29 July 2016

Dr Ron Ben-David
Chairperson, Essential Services Commission
Level 37, 2 Lonsdale St
Melbourne, VIC 3000

By electronic lodgement

Dear Dr Ben-David

INQUIRY INTO THE TRUE VALUE OF DISTRIBUTED GENERATION: NETWORK VALUE DISCUSSION PAPER

CitiPower and Powercor welcome the opportunity to respond to the Essential Services Commission of Victoria's (**ESCV**) discussion paper on the network value of distributed generation. Our submission builds on the previous material provided to the ESCV, as well as that submitted to the Australian Energy Market Commission (**AEMC**) in its review on local generation network credits. In particular, our submission demonstrates the following:

- the existing regulatory framework already ensures networks have the right incentives to reward distributed generation where it adds value to the network. This includes the capital expenditure sharing scheme, and cost-reflective network tariffs;
- the network value provided by distributed generation is through the potential deferral of demand-driven augmentation. Any network benefits due to lower replacement or operating expenditure are not expected to be material;
- residential solar PV may reduce energy at risk on our network, but will not materially reduce peak demand. Any network assets that are planned based on peak demand, therefore, will not be impacted by residential solar PV;
- distributed generation must meet a threshold level of capacity within a certain timeframe to defer augmentation, and below this threshold, there are no material network benefits;
- the potential network value provided by residential solar PV and residential solar PV plus battery systems may only be material for approximately 4 per cent of Powercor customers. The network value to CitiPower customers from distributed generation is zero; and
- any network value provided by distributed generation is best calculated by distributors.

Should the ESCV have any queries regarding this submission, please do not hesitate to contact Jeff Anderson on
.

Yours sincerely,

Renate Vogt

Head of Regulation, CitiPower and Powercor

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Network value of distributed generation

The network value of distributed generation is driven by a range of factors. This includes the location and timing of any distributed generation, as well as the categories of network expenditure which may be avoided. These factors also impact how investors in distributed generation may be compensated for any network value their investment provides.

Our submission builds on the recent discourse on the value of distributed generation, including that set out in response to the ESCV's inquiry, and the rule change proposal to the AEMC for the introduction of a local generation network charge. Notably, our submission is supported by modelling that quantifies where in our network distributed generation can provide value to our customers. It is structured into the following sections:

- method to determine the network value provided by distributed generation;
- source of network value provided by distributed generation; and
- network value provided by distributed generation on our network.

We also respond to the ESCV's questions, as set out in appendix A.

A detailed outline of the model used to determine the value of distributed generation on our network is attached to this submission as appendix B.

1.1 Method to determine network value provided by distributed generation

The determination of the network value provided by distributed generation is a complex task. As new technology emerges, and the challenge of remaining relevant to our customers continues, it is increasingly important we understand where non-network solutions can provide value to our customers.

In this context, we engaged ENEA to undertake a modelling exercise of our network to determine where distributed generation may provide network benefits, and to detail the magnitude of these potential benefits. This exercise was focused on sub-transmission lines and zone substations augmentations, which represent the largest share of demand-driven augmentation. The calculation could be applied to high-voltage feeders as well. The low-voltage (**LV**) network was not considered since the vast majority of LV augmentation expenditure is directly attributable to new connections (and customers can already balance connection or upgrade costs with alternatives such as distributed generation).

The threshold for network investment is typically driven by short periods of demand, generally occurring in summer. Given this pattern of electricity demand, ENEA's approach was to consider where distributed generation may defer planned augmentation by one year.

ENEA's approach to determining network value differs from (our understanding of) the preliminary approach proposed by the ESCV in several key areas, including the following:

- ENEA's method is based on planned augmentation capital expenditure, which is forecast as part of the distribution annual planning exercise. In contrast, the ESCV's preliminary approach considers a virtual counterfactual estimate of maximum peak demand without distributed generation. This counterfactual would be very difficult and/or costly to evaluate. It also appears to base forecast future benefits on historic consumption choices that may no longer be relevant (i.e. that demand growth rates are constant and that required investments to cope with this demand growth will be similar to those made in the past);
- ENEA's method has regard to network specific information, including maximum demand forecasts, asset load profiles and ratings, and energy at risk. The ESCV's preliminary approach, however, appears to only rely on the impact distributed generation may have on maximum demand;

- ENEA's method focuses on future distributed generation and network investments, rather than past installations. This ensures that price signals will be targeted to areas where investments are planned. In contrast, the ESCV's preliminary approach is likely to send price signals to the wrong locations on our network—that is, where the future value of additional distributed generation is zero; and
- ENEA's method considers the network assets used to service particular customers. The ESCV's preliminary approach appears to only have regard to location factors based on post-codes. This approach would be less effective at sending price signals to the right locations and customers on our network (e.g. as network planning and assets are not based on post-codes).

A more detailed explanation of ENEA's modelling is set out in appendix B, and their preliminary results are discussed in section 1.3. We also note that ENEA's modelling process is ongoing. In particular, ENEA's modelling will be updated to have regard to the following:

- updated demand forecasts;
- further analysis on the impact of residential solar photovoltaic (**PV**) and battery systems on peak demand; and
- valuation of generation export only (i.e. the current modelling values total generation output).

To the extent ENEA's updated modelling materially amends the results presented in this submission, we will provide these updates to the ESCV.

1.2 Source of network value provided by distributed generation

In its discussion paper, the ESCV set out four broad categories of network benefits, with three of these relating to 'economic' value—network capacity, grid support services, and electricity supply risk. The ESCV also identified whether it considered these values were driven by augmentation and/or replacement capital expenditure, or operating expenditure reductions. We discuss the ESCV's categories below.

For clarity, we recognise that distributed generation is likely to provide other benefits that do not accrue to the network—most notably, there are energy market benefits (which are the subject of stage one of the ESCV's inquiry).

1.2.1 Network capacity

We agree that distributed generation can provide network value through the ability to defer and/or avoid demand driven augmentation. However, as discussed below, much of this value is already captured by the existing regulatory framework, and/or is restricted by technical or practical constraints.

Further, any replacement capital or operating expenditure benefits driven by distributed generation are expected to be non-existent, immaterial and/or outweighed by inherent network costs.

Benefits captured in the existing regulatory framework

The existing regulatory framework already provides networks with the right incentives to reward distributed generation where it provides value:

- there is now an ongoing financial incentive for distributors to seek the least cost solution for network augmentation throughout a regulatory control period—the Capital Expenditure Sharing Scheme (**CESS**). As distributors will only receive a CESS benefit when network augmentation is efficiently deferred, it encourages distributors to develop dynamic and location specific price signals. The CESS is also a low cost scheme to administer; and
- distributors are now required to develop cost-reflective network tariffs. Over time, cost-reflective network tariffs will ensure any generation that reduces load will be compensated at the efficient cost-reflective rate; and
- probabilistic planning standards in Victoria result in our key augmentation projects, when required, being significant in capacity. That is, probabilistic planning encourages investment only when the value of energy at risk is greater than the cost of removing that risk. However, given non-network solutions are typically small

relative to the level of energy at risk under a probabilistic planning framework (particularly at local levels of the distribution network), non-network solutions may only defer augmentation (as opposed to removing the need). This may reduce any potential benefit of non-network solutions relative to network solutions.

Additionally, the existing regulatory framework ensures the potential benefits that distributed generation may provide through the deferral of demand driven augmentation expenditure are realised. For example, deferred augmentation benefits from distributed generation are reflected in our regulatory proposals. Specifically, the demand forecasts used to determine our augmentation expenditure requirements for the 2016–2020 regulatory control period took into account predicted growth in distributed generation on our network (including from solar PV systems). Where growth in distributed generation has lowered our demand forecasts, such that network augmentation is no longer required to address a network constraint, this benefit will already be reflected through lower tariffs to all of our customers over the 2016–2020 regulatory control period.

Technical and practical limitations of distributed generation

The potential for distributed generation to provide network capacity benefits may be restricted by the technical and practical limitations of distributed generation (in particular, residential solar PV systems). For example:

- the capacity of distributed generation required to defer planned network investment may be so great that the resultant contribution of reverse power flows at the time when solar PV generation peaks exceeds the network rating of the zone substation (such that no amount of additional distributed generation will reduce the energy at risk);
- the capacity of solar PV generation required at maximum demand to defer planned network investment may cause voltage issues. This may necessitate local augmentations of distribution transformers, or the changing of taps on distribution transformers, to connect the requisite level of solar PV. It is estimated that voltage issues can start when solar PV generation reaches 30 per cent of distribution transformer capacity;
- the number of solar PV systems required to defer planned network investment may exceed the available number of residential properties, or represent unrealistic penetration levels (particularly in the timeframes required for network planning processes); and
- ENEA's initial analysis indicates that distributed generation, particularly residential solar PV, is unlikely to materially lower maximum demand on our network (as the solar PV export peak may not coincide with our spatial network peaks, due to timing misalignment or cloud cover). This limits the ability for residential solar PV to defer or avoid demand-driven augmentation.

Each of the above examples exists on our network today, and the quantitative impacts of these factors on our network are discussed in section 1.3.

Critically, the deferral of planned network investment requires the cumulative capacity of the distributed generation to be sufficient. If the cumulative capacity of the distributed generation does not meet the required threshold—for example, for the reasons noted above—the network value of any distributed generation is zero. That is, the distributed generation capacity would be insufficient to defer the planned investment.

The requirement for the cumulative capacity of distributed generation to exceed the augmentation threshold also presents difficulties in considering how to compensate any investors in distributed generation. For example, where the cumulative capacity does not suffice, any ex-ante incentives paid to distributed generators would provide no value to our customers. It is not clear how the ESCV proposes to address this issue.

Replacement capital expenditure and operating expenditure

For the following reasons, the alleviation of network congestion due to distributed generation is also unlikely to drive reduced replacement expenditure or lower operating expenditure:

- the increased penetration of distributed generation, particularly residential solar PV, is changing our operational processes. For example, when a customer requests to connect a solar PV and/or solar PV plus battery system to our network, we need to assess the impact of this generation capacity on the relevant local distribution substation rating. If the solar PV capacity at a distribution transformer exceeds 30 per cent of transformer rating, further investigations—and corresponding operating expenditure—are required to assess whether local augmentation may be required;

- the increased penetration of residential solar PV generation is also changing the daily load profile on our network. Historically, our daily load profiles reflected a morning peak, followed by a larger evening peak and minimum night load. Our network, however, now displays a later evening peak and a decreasing minimum demand during the day. This increased range from minimum to maximum has caused much larger voltage variation resulting in increased operational expense to maintain voltage. This is driving different maintenance requirements. On this basis, the ESCV should not assume that increased penetration of distributed generation will result in reduced operating expenditure;
- over 80 per cent of our maintenance expenditure relates to vegetation management and maintaining our 'poles and wires'. None of this expenditure is directly demand related (e.g. a pole or cross-arm will deteriorate regardless of the circuit loading). The remaining 20 per cent of our maintenance expenditure is associated with largely fixed costs. On this basis, the ESCV should not assume that increased penetration of distributed generation will result in reduced operating expenditure;
- our network assets are assessed under a condition based monitoring regime. This program considers replacement needs against a combination of load and asset condition indices. For example, an ageing asset will be replaced as the combined load and condition profiles of the asset indicate a risk of not supplying energy to customers. Distributed generation, in specific circumstances, may result in lower asset condition indices. Load indices, however, are based on maximum demand. As noted previously, residential solar PV systems are unlikely to materially lower maximum demand (and therefore are unlikely to reduce load indices);
- as set out above, distributed generation, in specific circumstances, may result in lower asset condition indices. The ability for distributed generation to reduce the worsening of condition profiles, however, occurs over the lifetime of the asset. The replacement assets planned in the next ten years are already deteriorated to the extent that reducing their loading will have little effect on replacement timing; and
- many network assets are not impacted by load, such that distributed generation will have no impact on their replacement cycles. For example, residential solar PV and battery will not drive lower pole replacement rates.

1.2.2 Grid support services

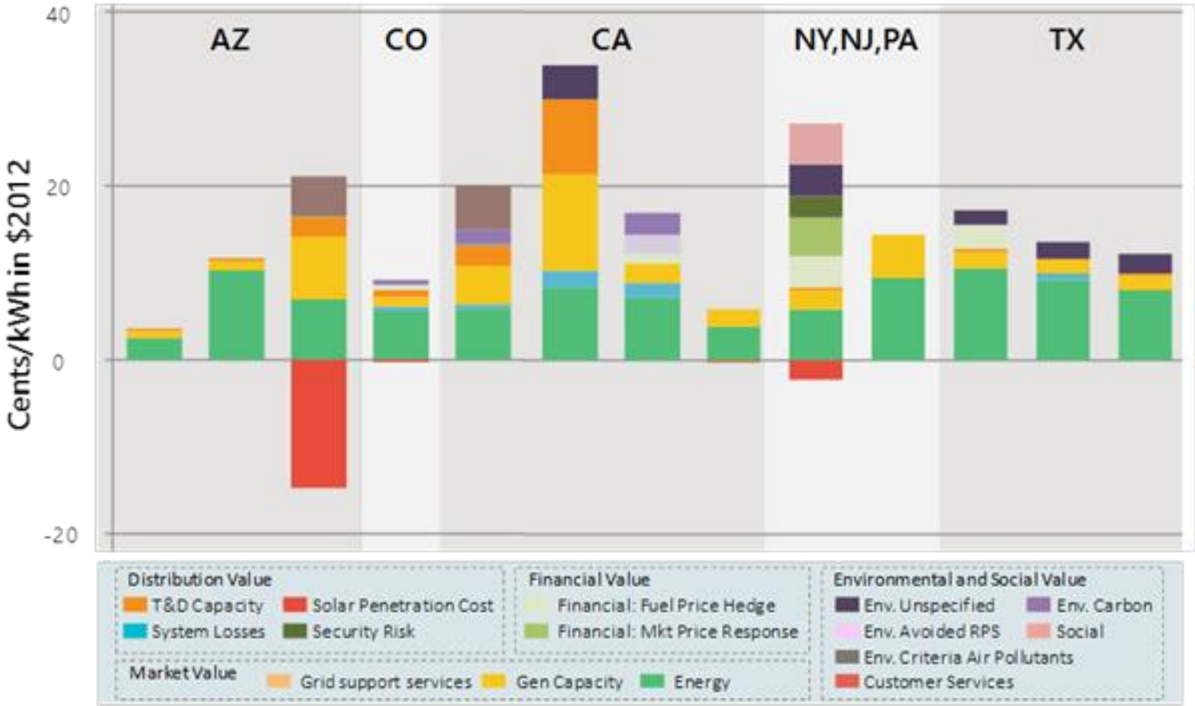
The ESCV outlined four technical benefits from grid support services that it considered may provide economic value to distribution networks—balancing energy supply and demand; managing voltage regulation; maintaining power quality; and avoiding AEMO use of system charges. Specifically, the ESCV considered these factors may provide operational expenditure benefits to distributors.

For the following reasons, the specific technical benefits outlined by the ESCV are unlikely to result in reduced network expenditure:

- the ESCV stated that a crucial part of network operation is balancing energy supply and demand at any time, and that distributed generation can be contracted by a network business to control the amount of exported electricity in a local area. It is not clear why the ESCV considers balancing energy supply and demand is a requirement of distributors, and by extension, where any corresponding network value exists (as opposed to wholesale market benefits). Moreover, the purchase of electricity from distributed generator would not be without cost, and hence, would presumably increase operating expenditure;
- managing voltage regulation is an increasing challenge with larger penetration levels of distributed generation, where at times, the same section of the network can have power-flows in reverse direction (especially with intermittent sources such as solar PV). Having reverse power-flows on the same area of the network results in a far greater variation of voltage, and more difficulty in maintaining voltage compliance. If not managed, high voltage levels result during times of high solar PV generation output; and
- there may be network benefits in managing these voltage variations, but only if all solar PV inverters in a local area were controlled to adjust the power factor of each solar PV installation (so as to keep within a required voltage range). Such a scheme would be very difficult to implement and would necessarily involve a reduction in active power generated to enable the control via reactive power. This would curtail the income to the generator.

The above reasons are consistent with studies previously undertaken in the United States, as summarised by the Rocky Mountain Institute. As shown in figure 1.1, these studies found that grid support services from distributed generation are not a material source of network value.[1]

Figure 1.1 Benefits and costs of distributed solar PV according to different US studies



Source: CitiPower and Powercor (adapted from Rocky Mountain Institute, *A review of solar PV benefit and cost studies*).

1.2.3 Electricity supply risk

The ESCV considered that distributed generation can provide islanding capability for consumers (or a group of consumers), and as such, provides network value to distributors through improved reliability and network resilience. Micro-embedded generators (such as residential solar PV systems), however, are designed to shut down when the grid connection fails—contrary to the ESCV's assumption, they are not designed to operate as an island.

Further, while an individual customer with a solar plus battery system may receive a (personal) reliability benefit from such a system, this is a private benefit. STPIS penalties apply where supply to the customer is lost, and this is measured at the meter. A customer with behind-the-meter storage, therefore, is still considered 'off-supply' during a network outage (irrespective of their ability to maintain supply on their side of the meter).

1.3 Network value provided by distributed generation on our network

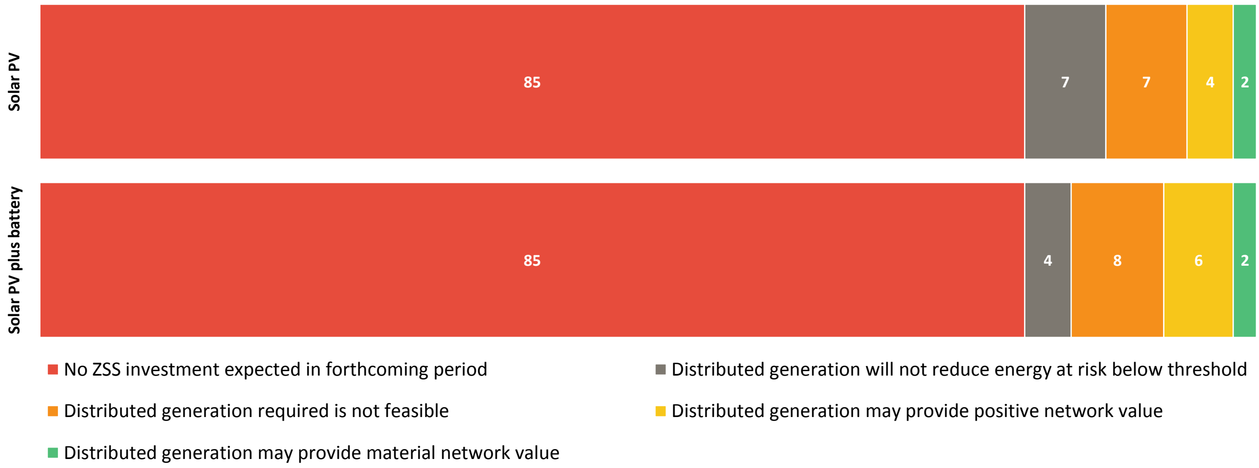
Under our existing network planning process, our key demand-driven investments are planned when the energy at risk at a given zone substation exceeds the value of the annualised augmentation capital expenditure. ENEA's modelling of the value of distributed generation on our network, therefore, focused on the volume of distributed generation required to return the energy at risk at a given zone substation to the level that existed in the year immediately prior to the planned investment.

Our summary of ENEA's preliminary results is set out in figure 1.2. This shows that residential solar PV generation may potentially provide value at six zone substations across our network. The number is slightly higher (eight) for

[1] See, for example: Rocky Mountain Institute, *A review of solar PV benefit and cost studies*.

residential solar PV plus battery systems. However, the potential network value is only material at two zone substations.[2]

Figure 1.2 Overview of zone substations where distributed generation may provide network value



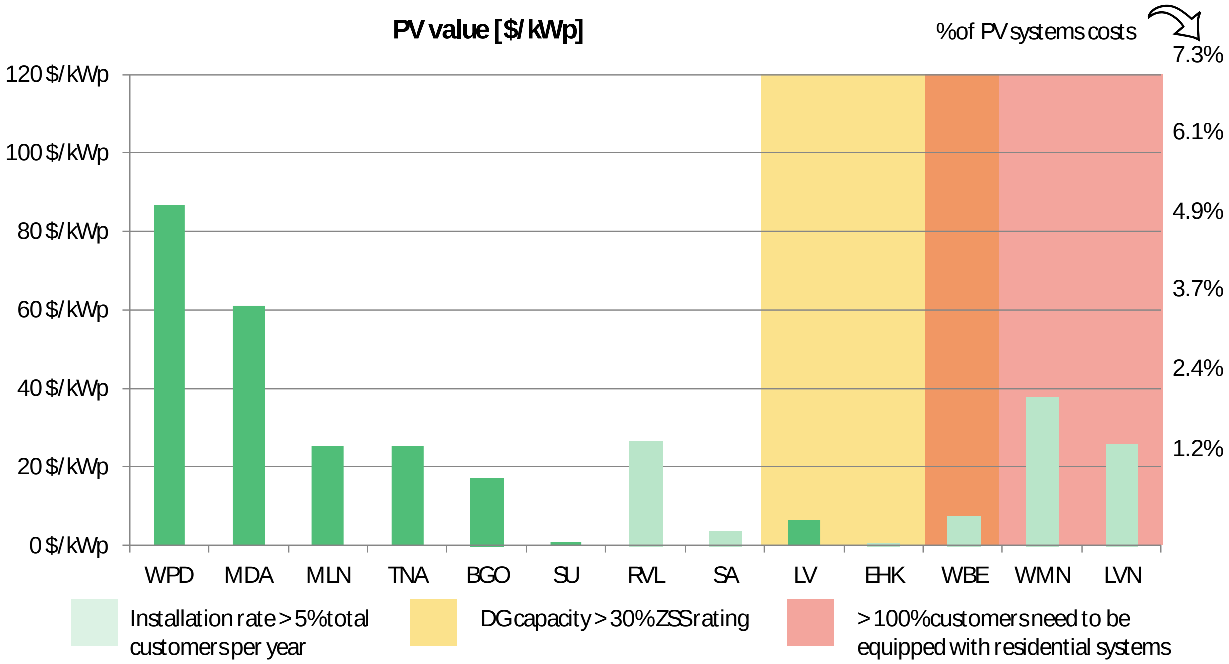
Source: CitiPower and Powercor.

The zone substations where distributed generation may provide network value are all located in Powercor's network. That is, ENEA found the value to CitiPower customers from distributed generation is zero. This is because planned investments in CitiPower's network over the forthcoming 10 year period are driven by replacement and security of supply obligations, and not demand.

In addition to being sparsely located, the modelling undertaken by ENEA also demonstrates that the potential value available to Powercor's customers from distributed generation is variable, and generally low relative to the installation costs of residential solar PV (and battery) systems. This is summarised in figure 1.3 (residential solar PV only), and figure 1.4 (residential solar PV plus battery).

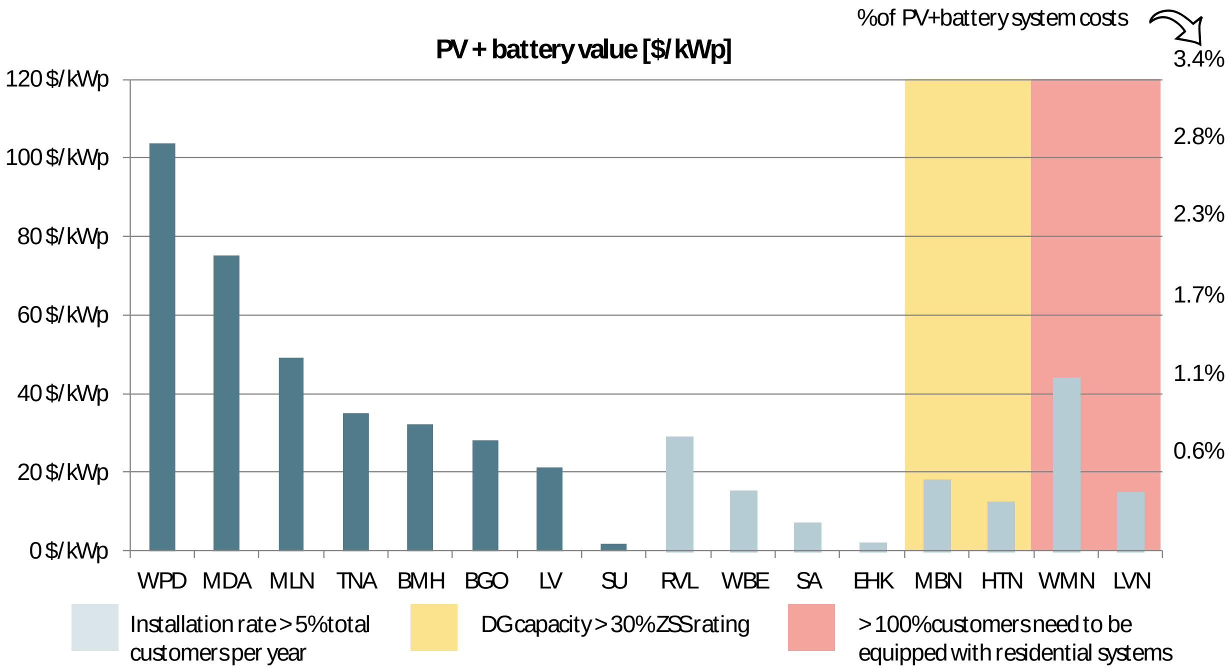
2 As set out in section 1.3.3, materiality is determined relative to the typical cost of purchasing and installing a solar PV system and/or solar PV plus battery system.

Figure 1.3 Potential value of residential solar PV generation on our network



Source: ENEA, *Investment deferral value of distributed generation*, July 2016.

Figure 1.4 Potential value of residential solar PV generation plus battery on our network



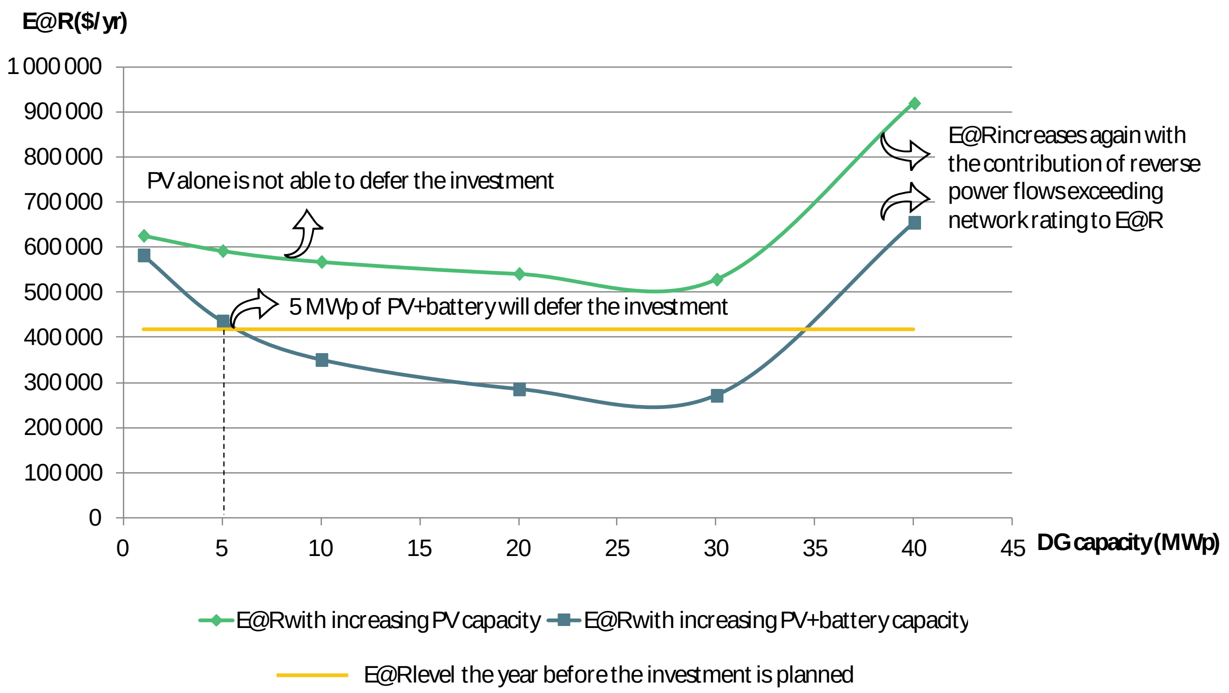
Source: ENEA, *Investment deferral value of distributed generation*, July 2016.

The following sections provide an explanation as to why distributed generation may not always defer network investment, and how the magnitude and materiality of any network value may vary. These reasons correspond to the shaded sections in the above charts (and the vertical axis on the right), and reflect the technical and practical constraints discussed in section 1.2.1.

1.3.1 Distributed generation will not reduce the energy at risk below threshold

The addition of distributed generation to our network will typically result in a reduction in energy at risk for a given zone substation. At some stage, however, the contribution of reverse power flows from the additional distributed generation will exceed the network rating of the corresponding zone substation. In such circumstances, no amount of additional distributed generation will ever reduce the energy at risk to below that which existed in the year immediately prior to the planned investment. An illustration of this is shown in figure 1.5—in this example, solar PV alone would not defer the planned investment (but solar PV plus battery would).

Figure 1.5 Energy at risk avoided by distributed generation



Source: ENEA, *Investment deferral value of distributed generation*, July 2016.

In the forthcoming ten year period, ENEA found seven zone substations in Powercor's network where no amount of solar PV systems will defer the planned augmentation. There are three zone substations where only solar PV plus battery systems could defer the network investment (i.e. solar PV alone would be insufficient).

1.3.2 Distributed generation required is not feasible

In addition to circumstances where no amount of additional distributed generation will sufficiently reduce energy at risk, it can also be the case that solar PV (and battery) systems do not provide a feasible solution to defer planned investment.

ENEA's modelling shows five zone substations where solar PV alone does not provide a feasible solution to defer planned investment, and four zone substations where solar PV plus battery systems are not feasible. These circumstances are discussed below.[3]

Required distributed generation capacity exceeds 30 per cent of the distribution substation rating

The potential for distributed generation to defer planned augmentation expenditure is reduced where the required solar PV and/or solar PV plus battery capacity exceeds 30 per cent of the distribution substation rating. This threshold corresponds to the maximum acceptable solar PV capacity on distribution transformers in our network, beyond which some augmentations may be required to fix voltage issues. ENEA assumed that if generation exceeds 30 per cent of the rating of a zone substation then it is likely that at least half of the distribution substations will also exceed the 30 per cent threshold. ENEA found three zone substations on our network where the volume of solar PV required to defer planned investment would exceed this threshold, and two zone substations for solar PV plus battery.

[3] For clarity, these constraints are not mutually exclusive.

Required distributed generation volume exceeds available residential properties

The ability for residential solar PV and/or solar PV plus battery systems to defer planned investment may also be limited due to the number of remaining residential properties without solar PV systems (relative to the number of systems required to be installed).

For example, ENEA's modelling shows that at our Wemen zone substation the number of new solar PV installations required to provide sufficient capacity to defer planned investment is more than double the number of residential properties. Similarly, for our Robinvale and Eaglehawk zone substations, solar PV systems would be required at 80 per cent and 46 per cent of the remaining residential properties to defer network investment. Such penetration levels are considered unrealistic.

Required distributed generation volume exceeds realistic deliverability timeframes

Additionally, the timeframes available for distributed generation to reach the required level of penetration may not be compatible with the timeframes required for network planning processes. Network augmentation may take in excess of 24 months, including project scoping and design, regulatory investment tests, materials procurement and construction. As a result, the penetration of residential solar PV systems would be required to meet (or be close to meeting) the relevant threshold well in advance of the network constraint occurring.

Similarly, to achieve the required level of penetration to defer planned investment the required installation rate for residential solar PV may not be realistic. For example, the highest annual solar PV installation rate previously achieved in Victoria was approximately 2.5 per cent.[4] Even if an annual installation rate of 5 per cent is assumed to be possible, ENEA's modelling showed that solar PV generation will not feasibly defer planned investment at five zone substations where network value potentially exists. For solar PV generation plus battery systems, there are eight zone substations where planned investment will not feasibly be deferred.

1.3.3 The magnitude and materiality of the network value at each zone substation varies

The ESCV previously acknowledged that the network value from distributed generation is driven by time and location specific factors. For example, distributed generation must be located near a network constraint to defer or avoid demand driven augmentation.

ENEA's modelling supports these conclusions. For example, the different shading in the maps shown in figure 1.6 and figure 1.7 indicates that the magnitude of any potential network value from distributed generation varies based on location (and that there is no value in most of our network). In these charts, value is calculated as the dollar per kilowatt peak of the distributed generation system.

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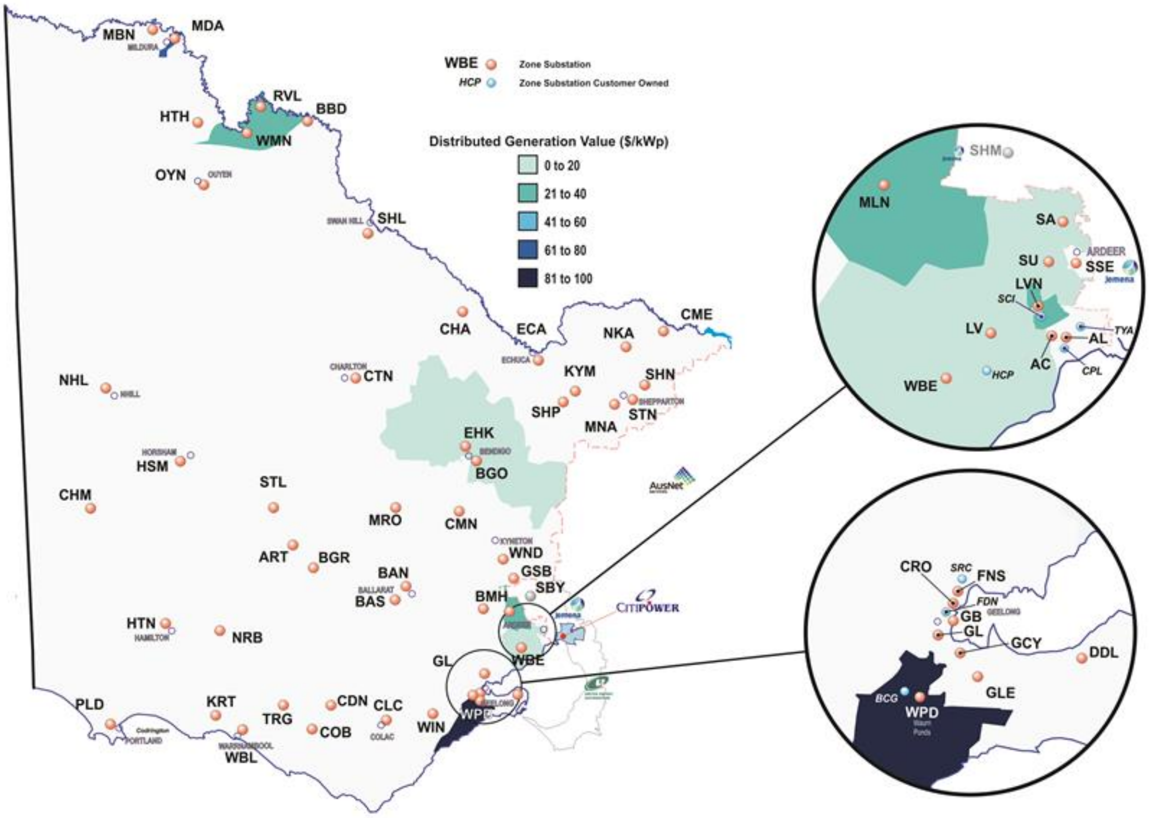
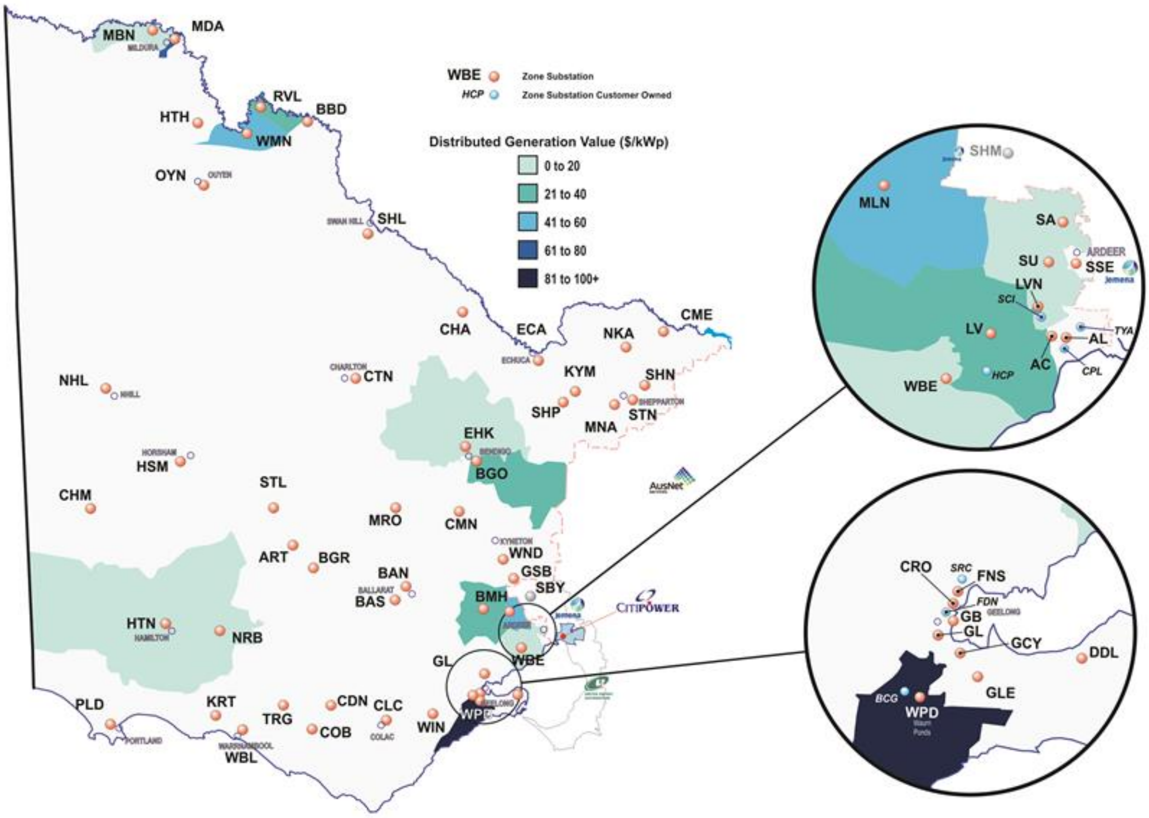
[4] ENEA, *Investment deferral value of distributed generation*, July 2016, p. 5.

Figure 1.6 Network map of potential network value: solar PV systems only



Source: ENEA, *Investment deferral value of distributed generation*, July 2016.

Figure 1.7 Network map of potential network value: solar PV systems plus battery storage



Source: ENEA, *Investment deferral value of distributed generation*, July 2016.

For residential solar PV and residential solar PV plus battery systems, the potential network value they provide may only be material for customers serviced by our Waurn Ponds and Mildura zone substations. Materiality is determined relative to the typical cost of purchasing and installing a solar PV system and/or solar PV plus battery system. For the purpose of this analysis, we consider the potential network value may be material to the customer—insomuch as it is likely to provide a reasonable incentive—where it exceeds 1.5 per cent of the total purchase and installation costs.

In total, our Waurn Ponds and Mildura zone substations service approximately 4 per cent of our customer base. The value of investment deferral driven by distributed generation, therefore, is unlikely to benefit 96 per cent of Powercor's customers.

A Response to ESCV questions

A.1 Approach, concepts and definitions

1. **Are there any other aspects of our definition of distributed generation that we should consider, in this stage of the inquiry?**

   The ESCV's definition is focused on distributed generators below 5MW, from any fuel type (including batteries). We support this definition.

   As outlined previously to the ESCV, however, the true value of distributed generation should consider both the costs and benefits of distributed generation, including any administrative/transaction costs associated with valuing distributed generation.

2. **What data and evidence is available about the potential network benefits of battery storage?**

   As recognised by the ESCV, we have recently installed 20 residential batteries across our CitiPower network to better understand the impact of such systems on our network. Further, in 2015 we installed a 2MW battery in Powercor's network.

   These battery trials are ongoing, and any network benefits are still being determined.

3. **On what basis should the network benefit from distributed generation be assessed—on the total output or on the total exports of the distributed generation system?**

   The network benefit from distributed generation should be considered on a total export basis. The ESCV's approach should aim for outcomes that are technology agnostic. Assessing the network value provided on a total export basis ensures reduced network demand from distributed generation is treated equally to energy efficiency measures and/or load curtailment.

   Smart meters in Victoria are also configured to measure net load and export (as required under the Victorian Government mandated roll-out program). If distributed generators are to be compensated for any network value based on total output, these meters would need to be reconfigured, together with the re-wiring of solar installations. Such reconfiguration would be at significant costs to customers.

   There are also practical and technical constraints to reconfiguring meters to measure total output, including the proximity of any residential solar PV installation to the meter panel, and the size of the existing panel. The cost of additional electrical works will be impacted by proximity, and meter panel replacements may be necessary to fit the additional meter required under a total output approach.

4. **What do you see as the main differences between network-led and proponent-led DG in terms of the network benefits they deliver?**

   The differences between network-led and proponent-led distributed generation (particularly small-scale, the focus of the review) are material, and include the following:

   – network-led investment is designed to target a network constraint, and will be subject to the regulatory framework that incentivises efficient behaviour (e.g. the CESS, including ex-post reviews of capital expenditure overspends, and regulatory investment tests). In contrast, there is no expectation that proponent-led investment will be located near a network constraint, or designed to operate at times when a network constraint occurs. The fact that significant proponent-led investment in residential solar PV has already occurred demonstrates that the realisation of network benefits is not a material driver in proponent-led investment decisions;

   – network-led investments are typically large in scale given our probabilistic planning requirements. This allows network-led investments to avoid the capacity threshold issues outlined in 1.2.1; and

- network-led investments are typically controllable (by the distributor), unlike residential solar PV systems. This may limit the firmness of their supply, and accordingly, restrict the ability of proponent-led investment to defer demand-driven augmentation.

5. Are there any other aspects of our definition of value that we should consider, in this stage of the inquiry?

Our previous submission to the ESCV's proposed approach paper outlined that internal and external benefits should be aligned with internal and external costs. Notwithstanding the ESCV has indicated its inquiry will consider the value of benefits only, its approach should not recommend outcomes that promote cross-subsidies between solar and non-solar customers as this will result in higher network charges.

6. Are there any other aspects to our proposed framework for assessing network value that we should consider?

No comment.

7. Do you agree with the Commission's proposed framework for the network value stage of the inquiry? Are there alternative approaches?

We support the Commission's proposed framework.

A.2 Economic benefits

8. Beyond those identified in the paper, are there other examples of applied methodologies for calculating network benefit that the Commission should consider?

As outlined in section 1.1, we engaged ENEA to undertake a modelling exercise of our network to determine where distributed generation may provide network benefits, and to detail the magnitude of these potential benefits. ENEA's modelling approach is explained in detail in appendix B.

9. Can you suggest any alternative or additional categories of network benefits regarding distributed generation?

Our assessment of the categories of network benefits from distributed generation is set out in section 1.2. In summary, we agree that distributed generation can provide network value through the ability to defer and/or avoid augmentation. However, much of this value is already captured by the existing regulatory framework. In contrast, any replacement or operating expenditure benefits driven by distributed generation are expected to be non-existent, immaterial and/or outweighed by inherent network costs.

The magnitude of these potential benefits on our network is discussed in section 1.3.

10. Can you suggest alternative or additional characteristics of distributed generation (that effect the capacity of distributed generation to provide network benefits)?

As outlined in section 1.2.1 and section 1.3, there are technical and/or practical constraints that may limit the ability of residential solar PV systems (including with batteries) to defer or avoid network investment. These constraints include the following:

- the capacity of distributed generation required to defer planned network investment may be so great that the resultant contribution of reverse power flows at the time when solar PV generation peaks exceeds the network rating of the zone substation (such that no amount of additional distributed generation will reduce the energy at risk). ENEA found seven zone substations in Powercor's network where no amount of solar PV systems will defer the planned augmentation. There are four zone substations where only solar PV plus battery systems could defer the network investment (i.e. solar PV alone would be insufficient);
- the capacity of solar PV generation required at maximum demand to defer planned network investment may cause voltage issues. This may necessitate local augmentations of distribution transformers, or the changing of taps on distribution transformers, to connect the requisite level of solar PV. It is estimated that voltage issues can start when solar PV generation reaches 30 per cent of distribution transformer capacity. ENEA found three zone substations on our network where the volume of solar PV required to

defer planned investment would exceed this threshold (and two zone substations for solar PV plus battery);

- the number of solar PV systems required to defer planned network investment may exceed the available number of residential properties. At our Wemen zone substation, for example, the number of solar PV systems required to provide sufficient capacity to defer planned investment is more than double the corresponding number of residential properties. Similarly, at our Robinvale and Eaglehawk zone substations, solar PV systems would be required at 80 per cent and 46 per cent of the remaining residential properties to defer network investment;
- the timeframes available for distributed generation to reach the required level of penetration may not be compatible with the timeframes required for network planning processes. For example, network augmentation may take in excess of 24 months, including project scoping and design, regulatory investment tests, materials procurement and construction. As a result, the penetration of residential solar PV systems would be required to meet (or be close to meeting) the relevant threshold well in advance of the network constraint—at a minimum, to avoid design and construction costs of an augmentation, distributed generation would need to prove its effectiveness 18 months ahead of the constraint occurring; and
- ENEA's initial analysis indicates that distributed generation, particularly residential solar PV, is unlikely to materially lower maximum demand on our network (as the solar PV export peak may not coincide with our spatial network peaks, due to timing misalignment or cloud cover). This limits the ability for residential solar PV to defer or avoid demand-driven augmentation.

11. Are there circumstances in which a fleet or 'portfolio' of passive distributed generation systems can provide suitably firm generation capacity to create circumstances in which network benefit is created?

Notionally, a fleet of passive distributed generation systems may provide some network benefit if they can reduce maximum demand. The limitations set out in response to question 10, however, are also relevant here.

A.3 Economic value methodological approach

12. What alternative or additional building blocks of a methodology should be considered for determining the network benefit of distributed generation?

We consider ENEA's modelling approach is preferable to the preliminary assessment method set out by the ESCV.

13. What do you see as the most appropriate unit of analysis and level of granularity is for the assessment of network benefits?

Network benefits can be assessed at the zone substation or high-voltage feeder level. As the low-voltage (**LV**) network is more greatly influenced by spot load connections, it is difficult to develop a method that calculates any corresponding network benefit. However, distributed generation typically causes voltage regulation issues at the LV level, which create additional costs to keep voltages within code limits (rather than providing any benefit).

14. What publicly available data sources can be accessed to apply the methodology, particularly with respect to network constraint and demand?

Publicly available data sources are likely to be insufficient to reasonably estimate the value of network benefits provided by distributed generation. For example:

- only network zone substation profiles are publicly available; and
- network capacity benefits depend on every distributors network planning outcomes. While some outputs of the planning process may be publicly available for each distributor (e.g. in distribution annual planning reports), much of the knowledge related to network planning remains within distributors planning departments.

To the extent the ESCV recommends investors in small-scale distributed generation be compensated for any network value, therefore, this value is best determined by distributors.

15. **What are the appropriate time parameters of a study into the potential network benefits of distributed generation?**

    The calculation of network capacity benefits provided by distributed generation could be performed every year, as distribution network planning is reviewed on an annual basis. This would also allow network planning revisions to be taken into account in the valuation (i.e. any benefits to the network may change as investment plans change).

    A critical issue, however, is what happens where the cumulative capacity of distributed generation is insufficient to defer the planned augmentation. For example, where the cumulative capacity does not suffice, any ex-ante incentives paid to distributed generators would provide no value to our customers. It is not clear how the ESCV proposes to address this issue.

A.4 Environmental and social benefits

16. **Can you suggest or provide evidence that supports those environmental or social benefits attributed to distributed generation listed in this discussion paper?**

    Consistent with our response to the ESCV's proposed approach paper, to ensure efficient investment in network infrastructure, only network costs should be reflected in network charges. In this context, should the Victorian Government develop policies to incentivise distributed generation (for example, for perceived social or environmental benefits), such policies should be transparently applied, and not enacted through network tariffs. To do otherwise may lead to inefficient investment decisions—in the extreme, it may result in inefficient disconnection from the network, even when this is not in the long-term interests of consumers.

    Similarly, feed-in tariff distortions may lead to the inefficient use of distributed generation. For example, distributed generators may have a choice of exporting electricity onto the grid, or using battery storage to avoid the cost of imported electricity. As the benefit of distributed generation is greater when electricity is stored and used at times when the cost of electricity supply is greatest, but customers only receive a feed-in-tariff when they export onto the grid, this may limit the use of battery storage even when it may be the best economic solution for society.

    In regard to the specific benefits identified by the ESCV, we note the following:

    - bushfire mitigation benefits would only occur if a line can be decommissioned, and the Victorian Government's powerline replacement fund and our bushfire mitigation plans already consider efficient means for mitigating bushfire risk caused by electricity networks;
    - insurance costs are driven by a range of factors, and separating any impact of distributed generation on these premiums is unrealistic; and
    - aesthetic and amenity benefits are subjective and difficult to value, and like increased customer empowerment, are personal benefits (i.e. internal benefits) that should be excluded.

17. **Outside those potential benefits listed, are you able to provide (and support with evidence) of how distributed generation reduces the environmental impact of the transportation of electricity?**

    No comment.

18. **Outside those potential benefits listed, are you able to provide (and support with evidence) examples of how distributed generation provides social benefit, as it relates to the transportation of electricity?**

    No comment.

A.5 Operation of the current regulatory framework

19. Are there other aspects of the current regulatory framework outlined in this paper that the Commission should consider?

The introduction of the CESS, improvements to our distribution annual planning reports, and network tariff reforms that require cost-reflective network tariffs, are all key changes to the regulatory framework that promote investment in distribution generation (where it is efficient). If the ESCV considers investors in small-scale distributed generation should be compensated for any network value they provide, it should first demonstrate why these existing mechanisms are insufficient.

20. Can you provide specific examples of payments made to distributed generators under the regulatory mechanisms listed in this discussion paper? What size of distributed generation systems received the payments? Were payments made to small-scale systems?

Table A.1 Avoided TUOS payments: CitiPower ($2015)

Source	Size	2011	2012	2013	2014	2015
Embedded generator 1	6.2MW	5,020	19,229	51,561	32,193	33,361
Embedded generator 2	6.2MW	99,885	35,020	117,211	44,864	46,492
Embedded generator 3	12.4MW	40,199	40,421	24,563	15,792	16,365

Table A.2 Avoided TUOS payments: Powercor ($2015)

Source	Size	2011	2012	2013	2014	2015
Embedded generator 1	4.4MW	56,143	36,158	119,182	56,054	58,088
Embedded generator 2	1.8MW	5,187	12,054	23,439	22,225	23,031
Embedded generator 3	1.0MW	-	28,585	21,057	11,230	11,638
Embedded generator 4	52.5MW	179,536	347,680	688,912	159,448	165,234
Embedded generator 5	0.8MW	-	37,186	31,429	14,488	15,013
Embedded generator 6	0.3MW	-	-	-	487	504
Embedded generator 7	5.5MW	77,078	51,101	110,659	55,287	57,293
Embedded generator 8	0.8MW	-	18,244	22,663	11,398	11,812
Embedded generator 9	1.0MW	8,589	6,527	19,568	7,471	7,742
Embedded generator 10	1.0MW	9,121	5,579	13,402	5,900	6,114
Embedded generator 11	18.2MW	109,633	126,095	237,256	129,006	133,687
Embedded generator 12	30.0MW	945,974	314,713	662,041	327,395	339,277
Embedded generator 13	9.5MW	-	-	533,166	158,727	164,487
Embedded generator 14	67.2MW	-	-	1,072,881	781,728	810,098
Embedded generator 15	5.0MW	57,839	-	-	-	-

Table A.3 Network support payments: CitiPower ($2015)

Source	2011	2012	2013	2014	2015
Network support 1	-	50,606	-	-	-
Network support 2	-	-	-	108,758	-

Table A.4 Network support payments: Powercor ($2015)

Source	2011	2012	2013	2014	2015
Network support 1	-	-	-	36,707	-

21. Are you able to provide data/evidence about the operation of the small scale generation aggregator framework as a mechanism by which network benefits of small scale distributed generation can be identified, valued and compensated?

No comment.

22. To what extent do the Tariff Structure Statements published by Victorian distribution businesses provide an indication of the benefit distributed generation can provide through reducing peak network demand?

Publicly available data sources, including our Tariff Structure Statements, are likely to be insufficient to reasonably estimate the value of network benefits provided by distributed generation. Our distribution annual planning reports, however, include relevant information on forecast network constraints at the zone substation level.

23. Are there are alternative conceptual frameworks that could be used to examine the benefits provided by proponent-led distributed generation? In particular, are there conceptual frameworks for considering potential benefits that were not anticipated in the planning forecasts associated with the five yearly pricing determination process?

For the reasons outlined in section 1.2.1, the existing regulatory framework already ensures that much of the potential benefits that distributed generation may provide through the deferral of demand driven augmentation expenditure are already realised. We consider these mechanism are low-cost, and best account for the dynamic, temporal and location specific factors of small-scale distributed generation.

A.6 Alternative mechanisms

24. How should the Commission consider the scope of the LGNC Rule Change Proposal with this current inquiry?

The AEMC's rule change assessment must have regard to both network benefits, as well as network costs. To the extent the ESCV forms a different view to the AEMC (in regard to network benefits), it is incumbent on the ESCV to clearly articulate the reasons for any differences.

25. Are there methodologies for calculating network value and/or regulatory mechanisms from any other jurisdiction that are suitable for consideration in the context of this inquiry?

We consider the existing regulatory framework already provides sufficient financial incentives for investment in distributed generation.

B Alternative model of distributed generation

Refer to attached report: ENEA, *Investment deferral value of distributed generation*, July 2016.

enea
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INVESTMENT DEFERRAL VALUE OF DISTRIBUTED GENERATION

July 2016

This document presents the methodology developed to compute the investment deferral value of distributed generation as well as its application to CitiPower and Powercor networks

Author: David MERCEREAU | **Approved by:** Olivier LACROIX

EXECUTIVE SUMMARY

The value of Distributed Generation (DG) for transmission and distribution networks is currently at the heart of two regulatory reviews in Australia: a rule change request submitted to AEMC at the national level and an inquiry conducted by the ESC in Victoria. CitiPower and Powercor (CP/PAL) has asked Enea to propose and implement a calculation methodology to assess the investment deferral value of DG[1] across its networks.

Most calculation methodologies used in studies computing this value are system- or at least area-wide. They are based on historical investment figures, which results in assuming that demand growth rates are constant and that the investments required to accommodate this demand growth will be similar to those made in the past. This does not reflect CP/PAL's current network planning practices based on demand forecasts, nor the reality. Moreover, those methodologies do not allow for a locational estimate of DG value. As a consequence, a more robust computation methodology was developed to overcome these limitations.

The proposed methodology aims at capturing how DG avoids future congestion and thus defer the need for network augmentation. The general calculation approach consists in determining the amount of DG systems required to defer the investment by one year where demand-growth driven augmentation CAPEX is planned. The methodology was applied to CP/PAL networks with a focus on sub-transmission lines and zone substations augmentations, which represent the largest share of the relevant investments. The calculation could be applied to HV feeders as well. The low voltage network is not taken into account since the vast majority of augmentation expenditure in the low voltage network is directly attributable to new connections; in that case, customers can already balance connection or upgrade costs with alternatives such as DG.

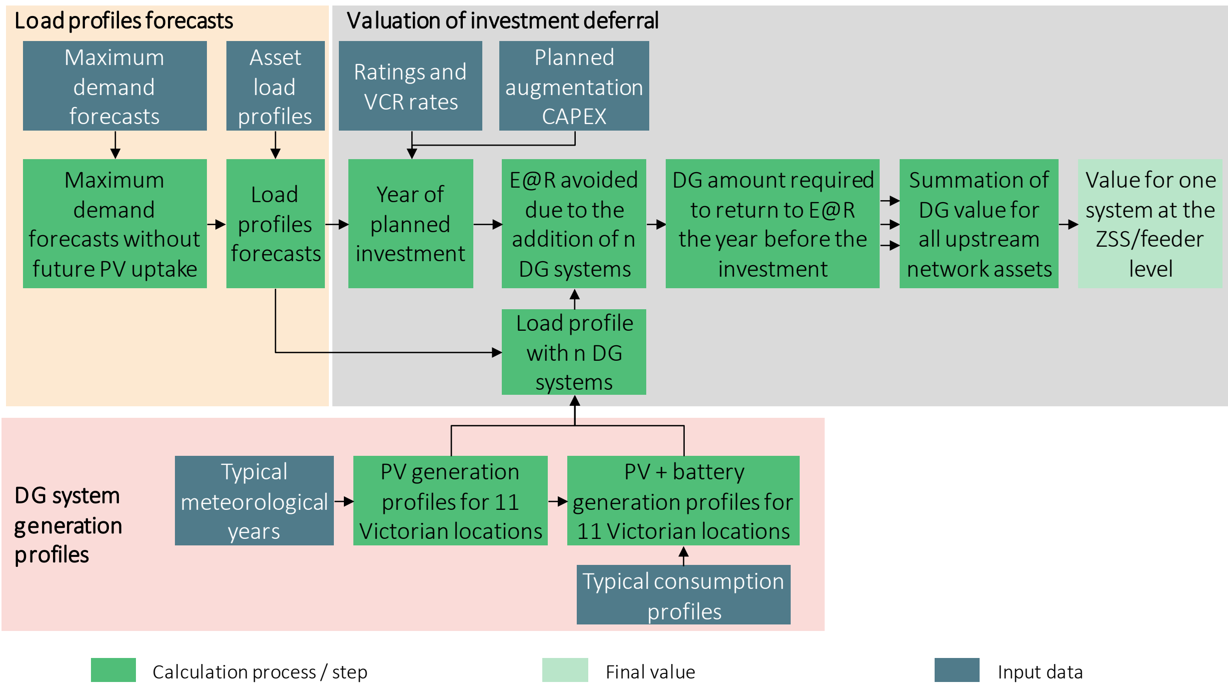


Figure 1 – Overall approach to compute the investment deferral value of DG

[1] PV and residential PV+Battery systems were considered. The methodology could easily be extended to other types of DG systems.

Applying this methodology to CP/PAL networks, by taking into account all demand-growth driven sub-transmission lines and zone substation projects planned over the next 10 years, shows that distributed generation cannot systematically defer investments, due to non coincident generation and peak demand periods[2].

In particular, our computation shows that there is no DG value linked to investment deferral on the CitiPower network. On the Powercor network, this value is highly locational (see Figure 2) and limited to a few geographical areas. Overall, there is no investment deferral value of DG for around 80% of CP/PAL customers.

For the remaining 20% of customers, the investment deferral value of DG varies; it ranges between 0.01 and 0.63 c$/kWh of electricity generated by DG systems (gross) or between 1 and 104 $/kWp of DG capacity in specific areas if a threshold capacity is reached. Behind-the-meter PV plus batteries have a higher value than PV alone except in one area where the peak consumption matches peak PV generation (See Figure 3).

Finally, significant additional DG amounts may be required to reach the threshold allowing to defer investment, which compromises the feasibility of the deferral in several cases (See Figure 3). For instance, it would require additional technical studies to assess technical feasibility in 3 cases (DG amount above 30% of the ZSS rating). Moreover, residential systems alone will not always be able to defer investment due to penetration and installation rate constraints: for 3 areas of the network, a penetration of residential systems of more than 100% would be required; and for 6 ZSS for PV and 9 for PV+batteries, the annual installation rate of new residential systems would require to be above 5% of their total number of customers. An annual installation rate of 5% is considerably above historic installation rates in Victoria[3].

Note that these results are indicative only, since they are based on 2015 demand forecasts which will shortly be replaced with updated demand forecasts. Additionally, HV feeders have not been factored into the value yet.

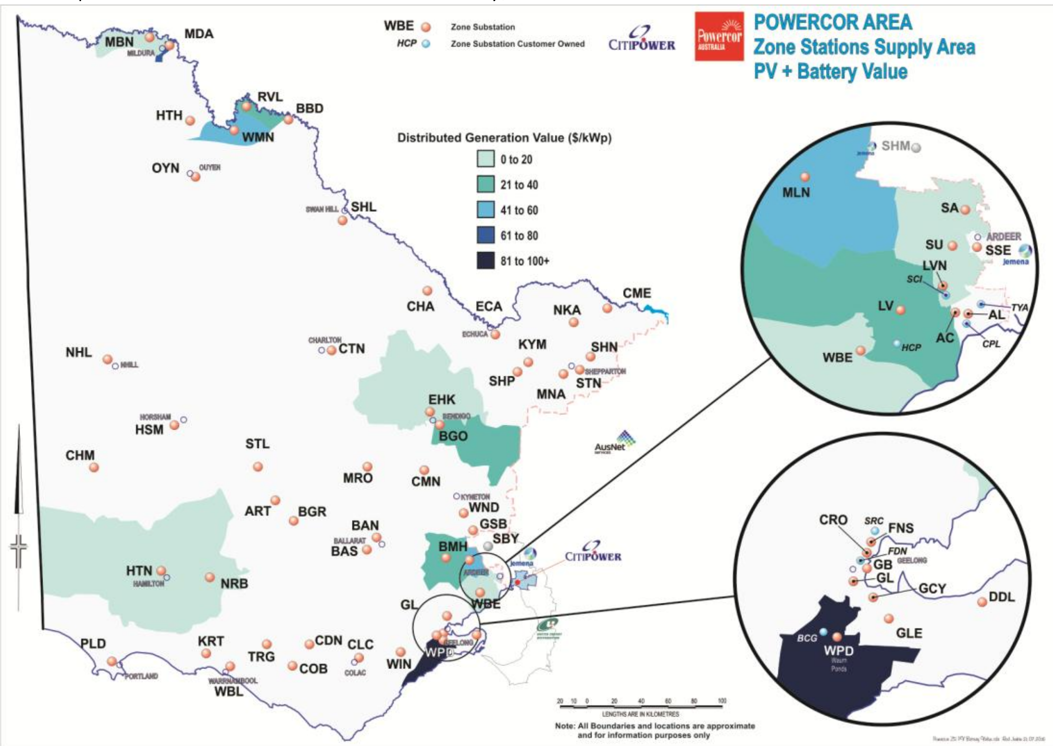
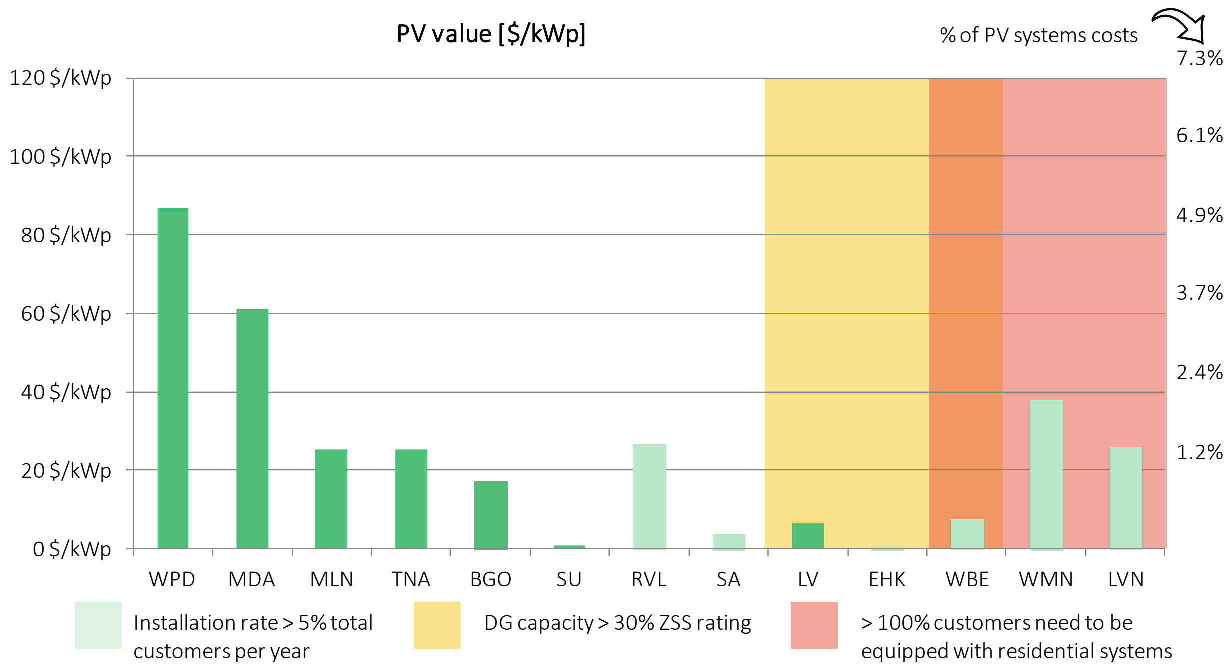


Figure 2 – PV + battery investment deferral value over Powercor network

[2] This would be different for dispatchable systems

[3] The highest installation rate in Victoria was achieved in 2012 with 66,204 installations for a total of 2.6 million customers, i.e. 2.5%



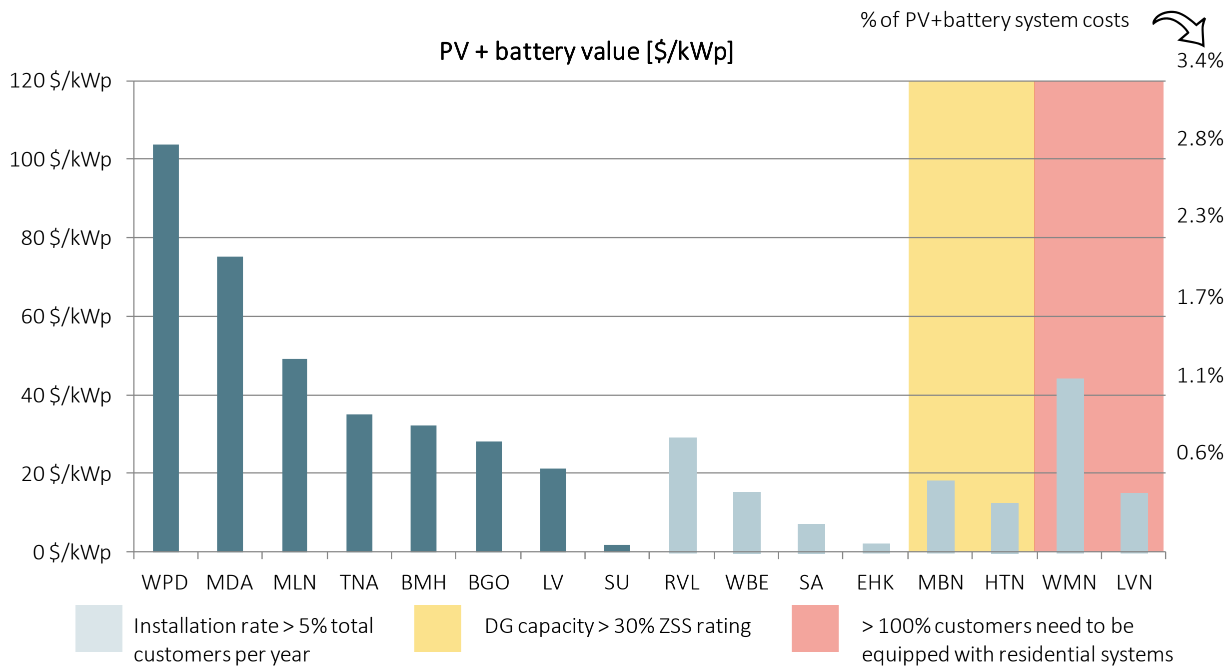


Figure 3 – Investment deferral value of PV (above) and PV + batteries (below) at the level of CitiPower and Powercor zone substations

CONTENTS

1 INTRODUCTION

A rule change request has been submitted to the Australian Energy Market commission (AEMC) that would require the Distribution Network Operators to:

- Calculate the long-term economic benefits that embedded generators provide to distribution and transmission networks.
- Pay embedded generators a local generation network credit (LGNC) that reflects those estimated long-term benefits.

At the same time, the Essential Services Commission (ESC) is conducting an inquiry into the true value of distributed generation (DG). The commission has to examine the value of DG including:

- The value of distributed generation for the wholesale electricity system
- The value of distributed generation for the planning, investment and operation of the electricity network
- The environmental and social value of distributed generation.

The Commission is willing to assess the most efficient and effective methodology for identifying and calculating the energy and network values of distributed generation and to determine whether the regulatory framework allows for this methodology(s) to be used.

In this context, CitiPower and Powercor (CP/PAL) has asked Enea to propose and implement a calculation methodology to assess DG value across their networks. Previous investigations have shown that the vast majority of the identified studies focusing on DG value calculation include investment deferral [1]. This value stream is also the most important value for distribution networks in many of these studies.

Most identified calculation methodologies are system-wide or at least area-wide. They are based on historical investment figures (usually over the last 10 years), which relies on assuming that demand growth rates are constant and that required investments to cope with this demand growth will be similar to those made in the past. A capacity-related cost ($/kW of additional capacity) is usually computed based on the 10 previous years and the NPV per kW of DG is then derived. This does not reflect CP/PAL's current network planning practices based on demand forecasts, nor the reality. It takes no account of threshold capacity requirements to derive any benefit. Moreover, those methodologies do not allow for a locational estimate of DG value. As a consequence, a more robust computation methodology was developed to overcome these limitations.

2 METHODOLOGY

This section describes the method developed to assess the Distributed Generation (DG) value for distribution networks in terms of investment deferral.

The proposed calculation methodology follows CP/PAL network planning practices. It thus focuses on sub-transmission, ZSS and feeders and excludes LV network. It aims at capturing how DG will defer forecast congestion on these network assets. The general calculation approach consists in determining the amount of DG systems required to defer the investment by one year where augmentation CAPEX is planned.

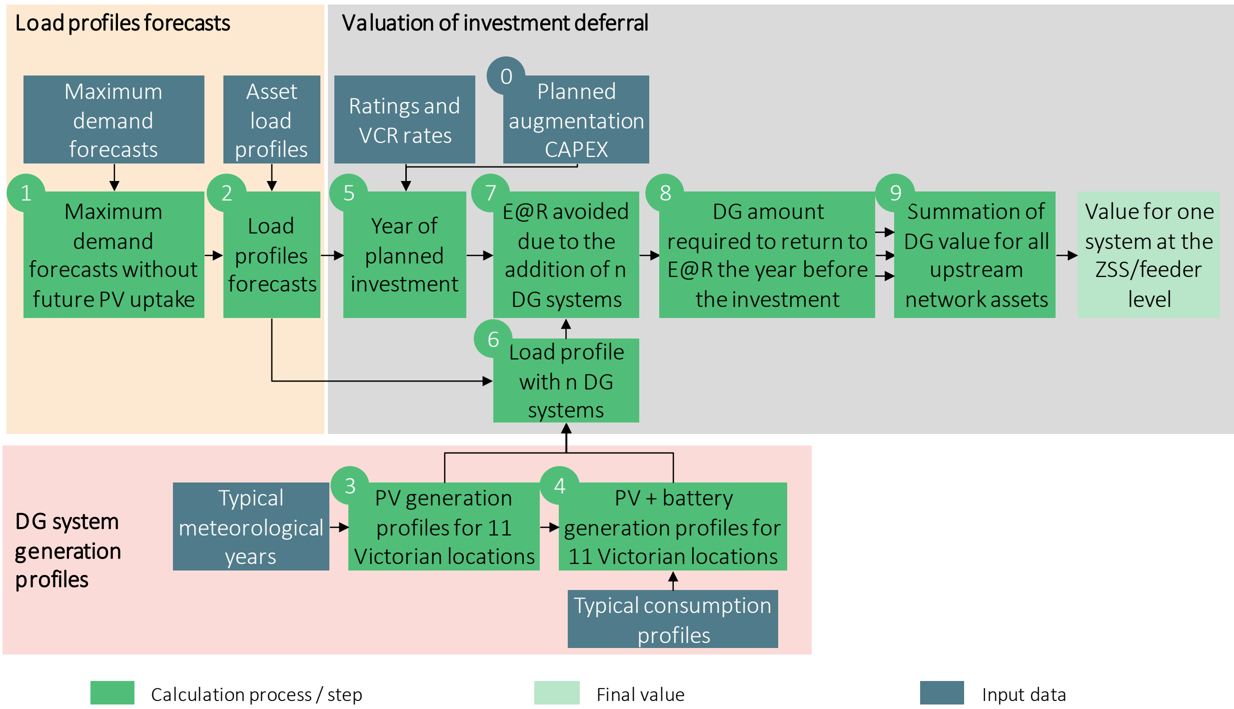


Figure 4 – Overall computation approach for DG value in terms of investment deferral

2.1 Main assumptions of the calculation methodology

The proposed calculation methodology relies on four main assumptions.

First, only DG impact on distribution network capacity constraints is captured. Other triggers for network investment (e.g. voltage support) are only related to a small number of specific constraints so have not been included.

Second, the calculation only applies to the network assets subject to systematic network planning: sub-transmission lines, zone substations and HV feeders. The vast majority of augmentation expenditure in the low voltage network is directly attributable to new connections; thus it was excluded from the calculation.

Third, the calculated value applies to new DG systems only. This means that the value of PV systems installed in the past is already considered (to the extent it is already reflected in demand forecasts) and thus do not provide additional value to the network. This is consistent with the objective to provide an incentive, which would apply to newly installed systems only.

Finally, behind-the-meter solar PV plus battery are assumed to be operated to maximise customers' own consumption of solar PV production. This operation mode is representative of current operation strategies.

2.2 Calculation method

2.2.1 Selection of network augmentation CAPEX (step 0)

The value of one kWp of distributed generation in terms of investment deferral is calculated by summing up the values of the upstream investments it contributes to defer. The first step is thus to identify the relevant investments on the distribution network. The planned investments linked to capacity augmentation were selected from the 10 year project list for CP and PAL networks[4]. Projects with another trigger than capacity constraints (e.g. capacitor banks, regulators as well as replacements and retirements) and projects already started or planned after 2026) were not considered. It is not realistic to include projects outside the 10 year investment window because CP/PAL have no reliable forecasts beyond 10 years and projects that may occur beyond 10 years would be heavily discounted, and therefore not have much value.

Overall, this resulted in selecting 37 projects concerning 35 CP & PAL sub-transmission lines and zone substations, worth $169 million. In addition to these investments, relevant HV feeder investments were estimated to be in the range of 150-190 projects worth $50-80 million over the next ten years[5].

2.2.2 Load profiles forecasts (steps 1 &2)

For the assets where congestion triggers an investment, future load profiles were computed without future DG uptake by:

- Forecasting the maximum demand without future DG uptake for the asset considered (step 1)
- Scaling the 2015 load profile of the considered asset to the forecast maximum demand (step 2)

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[4] This means that projects not falling under the responsibility of CP / PAL, such as terminal stations, were excluded.

[5] The methodology developed could apply to feeders, but the calculation has focused so far on sub-transmission and zone substation, that represent the largest share of the relevant investments.

Last year's CP/PAL maximum demand forecasts take into account future PV uptake based on both historical trend and additional uptake [2]. As a consequence, we re-established maximum demand forecasts to exclude both historical trend and additional uptake. This is illustrated for 2 examples in Figure 5.

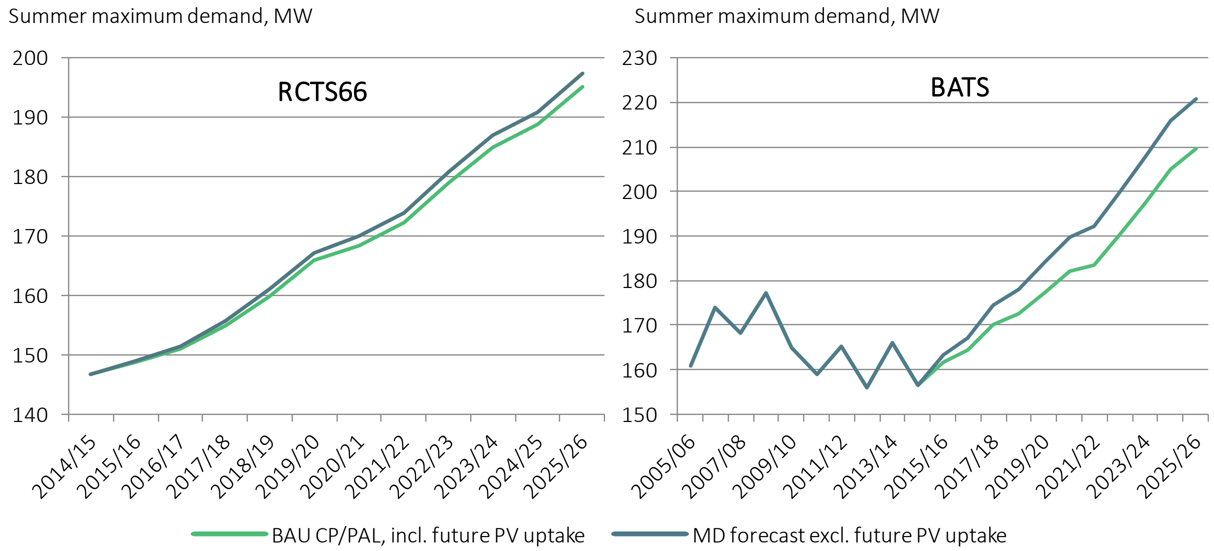


Figure 5 – 2015 Summer maximum demand forecasts including and excluding future PV uptake for Red Cliff (left) and Ballarat (right) terminal stations

For all CP / PAL terminal stations, we derived the ratios of maximum demand forecasts without future PV uptake compared to business-as-usual (BAU). These ratios were finally applied to the maximum demand forecasts of all downstream assets, i.e. sub-transmission lines, ZSS and feeders. Once the maximum demand forecasts without future PV uptake were established, 2015 load profiles for the planned assets were scaled to this maximum demand to obtain a forecast load profile without both historical trend and additional uptake.

2.2.3 DG systems generation profiles (steps 3 & 4)

The generation profiles of solar PV (step 3) and behind-the-meter solar PV plus battery (step 4) were then computed.

Solar PV generation profiles were computed using Typical Meteorological Years data developed by the Alternative Technology Association as part of their Sunulator tool [3] and PVSyst software[a] at 11 Victorian locations relevant to CP / PAL networks as illustrated in Figure 6.

Generation profiles of behind-the-meter solar PV plus battery[6] were determined at the same locations, for a typical residential consumption profile, and with an auto-consumption strategy[7].

An example of the resulting generation profile is shown in Figure 7.

[6] The system modeled is typical to systems available on the market. It comprises a storage device of 6.5 kWh with 95% efficiency, associated with a 5kWp PV system

[7] The battery is charged when PV generation exceeds consumption and discharged when consumption exceeds PV generation

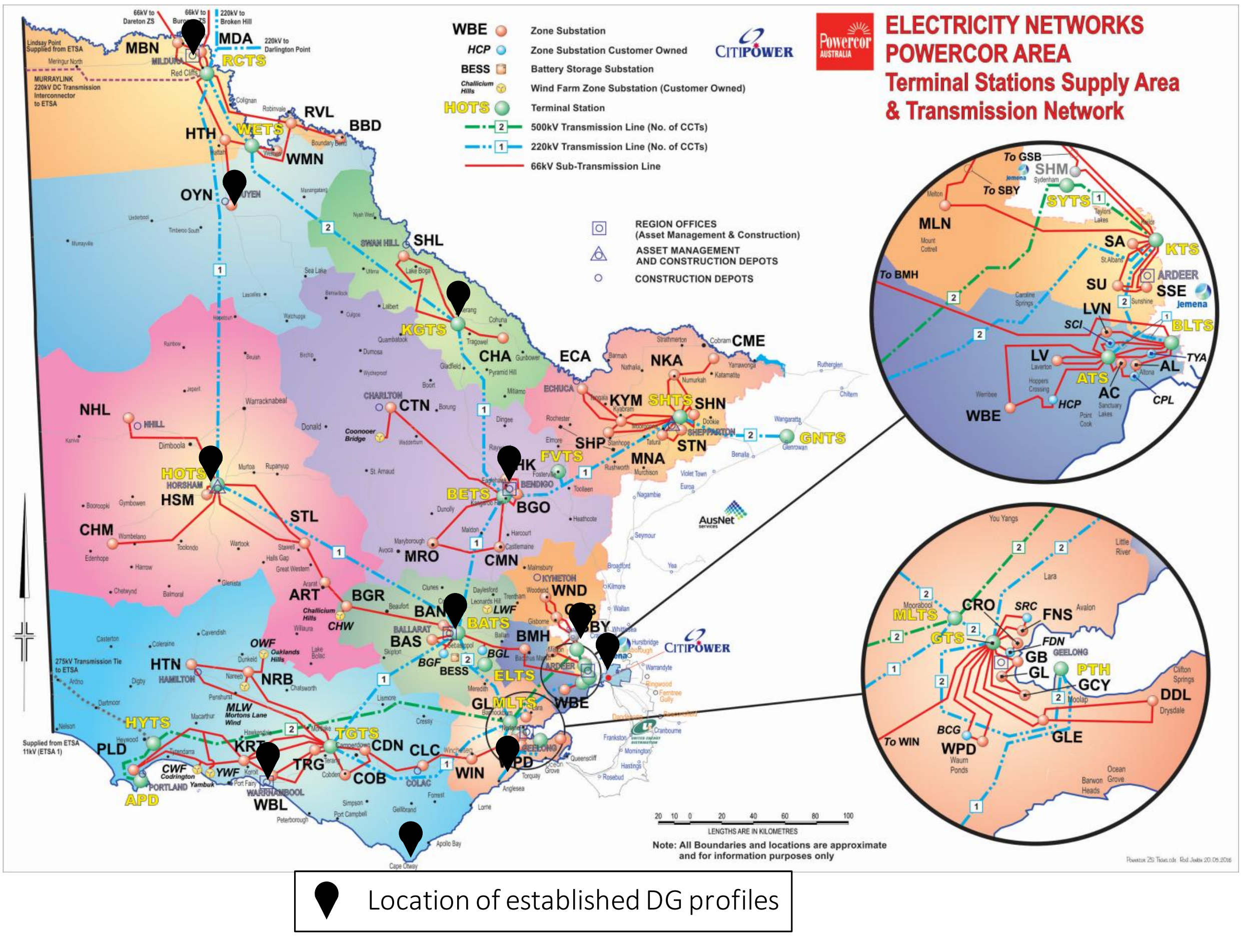


Figure 6 – Locations selected to establish Distributed Generation profiles

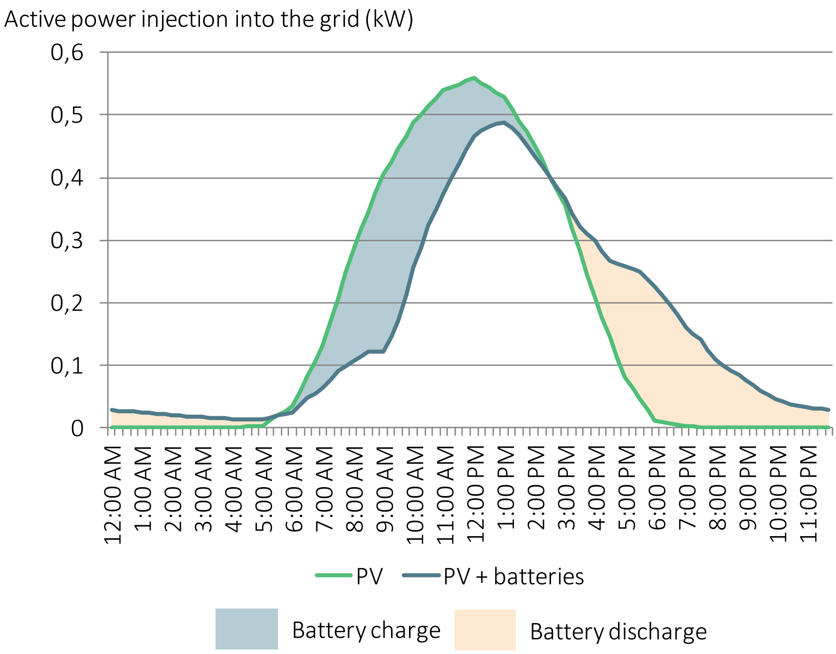


Figure 7 – Average active power injection into the grid (kW) of a 1 kWp DG system for a typical meteorological year in Melbourne

2.2.4 Valuation of investment deferral (steps 5 to 9)

The investment deferral value is then computed based on the estimated DG capacity required to defer planned sub-transmission line and zone substation investments by one year[8]. For one particular investment on a specific asset, DG value is calculated using the following steps illustrated in Figure 8:

- Step 5: The planned year of investment *Y*, that is the year of investment if no further distributed generation was installed, is computed. It corresponds to the first year when the value of energy at risk outgrows the annualised augmentation CAPEX[9]. Energy at risk evolution is computed based on load profile forecasts without future distributed generation uptake (refer to section 2.2.2).
- Step 6 & 7: The asset load profile with a specified amount of DG is then computed for the planned year of investment.
- Step 8: Then, the amount Q_{DG} of DG required to return energy at risk to its value one year before *Y* is computed. And finally, the unit value of distributed generation is assessed as:

$$DG\ Value = \frac{Annualised\ CAPEX\ Value}{(1 + WACC)^n \cdot Q_{DG}}$$

Where:

- *WACC* is CP/PAL's approved nominal weighted average cost of capital for 2016-2020 (6.11%)
- *n* is the number of years from 2016 to the planned year of investment. *n = Y-2016*
- Q_{DG} is the amount of distributed generation required to defer the investment by one year

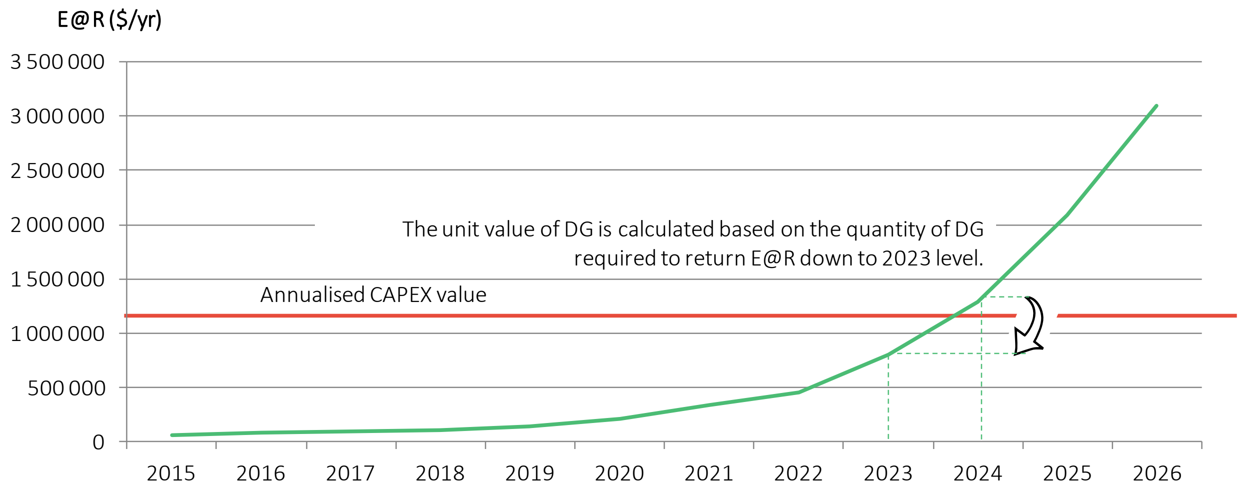


Figure 8 – Valuation approach for investment deferral

Finally, to compute the value at one network asset, values calculated for all upstream assets where an investment is planned are summed (step 9).

[8] Due to the yearly pattern of electricity demand, one year is the minimum unit of deferral that can be used, thus resulting in the computation of a "pseudo-marginal" value, averaged over a number of systems.

[9] This trigger is simpler than NPV comparison and results in the same outcome for the cases considered (energy at risk is monotonic in time).

Note: For investments alleviating energy at risk on multiple assets, the investment was allocated to the different assets depending on their contribution to the overall energy at risk the year the investment is planned (see Figure 9 for an example).

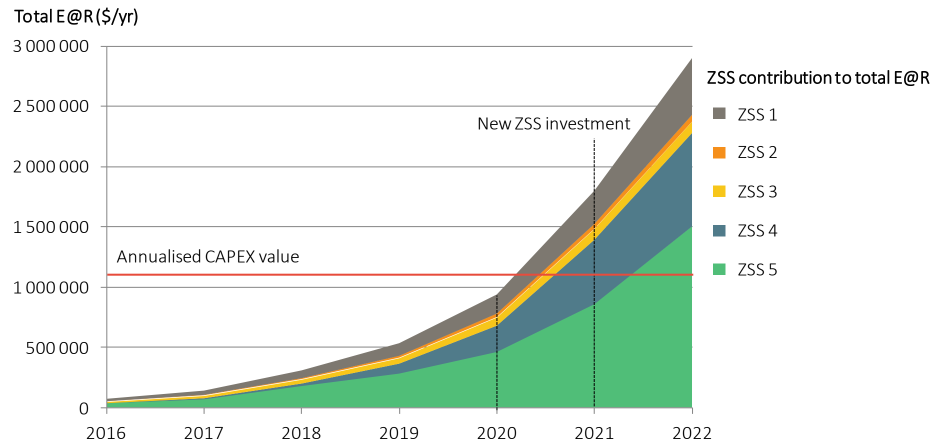


Figure 9 – Example of an investment alleviating energy at risk on multiple network asset: TNA Zone substation

2.3 Implementation

The proposed methodology was implemented in an excel tool developed to automate the calculation (Figure 10) and was applied to CitiPower and Powercor networks.

Hypotheses		
Name	WBE	-
N-1 exposure	0,65%	-
Network upgrade CAPEX		M$
Lifetime		years
Annualized CAPEX	161 724	$/yr
VCR rate	28 620	$/MWh
Reference meteo station	Melbourne Airport	-

Seasonal hypotheses	Summer
N Rating	123,3
N-1 Rating	82,8
Load tan(Phi)	
10%Poe/50%PoE peak load ratio	1,113
Capacitor Bank	0,00

Demand evolution	2015	2016	2017	2018	2019	2020
Summer 50%PoE load	105,4	91,9	95,4	100,0	104,5	109,2
Winter 50%PoE load	77,0	75,7	78,8	82,4	86,2	90,3

Update Network DB | Import load curve | Check load curve

Energy at risk	2015	2016	2017	2018	2019	2020
50%PoE, N Rating	0,0	0,0	0,0	0,0	0,0	0,0
10%PoE, N Rating	0,0	0,0	0,0	0,0	0,0	0,0
50%PoE, N -1 Rating	393,2	34,4	91,2	204,6	357,8	571,4
10%PoE, N -1 Rating	1 131,1	279,2	426,8	691,5	1 047,3	1 518,6
TOTAL	**4,0**	**0,7**	**1,2**	**2,3**	**3,7**	**5,6**
Compute EaR for all years	114 325	20 066	35 696	65 235	105 036	159 158

	PV	PV+Battery	
Planned year of investment	2021	2021	-
Amount of DG to defer investment by 1 year	58345	21540	kW_p
Investment deferal value of DG	2,77	7,51	$\$/kW_p$

Compute DG Value

Figure 10 – Screenshot of the tool developed to implement the calculation methodology

3 RESULTS

The proposed methodology was applied to CitiPower and Powercor networks. The results of this computation are presented in this section.

Note that they are indicative only, since they are based on 2015 demand forecasts which will shortly be replaced with updated demand forecasts. Additionally, HV feeders have not been factored into the value yet.

Our calculation shows that distributed generation cannot systematically defer investments. As illustrated in Figure 11, DG may be able to alleviate some risk on the assets, but not enough to reach the threshold required to defer the investments.

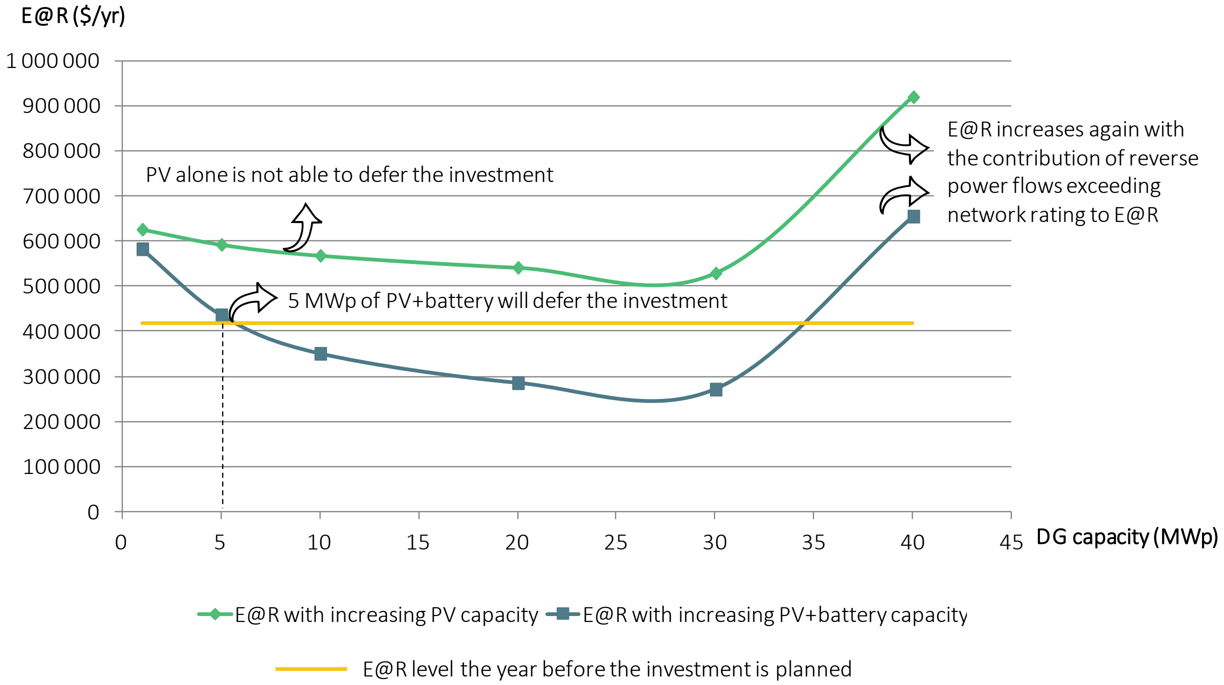


Figure 11 – Value of energy at risk for a specific asset with increasing DG capacities

This result can be explained by non coincident distributed generation with peak demand periods. One other consequence of this observation is that distributed generation may not be able to reduce the maximum demand on the assets, though it can reduce the energy at risk (Figure 12).

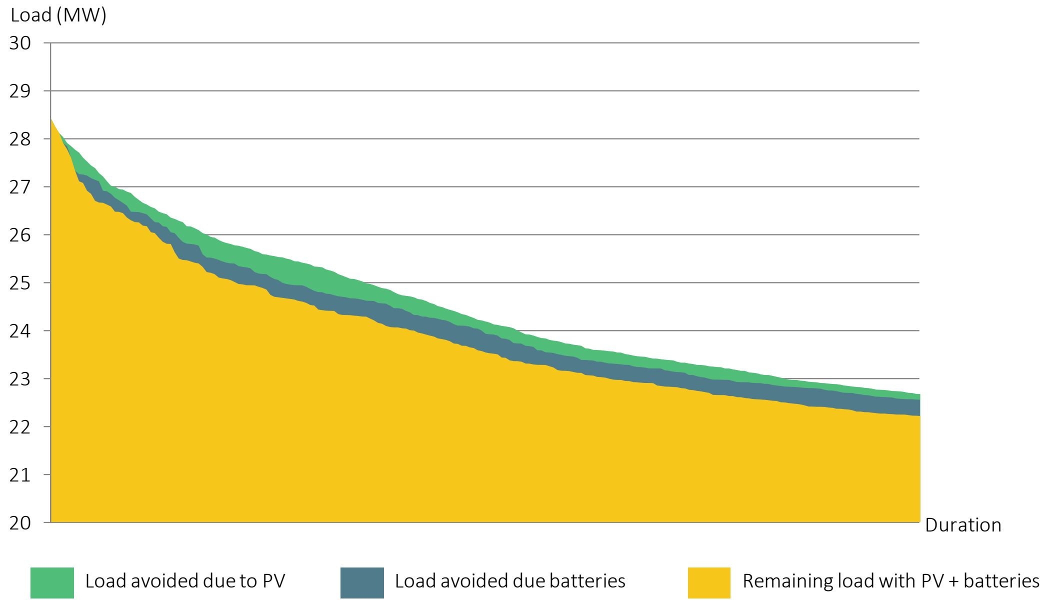


Figure 12 – Effect of distributed generation on the load duration curve of a zone substation

Our calculation shows that PV and PV plus batteries have no investment deferral value on CitiPower network. Indeed, for demand-driven investments within the 10 year investment window, DG is unable to defer the investment. On Powercor network, our calculation shows that DG investment deferral value is highly locational and limited to a few geographical areas for both PV (Figure 13) and PV plus batteries (Figure 14).

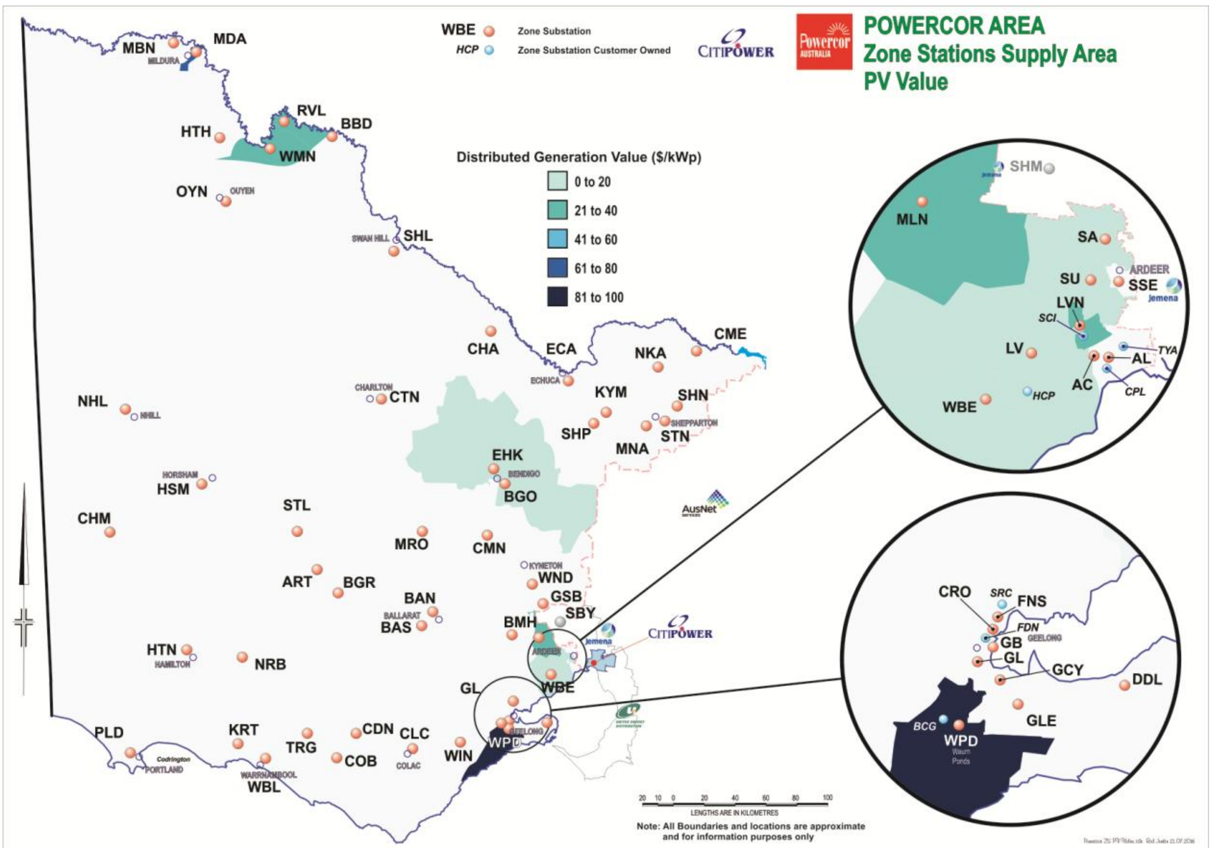


Figure 13 – PV investment deferral value over Powercor network

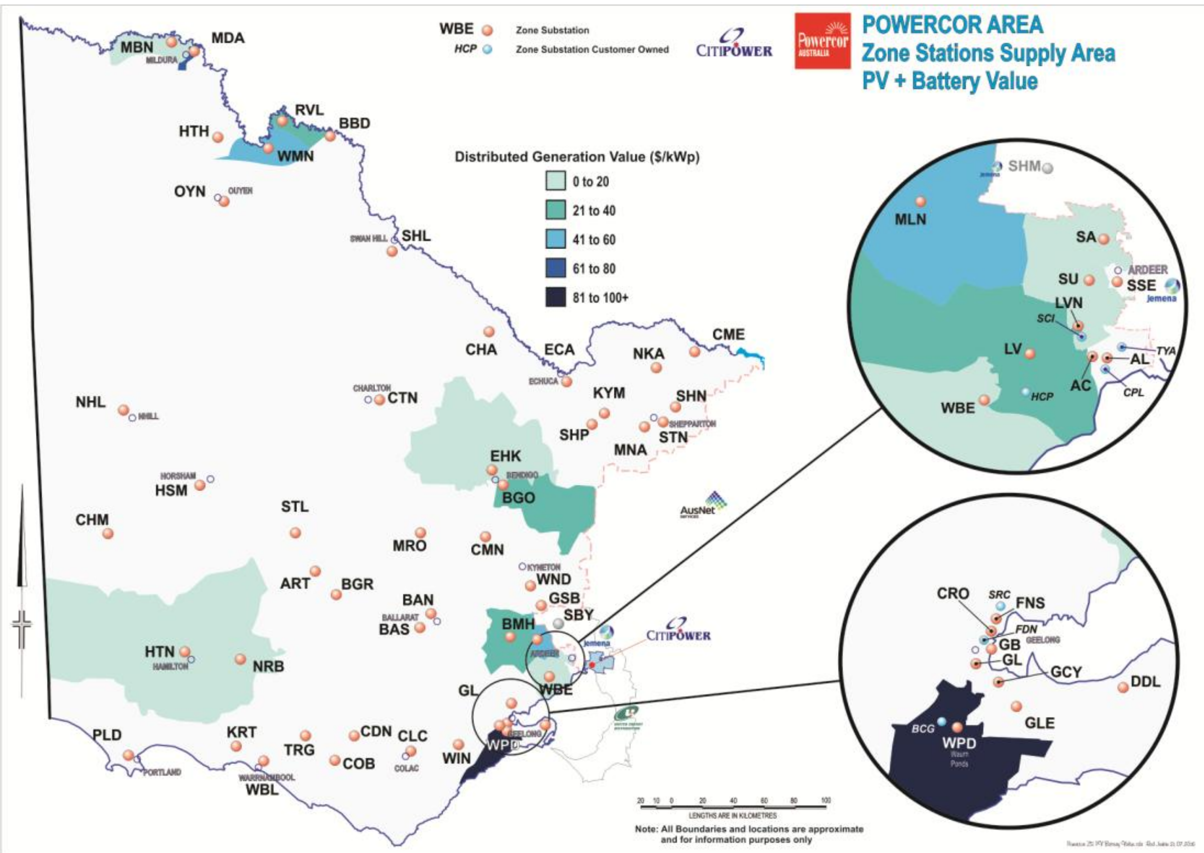


Figure 14 – PV + battery investment deferral value over Powercor network

Overall, 23 and 26% of CP/PAL customers see a positive PV and PV plus battery value respectively (Figure 15). For these customers, DG value is up to 0.7 c$/kWh or 110 $/kWp of DG capacity (Figure 16**Erreur ! Source du renvoi introuvable.**). PV plus batteries have a higher value than PV alone except in 1 case (LVN).

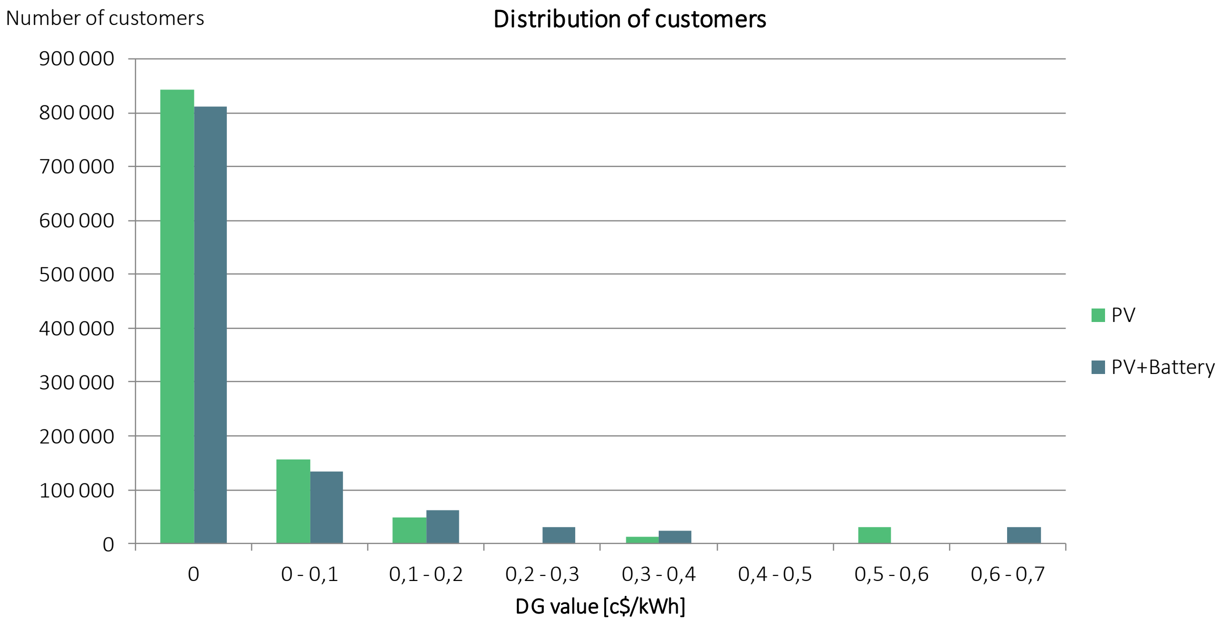
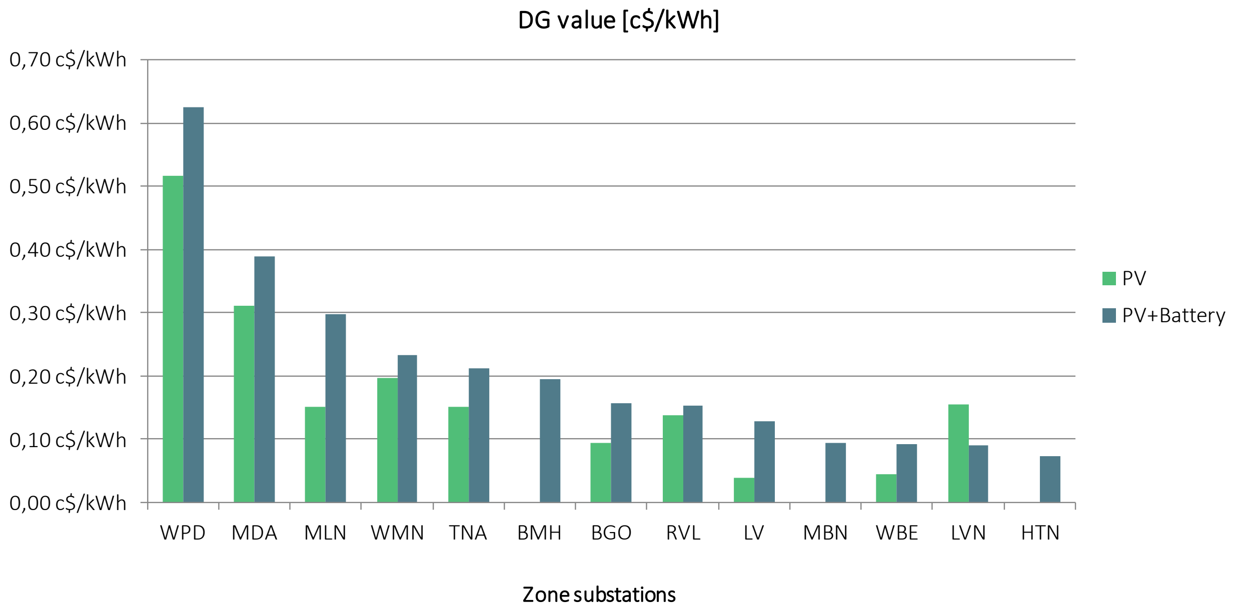


Figure 15 – Distribution of CP/PAL customers according to the value of DG at the level of the zone substation to which they are connected



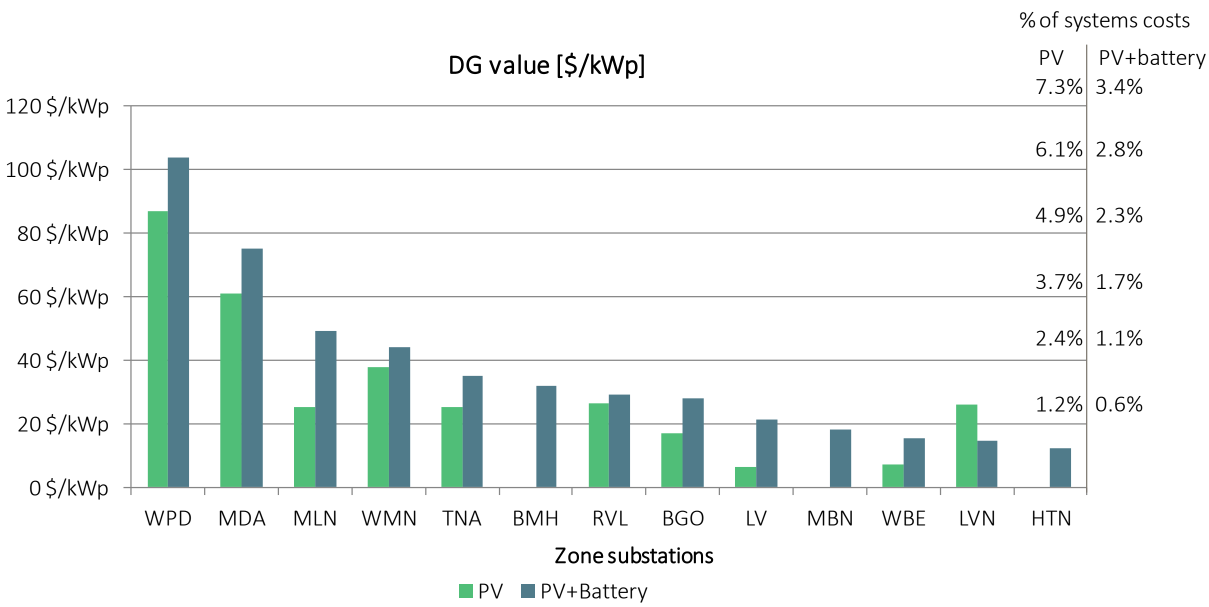
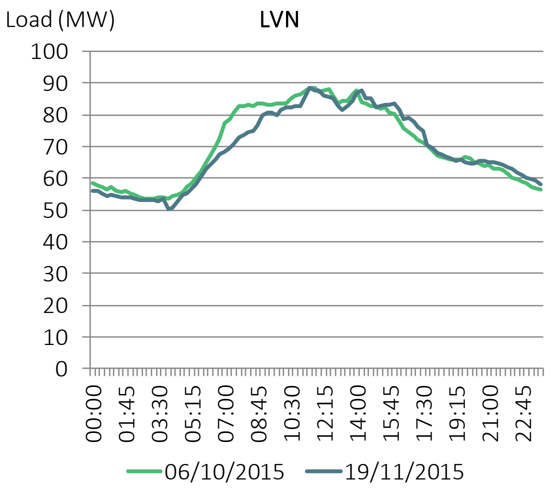


Figure 16 – DG investment deferral value at the level of CP / PAL zone substations in c$/kWh (above) and $/kWp (below). The value is compared with CAPEX of DG systems assumed to be $8k for a 5kWp PV system and $18k for a 5kWp PV + 6.5kWh battery system (including GST and STCs)

In the case of LVN, PV alone has a higher value than PV plus batteries because maximum demand occurs earlier in the day than for other zone substations (Figure 17). As a consequence, it is more favorable to PV whose peak generation better coincides with LVN peak consumption than PV plus batteries.



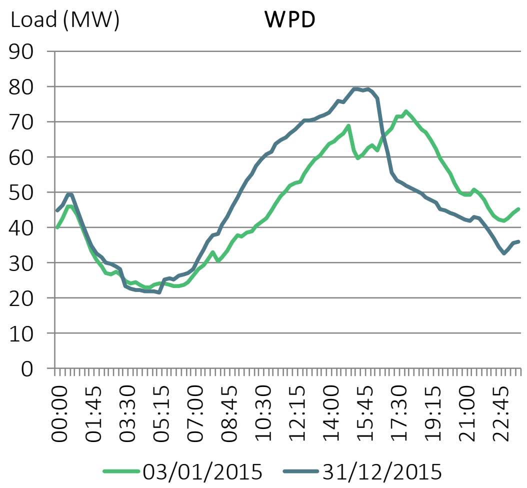


Figure 17 – LVN (left) and WPD (right) load profiles during the 2 days with the highest demands in 2015

Finally, high DG amounts may be required to defer the investments as shown in Figure 18. In particular, the required PV and PV + battery capacity exceeds 30% of the zone substation rating in 3 and 2 cases respectively (Figure 19). This 30% threshold corresponds to CP / PAL's maximum acceptable PV capacity on distribution transformers. Above this threshold, further analysis is required by CP / PAL to investigate the need to upgrade these transformers.

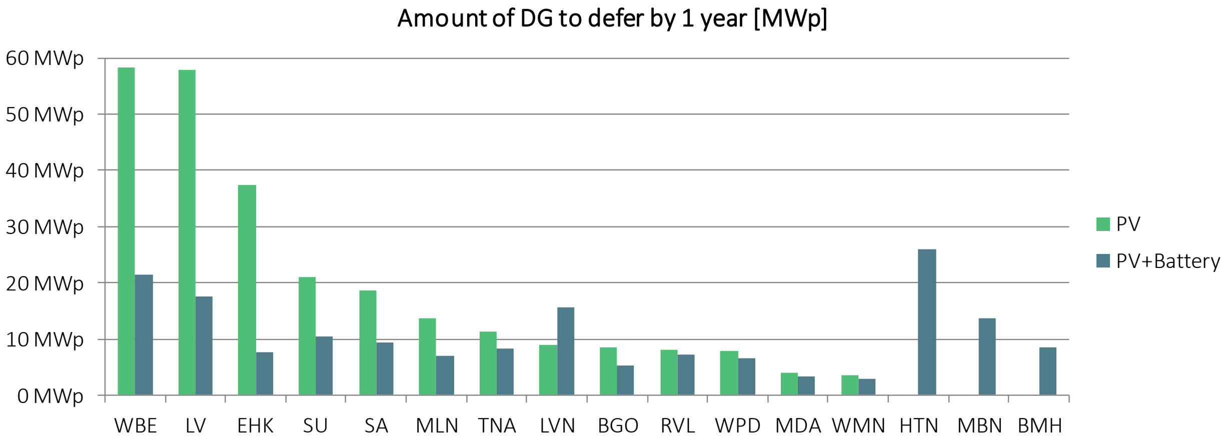


Figure 18 – DG capacities required to defer the investment by one year at each ZSS

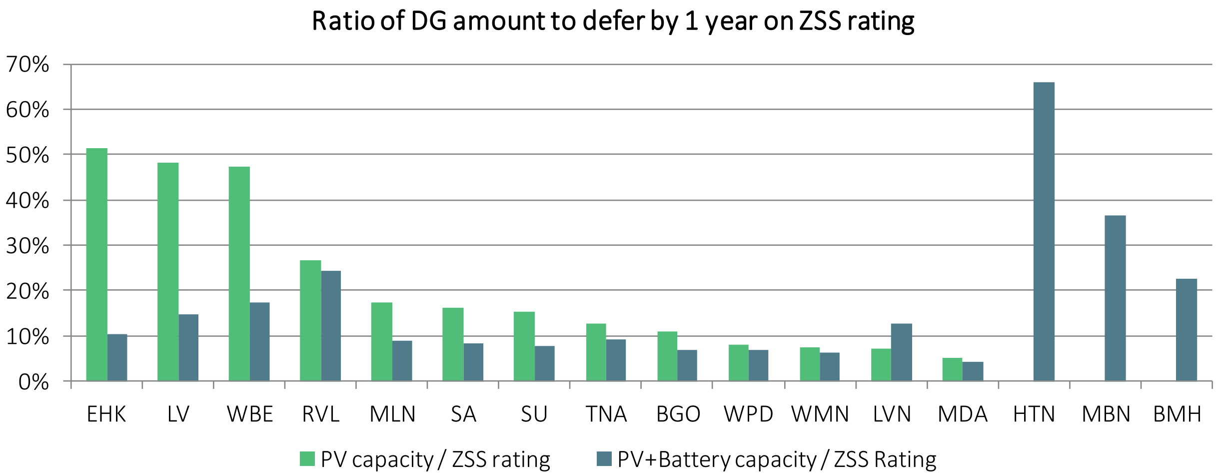


Figure 19 – Comparison of DG capacities required to defer the investment by one year with ZSS ratings

In addition, reaching these capacities with residential systems only will be challenging in some areas, due to both penetration limits and annual installation rate limits.

Indeed, in some areas, a high proportion of CP/PAL customers would need to be equipped with new residential DG systems (5kWp) to reach the DG amount required to defer the investment (Figure 20): on average, 63% and 45% of customers served by a ZSS would require a new[10] 5 kWp PV and PV+battery system respectively. For some cases, residential systems alone will not be able to defer investment: PV penetration rate would need to be higher than 100% in 3 areas to achieve deferral.

Moreover, the required penetration needs to be achieved prior to network investment. Figure 21 shows that in 8 geographical areas corresponding to 6 ZSS for PV and 9 for PV + batteries, the annual installation rate of new residential systems would require to be above 5% of the total number of customers of that area. For these zone substations, residential systems alone will not be able to defer investment: to date, the highest PV installation rate in Victoria was 2.5%[11].

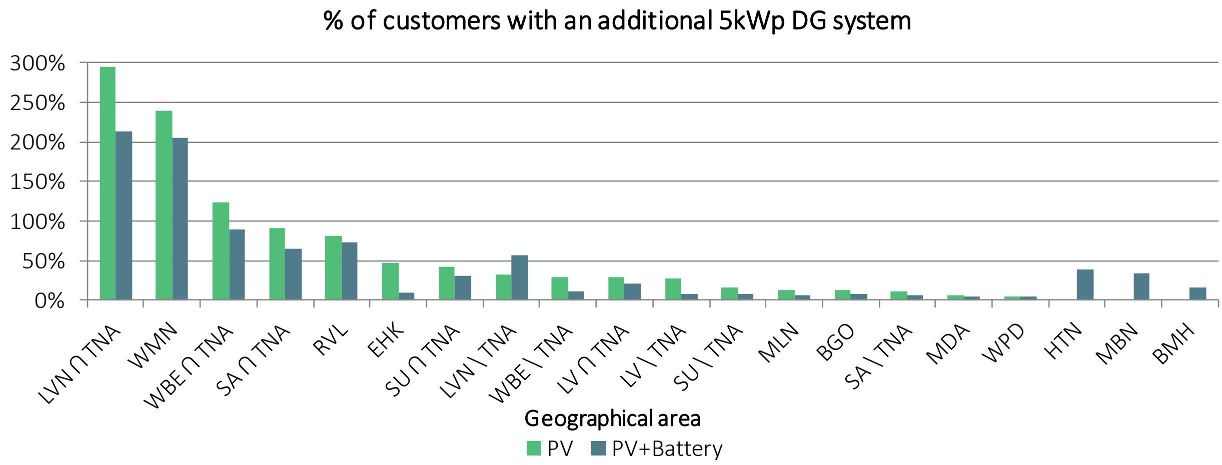


Figure 20 – Percentage of customers requiring an additional 5kWp DG system to defer the investment. As TNA is a new zone substation taking load from LV, LVN, SA, SU and WBE, customers of these substations have been affected to 2 different geographical areas: area that will be connected to TNA (e.g. LV ∩ TNA) or not (e.g. LV \ TNA)

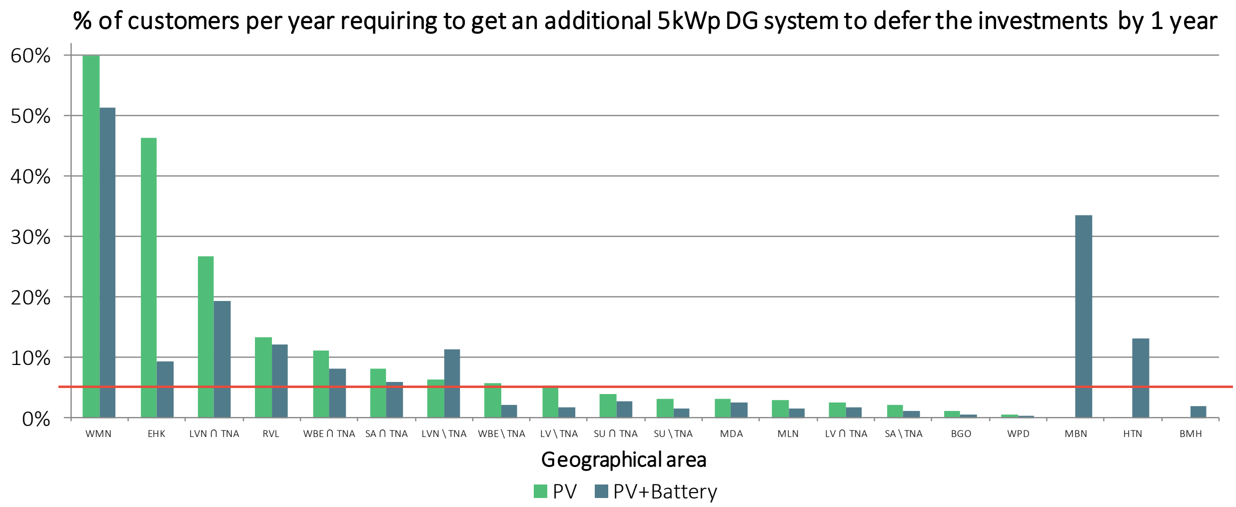
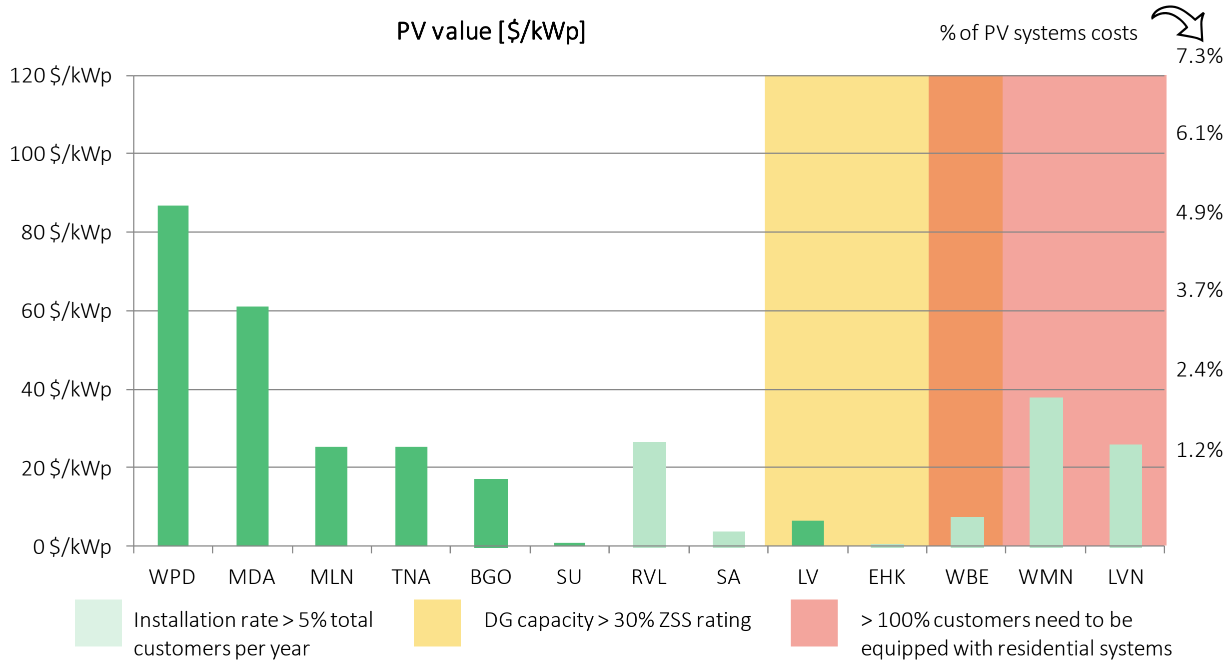


Figure 21 – Percentage of customers per year requiring an additional 5kWp DG system to defer the investment

[10] PV systems already installed are already taken into account in the forecast demand.

[11] This installation rate was achieved in 2012 with 66,204 installations for a total of 2,6 million customers [4].

Finally, these considerations suggest that out of CP / PAL's 105 zone substations, residential PV and PV+batteries alone may be able to defer investment on 6 and 8 ZSS respectively (see Figure 22).



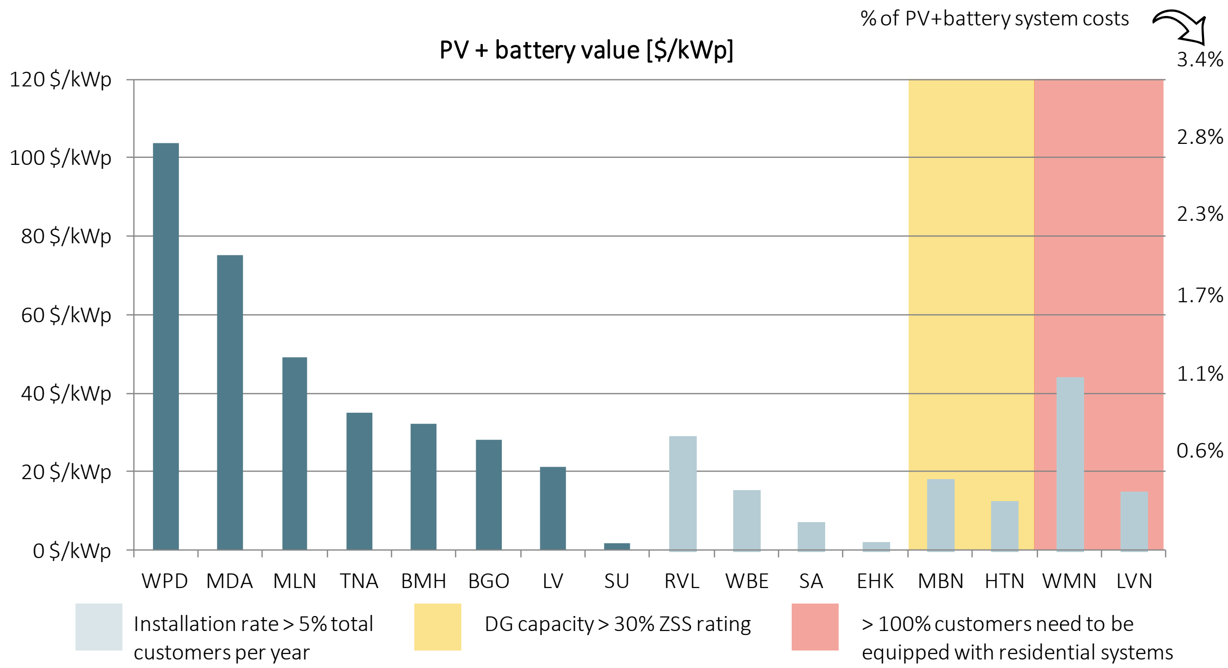


Figure 22 – Investment deferral value of PV (above) and PV + batteries (below) at the level of CitiPower and Powercor zone substations

GLOSSARY OF TERMS USED

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CP/PAL	Citipower and Powercor
DG	Distributed Generator / Distributed Generation
DNSP	Distribution Network Service Provider
E@R	Energy at Risk
ESC	Essential Services Commission
MD	Maximum Demand
STC	Small-scale Technology Certificate
TMY	Typical Meteorological Year
VCR	Value of Customer Reliability
ZSS	Zone substation

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