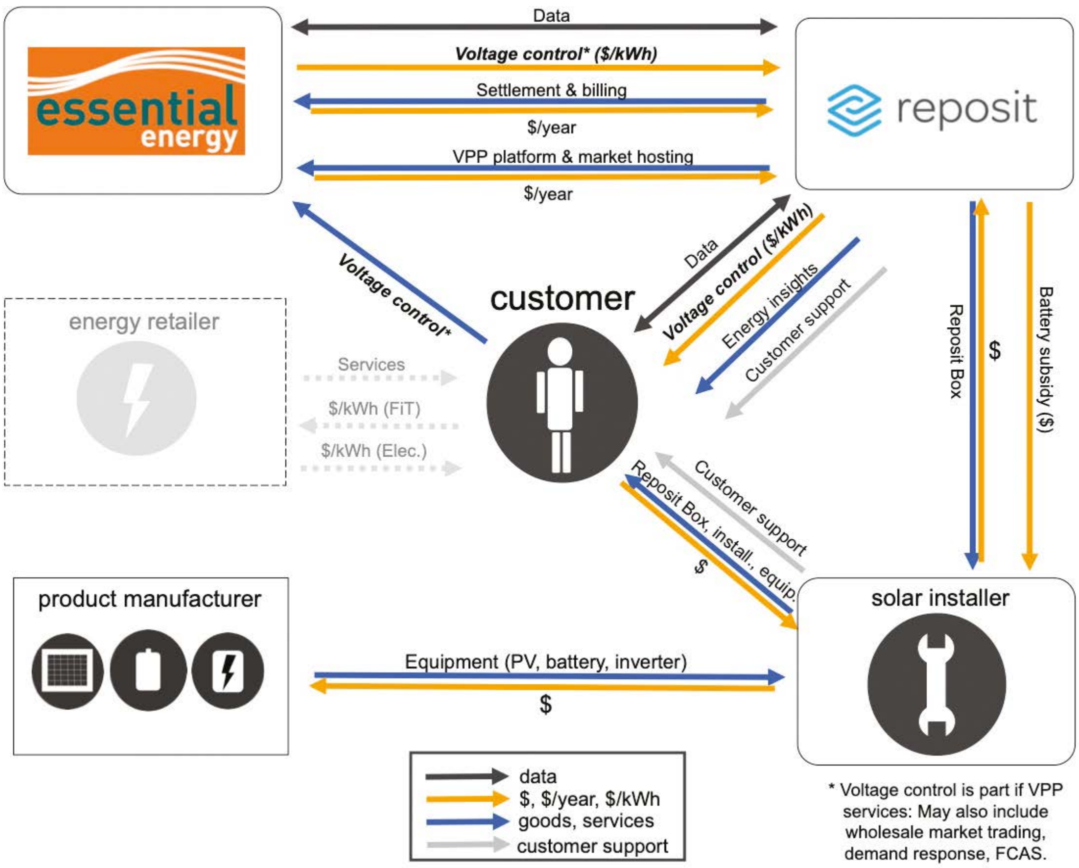
How it works - key points

Snapshot diagrams of the NSW and VIC business models were developed in workshops with project partners to ensure that all transactions occurring in practice have been captured. The NSW snapshot is shown in Figure 2 and it presents a succinct view of a number of interactions between stakeholders, including energy retailers who are not explicitly part of the project.

- The Installer (a local installation company) is the main interface with the Customer, providing the full service from marketing and sales to installation, commissioning, and aftersales.
- The Customer provides control of their system to Essential Energy for stabilising voltage in their area.
- Via Reposit Power, Essential Energy pays the Customer $1 per kWh[1] for allowing it to control their PV and battery system.

1 The rate of $1 per kWh was neither selected as a purely arbitrary number nor was it based on a calculated value. Rather it was a value chosen for the trial as it was known it would create a 'known response'. This known response was that given the value of $1 per kWh would be significantly more than any other value on offer, voltage regulation would always be the preferred service that the system would "choose" to offer.

Figure 2: Snapshot of the business model used in the NSW demonstration



SUMMARY

For the business model deployed in the NSW demonstration, the Installer is the main touchpoint with the customer (the 'Customer-Face') and the source of the main financial transaction.

Reposit Power provides the VPP platform and market hosting, facilitates the flow of data and provision of related insights to the other stakeholders, regulates voltage on behalf of the DNSP, passes on to the customer a $1 per kWh voltage regulation payment from the DNSP, and also provides the settlement and billing service to the DNSP. Reposit Power also provided the battery subsidy to the installer, which it received from UTS using ARENA funds, passing on the lower price to the customer.[2]

It differs from the VIC model in that:

a. the main financial transaction takes place between the Installer and the Customer, rather than between the VPP aggregator and the Customer.

b. the Customer is remunerated for providing voltage regulation services on an 'Earn as you Go' basis – with the Customer paid $1 per kWh per event – rather than as an upfront payment.

c. the customer does not pay any ongoing fees for energy insights.

The business model canvass and key stakeholder activities for the NSW demonstration are shown in Figure 3 and Table 2 respectively.

2 While the battery subsidy was funded by ARENA as part of this demonstration project, in the future a subsidy could be provided by the DNSP itself.

Figure 3: Business model canvas - the NSW demonstration

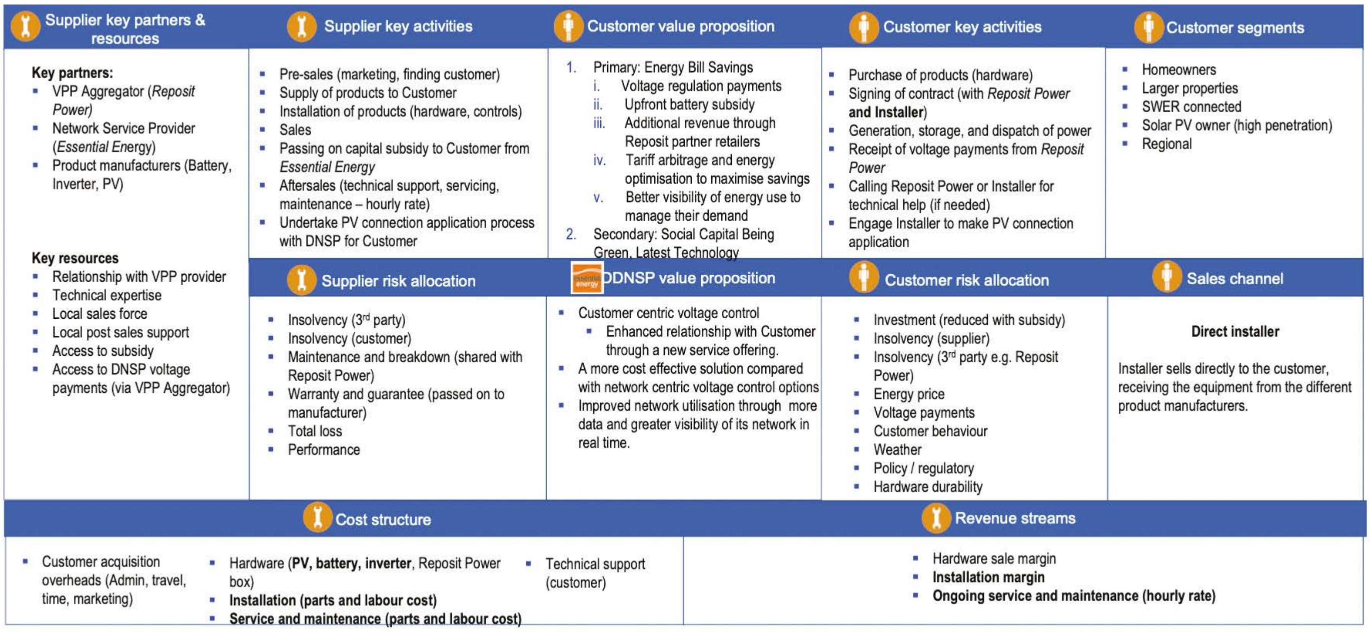


Table 2: Business model stakeholder (NSW) key activities

Stakeholder	Key activities
Customer **(e.g. homeowner, small business owner)**	- Purchase of products (hardware) - Signing of contract (with *Reposit Power* and Installer) - Generation, storage, and dispatch of power - Receipt of voltage payments from *Reposit Power* - Calling *Reposit Power* or Installer for technical help (if needed). - Engage Installer to make PV connection application - Receipt of energy insights from *Reposit Power*
Supplier **(The Installer)**	- Pre-sales (marketing, finding customer) - Supply of products to Customer - Installation of products (hardware, controls) - Sales - Passing on capital subsidy to Customer from *Essential Energy* - Aftersales (technical support, servicing, maintenance – hourly rate) - Undertake PV connection application process with DNSP for Customer
Reposit Power **(The VPP aggregation platform provider)**	- Pre-sales (marketing, finding customer) - Control of system - Supply of hardware & software - Technical support - Pass on voltage service payment to customer from *Essential Energy* - Pass on retailer grid credits to Customer from Energy Retailer - Provision of Customer data to *Essential Energy*
Essential Energy **(The Network Service Provider)**	- Provide payments to *Reposit Power* for providing voltage services ($1 per kWh) - Sending voltage service signals to Customer via *Reposit Power* - Paying capital subsidy to Customer for products via Installer
Product Manufacturer **(PV, battery, inverter)**	- Supply of products to Installer - Receipt of payment from Installer for equipment

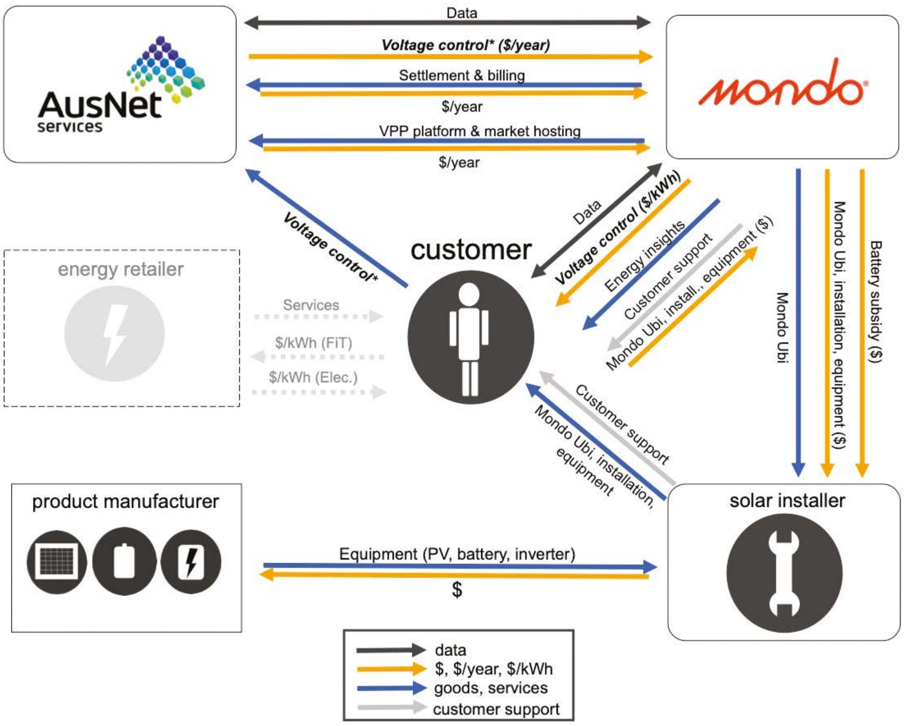
VIC Demonstration – Business Model

How it works – key points

The VIC snapshot is shown in Figure 4 and involves the following actors:

- Mondo Power (the VPP aggregator) is the main interface with the Customer, contracting with the Installer to provide the full service from marketing and sales to installation, commissioning, and aftersales.
- The Customer provides control of their system to AusNet Services for stabilising voltage in their area.
- Customers are paid $200 per year for allowing the control their PV and battery system.

Figure 4: Snapshot of the business model used in the Victoria demonstration



SUMMARY

Mondo Power are the main touchpoint with the customer, smoothing the flow of products into the customer's home by working with local installers. They participate in 2-way data flow with the customer, regulating voltage while passing on to the customer the $200/year payment from DNSPs for voltage regulation.

It differs from the NSW model in that:

d. the main financial transactions takes place between the Customer and Mondo Power, rather than between the Customer and the Installer.

e. the Customer is remunerated for providing voltage regulation services on an 'Upfront Payment' basis – with the Customer paid $200 per year – rather than as an 'Earn as you Go' series of payments.

The business model canvass and key stakeholder activities for the VIC demonstration are shown in Figure 5 and Table 3.

Figure 5: Business model canvas - the Victoria demonstration

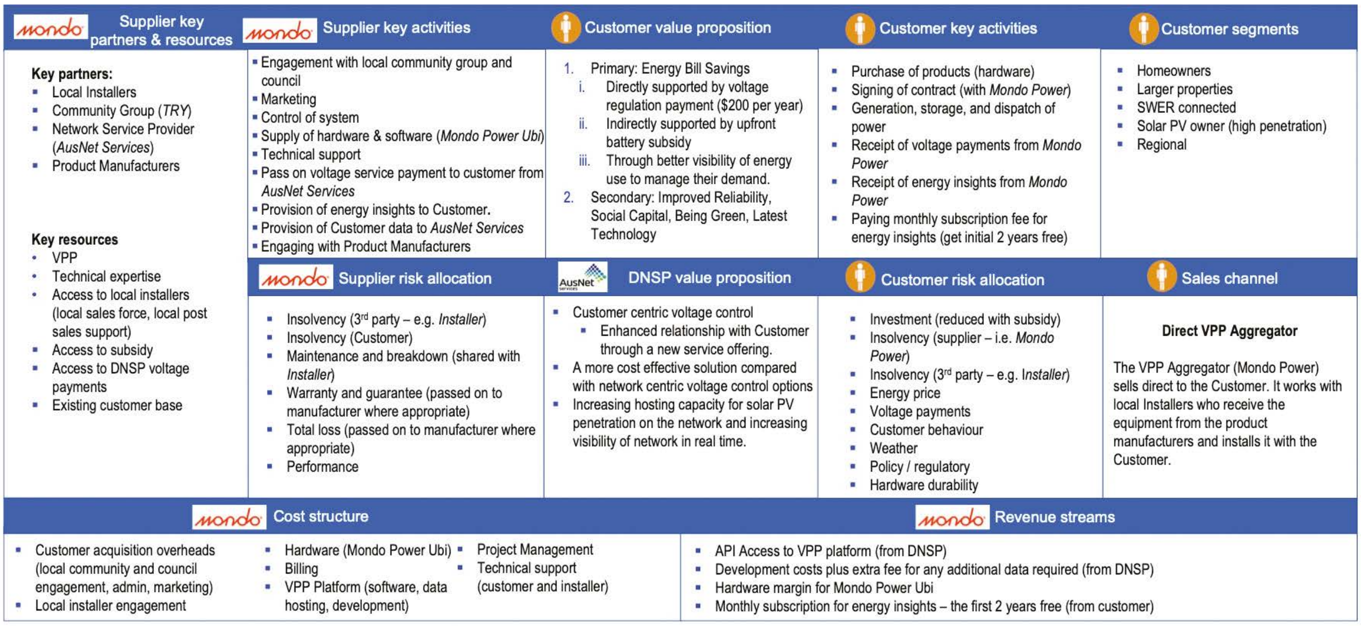


Table 3: Business model stakeholder (Victoria) key activities

Stakeholder	Key activities
Customer **(e.g. homeowner, small business owner)**	- Purchase of products (hardware) - Signing of contract (with *Mondo Power*) - Generation, storage, and dispatch of power - Receipt of voltage payments from *Mondo Power* - Receipt of energy insights from *Mondo Power* - Paying monthly subscription fee for energy insights (get initial 2 years free)
Supplier **(Mondo Power – the VPP aggregation platform provider)**	- Engagement with local community group and council - Marketing - Control of system - Supply of hardware & software (*Mondo Ubi*) - Technical support - Pass on voltage service payment to customer from *AusNet Services* - Provision of energy insights to Customer. - Provision of Customer data to *AusNet Services* - Engaging with Product Manufacturers
Installer	- Pre-sales (marketing, finding customer) - Supply of products to Customer - Installation of products (hardware, controls) - Passing on capital subsidy to Customer from *AusNet Services (via Mondo Power)* - Aftersales (servicing, maintenance)
AusNet Services **(The Network Service Provider)**	- Provide payments to *Mondo Power* for providing voltage services ($200 per year) - Sending voltage service signals to Customer via *Mondo Power* - Paying capital subsidy to Customer for products via *Mondo Power*
Product Manufacturer **(PV, battery, inverter)**	- Supply of products to Installer - Receipt of payment from Installer for equipment

Comparison Table of Behind-the-Meter and Network-Centric Approaches

This section contains the comparison table of the technical requirements, performance, and cost of behind-the-meter inverter control against traditional voltage regulation options.

Table 4 and Table 5 show how a summary of the most suitable options being considered for Collombatti and Yackandandah respectively (the full suite of options considered are given in Tables 6 and 7 in the next section, including those deemed unsuitable).

For Collombatti, there were only two options considered suitable when it came to the 'traditional' or 'network centric' options for voltage control. These were 'reconductoring' (the preferred option of the two), or 'deploying power electronic voltage regulators'.

For Yackandandah, there were more suitable options being considered by the local DNSP, including those that were available to Collombatti.

Network-centric approaches must be developed specifically for each network segment that requires better voltage regulation. It is not possible to define a general approach because the characteristics of networks are variable due to geography, customers, and design practices at the time of construction. The available solutions depend on how voltage regulation issues are presented. For example, voltage drop and rise may occur in the LV network backbone, and in the service lines from the backbone to each customer which usually have a higher impedance. The influence of the service lines is an important component of a voltage regulation strategy that can often go unnoticed.

The 'Behind the Meter' option is neither the most expensive option nor the least costly. However, there are a number of points that should be considered regarding the prices.

a. The prices given in the following tables are CAPEX only and do not take account of on-going costs, although implications for OPEX is given in the comments column.

b. While the network centric prices have been provided by each DNSP, estimations or averages based on the best information available have had to be made, in the absence of detailed survey work.

c. For the Behind the Meter option, the price includes the full subsidy value paid to the customer for the battery and the VPP control box.

d. The Behind the Meter option price is calculated based on the total number of homes on the local feeder. In reality, fewer homes would be needed to provide voltage regulation services for a given area to provide a corrective solution through optimised location of network support.

To illustrate a particular instance, Essential Energy was able to simulate how to address the emerging constraint within Collombatti, using 13 of the existing demonstration customers combined with 20 additional customer-sized batteries installed towards the end of the feeder. This simulates an optimal combination of customer inverters with two bulk network-side locations (noting that sufficient data have not yet been gathered from the demonstration to verify whether the network-side locations are required).

Annualised costs of the distributed inverter solution, based on current network services payments to Reposit Power were found to be marginally lower compared to the cost of reconducting indicated in Table 4. This comparison does not include subsidies for batteries or Reposit Power boxes which are anticipated to fall to the extent that subsidies are not required.

It is important to recognise that the pricing for the demonstration reflected its trial nature, and allowed for additional work from Reposit Power that would not be necessary in a large-scale rollout. The pricing is therefore not indicative of the long term cost of the solution to the DNSP.

Table 4: Summary of suitable options for voltage control measure: Collombatti (NSW)

Measure description	Technical requirements	Performance	Price	Comments
Behind the Meter voltage control	Installation of PV, battery, smart inverter, VPP control box at customer's home. Controlled remotely by DNSP via VPP platform.	To date shown to improve voltage regulation by 3% (target 5.5%). Positives are that the solution is adaptable, scalable as the issue grows, and requires smaller initial CAPEX.	$675,000 (~90 homes @ ~$7,500)	Suitable: There is an ongoing cost of $200-$300 a year[3] for voltage payments to the customer. This price does include the full subsidised cost of the battery.
Re-conductoring	Larger conductors used to reduce network impedance, making it easier to regulate voltage within the required limits.	Allows for future growth in demand and PV capacity. High capital cost.	$300,000	Suitable: Reconductoring between Regulator site and the start of SWER. This is the Network-centric Option preferred by the local DNSP.
Power electronic voltage regulators	Power-electronic devices that can maintain voltage at a point in a network feeder under varying load conditions. They can include Line Drop Compensators (LDCs) which maintain constant voltage at locations remote to the regulator. Long rural networks often use series voltage regulators (SVRs).	Power electronic based regulators have a much faster response time compared to mechanical regulators, however cost and the available size of electronic based regulators typically limits applications to subsections of LV circuits. They can provide fast response to sudden voltage change and can be operated remotely. Available size range limits use to small parts of LV networks.	$1,185,000	Suitable: However, power electronic equipment is expensive and is likely to need replacing every 7-10 years resulting in higher lifetime costs.

Table 5: Summary of suitable options for voltage control measure: Yackandandah (VIC)

Measure description	Technical requirements	Performance	Price	Comments
Behind the Meter voltage control	Installation of PV, battery, smart inverter, VPP control box at customer's home. Controlled remotely by DNSP via VPP platform.	To date shown to improve voltage regulation by 3% (target 5%). Positives are that the solution is adaptable, scalable as the issue grows, and requires smaller initial CAPEX.	$810,000 (~90 homes[4] @ ~$9,000)	Suitable
On Load Tap Changers (OLTC)	Responds to changes in demand, automatically adjusts voltage at the zone substation without interrupting power supply through adding or subtracting to the transformer winding. OLTCs are typically equipped with Line Drop Compensators (LDCs).	This is an imprecise measure as voltage is changed for all feeders connected to a zone substation. It also has potentially high maintenance and operation costs.	$200,000-$300,000	Suitable
Network reconfiguration	Transfer customers on far ends of feeder to adjacent transformer, or strategically install new transformer.	Generally limited to more urban networks with multiple customers and transformers in same area.	$250,000 to $350,000	Suitable: Although usually not suitable for a rural network (see Table 7) the opportunity exists to split the Ben Valley feeder in Yackandandah.
Capacitors, reactors, and static VAr compensators (STATCOMs)	Sinking or sourcing reactive power. Shunt connected capacitors typically installed at substations and switched capacitors along feeders to control reactive power flow, voltage and network losses. Reactors can reduce voltage rise in single-wire-earth-return (SWER) lines.	Flexible set of solutions for different circumstances. Reactive power may not be effective on high impedance networks.	$300,000-$500,000	Suitable
Reconductoring and upgrading distribution transformers	Larger conductors used to reduce network impedance, making it easier to regulate voltage within the required limits. For distribution transformers with underground cables and short overhead lines to supply customers, the transformer can be upgraded to a larger power rating.	Allows for future growth in demand and PV capacity. High capital cost.	$300,000 to $700,000	Suitable
Capacitors, reactors, and static VAr compensators (STATCOMs)	Sinking or sourcing reactive power. Shunt connected capacitors typically installed at substations and switched capacitors along feeders to control reactive power flow, voltage and network losses. Reactors can reduce voltage rise in single-wire-earth-return (SWER) lines.	Flexible set of solutions for different circumstances. Reactive power may not be effective on high impedance networks.	$300,000-$500,000	Suitable
Split SWER	Split a large SWER network into two by dividing customers into two separate SWER ISO transformers.	By having less customers on the SWER ISO transformer, voltage drop due to load and voltage rise due to generation is less pronounced.	$75,000-$150,000	Suitable

3 This is at $1/kWh. It should be noted that this price could change based upon the willingness of the DNSP to buy and the willingness of the customer to sell.

4 This is based on providing all customers with a controlled inverter. The market-scale demonstration will show how many are needed.

THE NETWORK CENTRIC VOLTAGE REGULATION OPTIONS

Table 6 and Table 7 contain a summary of the traditional voltage regulation options (or 'network centric options' versus the 'customer-centric' options of BTM inverter control) for addressing the voltage regulation issues at the two demonstration sites of Collombatti (NSW) and Yackandandah (Victoria).

As can be seen, the network centric options available to the two DNSPs are extremely limited. This is due to a number of reasons that include:

a. The measure is already implemented at that specific site but the issue is still growing.

b. The voltage range already being too great for the measures to be effective.

Where a network centric option is suitable, there are a number of short comings that include:

a. High CAPEX cost

b. High OPEX cost

This is where the opportunity for the 'customer-centric' options of BTM inverter control exists.

Table 6: Cost comparison table: network centric options for Collombatti (NSW)

Voltage control measure description	Technical requirements	Performance	Price	Comments
Refuse further connections of DER	None - customer applications to install further DERs on a feeder is refused.	Does not improve voltage regulation but prevents it getting any worse.	Zero cost initially	Not suitable: Inconsistent with Electricity Network Transformation roadmap - not customer centric, restricts customer choice. Will lead to customer dissatisfaction and risks more customers disconnecting from network in the future.
Transformer taps	Typically 5 or 7 tap settings on a distribution transformer, at 2.5% voltage increments, set at highest allowable voltage for minimum demand so that sagging voltage at far end of feeder is within allowable envelope. Some distribution transformers may have no taps at all, which is more likely on SWER networks.	Insufficient for longer feeders where the voltage sag is very large. This requires manual setting.	$120k and adjustments made to distribution transformers along the feeder.	Not suitable: The voltage range is already too large in Collombatti, and tap adjustments alone will not correct emerging issues within the local network area.
On Load Tap Changers (OLTC)	Responds to changes in demand, automatically adjusts voltage at the zone substation without interrupting power supply through adding or subtracting to the transformer winding. OLTCs are typically equipped with Line Drop Compensators (LDCs).	This is an imprecise measure as voltage is changed for all feeders connected to a zone substation. It also has potentially high maintenance and operation costs.	Can be several hundred thousand dollars including the zone substation transformer cost (i.e. the tap changer mechanism is integrated to the transformer.).	Not suitable: This is already in place at the zone substation at Collombatti and so is not a viable solution. However, even with OLTC at the zone substation, with voltage swing at the end of the feeder, emerging issues remain.
Power electronic voltage regulators	Power-electronic devices that can maintain voltage at a point in a network feeder under varying load conditions. They can include Line Drop Compensators (LDCs) which maintain constant voltage at locations remote to the regulator. Long rural networks often use series voltage regulators (SVRs).	Power electronic based regulators have a much faster response time compared to mechanical regulators, however cost and the available size of electronic based regulators typically limits applications to subsections of LV circuits. They can provide fast response to sudden voltage change and can be operated remotely. Available size range limits use to small parts of LV networks.	$1.185M total	Suitable: However, power electronic equipment is expensive and is likely to need replacing every 7-10 years resulting in higher lifetime costs.
Network reconfiguration	Transfer customers on far ends of feeder to adjacent transformer, or strategically install new transformer.	Limited to more urban networks with multiple customers and transformers in same area.	Not applicable	Unsuitable: Not suitable for a rural radial network such as in Collombatti.
Load balancing	Transfer customers between phases on a three-phase feeder to achieve balanced load, subject to variations between residential customers at different times of the day.	In some circumstances, may help to accommodate a higher number of PV systems.	Not applicable	Unsuitable: Not suitable for SWER lines.
Capacitors, reactors, and static VAr compensators (STATCOMs)	Sinking or sourcing reactive power. Shunt connected capacitors typically installed at substations and switched capacitors along feeders to control reactive power flow, voltage and network losses. Reactors can reduce voltage rise in single-wire-earth-return (SWER) lines.	Flexible set of solutions for different circumstances. Reactive power may not be effective on high resistive networks.	Estimated to be $50k to $75k per site.	Not suitable: Reactive power alone on high resistive line can't correct voltage drop issues (also limited by reactive power injected and isolation transformer kVA rating. Line reactors can be used on long SWER lines to compensate for capacitive voltage rise. However, this is not the case for Collombatti.
Re-conducting and upgrading distribution transformers	The lower source impedance from reconductoring reduces voltage swing (or voltage envelope) caused by generation and/or load. For distribution transformers with underground cables and short overhead lines to supply customers, the transformer can be upgraded to a larger power rating.	Allows for future growth in demand and PV capacity. High capital cost.	$300,000	Suitable: Reconductoring between Regulator site and the start of SWER. This is the Preferred Network-centric Option.
Line-drop compensators (LDCs)	These devices work with other regulators and OLTCs to consider the expected line drop between the regulator and a target location due to the current flow in the line. At times of higher current flow, voltage drop will be higher requiring greater corrective from the regulator.	Provides other regulating equipment with the ability to respond to voltage conditions at separate locations.	Not applicable	Unsuitable: Already in place.
Split SWER	Split a large SWER network into two by dividing customers into two separate SWER ISO transformers.	By having less customers on the SWER ISO transformer, voltage drop due to load and voltage rise due to generation is less pronounced	Estimated to be $180,000 to split SWER.	Unsuitable: Voltage issues will remain on 3 phase steel section between Voltage Regulator and SWER.

Table 7: Cost comparison table: network centric options for Yackandandah (VIC)

Voltage control measure description	Technical requirements	Performance	Price	Comments
Refuse further connections of DER	None - customer applications to install further DERs on a feeder is refused.	Does not improve voltage regulation but prevents it getting any worse.	Zero cost initially	Not suitable: Inconsistent with Electricity Network Transformation roadmap - not customer centric, restricts customer choice. Will lead to customer dissatisfaction and risks more customers disconnecting from network in the future.
Transformer taps	Typically 5 or 7 tap settings on a distribution transformer, at 2.5% voltage increments, set at highest allowable voltage for minimum demand so that sagging voltage at far end of feeder is within allowable envelope.	Insufficient for longer feeders where the voltage sag is very large. This requires manual setting.	Estimate not yet available	Not suitable: The voltage range is already large in Yackandandah. Tap adjustments alone will not correct emerging issues within the local network area.
On Load Tap Changers (OLTC)	Responds to changes in demand, automatically adjusts voltage at the zone substation without interrupting power supply through adding or subtracting to the transformer winding. OLTCs are typically equipped with Line Drop Compensators (LDCs).	This is an imprecise measure as voltage is changed for all feeders connected to a zone substation. It also has potentially high maintenance and operation costs.	\$200,000-\$300,000	Suitable
Mechanical voltage regulators	Uses a solenoid to operate a mechanical switch to disconnect or adjust power flow when there is a voltage excursion. The majority of regulators are High Voltage, although some Low Voltage regulators are used to address specific issues on subsections of Low Voltage circuits.	Potentially high maintenance with high operation costs if excursions are frequent. The number of voltage regulators that can be placed in series is typically limited by the reduction in fault current, which can lead to protection grading issues.	No data	Not suitable
Power electronic voltage regulators	Power-electronic devices that can maintain voltage at a point in a network feeder under varying load conditions. They can include Line Drop Compensators (LDCs) which maintain constant voltage at locations remote to the regulator – they are mentioned separately below. Long rural networks often use series voltage regulators (SVRs).	Power electronic based regulators have a much faster response time compared to mechanical regulators, however cost and the available size of electronic based regulators typically limits applications to subsections of LV circuits. They can provide fast response to sudden voltage change and can be operated remotely. Available size range limits use to small parts of LV networks.	No data	Not suitable
Network reconfiguration	Transfer customers on far ends of feeder to adjacent transformer, or strategically install new transformer.	Limited to more urban networks with multiple customers and transformers in same area.	\$10,000, depends on the network per customer/ New Transformer - \$250,000 to \$350,000 depending on location type, line configurations.	Unsuitable: May not be suitable for a rural network such as in Yackandandah.
Load balancing	Transfer customers between phases on a three-phase feeder to achieve balanced load, subject to variations between residential customers at different times of the day.	I n some circumstances, may help to accommodate a higher number of PV systems.	\$1,500 -\$2,500 per one location.	Unsuitable: Not suitable for SWER lines such as in the Ben Valley.
Capacitors, reactors, and static VAr compensators (STATCOMs)	Sinking or sourcing reactive power. Shunt connected capacitors typically installed at substations and switched capacitors along feeders to control reactive power flow, voltage and network losses. Reactors can reduce voltage rise in single-wire-earth-return (SWER) lines.	Flexible set of solutions for different circumstances. Reactive power may not be effective on high impedance networks.	Approximately \$300,000- \$500,000 depends on size.	Suitable
Reconductoring and upgrading distribution transformers	Larger conductors used to reduce network impedance, making it easier to regulate voltage within the required limits. For distribution transformers with underground cables and short overhead lines to supply customers, the transformer can be upgraded to a larger power rating.	Allows for future growth in demand and PV capacity. High capital cost.	Upgrading Conductors \$200,000 to \$400,000 depending on size of the conductor and the terrain. Upgrading of the transformer \$100,000 to \$300,000 depending on the size and the location and network configuration.	Suitable
Line-drop compensators (LDCs)	These devices work with other regulators and OLTCs to consider the expected line drop between the regulator and a target location due to the current flow in the line. At times of higher current flow, voltage drop will be higher requiring greater corrective from the regulator.	Provides other regulating equipment with the ability to respond to voltage conditions at separate locations. AusNet Services are considering how to implement LDC characteristics on existing voltage relays.	No Data.	Not suitable
Split SWER	Split a large SWER network into two by dividing customers into two separate SWER ISO transformers.	By having fewer customers on the SWER ISO transformer, voltage drop due to load and voltage rise due to generation is less pronounced.	\$75,000- \$150,000 Depending on location, type, line configurations.	Suitable

THE BEHIND THE METER VOLTAGE REGULATION OPTIONS

Customer CAPEX

Table 8 contains an indicative summary of the main equipment costs for customers under the behind the meter voltage regulation option for the Yackandandah trial. As can be seen, for a new customer with no existing PV or battery system, even with the significant subsidy the cost of the full package (PV + battery + VPP control device) is close to $20,000 for the customer. Collombatti customers were handled by several vendors, so the whole system cost cannot be broken down so cleanly, but customers paid in the order of $4,000-8,000 out-of-pocket for their solar/storage systems at the rate of subsidy that applied for the market-scale demonstration.

For Yackandandah, in the case where an existing PV owner is targeted, the marginal cost of adding a subsidised battery storage system (and VPP control device) can be reduced to just over $10,000.

Where an existing PV and battery owner is targeted, the marginal cost of adding a VPP control device would be around $1,000. It should be noted that at the time the Networks Renewed project was initiated in 2015/16, the residential battery storage market in Australia was still in its nascent phase. By 2017, 12% of solar PV installations had a battery installed grown from 5% in 2016.

Table 6: Cost comparison table: network centric options for Collombatti (NSW)

Item	Capital Cost	Subsidy	Whole System	New Battery + Mondo Ubi added to existing PV System	Mondo Ubi added to existing PV System & or Battery
Solar System (5kW)	$8,600	$0	$8,600	$0	$0
Battery & Hybrid Inverter (10kWh)	$16,700	$7,200	$9,500	$9,500	$0
Mondo Ubi Device	$830	$0	$830	$830	$830
		Total	$18,930	$10,330	$830

THE CUSTOMER'S FINANCIAL PROPOSITION

Tables 9 to 12 give an indicative analysis of the customer financial proposition from a publicly available commercial tool, using data inputs from this project and a feed-in tariff of 12 cents/kWh. In the case of Yackandandah, the capital cost of battery storage systems is still high, with paybacks of more than 10 years with the subsidy (and over 20 years without). Actual system installed prices are used, in comparison with the price list figures above.

The financial case for the customer improves wherever the Mondo Ubi VPP or Reposit Box control and voltage control payments become part of the package. Under the Yackandandah model, customers receive an annual payment of $200 to cover any potential losses in energy due to control actions. In the Yackandandah trial, the installation subsidy tips the balance from an unviable proposition (see base case in Table 9 to one with a low but acceptable IRR.

The best financial proposition is where an existing PV and battery owner purchases a Mondo Ubi VPP control or Reposit Box, with low marginal cost and a short payback possible with the voltage regulation payments.

Table 9: Yackandandah: Summary of customer financial analysis under various scenarios

Yackandandah outcomes (6kW PV 10kWh Battery)	Capital Cost	NPV (20 years, 5% discount)	IRR	Payback (years)
Base Case (New system): PV & Battery System (without Mondo Ubi, without subsidy)	$29,993	$9,991	0.66%	18.7
Whole System (without subsidy, with Mondo Ubi)	$30,823	$8,329	1.55%	17.1
Whole System (with subsidy and Mondo Ubi)	$21,963	$531	5.28%	12.2
Base case (pre-existing system) **New Battery added to existing PV System (without Mondo Ubi, without subsidy)**	$19,121	$881	5.54%	11.9
New Battery added to existing PV System (without subsidy, with Mondo Ubi)	$19,951	$2,544	6.46%	11.1
New Battery added to existing PV System (with subsidy and Mondo Ubi)	$11,091	$11,404	15.34%	6.1
Mondo Ubi added to existing PV System & battery (subsidy N/A)	$830	$21,664	217.47%	0.5

The Collombatti trial had slightly stronger financial outcomes, with quite short paybacks for the subsidised case, however the unsubsidised base case was reasonable too with a payback of 7 to 9 years. It is important to note that the Yackandandah subsidised battery cost is likely to be a good representation of what battery prices will be in the near future. The Collombatti subsidy was more generous due to the greater need to incentivise customers in this area, and the relative lack of access to capital that is experienced by residents in this area.

Table 11 presents the typically outcomes actually experienced by Collombatti participants. Table 12 examines what the financial case would realistically be should Essential Energy expand the program to other areas, retaining the ongoing network support payments but not providing an upfront subsidy. When compared with the BAU case in Table 10. It can be seen that payback periods for solar & battery systems are brought down approximately 1 year from 9 / 7 years to 8 / 6 years for a 6.5 / 9.8 kWh battery.

As the market scale demonstration continues and customer load data become available, it will be important to examine how much energy is used by voltage control during the experiments, as well as any other costs for the customer. On the customer revenue side, Essential Energy in NSW is investigating a reduction to the bid price for the purpose of lowering the overall cost of the solution, and widening the scope for application. This will require a major effort in customer education. Once the analysis of energy impacts and bid prices is complete it will be possible to develop a more realistic cash flow that takes these into account. We note however that as customers are unable to set their own 'accept' limits in response to an adjusted bid price from Essential Energy, they are in effect price-takers.

The Collombatti model uses $1 per kWh payments for control events, with annual payments to date averaging around $260 for a 6.5kWh battery up to $330 for a 9.8kWh battery, per year.

Table 10: Collombatti – BAU Summary of customer financial analysis under various system sizes

Battery size (kWh)	PV Size (kW)	Capital cost ($)	Capital cost after subsidy ($)[8]	Annual saving (BAU PV/ Battery operation)[9]	NPV ($)[10]	Payback period (years)
6.5	-	10,625	10,625	10,625	9,578	126
6.5	3	14,180	11,886	11,886	3,892	9
6.5	6	17,735	13,147	13,147	10,881	7
9.8	-	11,879	11,879	11,879	9,311	58
9.8	3	15,434	13,140	13,140	3,211	10
9.8	6	18,989	14,401	14,401	10,786	7

Table 11: Collombatti – Typical outcomes for trial participants under various system sizes

Battery size (kWh)	PV Size (kW)	Capital cost ($)	Capital cost after subsidy ($)[11]	Annual saving (BAU PV/Battery operation)	Networks renewed: average additional saving/kWh of storage (during trial period only)[12]	NPV ($)[10]	Payback period (years)
6.5	-	10,625	1,700	84	141	512	19
6.5	3	14,180	2,961	1,266	141	12,958	2
6.5	6	17,735	4,222	1,928	141	19,947	2
9.8	-	11,879	1,704	206	179	1,042	7
9.8	3	15,434	2,965	1,312	179	13,564	2
9.8	6	18,989	4,226	2,021	179	21,139	2

Table 12: Collombatti – Hypothetical financial outcomes for ongoing Essential Energy network support

Battery size (kWh)	PV Size (kW)	Capital cost ($)	Capital cost after subsidy ($)[8]	Annual saving (BAU PV/Battery operation)	Networks renewed: average additional saving/kWh of storage (during trial period only)	NPV ($)[10]	Payback period (years)
6.5	-	10,625	10,625	84	265	6,277	30
6.5	3	14,180	11,886	1,266	265	7,193	8
6.5	6	17,735	13,147	1,928	265	14,182	6
9.8	-	11,879	11,879	206	332	5,171	22
9.8	3	15,434	13,140	1,312	332	7,352	8
9.8	6	18,989	14,401	2,021	332	14,926	6

8 The only subsidy is STCs at an assumed STC price of $37.

9 Battery-only systems assume off-peak charging. Battery and solar systems assume only charging from solar excess.

10 Discount rate 5%, Project life 20 years.

11 Includes STCs and Networks renewed upfront subsidy covering Reposit box and $1350/kWh up to a 7.5kWh maximum.

12 Payments reflect only part of the year, as trials were run at different times.

Market Participation Value Assessment

This section contains the assessment of the market participation value when providing aggregated FCAS.

BACKGROUND ON FCAS

Frequency Control Ancillary Services (FCAS) are used by AEMO to manage the power system to ensure safe, reliable and secure supply of energy.

There are eight separate FCAS markets and participants can receive payments for providing availability and for delivery of the services. Regulation markets are suitable for generators and loads that have a suitable direct communication method with AEMO, but contingency markets are locally activated and are suitable for residential inverter-connected resources. The eight markets are:

Regulation

1. Regulation Raise: Regulation service used to correct a minor drop in frequency.
2. Regulation Lower: Regulation service used to correct a minor rise in frequency.

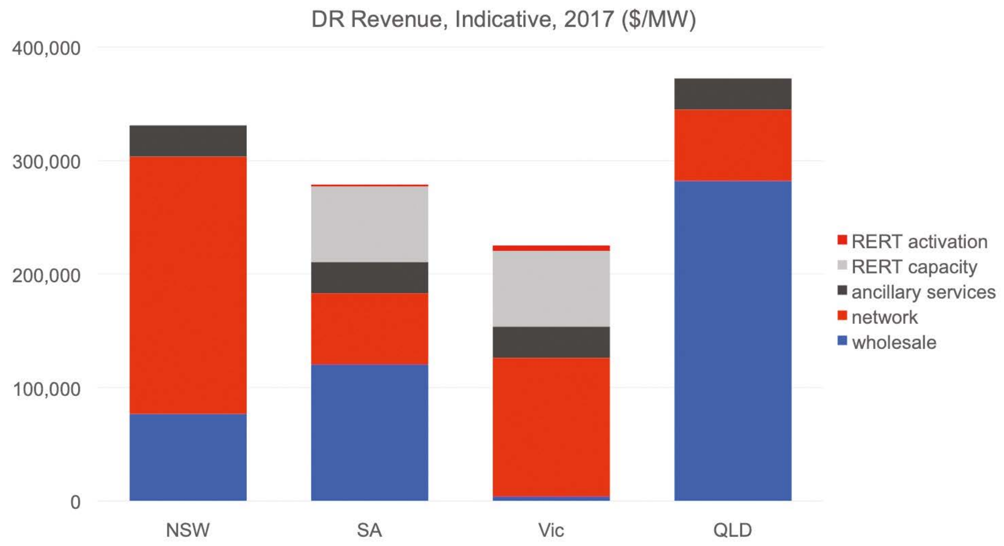
Contingency

3. Fast Raise (6 Second Raise): 6 second response to arrest a major drop in frequency following a contingency event.
4. Fast Lower (6 Second Lower): 6 second response to arrest a major rise in frequency following a contingency event.
5. Slow Raise (60 Second Raise): 60 second response to stabilise frequency following a major drop in frequency.
6. Slow Lower (60 Second Lower): 60 second response to stabilise frequency following a major rise in frequency.
7. Delayed Raise (5 Minute Raise): 5 minute response to recover frequency to the normal operating band following a major drop in frequency.
8. Delayed Lower (5 Minute Lower): 5 minute response to recover frequency to the normal operating band following a major rise in frequency.

Figure 6 illustrates the revenue that could have been available within each of the major state markets during 2017 for providing energy market services, in these categories:

- **System reserves (RERT)** - 2017-18 summer payments (note: RERT capacity must be off-market and is not available for wholesale or FCAS market).
- **Wholesale markets** - value is based on bidding 1MWh into each half-hour settlement > $500/MWh (minus a 15% retailer margin).
- **Ancillary services** – value based on information provided by an aggregator.
- **Networks** - value is based on 75% of the average deferrable investment where there is a network constraint in each state (note: less than 10 per cent of zones in most distribution networks have a constraint).

Figure 6: Indicative demand response revenue by state for different services (not specific for this project)



Source: ISF & A2EP (2018). Renewable Energy and Load Management: REALM for Industry Report. Report for ARENA. Available at: arena.gov.au/projects/realm-renewable-energy-load-management-businesses

UNCERTAINTY AND RISK

Values vary dependent on the amount of service required (and provided) at any time and as this varies considerably, costs can also vary.

An example of was with the Hornsdale Power Reserve (HPR) in the first half of 2018. The HPR took 55% of South Australia's FCAS market despite only representing 2% of the capacity. The impact on this was a 90% lowering of price and this decline was against the trend in FCAS prices in other NEM states. There were cited issues that the fast response of the HPR meant that FCAS services provided weren't able to be counted and as a result, didn't end up any payment being made.

This highlights the uncertainty and risk that underlies any plan to base a business case on FCAS revenue alone.

CURRENT AND FUTURE OPPORTUNITY FOR FCAS WITH NETWORKS RENEWED

In principle, at the regulatory level the current framework is not well adapted to enable the capturing of market participation value in a residential setting when providing aggregated FCAS. This was the direct experience of the project partners who had been spending significant effort in recent years to access these values. Some participating customers chose to make their batteries available for FCAS trading, through a suitable retailer offering, and the technical means for this are all in place. However no FCAS bids were placed during the trial.

This does highlight the need for further regulatory reform in this area. In future, new opportunities may also still emerge for voltage and frequency management under the Demand Management Incentive Scheme which provides around $1 billion for cheaper alternatives to new poles and wires.

In addition, uncertainty and risk around FCAS does make voltage regulation payments, such as those provided by the DNSPs in this project, seem less risky and more certain than other potential values streams that may have been sought.

Canvassing DNSPs on Voltage Regulation Value

This section describes how a broader set of DNSPs will be helpful in developing a value estimating tool for voltage regulation services.

A competitive market with a diversity of suppliers is an efficient way to determine the value of services – however, for voltage regulation in electricity distribution networks, there is only the Networks Renewed project demonstrating a service-based approach. Two demonstrations in selected feeders of two DNSPs can indicate the costs involved and the willingness of networks to pay for voltage regulation services, but due to their modest scale, neither represents the efficient costs and competitive pricing that will be achieved in a well-functioning market. They are an important precedent towards establishing such a market, and will at least provide sensible bounds on likely future market costs.

The other available approach available to understanding the value of voltage regulation services is the cost of achieving the same result using more traditional network-side solutions. The extensive suite of options given and approximately costed in Tables 6 and 7 provides a helpful guide, and to achieve a broader view these tables will be circulated among a wider set of DNSPs, especially those who are actively considering customer-side approaches and may be intending to carry forward the knowledge from Networks Renewed.

As start has been made at the public forum on the market-scale demonstration which was held in Melbourne on 5th October 2018. As well as the two existing DNSP partners, two other DNSPs attended and participated actively, SA Power Networks and Energy Queensland, and some others are also being approached to extend the geographic reach. A continuing engagement will include assessment of and contribution to the existing tables to incorporate the experience that exists within these businesses.

A systematic approach like the following will be developed with existing and new DNSP partners to convert this knowledge into an approximate yet widely applicable estimating tool:

1. Provide statistical or explicit data on the occurrence of voltage issues across the whole of the networks managed by each DNSP, as far as available data allow, and categorise the types of voltage pathology that occur (they are not always due to solar generation).
2. Agree on a set of network types that will exhibit similar voltage behaviours and for which a similar approach is likely to be applicable (for example, single-wire earth-return rural network, high-density urban overhead 3-phase LV network, low-density suburban overhead 3-phase LV network, commercial HV feeder hosting MW-scale rooftop solar generation, etc.).
3. Assign network-side solutions to each type and estimate their cost as a function of MW of load or solar capacity. This will be inherently uncertain but within a factor of two is a reasonable expectation.
4. Consider what fraction of the cost of each solution should be assigned to voltage regulation, because some network upgrades will be done to solve multiple problems, not only voltage issues (for example, reconductoring permits load growth as well as reducing the voltage envelope).
5. Work collaboratively to define and develop the estimating tool, which may be in the form of a document, a spreadsheet, or web-based "wizard" software.

This will be delivered alongside the quantified Business Case report at the end of the project.

Referencing Relevant Findings from the Electricity Network Transformation Roadmap

FEATURES OF A WINNING BUSINESS MODEL

The Electricity Transformation Roadmap was developed as a guide for networks to deliver on a number of key customer outcomes amidst the major ongoing changes in the energy system over the period 2017 to 2027. Published in 2017, it was jointly produced by CSIRO (the national science agency) and Energy Networks Australia (the peak national body representing gas distribution and electricity transmission and distribution business in Australia.

There are a number of key quotes that relate to customers and the business models deployed in the trial are clearly a step towards this vision.

ELECTRICITY NETWORK TRANSFORMATION ROADMAP

“Networks should seek to expand information services to enhance interactions with customers.”

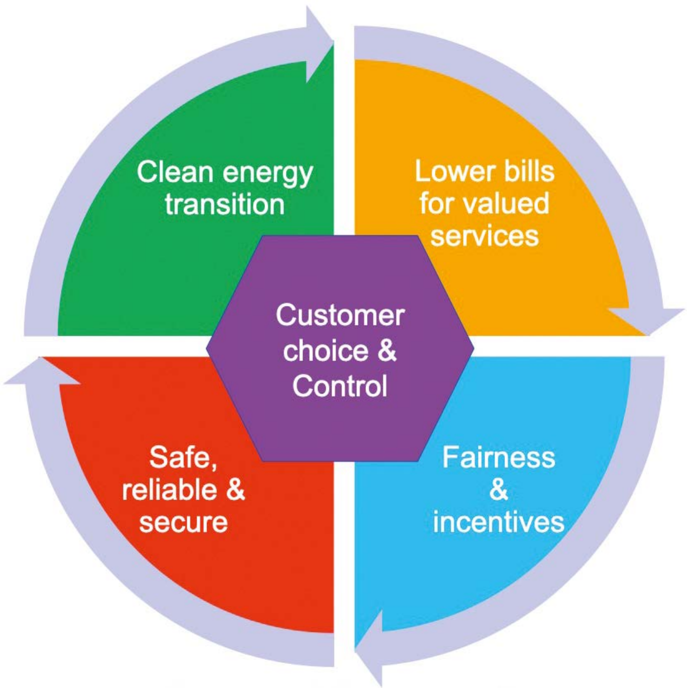
“Networks need to enhance relationships with customers built on improved data analytics capabilities and a deeper understanding of increasingly diverse customer need.”

“Transforming the network business model to align future network products and services with the needs of customers and the diverse market actors which will create value on the grid platform.”

“Networks will play a key role in the delivery and connection of an expanding range of innovative products and services to customers.”

“Networks enable new customer value with and on behalf of diverse market actors and customer agents through financially valuing system benefits provided by distributed energy resources.”

Figure 7: Balanced Scorecard of Customer Outcomes



Source: Electricity Network Transformation Roadmap – Final Report (ENA, CSIRO 2017).

Other features of a winning business model – in terms of the customer and the network were highlighted at a technical workshop in Melbourne.

These are summarised in Figure 7.

For the customer, these have been grouped by the headings of the balanced scorecard of Customer Outcomes (from the Electricity Network Transformation Roadmap), of which customer choice and control is the central tenet.

VOLTAGE CONTROL – MOVING TO A MODEL OF SHARED BENEFITS

At the workshop held on 5 April in Melbourne and attended by the different DNSPs, participants were asked to list the features for a successful business model for BTM inverter voltage control. The responses are grouped and summarised in Table 13 and Table 14.

For the Customer, these are grouped according to the Balanced Scorecard of Customer Outcomes from the Electricity Network Transformation Roadmap.

Table 13: Features of a winning business model – for the customer

Q: What are the features of a winning business model for this study – for the Customer?	
Clean energy transition	- Provide more options for investing in DERs - Reduce barriers to entry for installing DERs
Safe, reliable, secure	- Provide reliability of power supply
Lower bills for valued services	- Be a 'cheap' option (less than $10,000 CAPEX) - Reduce energy costs - Cost and value reflective
Fairness & Incentives	- Enhance transparency of ongoing energy costs - Balance of customer benefit and network benefit

Table 14: Features of a winning business model – for the DNSP

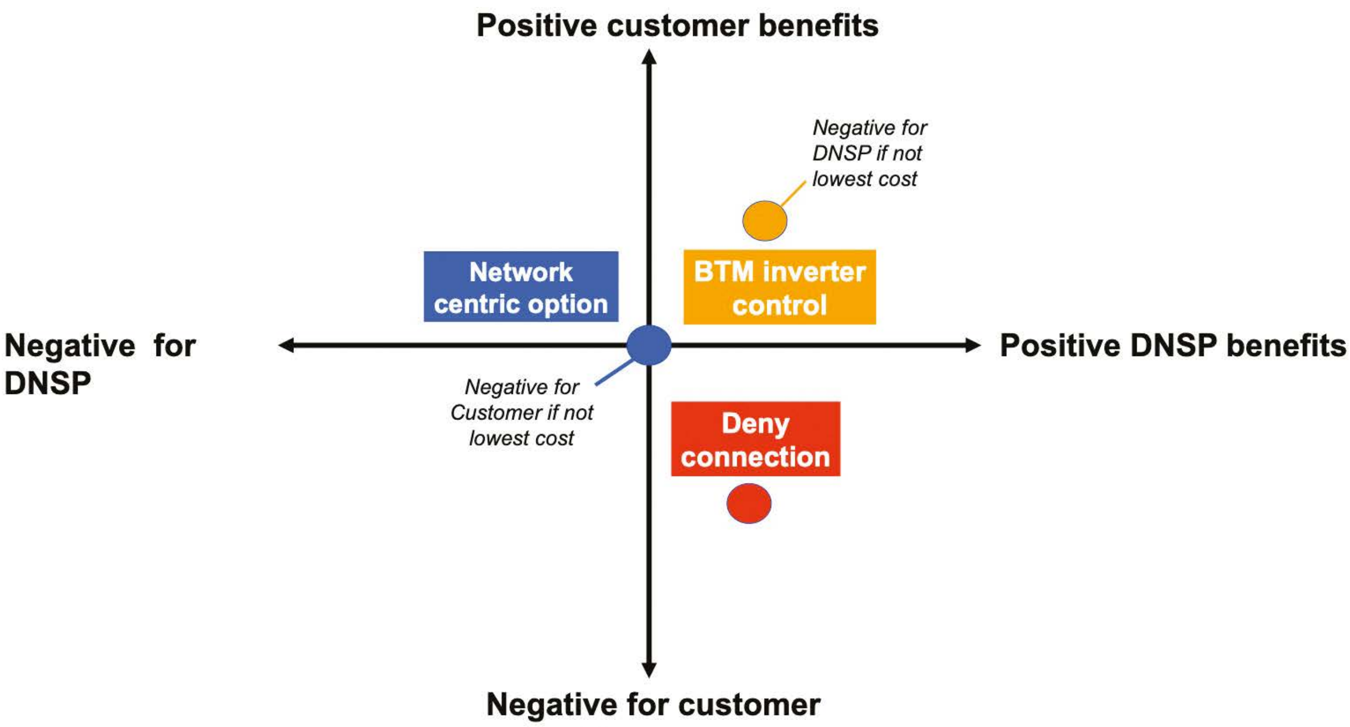
Q: What are the features of a winning business model for this study – for the Network Service Provider?	
Be scalable to 1,000s and more **Allow risk management** **Be compliant with electricity regulations** **Provide a predictable impact on the network / Deliver reliance performance outcomes / Provide reliable comms and control** **Put downward pressure on network charges**	- Improve network utilisation / Improve network visibility. - Unlock value from the Network for customers at least cost - supporting uptake of renewables. - Be more cost effective than other network solutions / Offer the least cost solution to address Network Constraints / Be cost effective over the whole lifecycle.

This can be further summarised in Table 15, with inferences drawn on what would be a positive outcome for the two main stakeholders of the customer and the DNSP for the comparison of network improvement options. This allows, for example, voltage regulation strategies to be mapped on an indicative scale of benefits as shown in Figure 8 – a qualitative exercise helpful for communicating the rationale that leads to choosing one option over another.

Table 15: Comparing the network improvement options

Stakeholder	Negative for stakeholder	Positive for stakeholder
Customer	*- Restricts choice* *- Increases energy cost* *- Complex* *- Un-predictable earnings* *- "Expensive"*	*- Provides choice* *- Reduces energy cost* *- Easy to understand* *- Predictable earnings* *- "Cheap"*
DNSP	*- Prevents risk management* *- Not cost effective* *- Unreliable* *- Unpredictable* *- Increases network charges* *- Does not enhance customer relationship* *- Reduces network utilisation*	*- Allows risk management* *- Cost effective solution* *- Reliable* *- Predictable* *- Reduces network charges* *- Enhances relationship with customer* *- Increases network utilisation*

Figure 8: The alternatives for voltage control – moving to a least-cost model of shared benefits



Appendix 1: The Customer Journey

THE CUSTOMER JOURNEY

The customer journey illustrates the steps the customers go through in engaging with a company. For the two trials this was broadly the same, although there were subtle differences. The main steps have been characterised below.

Awareness

Raised through press releases, word of mouth, 'Townhall' meetings, mass mail drops.

Consideration & research

Undertaken through visiting stakeholder websites, completion of online EOI forms, discussing directly with installers (through phone call and home visit).

Purchase

Initiated through review and signing of contract, paying the Supplier, agreeing an installation date.

Service

Receiving of alerts on mobile phone via app, checking of smart phone app, contacting VPP aggregator or Installer by phone or email.

Retention

Visiting online portal, opening smart phone app, reviewing energy usage and any savings or payments.

Advocacy

Attending community form events, discussing with neighbours, engaging with social media platforms.

Appendix 2: Risk Definition Summary

DESCRIPTION OF RELEVANT RISKS

Relevant Risk	Notes
Investment	Bearing the risk (and assuming the obligation) of providing the investment needed for the deployment of the BTM voltage control system.
Insolvency (Supplier)	Bearing the risk that is linked to the potential insolvency/bankruptcy of the Supplier.
Insolvency (3rd party)	Bearing the risk that is linked to the potential insolvency/bankruptcy of the third party (e.g. inverter manufacturer, aggregator, etc.).
Insolvency (Customer)	Bearing the risk that is linked to the potential insolvency/bankruptcy of the Customer.
Maintenance & breakdown	Bearing the risk of providing the ongoing service and maintenance regarding the BTM voltage control system and the corresponding risk of temporary breakdown of the equipment (technical risk).
Warranty and guarantee	Bearing the risk of obligations that arise out of legal warranties or issues guarantees.
Total loss	Bearing the risk of a total loss of the BTM voltage control system.
Performance	Bearing the risk of the amount of power available for providing BTM voltage control.
Energy price	Bearing the risk of changes in the price of energy.
Voltage payment incentive	Bearing the risk of the amount the customer's being paid for providing BTM voltage control.
Customer behaviour	Bearing the risk of customer´s behaviour regarding their use of power and the amount of BTM voltage control they choose to make available.
Weather	Bearing the risk of unusual weather.
Policy / regulatory	Bearing the risk of changes of the legal/regulatory framework that are linked to the business model (e.g. surcharges, taxes, discontinuation of subsidies).
Hardware durability	Bearing the risk of any accelerated ageing of the hardware through increased utilisation as part of the VPP.

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