STAFF PAPER – VALUATION METHODS AND CONSIDERATIONS

Distributed Generation Inquiry Stage 2 Network Value

October 2017

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GLOSSARY

Annuitisation	A financial-based process that converts a lump-sum investment into a series of periodic payments.
Co-generation	A type of distributed generation system designed to generate electricity and useful heat jointly.
Cost-curve	A table of costs related to a variable.
Current	An electric current is the flow of an electric charge at a defined rate.
Cyclic rating	See box 2.1.
Derating	The operation of equipment lower than its rated capacity, usually to extend the life of the equipment.
Differential	In mathematics, a differential refers to the infinitesimal difference between the relationships of variables.
Dispatchable generation	Generation whose output can be controlled, and which therefore can be dispatched according to the instructions of an operator. This can be contrasted to passive generation, the output of which cannot be actively controlled by an operator.

Distributed generation	Any electricity generation that is connected to the electricity distribution system. Distributed generation can come in varying sizes and be powered by a variety of fuel sources. Refer to section 3.2 of the Network Value Final Report.
Distribution business	A type of network business who engages in the activity of owning, controlling, or operating a distribution system – referred to in the NER as a Distribution Network Service Provider (DNSP).
Energy at risk	Refer to 'expected unserved energy'.
Expected unserved energy	The forecasted amount of energy that is required by customers but cannot be supplied due to the failure of a critical piece of network equipment.
Feeder	An electric line that transfers power from different points in a network (often between substations, from a generator, and to the customer).
Firmness	A shorthand means of referring to matters relating to the reliability of generation, which may include intermittency, predictability, dispatchability.
Function	A mathematical equation.
Generation profile	The pattern of electricity produced across time by a generation technology, such as solar PV systems.

Load transfer	A network operation practice to meet the load at a point of the network by reducing loads at that point and increasing loads at a different point.
N-1 rating	The capacity of a zone substation (or any network asset) in a scenario where the largest piece of equipment has failed.
Network augmentation	Also referred to in this staff paper as ‘network upgrade projects’. A modification or upgrade to an existing network for the purposes of increasing the capacity to supply load or to increase reliability of supply. Augmentations are distinct from projects intended to replace existing network infrastructure due to infrastructure assets reaching the end of life.
Network business	A transmission or distribution network business.
Network optimised	The attribute, as it applies to a generation resource, of being fully optimised for the purposes of creating network benefits. Encompasses both reliability and timeliness (i.e. coincidence with peak demand).
Passive generation	Generation whose output cannot be actively controlled by an operator. This includes most forms of solar photovoltaic systems (assuming the array does not include control systems or energy storage).

Power	Power (also referred to as real power) is the rate, per unit time, at which electrical energy is transferred by an electric circuit. Apparent power is the product of line voltage and current.
Power factor	Total power includes real and apparent power. Power factor is the ratio of real power (kilowatts or kW) to apparent power (kilo volt-amps or kVA).
Project deferral	Where a network project that is planned in a certain year, is deferred (or delayed).
Project lead time	The time between a project being designed and fully operational.
Probabilistic planning approach	An approach used by network planners to determine the time when a network upgrade should occur. See section 3.3.3.
Rated capacity	Also known as nameplace capacity, is the intended output of equipment (such as a power plant or transformer) when operating at a sustained full-load.
Reactive power	Reactive power is power where the current is completely out of phase with the voltage and which delivers no net energy to the customer. Reactive power has an important influence on voltage.
Regression analysis	A statistical method that estimates a relationship between one variable and a series of changing variables.

Reserve margin	The supply capacity of a network less the peak demand faced by the network. It is defined as the measure of capacity divided by the applicable peak demand minus one.
Small-scale	For the purposes of this inquiry, small-scale refers to distributed generation of below 5 MW capacity.
Thermal time constant	The time taken for the max temperature of equipment (such as a transformer) is a function of the thermal time constant.
Transformer	Electrical equipment that can reduce or increase voltage.
Tri-generation	A type of distributed generation system designed to generate useful heat, cooling and electricity jointly.
Value of Customer Reliability	The value of expected unserved energy in dollars per megawatt-hour at any given customer connection point in the network. The value is assessed according to class of customer (e.g. residential, commercial, industrial, or agricultural).
Voltage	The amount of potential energy per unit of electrical charge between two points on a circuit.
Zone Substation	An electrical substation that connects a distribution to a sub-transmission network. Substations can switch two or more lines for operational purposes and may have one or more transformers to connect lines operating at different voltages.

ACRONYMS

DG	Distributed generation
ZSS	Zone substation
CAPEX	Capital cost
OPEX	Operational cost
N-1 capacity	Capacity of the ZSS minus one failed transformer or piece of critical equipment
VCR	Value of Customer Reliability
kWh	kilowatt-hour
AEMO	Australian Energy Market Operator
PV	Photovoltaic
MW	megawatt
MVA	megavolts-amps
WACC	Weighted average cost of capital
NPV	Net Present Value
DAPR	Distribution Annual Planning Report
DNSP	Distribution Network Service Provider
MWh	megawatt hour

kVA	kilovolts-amps
ESC	Essential Services Commission

CONTENTS

SUMMARY

INTRODUCTION

The Essential Services Commission has conducted an inquiry into the wholesale market value and the network value that distributed generation can provide.

In August 2016, the commission submitted to the Government its final report on the energy value of distributed generation.[1] In addition to the benefits associated with energy supply, distributed generation may provide network benefits, particularly if it reduces peak demand in a predictable way. In February 2017, the commission submitted to the Government its final report on the findings into the network value of distributed generation.[2]

PURPOSE OF THIS PAPER

This staff paper provides further detail about our considerations in calculating the network value of distributed generation, and our choice of a counterfactual method for the valuation calculation. It also describes other valuation methods considered by the inquiry.

WHAT DID WE CALCULATE AND HOW?

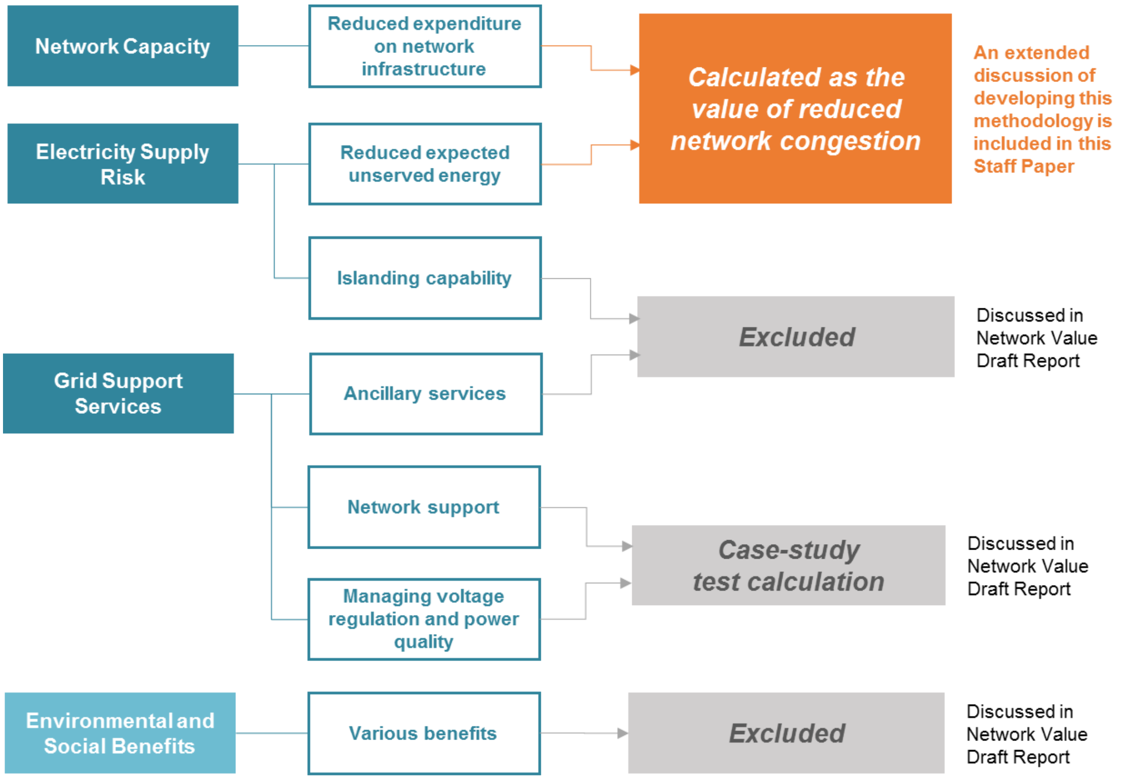
In our final report into the network value of distributed generation, we calculated the value of existing and forecast distributed generation systems in Victoria in terms of dollars per kW of installed capacity per year between 2016 and 2020. This value includes the ability for distributed generation to reduce network congestion, which potentially delays or reduces network expenditure or reduces the cost of expected

[1] Essential Services Commission 2016, *Final Report into the Energy Value of Distributed Generation*, August

[2] ESC 2017, *Final Report into the Network Value of Distributed Generation*, February

unserved energy. As shown in figure S. 1 below, other benefits were considered. However these benefits were considered to be not material and so were excluded from the analysis.

FIGURE S. 1 TREATMENT OF NETWORK BENEFITS IN THE INQUIRY



Source: ESC

We valued distributed generation using well established economic principles and industry techniques. Our ‘counterfactual’ valuation method drew on publically available data from Annual Planning Reports and data published by the AER to evaluate the cost of building and operating the network without distributed generation. We then compared this cost to the current forecast of network augmentation costs with distributed generation. The difference between the two costs reveals the annual aggregate value of our current forecast stock of distributed generation in Victoria at each location.

WHAT ARE THE OTHER METHODS TO CALCULATE VALUE?

Before deciding on the Counterfactual method we considered four other methods. The methods we considered are summarised in table S. 1.

TABLE S. 1 COMPARISON OF VALUATION METHODS

Method	Author	Change in DG	Brief description of method
Counterfactual	Jacobs, ESC	Minus all DG	Calculates difference in network costs by removing existing and forecast DG from the current forecast capacity.
Counterfactual Incremental	Jacobs	Forecast +1MVA	Calculates difference in network costs by adding a small amount of DG to the current forecast capacity.
Turvey Incremental	Turvey R.	Forecast + amount to defer project	Calculates difference in network costs by adding enough DG to the current forecast to defer a network project by exactly one year.
Long-run Growth Incremental	Mann et al	Forecast + peak demand growth	Calculates difference in network costs by removing all future growth from current forecast (equivalent to there being enough DG installed to exactly meet future peak demand growth).
Marginal 'Cost-curve'	Gawler R.	Infinitesimal amount	Perform regression and differentiation on a table of network costs versus DG quantity.
Marginal 'Differential of Functions'	Gawler R.	Infinitesimal amount	Create an algebraic equation of network cost versus installed DG quantity, and then differentiate with respect to change in DG quantity.

Source: ESC

Two noteworthy differences between the methods are as follows:

- **The way a method assesses the change in distributed generation.** The change in distributed generation refers to how much distributed generation was assumed to have been added or removed. This turns out to be crucial. Smaller amounts of distributed generation tend to have more volatile value from year to year because they typically have little impact on the timing of network projects. But when they do happen to change project timing, the effect can be quite large relative to the quantity of distributed generation.

- **The way a method assesses value over time.** Some of the methods considered average or sum value over the lifetime of distributed generation assets rather than the value it provides in each year. Lifetime valuation methods are much smoother from year to year because they consider a 20 year rather than a one year period.

Overall the different methodologies share the same underlying concept of network value, however they make different assumptions about the quantity of distributed generation to be valued and the period of valuation. Different methods will be suitable for different applications, depending on the intended use of the value derived.

THE COUNTERFACTUAL METHOD

For the purposes of this inquiry, the objective of our chosen valuation method is to identify the value of the network benefits produced by distributed generation in Victoria in a given year. We examined a range of potential methods for undertaking this analysis, and ultimately used a form of counterfactual method that was best suited to the exercise. The counterfactual method calculates a value for the existing and forecast fleet of distributed generation assets within a given year.

This can be contrasted to a method such as the Turvey incremental or Counterfactual incremental method, which is geared towards identifying the value of a particular tranche (or increment) of additional distributed generation installed over a given time period.

1 INTRODUCTION

1.1 ABOUT THIS REPORT

The Network Value Final Report presents the commission's final findings regarding the network value of distributed generation. Separately, we have published a report by Jacobs Consultancy, which provides extended and detailed information on the results presented in the Network Value Final Report.

This staff paper provides further detail about our choice of the counterfactual method for application in the inquiry. It also provides further detail of other valuation methods considered as part of the inquiry.

1.2 STRUCTURE OF THIS REPORT

This report is divided into the following chapters:

- chapter 1 contains an introduction to this staff paper
- chapter 2 describes the background to methods for valuing distributed generation
- chapter 3 describes the design of methods for valuation
- chapter 4 describes six different methods for calculating network value
- chapter 5 presents observations on the variability of network value
- chapter 6 describes why the counterfactual method was chosen for the inquiry

2 BACKGROUND

2.1 INTRODUCTION

This chapter provides background on key elements considered in developing methods to value the network benefits provided by distributed generation. The following questions are discussed:

- How does distributed generation provide network benefit and how can it be considered in valuations?
- What characteristics of distributed generation impact network value?
- What are the data sources and assumptions required to value the network benefit from distributed generation?

2.2 BENEFITS INCLUDED IN VALUATION METHODS

As described in the Network Value Final Report, we considered a range of potential network benefits that can be provided by distributed generation, including potential economic, environmental and social benefits.[1]

We found that distributed generation can and does create network value – particularly in reducing network congestion, which accounts for deferring the need to upgrade the network and thereby save costs, and in reducing the amount of expected unserved energy.

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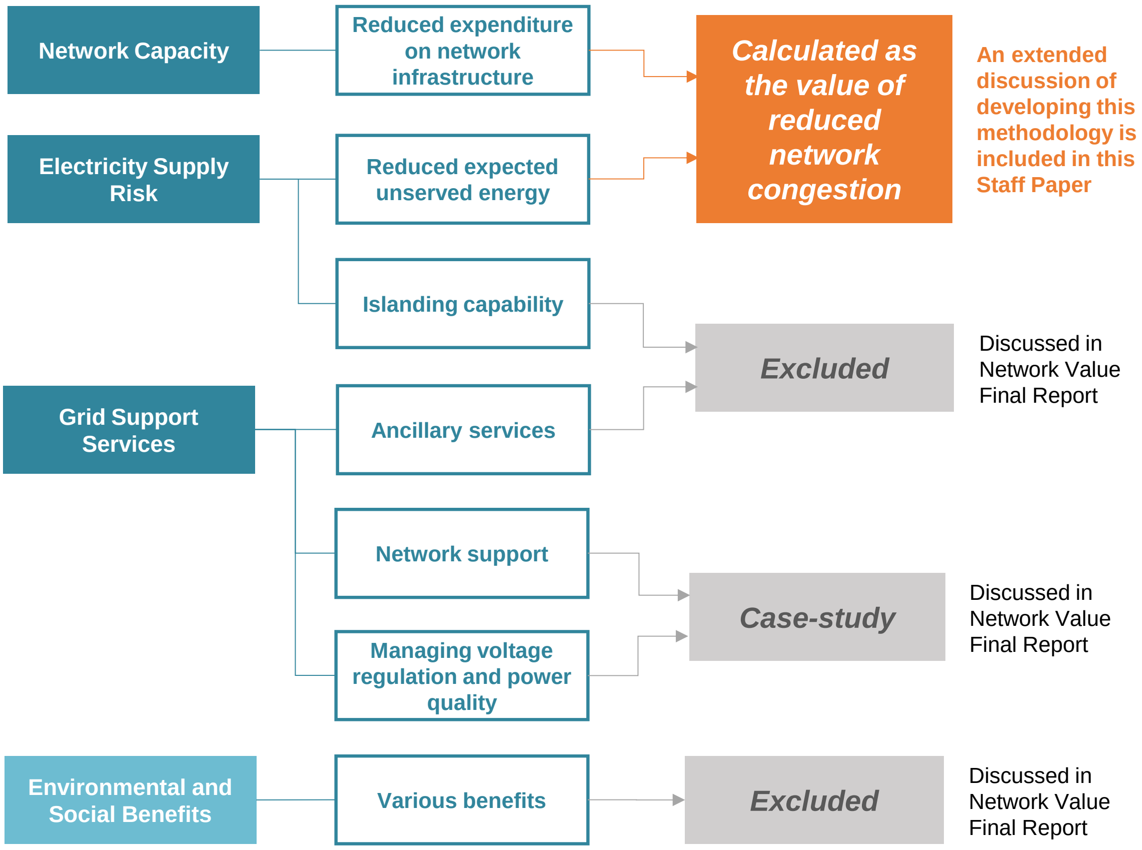
[1] ESC 2017, *Final Report into the Network Value of Distributed Generation*, February, pp. 15-19.

Distributed generation can also provide other economic network benefits but these were not currently material with respect to calculating network value for the purposes of the inquiry. The commission did not identify evidence that the network effects of the distributed generation installed in Victoria is creating additional social or environmental benefits.

As the material network benefits from distributed generation relate to reducing network congestion as shown in figure 2.1, the commission considered a number of specific methodologies to quantify and value this benefit – we refer to these as valuation methods in this staff paper. Further detail in developing and applying these valuation methods are provided in chapter 3 and 0.

FIGURE 2.1 TREATMENT OF NETWORK BENEFITS IN THE INQUIRY



Source: ESC

2.2.1 REDUCED EXPENDITURE ON NETWORK INFRASTRUCTURE

One benefit from reducing network congestion is reducing or deferring the need to invest in network infrastructure upgrades. Electricity networks are designed to have enough capacity (referred to as supply capacity) to meet peak electricity demands from consumers. If a network business forecasts peak demand reaching the supply capacity of the network, it will invest in network projects that increase their capacity. Large network assets such as zone substations (ZSS), which cover up to tens of thousands of homes, could cost millions of dollars to upgrade. This includes the capital cost (CAPEX) of the asset itself and its on-going annual operational costs (OPEX).

Distributed generation generates electricity locally and it can reduce the peak energy demand faced by an area of the local network. In doing so, distributed generation could defer the time when a network project is needed. Deferring the time when a network project is needed has financial value.

2.2.2 REDUCED EXPECTED UNSERVED ENERGY

Distributed generation can also provide value in reducing the likelihood of customers' energy not being supplied due to an outage. The measure of this likelihood is referred to as expected unserved energy.

Unserved energy arises when a network asset, such as a substation transformer, fails thereby reducing the overall supply capacity of a part of the network. A scenario of this occurring is shown in figure 2.1, representing a ZSS with two transformers. If one of the transformers within the ZSS fails, it will reduce the overall capacity of the network by one transformer – the capacity of the ZSS minus one failed transformer is known as its 'N-1' capacity.[2] In practice, if one transformer failed, as in figure 2.1, the network business may disconnect a distribution feeder to reduce the load above the N-1 capacity of the zone substation. This may result in some households and businesses losing supply.

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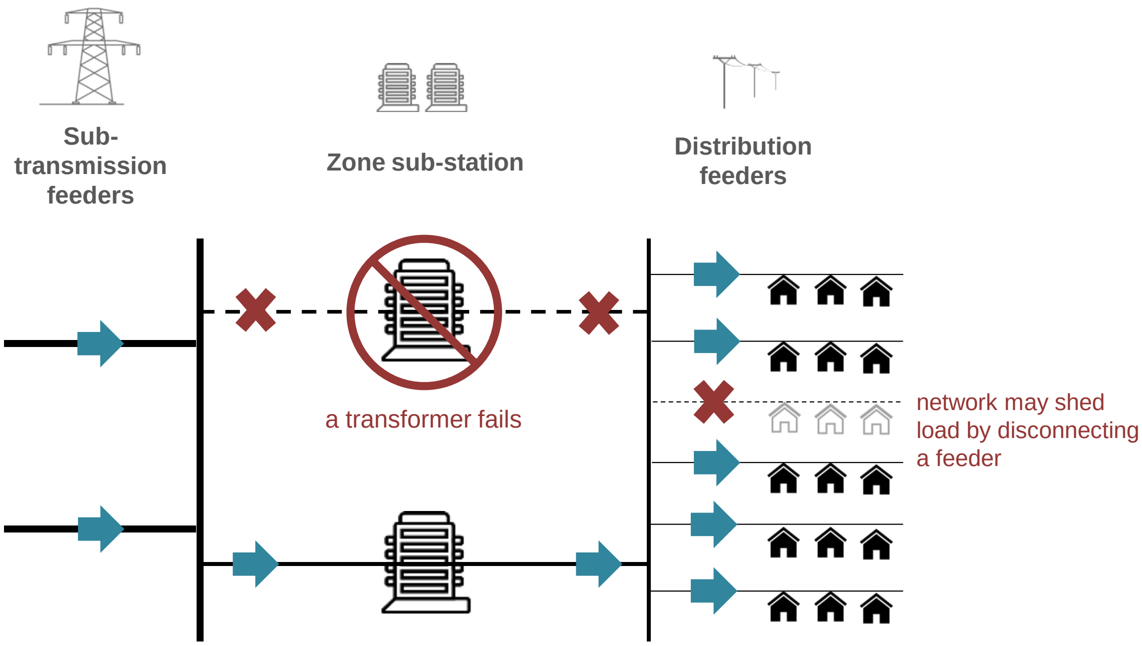
[2] In this case, the N-1 capacity is the capacity of the remaining transformer.

FIGURE 2.1 SUBSTATION WITH TRANSFORMER FAILURE AND LOAD SHEDDING

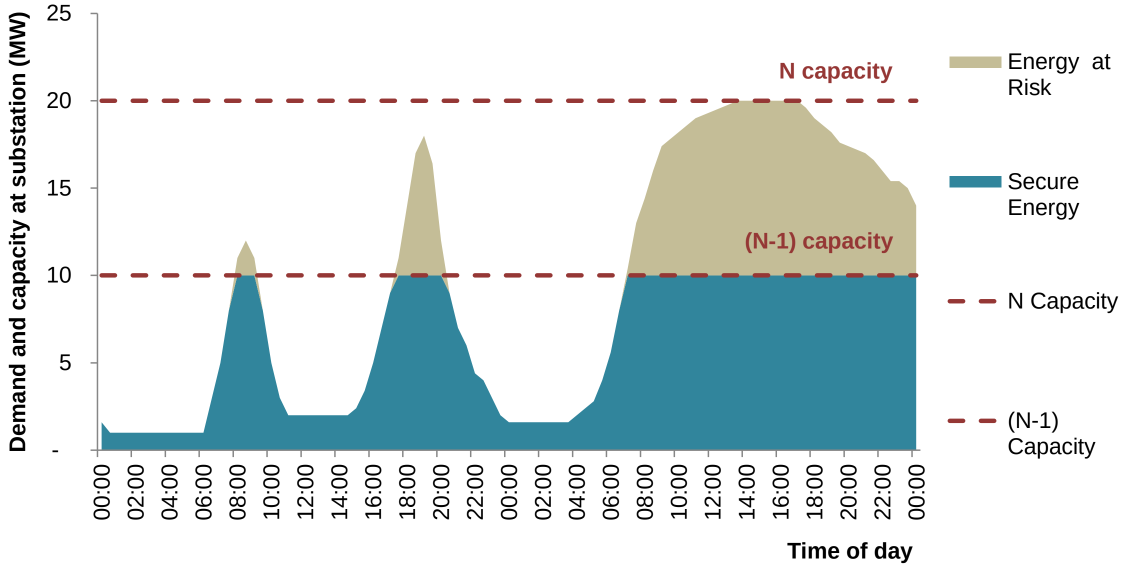


Source: ESC

The energy demand above the N-1 capacity of a zone substation is referred to as 'energy at risk', because a zone substation may not supply energy above that capacity following a failure at the substation. 'Energy at risk' is shown in the example in figure 2.2 as the energy above N-1 shaded in light brown.[3]

[3] In network planning, the quantum of 'energy at risk' is also referred to as expected unserved energy.

FIGURE 2.2 SUBSTATION LOADING ABOVE N-1 CAPACITY
Example only

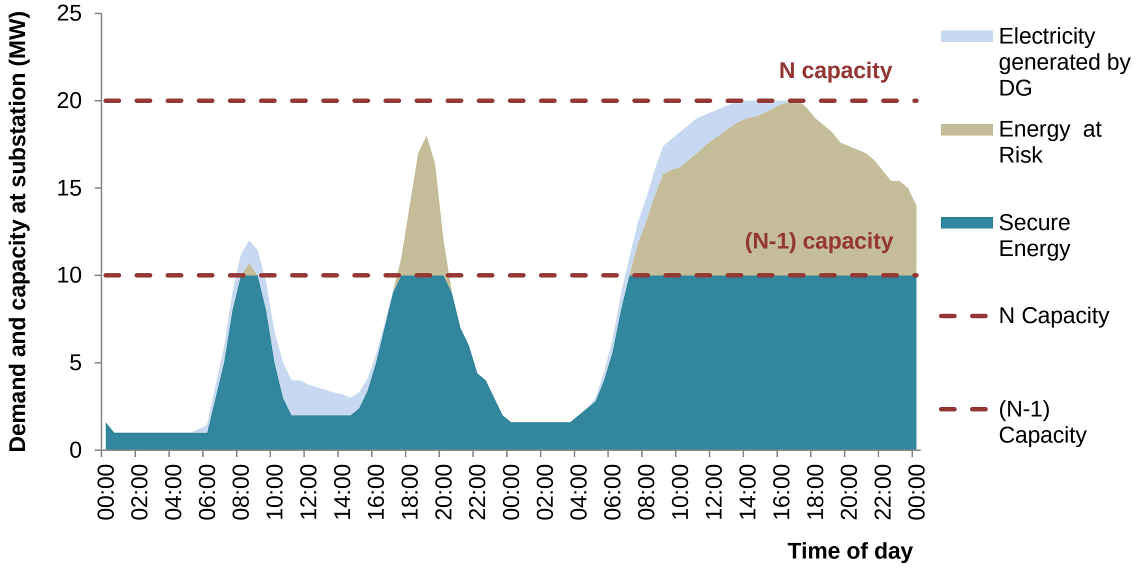


Source: ESC

The cost to households and businesses resulting from energy that is not served to the customer as a result of an outage is known as the 'Value of Customer Reliability' (VCR). VCR is routinely calculated and published by AEMO and is measured as a $ per kWh of unserved energy.

Distributed generation can reduce the amount of expected unserved energy if the electricity it generates is during the times of energy at risk. This is shown in figure 2.3, in an example where the substation in figure 2.2 now has distributed generation installed in its network area. During some periods of the day, the energy generated by distributed generation has directly reduced the amount of energy at risk.

FIGURE 2.3 ELECTRICITY GENERATED BY DISTRIBUTED GENERATION REDUCING ENERGY AT RISK
Example



Source: ESC

The energy at risk or the amount of expected unserved energy is routinely calculated and published by AEMO. In reality, calculating energy at risk is not as simple as illustrated in figure 2.2 because the prevailing capacity changes with prior weather conditions and loading patterns.[4]

INTERACTIONS BETWEEN UNSERVED ENERGY AND NETWORK PROJECT TIMING

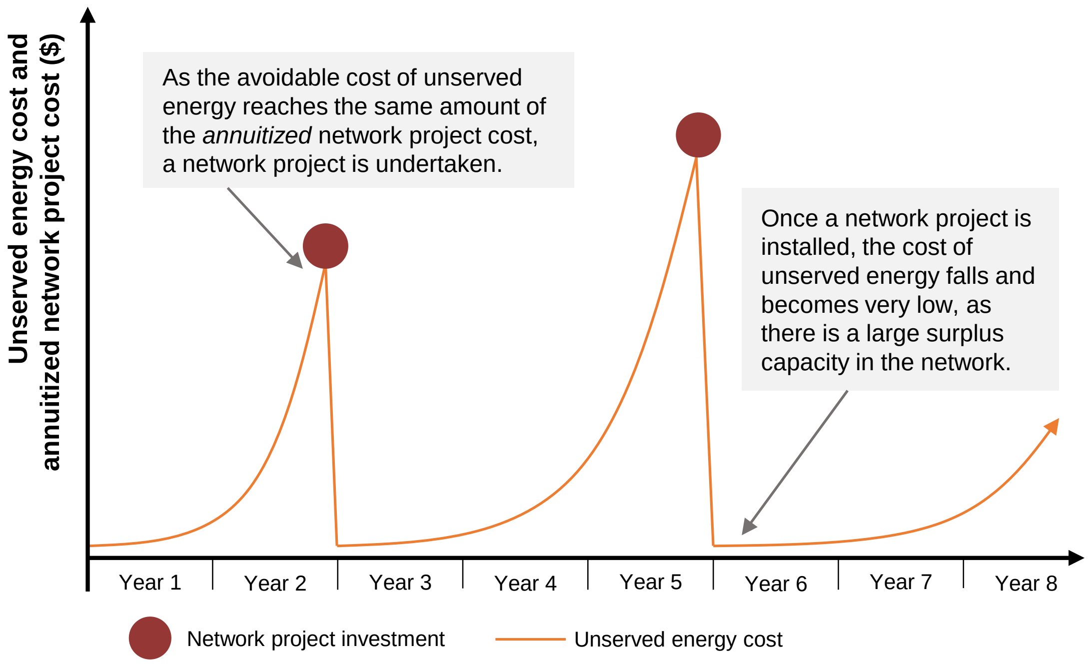
Unserved energy considerations have interesting interactions with value derived from when network projects are undertaken. Typically as network demand increases the energy at risk also increases, leading to an increase in expected unserved energy

[4] These patterns and variations have an impact due to the heat flow characteristics of network assets such as powerlines and transfomers.

costs – approximately an exponential trend. Under the probabilistic planning method approach – an approach used by Victorian distribution businesses to determine the time where a network project is required – network projects will only be considered when the cost of expected unserved energy that can be avoided by the network project just exceeds the annuitised cost of that network project.

This interaction between unserved energy costs and the timing of project deferrals is illustrated in figure 2.4.

FIGURE 2.4 EXAMPLE OF INTERACTIONS BETWEEN UNSERVED ENERGY AND NETWORK PROJECT TIMING



Source: ESC

The timing of network projects can also be deferred as a result of distributed generation reducing expected unserved energy. But where network upgrades are deferred because of distributed generation, unserved energy costs actually become higher and often remain so until the project goes ahead. This may reduce the benefit derived from deferring network projects and occasionally these two components of value could cancel each other out. This is discussed further in section 3.3.5

2.3 CHARACTERISTICS OF DISTRIBUTED GENERATION THAT IMPACT VALUE

In the inquiry, it was important to consider the characteristics of distributed generation systems that lead to network value. Unsurprisingly, value depends primarily on distributed generation generating electricity when networks are congested. The extent of that value also increases based on the ability of a distributed generation system to reduce peak demand.

As described in the Final Report, the size of network value is affected by certain characteristics of distributed generation, described as follows:[5]

- **Time –** The value also varies according to the extent to which the electricity generation coincides with the periods of peak demand within the section of the network to which the generator is connected. This timing may be dependent on the type of distributed generation system technology, as different technologies have different generation profiles. For example, solar PV systems generate electricity during the day (as it may be on hot summer days), wind systems are dependent on the availability of wind resources, and diesel generators may have limits such as fuel storage. The network value of a distributed generation system will depend on whether its energy generation profile coincides with periods of network congestion.[6]

  The impact of different distributed generation systems (or technologies) can be accounted for by measuring or deriving hourly generation profiles for each technology type. Generation profiles like demand are often related to the weather, so it is important that consistent weather assumptions are used for all technologies

[5] ESC 2017, *Final Report into the Network Value of Distributed Generation*, February, pp. 43-44

[6] It should be noted that energy production of the system over a long period of time (annually or seasonally) does not strongly influence network value. For most of the time, the energy generation profile of the system has no impact on network congestion.

and network demand. This approach preserves the correlation between network congestion and distributed generation.

Separately, distributed energy generation during a network peak day could also reduce the thermal loading on transformers, which increases the capacity of transformers for a short number of hours. This peak load carrying capacity is defined as cyclic rating (as distinct from a nameplate rating, which is defined for standard conditions at constant load). This short-term increase in capacity can have a slight influence on network capacity and expected unserved energy during peak hours – this impact on cyclic rating is discussed further in box 2.1.

- **Capacity –** The generation capacity of the distributed generation. For instance, there may be a minimum capacity needed to obtain material value. In particular, the maximum output from distributed generation determines the maximum potential to reduce network power flows, which can reduce network congestion. Furthermore, depending on the network configuration in a given location there may be a capacity above which additional distributed generation incurs network costs.

  The equipment reliability and derating of distributed generation systems also impact its capacity, as follows:

  - The reliability of the equipment impacts the capacity of a distributed generation system. Equipment reliability can be measured by the probability that the system is in operation when it is scheduled to generate. Network value of distributed generation is approximately proportional to its generation reliability. Usually the reliability is greater than 95% for mechanical systems and greater than 99% for static systems.[7]
  - Derating of system generation capacity at high ambient temperatures would be an important factor if peak network power flows occur at times of high ambient temperature. Derating can be a component of the peak generation output of a system.

- **Optimisation –** 'Optimisation' refers to the extent to which the generation is optimised for delivery of grid services, which is largely a function of being both

[7] It should be noted that mechanical generation equipment needs to be taken out of service for maintenance periodically. The maintenance of the system (and its unavailability) could be scheduled to avoid any detriment to its network support value, i.e. during periods of low network demand. Static systems are those without moving parts.

predictable and responsive to the needs of the network. The industry terms applied to these qualities are 'firm' and 'dispatchable'. A system that is highly optimised for network benefits is one that reliably produces output at the time it is most needed by the network.

Distributed generation systems can generally be optimised by considering its predictability and controllability, as follows:

- The predictability of a system's generation output is important for networks to schedule local thermal generation (if available) and to perform maintenance on parts of the network. Predictability of output influences the extent to which the generator can be relied upon to reduce peak network flows. In some situations, predictability may affect the planning of network operations where load transfers are feasible between zone substations. This has an indirect influence on the assessment of the energy at risk in that greater predictability enables higher network utilisation and reduces energy at risk.
- Controllability is the ability for a system to generate electricity when the network needs support (or during a time of network congestion). This controllability could be at the command of the distributed generator owner or a network business. Value is maximised when the distributed generation is controlled according to prevailing network conditions.

It is possible but not practical, to consider all characteristics of distributed generation when designing a valuation method – these characteristics are not always easy to measure as they vary over time and differ for each installation. Simplification and aggregation is often necessary for useful analysis.

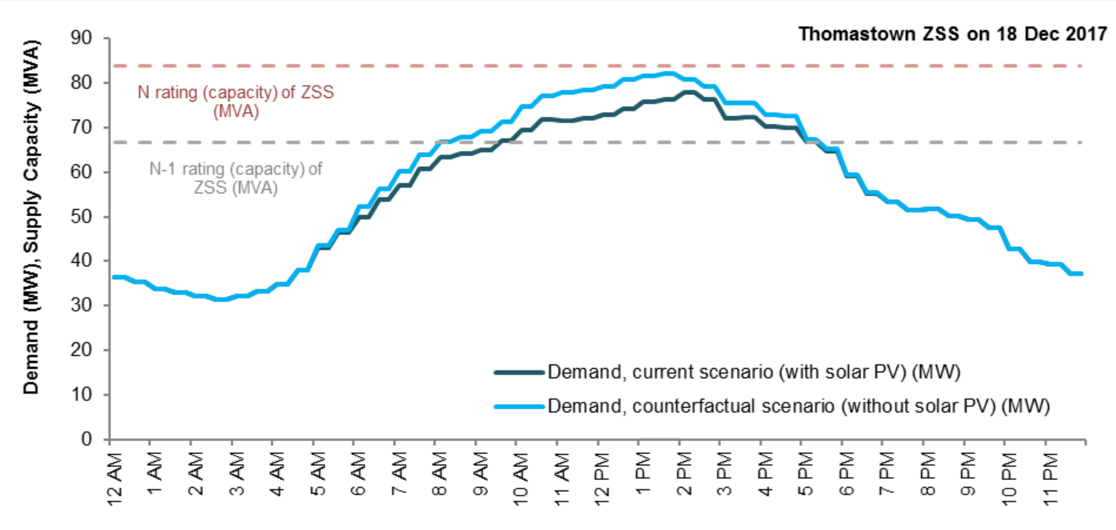
BOX 2.1 IMPACT OF DISTRIBUTED GENERATION ON CYCLIC RATING

Electrical equipment is rated to perform at a certain capacity. The rated capacity of network assets is determined as the maximum capacity it can operate at a certain rated maximum equipment temperatures. In practice, network assets could operate at different maximum capacities depending on the temperature that equipment is operating under – this is referred to as its *cyclic rating*. The cyclic rating is usually higher than the rated capacity of the equipment because it takes time for the equipment to heat up to the rated temperature when high demand occurs.

Distributed generation could reduce the demand on network assets in the lead up to peak demand, which could increase the cyclic rating of assets. This has benefits such as extending the serviceable life of equipment. The impact of distributed generation on reducing load prior to peak demand can be seen in figure 2.5 for Thomastown ZSS. Without solar PV, demand during 11am-2pm remains high and equipment assets would be facing higher temperatures leading up to the peak demand at 2pm.

But with solar PV, demand during the same period stays lower, which supports an increase of cyclic rating in the lead up to peak demand.

FIGURE 2.5 PEAK DAY DEMAND-PROFILE WITH AND WITHOUT DISTRIBUTED GENERATION
Example ZSS using data based on Thomastown ZSS



Source: ESC based on Jacobs modelling

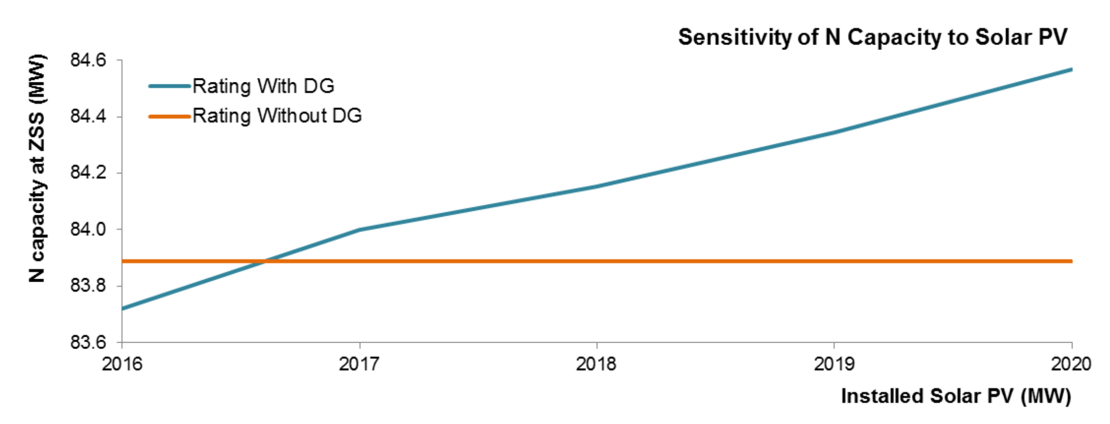
To test the impact of distributed generation on cyclic rating, we analysed load profiles for installed solar PV at Thomastown ZSS from 0 to 20MW – load profiles were scaled to give a peak demand of 83.44 MVA (the demand which would trigger a network project, based on the unserved energy functions for Thomastown ZSS, using the technique described in section 3.3.5). A simple thermal model of a transformer was applied to Thomastown ZSS, assuming:

- a two hour thermal time constant
- a continuous rated capacity defined for 25°C ambient temperature and

- ambient temperature on extreme day range from 20°C at 5am to 45 °C at 5pm.

The temperature cycle of a transformer for cases with and without solar PV was modelled to determine the change in peak demand as solar PV varies relative to underlying load. We found that solar PV could have an impact on cyclic rating, depending on the amount of solar PV installed. As shown in figure 2.6, as solar PV increases over time, cyclic ratings could increase by around 1% in 2020.

FIGURE 2.6 EFFECT OF SOLAR PV CAPACITY ON CYCLIC RATING
Example ZSS using data based on Thomastown ZSS



Source: ESC analysis

The case-study indicates that distributed generation could an impact the cyclic ratings of network assets, but this impact depends on load profiles and generation profiles at that asset. Further analysis is needed to better characterise these impacts.

2.3.1 ACCOUNTING FOR DISTRIBUTED GENERATION CHARACTERISTICS

The methodology applied for the Network Value Final Report focussed on existing distributed generation systems which are installed in Victoria. The characteristics of solar PV systems were accounted for by taking samples of 300 actual generation profiles of installations in Australia – it would also account for equipment reliability and derating. ‘Firm’ dispatchable systems were assumed to have 100% equipment reliability and be able to provide generation at exactly the time of peak demand – these systems were described as being ‘network optimised’. Further information regarding the solar PV profiles is provided in the Jacobs report for the inquiry.

2.4 DATA AND ASSUMPTIONS

All valuation methods could be applied using the same underpinning data and assumptions.[8] A large proportion of the data and assumptions were based on the availability of detailed information for each network asset group (substation, sub-transmission loop or transmission terminal station).

A summary of the necessary data and assumptions, for full application of each valuation method is described below. For further information about the full sets of data and assumptions used for the counterfactual valuation applied in the Network Value Final Report, refer to the Jacobs report for the inquiry.[9]

2.4.1 NETWORK ASSETS AND EXPENDITURE ON NETWORK UPGRADES

The following assumptions relate to the treatment of network assets in valuation, particularly regarding how the expenditure on project network upgrades has been considered:

- **Analysis occurs at the ZSS level:** The method can be applied to any area of the network, as long as there are sufficient levels of data available for that area. In the Network Value Final Report, the extent of the full valuation exercise (the full application of the counterfactual method) was limited by the public availability of data and therefore focussed on zone sub-stations, terminal stations and sub-transmission feeders.[10] The terminal station analysis relies on the aggregated

[8] Although some valuation methods may have greater limitations than others – refer to section 0 regarding the specific considerations and assumptions required for the application of distinct valuation methods.

[9] Jacobs 2017, *Distributed generation inquiry – network benefits report,* March

[10] ESC 2017, *Final Report into the Network Value of Distributed Generation*, February, pp. 26-27

demand and installed capacity of distributed generation from zone substations, specifically associated with a terminal station.

- **ZSS load profiles:** The load profile used in the valuation was aggregated quarter-hourly demand data, at a network asset location (ZSS) for a year. This is based on historical metered data.

  Load profiles are scaled to changes in forecast peak demand assuming annual energy increases at the same rate.[11]

- **Peak demand forecasts:** The valuation accounts for forecast growth in annual peak demand for the peak season, summer or winter, or both if relevant. The Network Value Final Report applies peak demand forecasts as stated in the Distribution Annual Planning Reports by network businesses. In particular, valuation methods applied a mixture of the 10th percentile (30% weight) and 50th percentile (70% weight) loads.[12]

  Peak demand measures include apparent power (MVA), real power (MW) and power factor (real power divided by apparent power). Peak demand forecasts are assumed to be accurate and no allowance has been made for the impact of forecast uncertainty on distributed generation value.[13]

- **ZSS capacity:** Total existing supply capacity at a network asset, comprised of a number 'N' of transformers. The capacity is measured with all assets in service (N capacity) and for the largest capacity element out of service (N-1 capacity).[14]

  It should also be noted, as discussed in box 2.1, that there is a potential benefit of distributed generation in increasing the supply capacity of a ZSS by improving its cyclic rating.

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[11] Where energy forecasts are available, the load shape could be rescaled to match the annual energy. This would have an immaterial impact on assessed values because only the top 5% or so of the load shape is relevant to assessing expected unserved energy. In this study, annual or seasonal energy forecasts were not considered.

[12] Refer also to Jacobs 2017, *Distributed generation inquiry – network benefits report,* March.

[13] Forecast uncertainty increases the value of DG because it can be installed in small amounts and progressively added as demand grows. The approximately exponential relationship between peak demand and expected unserved energy also serves to enhance the value of DG under higher forecast uncertainty.

[14] Note that where network assets have parallel elements of differing but similar capacity, multiple outage states may need to be evaluated to correctly estimate the expected unserved energy. In this study we have only focused on the outage of the larger elements and assumed that the outage of any parallel smaller elements has no material impact on expected unserved energy.

- **Load transfers:** Load transfer capabilities of zone substations and terminal stations are accounted for in the calculation of the N-1 capacity and hence the quantity and value of expected unserved energy. It was assumed that load transfers would only be applied after a transformer failure, so load transfers contribute to N-1 capacity but not the N capacity.[15]
- **Asset failure probability:** Probability of failure of one critical piece of network equipment, for N-1 cases. When calculating the probability of one transformer out of service (for p_2, p_1 and p_0 if required in equation 3.5), the load transfer capability was treated as if it were an additional transformer.[16]
- **Cost of network upgrades:** With regard to the cost of network upgrades we assumed that:
  - cost includes both CAPEX and project related OPEX
  - cost of a future network augmentation project at a specific network asset location, either based on actual forecasted costing (from a network business)[17] or estimated for a generic project
  - deferring a project does not change its cost in real terms and
  - there is no inter-dependency between projects i.e. the cost of one project is not affected by its timing with respect to another project.[18]
- **Network asset life:** Assumed standard life of network augmentation upgrades ranged between 44 and 75 years depending on the nature of the project.
- **Impact of network project lead time:** Certain valuation methods may need to account for the lead time in planning and implementing network projects.[19] However, for counterfactual and incremental methods, lead time is not considered

[15] For analysis purposes, load transfers are considered as the addition of one transformer to estimate the N capacity.

[16] This affects the probability of the N-1 failure state and the calculation of expected unserved energy.

[17] In Australia, network businesses are required to submit data on upcoming network upgrade projects over a five-year reporting period. These reports are referred to as Annual Planning Reports, and are submitted to the AER on an annual basis. Other information and data can be obtained from Regulatory Impact Notices, also submitted by network businesses to the AER on an annual basis.

[18] In reality this may not hold, however these types of interdependencies are difficult to model and we have no data to do so. Additionally there is no reason to believe they would have any consistent positive or negative impact on value under competitive market conditions for project design and construction.

[19] Marginal methods consider project lead time, which is discussed in section 4.6.1.

because the assessment focuses on “with” and “without” distributed generation scenarios that assume network projects are implemented with perfect foresight.

- **Marginal loss factors**: Marginal system loss factors have been applied at the zone substation level. These factors reflect the value of losses from transmission and sub-transmission level down to the zone substation level. Marginal loss factors at the customer level have not been applied.

2.4.2 DISTRIBUTED GENERATION SYSTEMS

The following assumptions relate to the treatment of distributed generation systems in the valuation exercise:[20]

- **Impact on network demand as a result of distributed generation:** In the Network Value Final Report, distributed generation profiles were derived for existing systems in each network area. These distributed generation profiles were accounted for in a counterfactual scenario, deriving load profiles for each ZSS on a 15-minute basis.
- **Distributed generation asset life:** The assumed average life of 20 years for distributed generation systems were included in the analysis. Any impacts on network costs beyond 20 years from the assessed year are excluded on the basis that the distributed generation system would have been retired.[21]
- **Growth in distributed generation:** Growth forecasts from 2016 to 2020 for each ZSS were as per the DAPRs at each ZSS. Extrapolation of these growth forecasts would be required (or new forecasts generated) for analysis beyond 2020.

2.4.3 REGULATORY AND ECONOMIC ASSUMPTIONS

The following are regulatory and economic assumptions related to valuation:

[20] Refer also to Jacobs 2017, *Distributed generation inquiry – network benefits report,* March.

[21] Ideally in the full application of each method, the degradation of the existing fleet should be included where relevant. This degradation has not been explicitly considered in the present study.

- **Value of Customer Reliability (VCR):** A specific VCR has been applied for each substation location based on its customer mix. VCR is measured in $ per kWh of electricity.
- **WACC (discount rate):** The regulated weighted average real cost of capital (WACC) was applied as the assumed discount rate.

  The current applicable WACC of each network business has been applied to their respective assets.
- **Values are real:** All values are real and inflation is ignored.

3 METHOD DESIGN AND VALUATION TECHNIQUES

3.1 INTRODUCTION

This section briefly describes techniques used in the valuation methodologies considered in this paper, and the considerations which drive method design. The descriptions in this chapter provide high level and conceptual explanations on techniques underpinning each of the valuation methods. We also describe the techniques that are different or common between valuation methods.

3.2 TECHNIQUES THAT DIFFER BETWEEN METHODS

Different methods for valuing distributed generation exist because their intended applications are different. For example, a valuation could be used to set a once-off or an annual subsidy and these payments could apply to the very next unit of distributed generation, the next thousand units or perhaps all distributed generation already installed. These considerations lead to substantive differences between methods and different values.

Depending on the application of the valuation method, the following considerations will be accounted for differently:

- the increment of distributed generation being assessed
- whether the values are annual values or capital values, that may be annuitised and
- the mix of distributed generation system types.

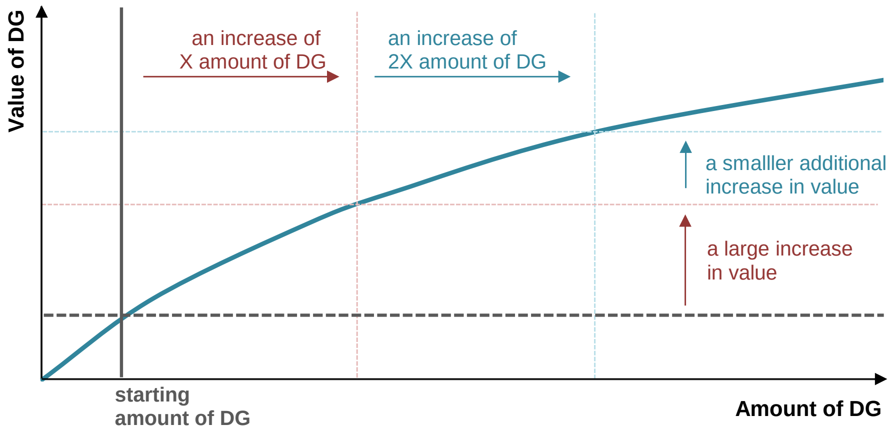
3.2.1 THE INCREMENT OF DISTRIBUTED GENERATION

The difference in distributed generation increment size and direction is significant because the value of distributed generation changes depending on how much is added or removed. Value changes with the increment size for two reasons, diminishing marginal returns and the sufficiency of the distributed generation increment to delay network projects.

DIMINISHING MARGINAL RETURNS

The value of distributed generation increases as peak demand grows and the reserve margin[1] gets smaller. However, the reserve margin also increases by adding more distributed generation (as it reduces the peak demand faced by the network) – this also reduces the amount of exposure to unserved energy and its costs. As a result, all other things being equal, more distributed generation results in greater total value but a lower marginal value (the value of the next unit of distributed generation). This is referred to as diminishing marginal returns and is a common principle to many economic systems, as is illustrated in figure 3.1.

FIGURE 3.1 DIMINISHING MARGINAL RETURNS OF DISTRIBUTED GENERATION



Source: ESC

[1] Reserve margin is the supply capacity of a network less the peak demand faced by the network. It is defined as the measure of capacity divided by the applicable peak demand minus 1.0. It is often described as a percentage.

The figure shows that the total value of all distributed generation increases as more is added, however the amount of additional value gets smaller and smaller per unit of distributed generation.

This principle also applies to future deferrable network costs. As more distributed generation is added, the required service date of network projects is advanced further into the future and so the present value of deferrals increasingly diminishes.

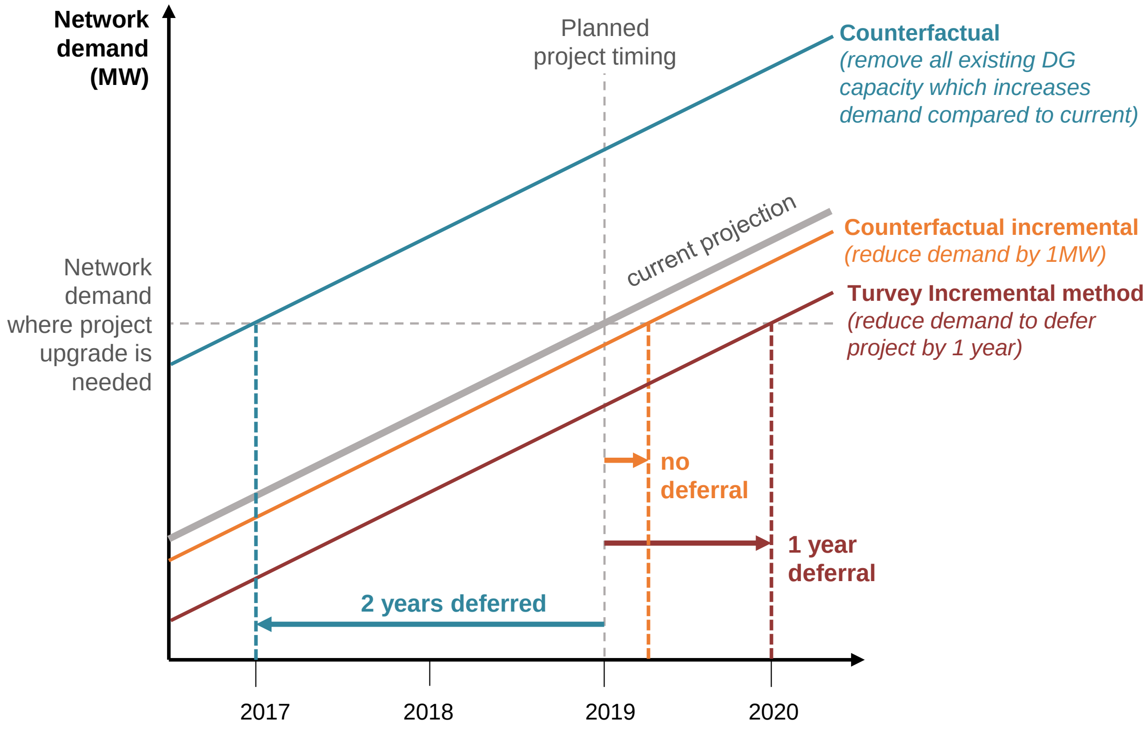
THRESHOLD OF AN INCREMENT OF DG TO DELAY NETWORK PROJECTS

The timing of a network project is affected by the amount of distributed generation being installed. If the quantity of distributed generation is able to meet a certain threshold then projects may be deferred.

Figure 3.2 provides an example of this ‘threshold’ for network projects. In the figure, three different valuation methods are compared against the current projection of an example network facing steady growth in network demand. If nothing changes, a network project would be required in 2019 (because network demand would become high enough to require an upgrade, i.e. the demand meets the ‘threshold’).

In the example, if only 1 MW of firm distributed generation was added to the network, as shown by the counterfactual incremental method, there would not be enough distributed generation to defer the project – a network project would still be required in 2019. The Turvey incremental requires an amount of distributed generation to defer the network project by exactly one year, to 2020. The counterfactual method removes all the existing installed distributed generation capacity in the network to determine when the network project would have been required without the presence of distributed generation. The example shows that without existing distributed generation, a network project would have been required in 2017, two years earlier than is currently expected.

FIGURE 3.2 THE IMPACT OF AN INCREMENT OF DISTRIBUTED GENERATION ON NETWORK PROJECT TIMING
Example only



Source: ESC

Any calculated network values will depend on the increment of distributed generation being assessed and whether that amount would exceed the 'threshold' for a change in network project timing. Because each methodology considers different increments of distributed generation, different network values will be calculated.

3.2.2 ANNUAL VALUES OR CAPITAL VALUES THAT ARE ANNUITISED

Value can be measured at a point in time or averaged or summed over a longer period. The choice depends on the intended use of the valuation. For example, the calculation of a once-off subsidy for solar may consider the total value over the life of the solar asset. Conversely, a detailed study of distributed generation value over time might use more granular time periods such as trading intervals (30 mins) or days. As these periods get smaller, the complexity of such values increase. Since the value is created in a few periods of a few hours over several days per year, it is convenient to consider an aggregate annual value over these important time periods.

In this section, we describe two possible approaches to assessing value; annual values or capital values that are annuitised.

ANNUAL VALUES

An 'annual value' approach to valuation considers network benefits as follows:

- **Reduction of expected unserved energy occurring *in that year*.** The cost of reduced expected unserved energy can be calculated annually, as the calculation depends on the amount of energy supplied by the network over small increments of time (15-minute periods). An annual value can be calculated for the energy generated and supplied in the network across a year.
- **Deferred cost of network upgrades, *annuitised* over the life of the network asset.** Network upgrades are very costly and network assets have long asset lives (over forty years). Applying the full capital cost of network upgrades in a single year would provide a very volatile and unrealistic indication of 'annual' network value. To overcome this issue we have annuitised network upgrade costs over the life of the network upgrade assets, which distributes the cost out evenly.

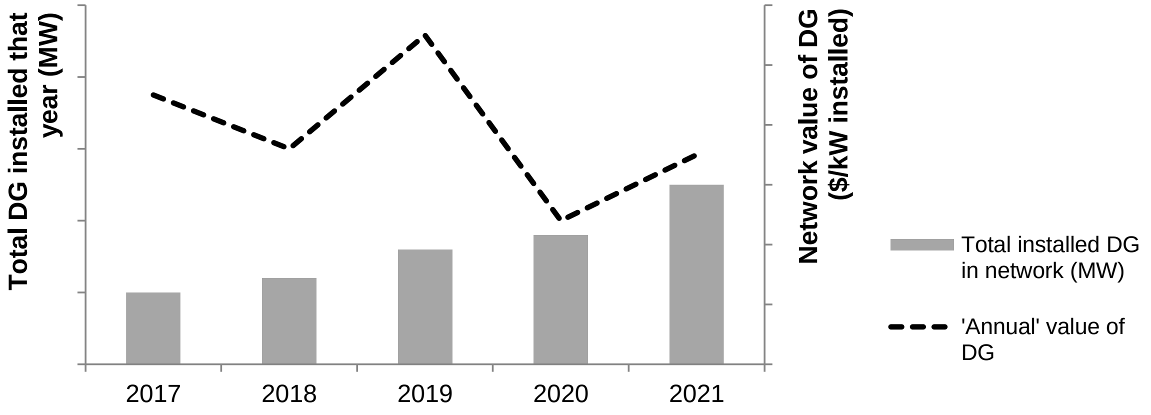
  Annuitisation is a financial-based process that converts a lump-sum investment into a series of periodic payments. Our application of annuitisation is similar to assuming that network upgrades are purchased using a loan that is repaid yearly over the life of the asset at an interest rate equal to the real regulated WACC.[2]

Applying this technique shows how value changes from year to year depending on available capacity, demand and the amount of distributed generation installed in the network in that given year. This is shown in figure 3.1, where annual values are based on the amount of distributed generation considered within a particular year.

[2] As the regulated WACC accounts for inflation, annuitisation derives values that are constant in real terms.

This approach is applicable for the counterfactual, counterfactual incremental and Turvey incremental[3] methods, described in chapter 0.

FIGURE 3.1 ANNUAL VALUES
Annual values are calculated each year for the amount of distributed generation being considered in that single year.



Source: ESC

CAPITAL VALUES THAT ARE ANNUITISED

‘Capital values’ calculate the present value of distributed generation benefits over the life of the distributed generation asset (assumed to be twenty years) – both costs of expected unserved energy and network projects are first calculated as capital costs. Under this approach, a ‘capital value’ is calculated for the distributed generation installed in a given year. These capital values can be re-calculated each year, providing a capital value of distributed generation installed in that year.

Similar to the approach of ‘annual values’ described earlier, annuities can be derived from a capital value, calculating a stream of equal average annual values (in real terms). Under this approach, both expected unserved energy and network project costs are annuitised over the life of the distributed generation equipment.

[3] Annuitisation of the change in the future project costs is used for the Turvey Incremental method to distribute the future network project cost savings over the life of the DG.

THE CHOICE OF ANNUAL OR CAPITAL VALUE APPROACHES

The choice of whether a capital or annual value approach to valuation depends on the intended application of the calculated value. There are many different applications of capital or annual values, such as:

- capital values could be used to calculate up-front and lump sum payments
- annual or annuitised values could be used to calculate a constant stream of payments under a performance based contract based on the year of commencement of the distributed generation or
- annuitised values could be used to support calculation of payments to distributed generation irrespective of years of service, but depending on their reliability and generation profile.

It should also be noted that capitalised values could be calculated from annual values, to indicate the long-term present value of a distributed generation investment. Annual values would need to be calculated each year for twenty years, discounted for time using the WACC, then added together for a capitalised value.

3.2.3 MIX OF DISTRIBUTED GENERATION SYSTEM TYPES

Different distributed generation technologies have different network values based on their ability to reduce peak demand. Generally, distributed generation systems that can generate during network peaks have higher value. Because of this, different technology types need to be evaluated separately first before calculating overall or average values.

In this inquiry we have considered three types of distributed generation technologies:

- **Solar.** Solar is assumed to generate when and only when the sun shines. Its value to the network depends on how closely the pattern of solar irradiation matches the pattern of network needs over the year.
- **Wind.** Wind is assumed to generate when and only when there is sufficient wind. Its value to the network depends on how closely wind patterns match the pattern of network needs over the year. We found very small amounts of installed wind-based distributed generation systems with very little value currently occurring in Victoria.

- **Dispatchable.** Dispatchable distributed generation can be deployed at will. For example, a battery or diesel generator can be thought of as ‘dispatchable’. For our purposes, we have not considered any fuel constraints like charge level or fuel storage constraints.

  The Network Value Final Report considered ‘network optimised’ systems as dispatchable systems that could be configured to generate electricity exactly at the time of network congestion.

3.3 TECHNIQUES SHARED BY ALL METHODS

There are a variety of well-known economic principles and techniques which are common to many of the methods. In this section we briefly describe the key techniques employed for the valuation methods described in this staff paper.

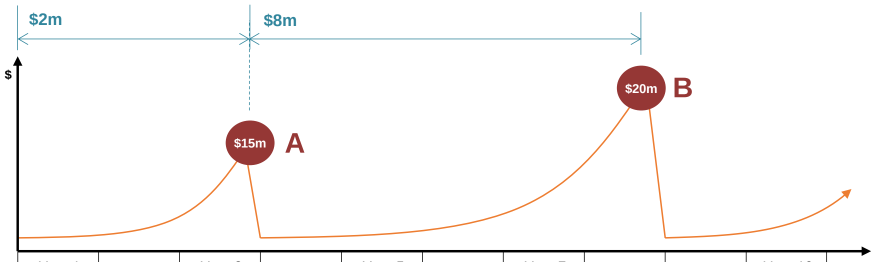
3.3.1 COMPARING COSTS BETWEEN TWO SCENARIOS

The valuation methods in this staff paper each consider costs under two scenarios, one with the actual and forecast amount of distributed generation – the base case – and one with more or less distributed generation – the alternative scenario. The value of distributed generation is the difference in costs between the two scenarios. As shown in the base case (with distributed generation) in figure 3.3, the growth of unserved energy and network upgrades are delayed, resulting in a lower overall cost.

FIGURE 3.3 COMPARING SCENARIO COSTS

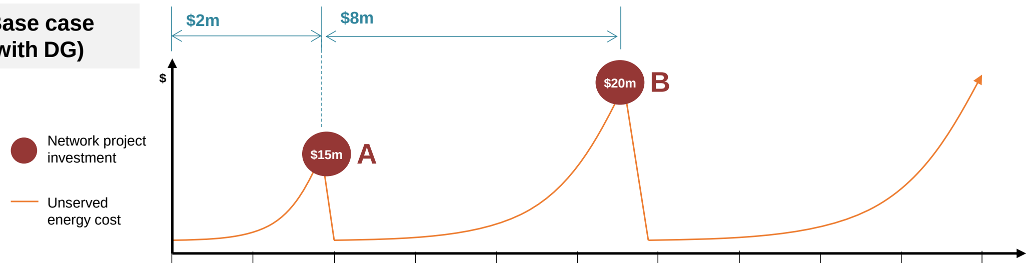
Example only

Alternative case (no DG)



	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Network cost	$0.3m	$0.3m	$0.3m	$0.5m	$0.5m	$0.5m	$0.5m	$0.5m	$0.8m	$0.8m
Unserved energy cost	$0.1m	$0.2m	$0.6m	$0.1m	$0.1m	$0.1m	$0.3m	$0.8m	$0.1m	$0.2m
Annual cost (with DG)	**$0.4m**	**$0.5m**	**$0.9m**	**$0.6m**	**$0.6m**	**$0.6m**	**$0.8m**	**$1.3m**	**$0.9m**	**$1.0m**

Base case (with DG)



	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	
Network cost	$0.3m	$0.3m	$0.5m	$0.5m	$0.5m	$0.5m	$0.8m	$0.8m	$0.8m	$0.8m	
Unserved energy cost	$0.1m	$0.8m	$0.1m	$0.2m	$0.9m	$1.2m	$0.1m	$0.2m	$0.3m	$0.8m	
Annual cost (no DG)	**$0.4m**	**$1.1m**	**$0.6m**	**$0.7m**	**$1.4m**	**$1.7m**	**$0.9m**	**$1.0m**	**$1.1m**	**$1.6m**	
Annual value (no DG *minus* with DG)	**$0m**	**$0.6m**	**-$0.3m**	**$0.1m**	**$0.8m**	**$1.1m**	**$0.1m**	**-$0.3m**	**$0.2m**	**$0.6m**	**$2.9m after 10yrs**

Source: ESC

3.3.2 CALCULATING VALUE OVER TIME

The impact of time on value needs to be accounted for because network benefits occur variably over the entire life of distributed generation systems. To account for the value of time, a standard economic technique is applied – Net Present Value (NPV) analysis. NPV discounts later values to determine a present value. Earlier benefits have greater value than later benefits. The discount rate used in the NPV calculations for the inquiry is the real regulated WACC for each network business.

3.3.3 THE PROBABILISTIC PLANNING APPROACH

The timing of network upgrade projects is a key driver of distributed generation value and this timing differs between the base case and the alternative case. In our valuations, project timing takes into account the existing capacity of network assets, forecast growth in peak demand and forecast growth in distributed generation.

For each of the two cases, project timing is determined in the following way:

- In the base case, project timing is as it occurs in publicly available Distribution Annual Planning Reports (DAPR) and then according to the 'probabilistic planning approach'.[4]
- In the alternative case, project timing is according to the 'probabilistic planning approach'.

The probabilistic planning approach is used by network planners to determine the time when a network upgrade should occur – it is an industry standard used by network businesses in Victoria. The approach compares the cost of a network upgrade against the cost of avoidable expected unserved energy (as a result of no network project being invested) then proceeds by selecting the least cost option.

More specifically, the approach calculates the following costs during each peak demand season (normally summer) over a period of several years:

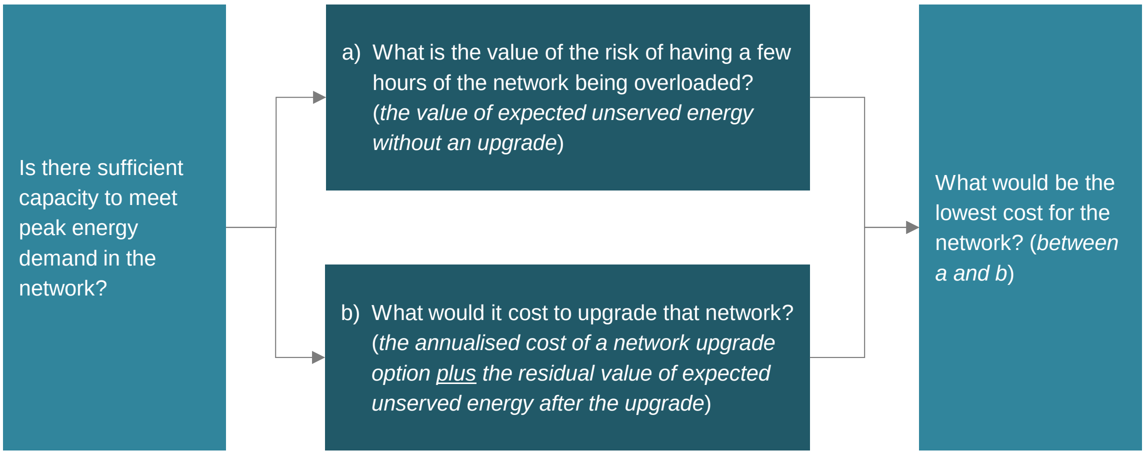
a. the value of expected unserved energy without a network augmentation or upgrade, and
b. the annuitised cost of a network upgrade option, plus the residual value of unavoidable expected unserved energy that remains after the upgrade.

The upgrade project is then timed to occur before the first peak season when (a) exceeds (b) as described above and in figure 3.4.

[4] For the analysis in this staff paper, there may be some cases where our assessed timing might slightly differ from the DAPR in the base case due to the approximation in formulating the expected cost of unserved energy as a function of reserve margin. This approximation was applied in the same way across all methods.

It should also be noted that this approximation was not applied for the full counterfactual methodology applied in the Network Value Final Report – the project timings stated in the DAPRs were used.

FIGURE 3.4 A 'PROBABILISTIC PLANNING APPROACH'



Source: ESC 2016, Network Value Final Report

It should be noted that this general approach considers that network upgrades are likely the lowest cost option for the network. This may not always be the case, particularly under low or uncertain demand growth, where a non-network support service such as a peaking generator or demand side resource (including certain types of distributed generation) may provide a lower cost solution – this could be considered a third cost option in figure 3.4. Non-network options are often not publicly identified or have limited information compared to network upgrade projects. These options have not been separately considered in the valuation models in this staff paper.

3.3.4 ACCOUNTING FOR THE IMPACT OF DISTRIBUTED GENERATION

In all methods, the impact of distributed generation under the alternative scenarios is accounted for by either adding or subtracting its impact on a base case scenario. How distributed generation affects overall demand depends on both the amount of generation and its generation profile.

In this inquiry two different profiles were used:

- **Solar profiles.** To add or subtract solar generation we developed hourly solar generation profiles specific to Victoria and added or subtracted those to the 15 min demand profiles at each ZSS. Further information regarding the solar PV profiles is provided in the Jacobs report for the inquiry.

- **Dispatchable systems.** Firm generation in this inquiry has an idealised generation profile which generates when required to avoid unserved energy. This assumes that dispatchable systems can reduce peak demand and is referred to in the Network Value Final Report as ‘network-optimised’ distributed generation.

3.3.5 CALCULATING UNSERVED ENERGY

In section 2.2.2 we briefly introduced the concept of unserved energy. Here we provide more detail concerning how we have calculated and applied expected unserved energy in this inquiry. Broadly, we have applied two techniques:

- **Direct analysis of historic demand data.** This technique is data intensive and was used to estimate distributed generation value in the Network Value Final Report.
- **Trend analysis (using regression).** This technique simplifies the analysis using historic demand data and was applied for the work supporting this staff paper (as described in chapter 5).

We describe these techniques in the following section.

DIRECT ANALYSIS OF HISTORIC DATA

This direct analysis of historic data calculates expected unserved energy using equation 3.1. This is the approach used in the Network Value Final Report. Historic demand data, essential to this approach, was provided by DNSPs with analysis conducted by Jacobs.[5]

$$E_{unserved} = p \sum_{i=1}^{35,040} D_{>N-1} + (1-p) \sum_{i=1}^{35,040} D_{>N} \tag{3.1}$$

[5] Historic demand data at each ZSS in Victoria is publicly available for each network business.

The unserved energy cost is then the expected unserved energy multiplied by the VCR:

$$U = VCR.E_{unserved} \tag{3.2}$$

BOX 3.1 VARIABLES FOR EQUATIONS 3.1 AND 3.2

$E_{unserved}$ is the amount of expected unserved energy calculated for a certain scenario in a year, for a given probability of the demand, (MWh) where

$D_{>N-1}$ is the amount of demand greater than the N-1 capacity of the network infrastructure in a given hour (MWh)

$D_{>N}$ is the amount of demand greater than the N capacity of the network infrastructure in a given hour (MWh)

p is the probability of a failure in a piece of network infrastructure (or the probability of a major outage causing the N-1 capacity condition)

U is the expected unserved energy cost in constant value dollars per year

VCR is the value of customer reliability applicable to the location ($/MWh)

i is an integer

Note: the summation formula considers 15-minute interval demand data at a network asset, with 35,040 intervals in a year.

The direct analysis of historic load data is useful for medium term valuations of a few years, such as the valuation undertaken in the Network Value Final Report between 2016 and 2020.

TREND ANALYSIS OF EXPECTED UNSERVED ENERGY

For approximations of value over longer periods (e.g. twenty years), it may not be practical to use a direct analysis approach to calculate the cost of expected unserved energy – it requires detailed forecasts of demand and capacity for each hour of every forecast year. Instead, a 'trend analysis' approach could be used, as was conducted in this staff paper.

Jacobs provided detailed estimates of expected unserved energy for Victorian ZSSs between 2016 and 2020, using the direct analysis approach. Using regression analysis, these estimates can be used to develop equations (or functions) of the relationship between expected unserved energy cost and the reserve margin of a network asset. A set of equations need to be developed for each ZSS covering scenarios with and without distributed generation, and with and without network upgrades.

The following section describes an approach to deriving these equations.

In the data we reviewed, the relationship between unserved energy and reserve margin tends to be exponential – as reserve margin decreases, unserved energy increases exponentially. We hypothesised that equation 3.3 could be used to model this relationship (and equation 3.4 when transformed to represent a linear equation).

$$U = D_{peak} \ e^{a+b\left(\frac{C}{D_{peak}}-1\right)} \tag{3.3}$$

$$\ln\left(\frac{U}{D_{peak}}\right) = a + b\left(\frac{C}{D_{peak}} - 1\right) \tag{3.4}$$

BOX 3.2 VARIABLES FOR EQUATIONS 3.3 AND 3.4

U is the expected unserved energy cost in constant value dollars per year

D_{peak} is the peak demand in MVA based on weighting the median peak demand and the peak demand with a 10% probability of exceedance

C is the N-1 network capacity in MVA

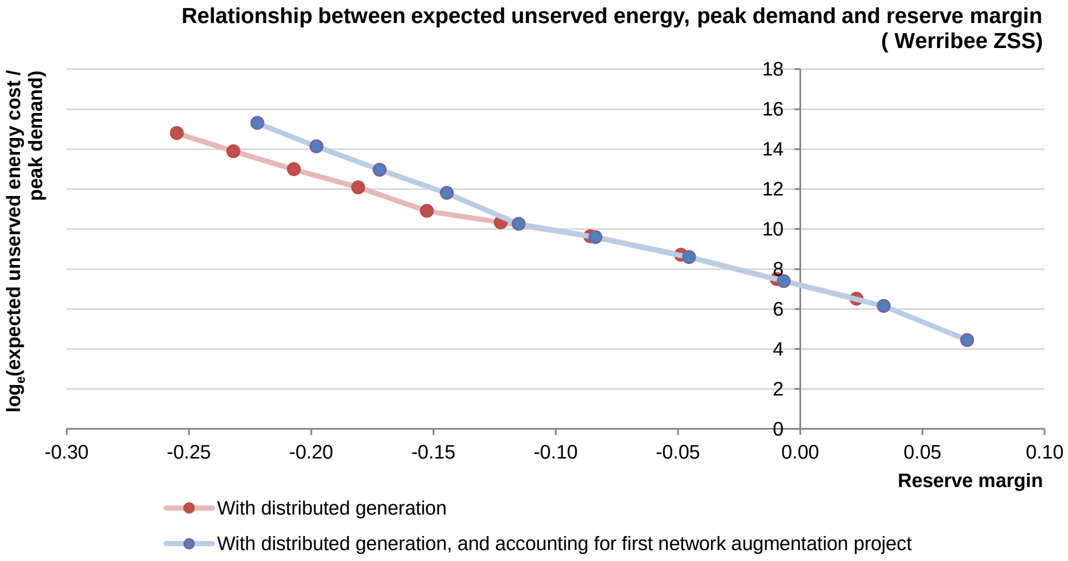
$\left(\frac{C}{D_{peak}} - 1\right)$ is the 'reserve margin'

a and b are constants determined by regression

As described in box 3.2, the constants a and b need to be determined using the historic data at a ZSS. A worked example is provided for Werribee ZSS in figure 3.4 – the historic data shows a relationship that is approximately linear in two segments.

FIGURE 3.2 RELATIONSHIP BETWEEN UNSERVED ENERGY COST, PEAK DEMAND AND RESERVE MARGIN

Example of piece-wise linear relationship



Source: ESC

Using Microsoft Excel's linear regression function, a and b can be estimated for two linear segments of the expected unserved energy cost (with the dependent value being the left hand side of equation 3.4). Where a plot of data shows two distinct linear segments, the segments should be separated along the reserve margin horizontal axis to yield the best fit with the lowest square errors. It is also assumed that unserved energy is proportional to the scale of the network. This also means that unserved energy is assumed to be proportional to peak demand for a constant reserve margin.[6]

Different equations with different a and b constants were estimated for a range of scenarios related to network projects: a do nothing case, a case where one network project is required, and a case where a second network project is required. Many ZSSs have data to estimate expected unserved energy when only one project is required. For analysis over longer periods, ZSSs may require a second network project and sufficient

[6] These relationships are also implied by our hypothesized unserved energy equation 3.3. This also further implies that the peak day load shape does not change materially around the time when a network upgrade is needed.

data may not be available. In these cases, the constants a and b can be adjusted by using equation 3.5 as follows:

$$a_1 = a_0 + \ln(p_1/p_0)$$

$$a_2 = a_1 + \ln(p_2/p_1) \qquad (3.5)$$

BOX 3.3 VARIABLES FOR EQUATION 3.5

a_0 is a coefficient with no new network project derived from the regression of the unserved energy analysis, as per figure 3.4 without a new project

a_1 is a coefficient with the first new project

a_2 is a coefficient with the first and second new project

p_0 is the probability of one transformer out of service with no new project

p_1 is the probability of one transformer out of service with the first new project

p_2 is the probability of one transformer out of service with the second new project

4 SIX METHODS FOR CALCULATING NETWORK VALUE

4.1 INTRODUCTION

This section describes six different methods for valuing distributed generation which were considered during the Inquiry. Two of these methods the ‘Turvey Incremental’ and ‘Long Run Growth Incremental’ are common within the industry and literature. The remaining methods were considered as part of this inquiry and the Counterfactual method was the method selected to provide an annual value that represents the average value for installed and forecast distributed generation.

This section builds on techniques described in section 3. As shown in table 4.1 and figure 4.1, the techniques of significance which differ between the methods are:

- the increment of distributed generation (i.e. the amount of distributed generation which is added or subtracted)
- the treatment of the deferral of network project costs
- the treatment of avoided expected unserved energy costs and
- whether other techniques were applied (such as the smoothing of network costs).

Techniques that are common to all methods, such as the ‘probabilistic planning approach’, are addressed in section 3.3. The remainder of this section addresses each method describing:

- its overarching approach
- its valuation equations and
- the general features of values derived from each method.

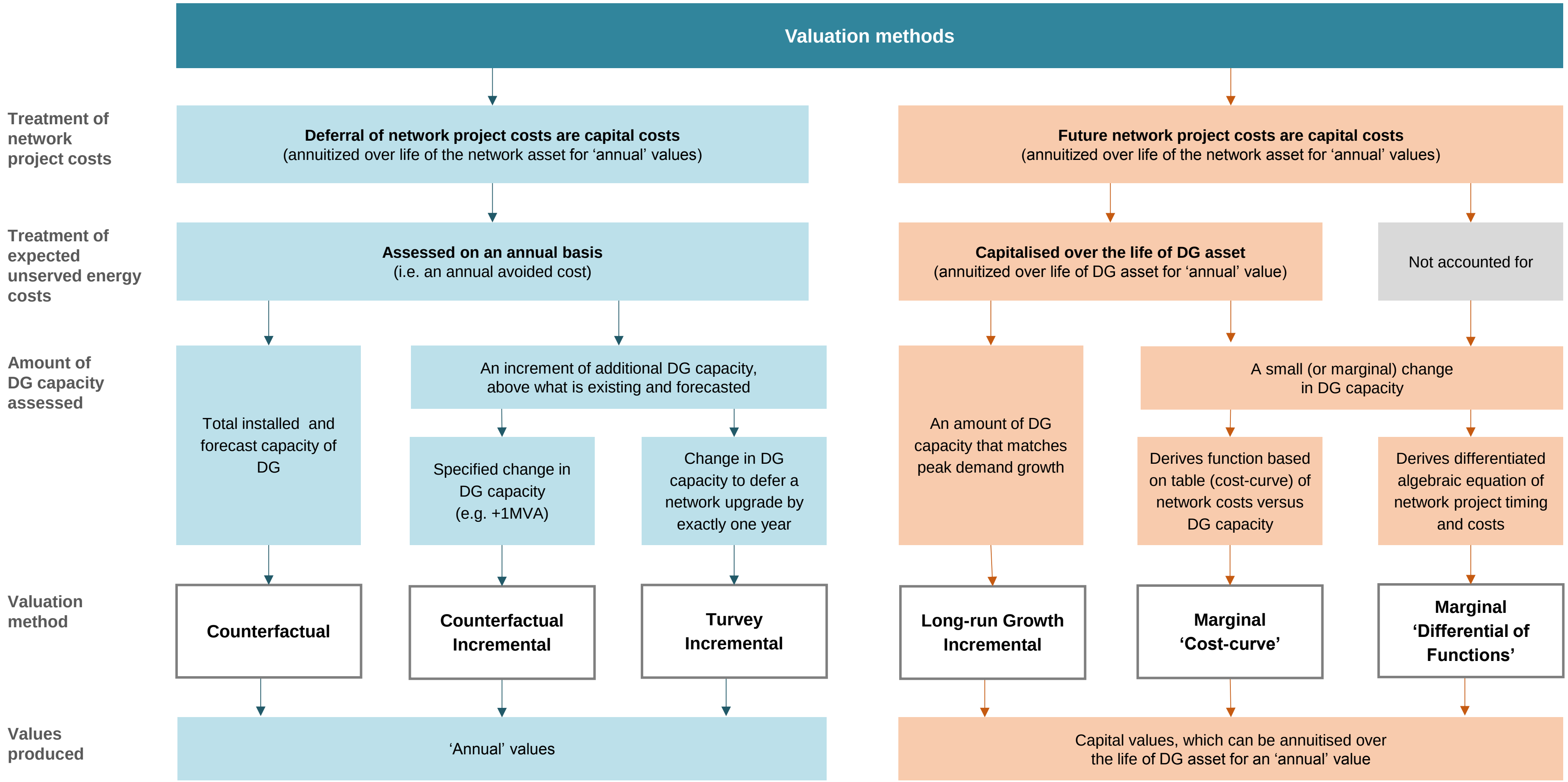
TABLE 4.1 METHODS SUMMARY

Method	Method source	Increment of DG capacity assessed	Treatment of network project costs	Treatment of avoided expected unserved energy costs	Other techniques applied
Counterfactual	Jacobs and ESC, for ESC 2017, *The Network Value of Distributed Generation*, February	Removes existing and forecast DG from the current forecast capacity.	Network project costs are annuitized over the life of the network asset and the change in annual cost is assessed in the year of analysis.	Avoided expected unserved energy costs are calculated on an annual basis.	-
Counterfactual Incremental	Jacobs and ESC, for ESC 2017, *The Network Value of Distributed Generation*, February	Add a small amount of DG to the current forecast capacity.	Network project costs are annuitized over the life of the network asset and the change in annual cost is assessed in the year of analysis.	Avoided expected unserved energy costs are calculated on an annual basis.	-
Turvey Incremental	Turvey R. 2000, *What are marginal costs and how to estimate them?*, March	Add enough DG to the current forecast to defer a network project by exactly one year.	Present value of deferral of network project costs for 20 years (life of DG assets) is annuitized over the life of the DG asset (at the year of analysis).	Avoided expected unserved energy costs are calculated on an annual basis.	-
Long-run Growth Incremental	Mann et al. 1980, *A note on capital indivisibility and the definition of marginal cost*, June	Remove all future growth from current forecast (equivalent to there being enough DG installed to exactly meet future peak demand growth).	Present value of future network project costs for 20 years (life of DG assets) is annuitized over the life of the DG asset (at the year of analysis).	Present value of annual future expected unserved energy costs accounted for in present value..	-

Method	Method source	Increment of DG capacity assessed	Treatment of network project costs	Treatment of avoided expected unserved energy costs	Other techniques applied
Marginal 'Cost-curve'	Gawler R. *Unpublished*	Add DG to the current forecast in small increments (marginal amounts).	A table of present value network costs versus installed DG quantity is derived for 20 years (life of DG assets). Future network project costs are annuitized over the life of the DG asset (at the year of analysis).	Avoided expected unserved energy costs are incorporated into the tabulated costs, which are capitalised over the life of the DG asset.	Smoothing has been applied by using a regression on tabulated costs to derive marginal value function versus DG.
Marginal 'Differential of Functions'	Gawler R. *Unpublished*	Add DG to the current forecast in small increments (infinitesimal amount).	An algebraic equation of present value network costs versus installed DG quantity is derived for 20 years (life of DG assets). Future network project costs are annuitized over the life of the DG asset (at the year of analysis).	Avoided expected unserved energy costs are not incorporated into the present value cost function.	Smoothing has been applied by creating an algebraic equation of network cost and differentiates cost with respect to change in DG quantity.

Source: ESC

FIGURE 4.1 METHODS SUMMARY



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4.2 THE COUNTERFACTUAL METHOD

The counterfactual valuation method was developed by the commission and Jacobs, specifically to meet the terms of reference of this inquiry. As such, it estimates average annual value of *all distributed generation current and forecast*. For the Network Value Final Report, Jacobs applied the counterfactual method at each zone substation in Victoria in 2017.[1] Here we describe the counterfactual method and discuss relevant data and assumptions.

The counterfactual method compares the estimated annual cost of the network in two scenarios one 'with' and one 'without' distributed generation. To calculate the cost of the network in a 'without' distributed generation scenario, the method sets the quantity of distributed generation (currently installed in the network) to zero and estimates the additional annual network costs required to meet the increased demand. The difference between the two scenarios in each year is then divided by the amount of distributed generation being considered for that year as measured by the peak demand reduction.

4.2.1 VALUATION EQUATIONS – COUNTERFACTUAL METHOD

The annual value of distributed generation to the network is calculated via the counterfactual method according to equation 4.1, the equivalent capitalised value (equation 4.2) is just the present value of annual values over the life of the distributed generation asset.

$$\begin{aligned} AV_t = \Big\{ &\mathrm{MIN}\Big[U_{t,no\ DG,no\ project}\,,\ \Big(U_{t,no\ DG,project} + X\Big(\frac{r(1+r)^{-0.5}}{1-(1+r)^{-N}}\Big) + Y_t\Big)\Big] - \\ &\mathrm{MIN}\Big[U_{t,DG,no\ project}\,,\ \Big(U_{t,DG,project} + X\Big(\frac{r(1+r)^{-0.5}}{1-(1+r)^{-N}}\Big) + Y_t\Big)\Big]\Big\} \div D_{reduction,t} \end{aligned} \tag{4.1}$$

$$CV = \sum_{i=1}^{n} \frac{AV_i}{(1+r)^{(i-0.5)}} \tag{4.2}$$

[1] Jacobs applied the method for solar PV and dispatchable systems, based on the total known installations in Victoria. For dispatchable systems, Jacobs assumed those systems dispatch energy during all hours of the year. In reality, dispatchable systems will generate electricity at the control and discretion of its operator.

A full description of the counterfactual method is also provided in the Jacobs consultancy report.

BOX 4.1 VARIABLES FOR EQUATION 4.1 AND 4.2

AV is the Annual Value (middle of year) of distributed generation to the network

CV is the present value (beginning of current year) of a distributed generation asset to the network over the asset life a_2 is a coefficient with the first and second new project

t is the year of valuation

U is the expected unserved energy cost in dollars per year, as in equation 3.2 or 3.3, where U can vary depending on three factors as follows:

> U_t refers to the expected unserved energy cost at time t
>
> $U_{no\ DG}$ and U_{DG} refers to the calculated expected unserved energy cost where there is no DG installed on the network, and when there is DG installed in the network, respectively
>
> $U_{project}$ and $U_{no\ project}$ refers to the calculated expected unserved energy cost where there is a network project required, and when no network project is required, respectively.

$D_{reduction,\ t}$ is the reduction in peak demand resulting from the quantity of distributed generation removed at time t

X is the real capital cost of a network upgrade (at the beginning of year)

Y is the future operating and maintenance costs of the network project (capitalised over the life of the network project) and Y_t is the additional annual operating cost associated with a network upgrade (in the middle of year)

N is life of the network project

n is the life of the distributed generation system

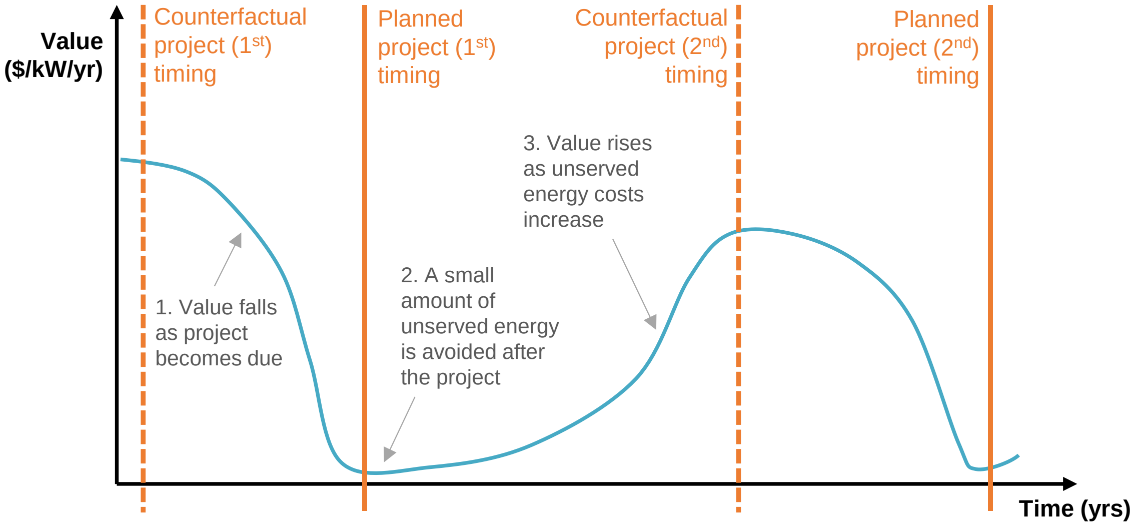
r is the current regulated pre-tax WACC

i is the year of service of the distributed generation project commencing service in the year of interest.

4.2.2 FEATURES OF COUTNERFACTUAL VALUES

The features of the annual counterfactual value over time are illustrated qualitatively in figure 4.2. The example assumes a network area with moderate levels of linear demand growth and that two network upgrade projects are currently being planned.

FIGURE 4.2 FEATURES OF THE COUNTERFACTUAL VALUE OVER TIME
Annual values



Note: The 'counterfactual project timing' is the calculated time when a network project would have been required if there was no distributed generation in the network – this would occur before what is currently being planned.

Source: ESC

With reference to the numbered items in figure 4.2:

1. The value falls to the timing of the network project as currently being planned for. The decrease in value occurs is because the cost of unserved energy in the 'with distributed generation' scenario increases whilst the cost of unserved energy is lower in the 'without distributed generation' scenario.
2. During the year of the currently planned project timing, distributed generation has no effect on project costs in that year. Distributed generation has a very small

impact on reducing unserved energy cost because the planned project would provide a large amount of capacity (the value could even be zero).

3. The value rises again, due to the increased expected unserved energy as demand for electricity grows over time.

Generally, the counterfactual value will peak at the time when a network upgrade project would have been required without any distributed generation installed. The value will then decline, becoming the least at the time when network upgrade project is currently being planned.

In a case where there is high demand growth, the periods of high value could be very short. This is particularly relevant if the growth in distributed generation cannot match the growth of demand. However, if demand growth is low and the volume of distributed generation is high, then there may be longer periods of high unit values followed by long periods of very low values.

4.3 COUNTERFACTUAL INCREMENTAL METHOD

The counterfactual incremental method calculates the average annual value of 1MW of distributed generation *in addition* to current and forecast distributed generation. This method is identical to the Counterfactual Method except that an amount of distributed generation is added to the alternative scenario rather than the existing capacity removed. In this method 1 MW is added.

4.3.1 VALUATION EQUATIONS – COUNTERFACTUAL INCREMENTAL METHOD

The annual value of distributed generation under the counterfactual method is calculated using equation 4.3. The capitalised value (equation 4.4) is simply the present value of annual values over the life of the distributed generation asset.

$$AV_t = \text{MIN}\left[U_{t,current\ DG,no\ project}\ ,\ \left(U_{t,current\ DG,project} + X\left(\frac{r(1+r)^{-0.5}}{1-(1+r)^{-N}}\right) + Y_t\right)\right] - \text{MIN}\left[U_{t,add\ 1MW\ DG,no\ project}\ ,\ \left(U_{t,add\ 1MW\ DG,project} + X\left(\frac{r(1+r)^{-0.5}}{1-(1+r)^{-N}}\right) + Y_t\right)\right] \tag{4.3}$$

$$CV = \sum_{i=1}^{n} \frac{AV_i}{(1+r)^{(i-0.5)}} \tag{4.4}$$

BOX 4.2 VARIABLES FOR EQUATIONS 4.3 AND 4.4

U is the expected unserved energy cost in dollars per year, as in equation 3.2 or 3.3, where U can vary depending on three factors as follows:

U_t refers to the expected unserved energy cost at time *t*

$U_{current\ DG}$ and $U_{add\ 1MW\ DG}$ refers to the calculated expected unserved energy cost where there is the current level of DG installed on the network at time *t*, and when there is an additional 1MW of DG installed in the network, respectively

$U_{project}$ and $U_{no\ project}$ refers to the calculated expected unserved energy cost where there is a network project required, and when no network project is required, respectively.

All other equation variables are defined in box 4.1.

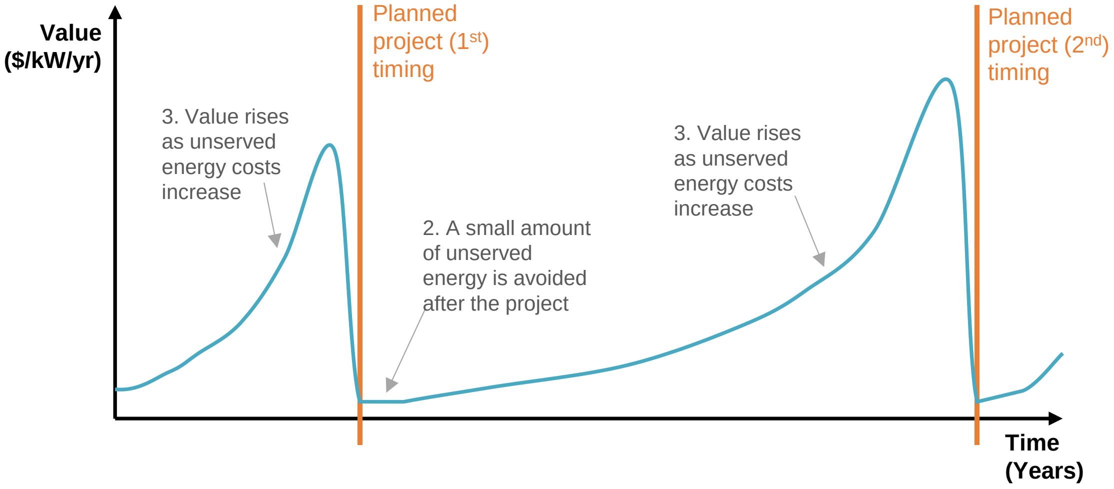
4.3.2 FEATURES OF COUNTERFACTUAL INCREMENTAL VALUES

The features of a counterfactual incremental value over time are illustrated qualitatively in figure 4.3. This illustration assumes a network area with moderate levels of linear demand growth, and assuming that two network upgrade projects will be required in the analysis horizon (referred to as Planned Project Services).

In the example shown below, the increment of 1 MW is not sufficient to change project timing – the values shown are solely influenced by the effect that distributed generation has in reducing unserved energy cost. If the increment of distributed generation is large enough to impact project timing, the pattern of value will flatten.

FIGURE 4.3 FEATURES OF THE COUNTERFACTUAL INCREMENTAL VALUE OVER TIME

Annual values



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With reference to the numbered items in figure 4.3:

1. The value increases because the cost of reduced unserved energy in the 'without distributed generation' scenario increases (as demand increases).
2. At the timing of the planned network project, the value falls to a very low level. Distributed generation has no effect on the network project costs in that year and the impact on unserved energy cost is usually very small because the planned project would lead to a large amount of surplus capacity.
3. The value gradually increases again after the planned project, as cost of expected unserved energy increases.

The counterfactual incremental valuation method generally calculates higher annual value just in advance of when a planned network project will be needed. If there is high demand growth, then the periods of high value can be short-lived because there is not much exposure to critical supply conditions. If demand growth is low, the cycles of value will be stretched out over long periods of time.

Peak values under the counterfactual incremental method will depend on the balance of network supply and demand prior to the network project – it is highly sensitive to unserved energy costs. Peak values will also depend on the size of the 'increment' of additional distributed generation analysed, which is at the discretion of a practitioner (refer to section 3.2.1). In the Network Value Final Report, an increment of 1MW of solar PV capacity and dispatchable generation was applied for the purposes of comparison.

4.4 TURVEY INCREMENTAL METHOD

The Turvey Incremental method as applied in this study calculates the value of a quantity of distributed generation enough to defer the next network project by exactly one year. This method is based on the work of the late Professor Ralph Turvey of the London School of Economics and later as the Chief Economist of the UK Electricity Council.[2] A variation to this method was adopted and applied by ENEA on behalf of CitiPower and Powercor in their submission to the inquiry.[3]

The Turvey Incremental method is useful in calculating values that may be used to incentivise additional distributed resources. It assumes that the deferment of project timing is accommodated in the planning process with perfect foresight.

4.4.1 VALUATION EQUATIONS – TURVEY INCREMENTAL METHOD

The Turvey Incremental method calculates the value of *additional* distributed generation based on the present value change in future network costs. It first determines the potential cost for network upgrades for additional supply capacity (accounting for the existing installed and forecast distributed generation in the system). The method then adds distributed generation capacity to the network by an exact amount required to defer that future project by exactly one year.[4]

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[2] Turvey 1976, *Analyzing the marginal cost of water supply*, Land Economics, 71(4), pp. 158-168.

[3] Citipower Powercor 2016, *Submission to the Essential Services Commission Inquiry into the true value of distributed generation, Discussion Paper*, July, Appendix. Note: the ENEA study considered expected unserved energy as the basis of calculating the network project requirement, but the value of reduced expected unserved energy was not incorporated as part of the overall network value described in its submission.

[4] A separate calculation of the load change will be required for each project if the linear growth that is assumed is not constant, or if the nature of subsequent projects varies.

The method primarily calculates a capitalised value, based on a deferral of the capital cost of the network project – this is observable in the left hand third of the equation 4.5, representing the difference between the present value CAPEX and capitalised OPEX for a one year delay from year *p* to year *p*-1. Only projects within the expected 20 year life of the distributed generation assets are included. An annual value is calculated by annuitizing this project deferral over the life of the distributed generation (as per the second bracketed term in equation 4.5).

The avoided cost of expected unserved energy is separately calculated on an annual basis (as shown on the right hand side of the equation).

The cashflow equations for the Turvey incremental method is described as follows:

$$AV_t = \frac{\left[\left(\frac{X+Y}{(1+r)^{T_p}} - \frac{X+Y}{(1+r)^{T_p-1}}\right)\left(\frac{r(1+r)^{-0.5}}{1-(1+r)^{-N}}\right) + U_{t,current\ DG} - U_{t,DG\ to\ defer}\right]}{D_{reduction,t}} \tag{4.5}$$

$$CV = \sum_{i=1}^{n} \frac{AV_i}{(1+r)^{(i-0.5)}} \tag{4.6}$$

BOX 4.3 VARIABLES FOR EQUATIONS 4.5 AND 4.6

T_n is the year of the network project being implemented. Note also that when $T_p < 0$ only the VCR components are included unless there are further projects within the lifetime of the distributed generation

U is the expected unserved energy cost in dollars per year, as in equation 3.2 or 3.3, where U can vary depending on three factors as follows:

> U_t refers to the expected unserved energy cost at time *t*
>
> $U_{current\ DG}$ and $U_{DG\ to\ defer}$ refers to the calculated expected unserved energy cost where there is the current level of DG installed on the network at time *t*, and where there is an amount of DG that can defer the next network project, respectively

All other equation variables are defined in box 4.1.

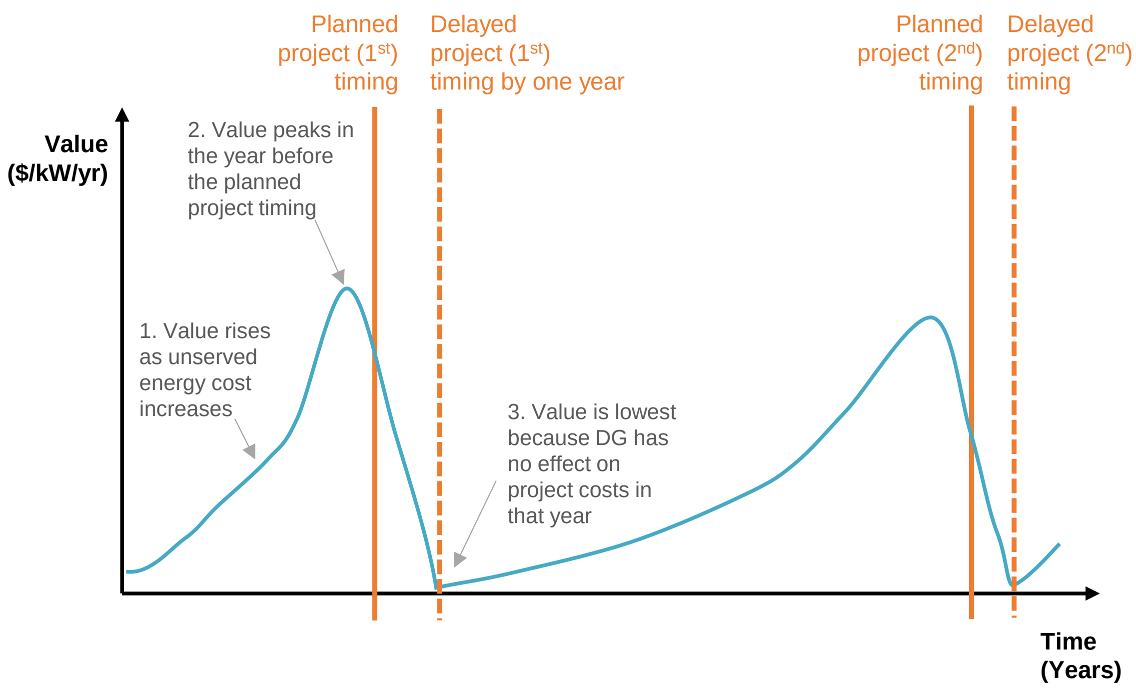
It should be noted that in these equations, X is the project capital cost (CAPEX) and Y is the capitalised OPEX cost over the life of the project, not the annual OPEX cost Y_t as in previous equations.

4.4.2 FEATURES OF TURVEY INCREMENTAL VALUES

The features of a Turvey Incremental value over time are illustrated qualitatively in figure 4.4. This illustration assumes a network area with moderate levels of linear demand growth, and assuming that two network augmentation projects will be required in the analysis horizon (referred to as Planned Project Services).

In this example, a chosen increment of distributed generation defers the Planned Project Service by exactly one year (referred to as the 'Delayed Project Service').

FIGURE 4.4 FEATURES OF THE TURVEY INCREMENTAL VALUE OVER TIME
Annual values



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With reference to the numbered items in figure 4.4:

1. The value rises as the timing of the planned project because the cost of expected unserved energy increases with and without new distributed generation.
2. The value peaks in the year before the planned project timing. The peak value is dominated by the high cost of expected unserved energy prior to the network project.
3. The value is lowest at the delayed project timing because the additional distributed generation has no effect on the network project costs in that year.[5]

The Turvey incremental value generally peaks sharply in the year before the network project would be required with distributed generation. As in the counterfactual incremental method, the peak value amount will depend on the balance of demand and network capacity prior to a planned project – it is very sensitive to the unserved energy impact at this time. The cycles of value will also depend on demand growth.

4.5 LONG-RUN GROWTH INCREMENTAL METHOD

The 'Long-run growth incremental method' calculates the average cost of peak demand growth over a long period of time. This method was proposed by Mann et al. for the purposes of calculating the amount of capital expenditure needed to meet an increase in demand, summarising its approach as follows:

> *…discounting all incremental costs which will be incurred in the future to provide for estimated additional demand over a specified period, and dividing that by the discounted value of the incremental output over the period…*[6]

This method does not explicitly consider distributed generation. However it could be used to value an amount of firm dispatchable distributed generation that exactly matches growth in peak demand. As a consequence, this method requires some

[5] It should be noted that under the Turvey incremental method, a negative value could be derived if the increase in unserved energy cost in a year is greater than the present value of the deferred project cost.

[6] Mann et al. 1980, *A note on capital indivisibility and the definition of marginal cost*, June

demand growth to result in meaningful values – zero or negative growth simply results in no value.

We considered this method because of its general use by infrastructure businesses to develop tariffs. The method considers the value of long-term future projected demand growth – at least 15 to 25 years of forecast growth and network planning information is required for this method. Because the method calculates a value over a long analysis period, it is not suitable for valuing the short and medium term impact of distributed generation.

4.5.1 VALUATION EQUATIONS – LONG-RUN GROWTH INCREMENTAL METHOD

The Long-run Growth Incremental method produces an annual average value of avoiding demand growth. The method considers the difference in the cost of:

- the current system with no change in demand and no growth-related upgrades and
- a forecast system with demand growth requiring growth-related CAPEX, OPEX and changes in the value of expected unserved energy.

This value is shown in equation 4.7 and is calculated as the present value of the network project and unserved energy cost difference, divided by the present value of annual changes in demand.[7]

$$AV_g = \left(\sum_{j=1}^{P} \frac{X + Y}{(1+r)^{T(j)}} + \sum_{i=1}^{n} \frac{U_i - U_1}{(1+r)^i} \right) \div \sum_{i=1}^{20} \frac{g_i}{(1+r)^i} \tag{4.7}$$

BOX 4.4 VARIABLES FOR EQUATION 4.7

AV_g is the annual value of growth

[7] Savings associated with the development of growth assets could be deducted if applicable. However, no such deductions were identified in our analysis for this staff paper.

g_i is the annual growth in peak demand in year i

P is the number of network projects in the 20 year outlook period and

$T(j)$ is the timing of the jth project

U_i is the unserved energy cost in year i

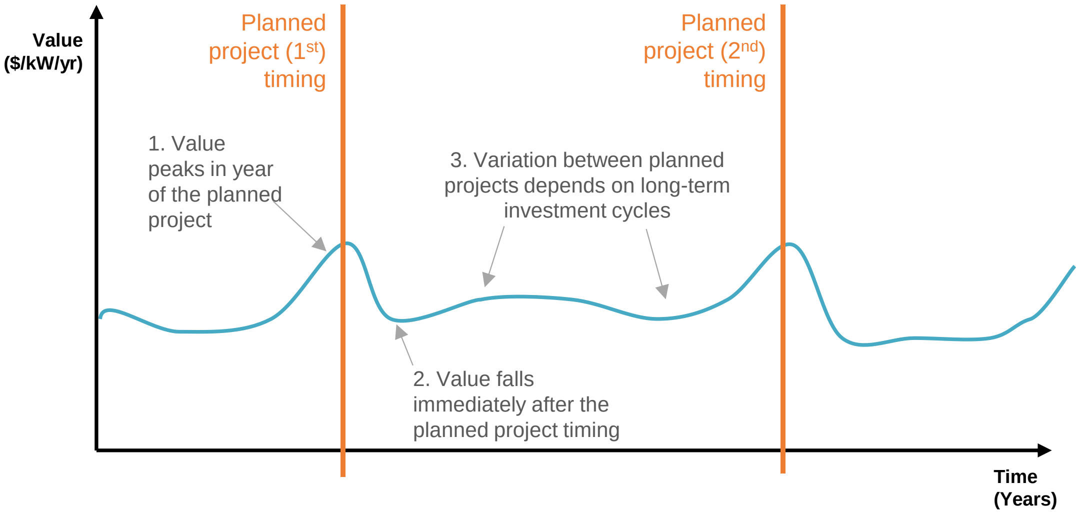
All other equation variables are defined in box 4.1.

When applying this method, the valuation is dominated by the longer term growth impacts on costs and the lumpiness of long-term future investments. The method gives an annual value because the denominator is the present value of multiple years of additional peak demand.

4.5.2 FEATURES OF THE LONG-RUN GROWTH INCREMENTAL VALUE

The features of a Long-run Growth Incremental value are illustrated in figure 4.5 for a situation with moderate linear demand growth with two projects in the analysis horizon.

FIGURE 4.5 FEATURES OF THE LONG-RUN GROWTH INCREMENTAL VALUE OVER TIME
Annual values



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With reference to the numbered items in figure 4.5:

1. The value rises to a maximum at the timing of the planned network project – the present value of the network project cost is at its maximum at that point in time.
2. The value decreases immediately (and is generally lowest) after the planned project – the network project cost is no longer considered in the forward growth outlook.
3. Between projects, the value will vary based on the long-term planning horizon and the lumpiness of network projects within the next twenty years.

The variability of annual value in this method is generally less than other valuation methods. If there is high demand growth, the pattern of value can be quite stable because multiple projects are included in the cost analysis. Generally, the higher the network demand growth, the higher the value.

4.6 MARGINAL METHODS

Marginal methods aim to calculate the ‘rate of change’ of the relationship between future network costs compared to growth in distributed generation capacity over a long period of time. These methods aim to value a very small change in distributed generation and its impact on network and expected unserved energy costs. To calculate this change, a relationship between network costs and changes in peak demand need to be developed – this can then be mathematically differentiated to provide an equation that represents the ‘rate of change’ between costs and demand.

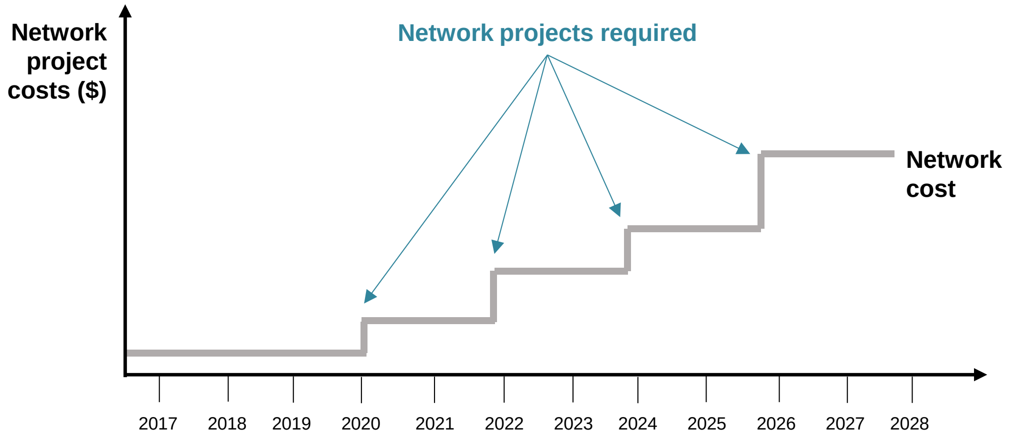
Two approaches in developing a marginal method were developed by Dr Ross Gawler of Monash University for the purpose of facilitating the integration of network and demand side planning. We describe these two approaches in the following sections.

4.6.1 VALUATION EQUATIONS – MARGINAL METHODS

Mathematically, marginal methods require an infinitesimal change in network costs. But an infinitesimal change in peak demand cannot have an impact on project timing, because network projects are invested in discrete times (annually) and in large discrete amounts (millions of dollars at a time) (as shown in the example in figure 4.6).

Likewise, discrete amounts of distributed generation are required to have an effect on the timing of network projects to create a benefit (as discussed in section 3.2.1).

FIGURE 4.6 DISCRETE PROJECT TIMING
Example only



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However, the 'marginal' methods in this staff paper apply mathematical differentiation that requires functions of network costs to be continuous and smooth. A pragmatic approach to 'smooth' network costs has been applied for the purposes of these marginal methods.

The two marginal methods use different approaches to smooth the discreteness of project timing, network costs and expected unserved energy costs. The methods differ by either:

- **A 'cost-curve' approach.** This approach calculates the network cost with known historical project timings, then smooths the relationship between cost and distributed generation quantity (a 'cost-curve' approach) or
- **A 'differential of functions' approach.** This approach smooths a function (equation) based on network project timing and costs using mathematical differentiation.

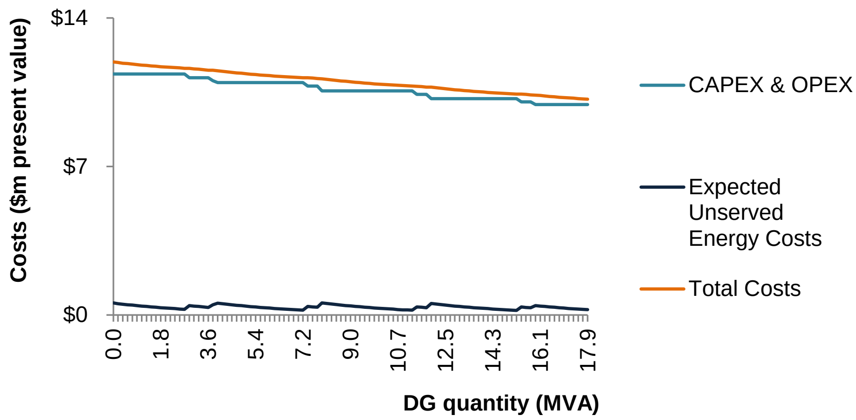
The following section describes these two particular approaches to deriving a marginal method for valuing distributed generation in further detail.

MARGINAL METHOD – USING A 'COST-CURVE' APPROACH

This approach relies on a table of different network costs corresponding with amounts of distributed generation capacity added to a network – described as a 'cost curve'. The 'cost curve' can be constructed by calculating the present value of network costs over a series of small cumulative increments of distributed generation. The timing of future projects is calculated for each small increment of distributed generation capacity added to the network in a given year.[8] An example cost-curve is shown in figure 4.7 based on data from Werribee ZSS, incorporating network project costs and changes in expected unserved energy costs. Network project costs were evaluated for an assumed distributed generation system life of 20 years.

FIGURE 4.7 QUADRATIC FIT OF DISCRETE PRESENT VALUE NETWORK COST VERSUS PEAK DEMAND REDUCTION

Example ZSS using data based on Werribee ZSS in 2016



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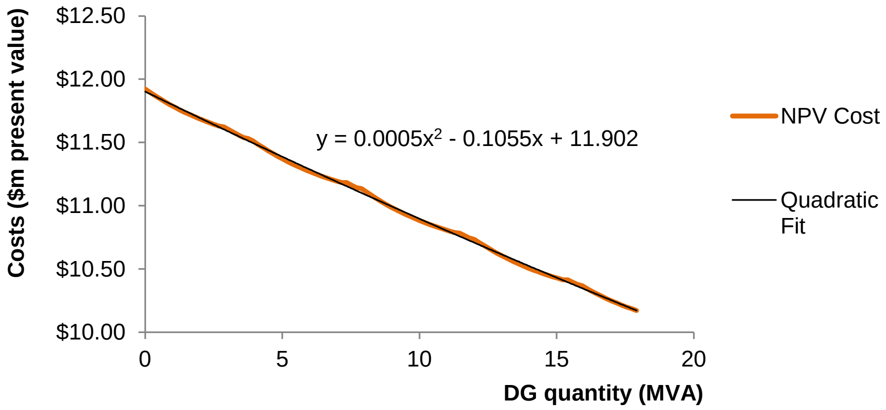
It is interesting to note that in figure 4.7, the discrete steps in network project costs correspond with changes in expected unserved energy costs. In as the amount of distributed generation changes, the costs of expected unserved energy counteract the discrete steps in project costs. When these two costs are added together, the resulting

[8] When developing the 'cost curve', a declining slope is developed. As the amount of distributed generation is increased and each year's threshold is met, the project timing will be deferred by year by year and the project costs in present value terms will decline in steps.

total costs appear relatively smooth. Using regression analysis, the cost-curve can be fitted with an appropriate equation. Based on our analysis of data from each Victorian zone substation, regression analysis showed that a quadratic functional curve fit was generally appropriate for developing a cost-curve, as shown in figure 4.8 (for the total value corresponding to the black line in figure 4.7).[9]

FIGURE 4.8 QUADRATIC COST-CURVE FOR A ZONE SUBSTATION
Example ZSS using data based on Werribee ZSS in 2016



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To calculate the marginal network value of distributed generation, the regressed quadratic equation of the cost-curve, can be differentiated. The following workings show how the marginal value can be derived using Werribee ZSS as an example. Firstly, the regressed quadratic equation (the cost-curve for Werribee ZSS) is:

$$Z_{long-run} = 0.005D^2 - 0.1055D + 11.902 \quad (4.8)$$

[9] A quadratic equation was sufficient in most cases, provided the maximum distributed generation added was not larger than around half the peak demand at the end of the analysis horizon. An exponential equation could also be derived by taking the logarithm of the present value cost and conducting a linear regression on that value. It would be expected to give a similar result.

Taking the derivative of equation 4.8 is:

$$\frac{dZ_{long-run}}{dD} = -0.001D - 0.1055 \tag{4.9}$$

Therefore, the marginal value of distributed generation at the ZSS (multiplied by 1000 to provide units in $/kW) is $V_{marginal}$, expressed as the negative of the derivate:

$$V_{marginal} = -\frac{dZ_{long-run}}{dD} = 105.5 - D \tag{4.10}$$

BOX 4.5 VARIABLES FOR EQUATIONS 4.8 TO 4.10

$Z_{long\text{-}run}$ is the total present value long-run costs (capital and operational network costs and expected unserved energy cost) in millions of dollars

D is the peak demand reduction in MVA

$V_{marginal}$ is the marginal value of distributed generation at the ZSS (in $/kW)

Therefore, using this ‘cost-curve’ approach, the marginal value for distributed generation at Werribee ZSS is $105.50 per kVA of installed capacity.

This approach can be replicated for each ZSS using the project costs and impact of distributed generation systems unique to that ZSS. Equation 4.10 provides a capitalised network value for a unit of distributed generation added to the existing system (which can be annuitised over an assumed life of a distributed generation system to represent an annual value, as per section 3.2.2).

MARGINAL METHOD – USING A ‘DIFFERENTIAL OF FUNCTIONS’ APPROACH

This approach develops equations (or functions) based on both project timing and network costs. It then takes the differential (mathematical) of both equations with respect to distributed generation capacity.

For each future network project, a function for 'project timing' is developed to calculate the timing of a network project according to the peak demand at a zone substation. A simple linear project timing function is generally appropriate in Victoria.[10] If this is not the case, the project timing equation could be formulated into a series of separate linear equation segments. A function for 'project timing' can be described as follows:[11]

$$T = Ax + B \tag{4.11}$$

Then for each network project i, an individual 'project cost' function can be described in present value terms as:

$$Z(i) = (X(i)+Y(i))(1+r)^{-T(i)} \tag{4.12}$$

Based on these two functions a marginal value can be determined by mathematically differentiating the 'project cost' function (equation 4.12) with respect to time T, and multiplying it with the derivative of the 'project timing' function (equation 4.11) with respect to change in demand x. The resulting equation is:

$$V_{marginal} = \frac{dZ(i)}{dx} = \frac{dZ(i)}{dT}\frac{dT}{dx} = -a(i)\ (X(i)+Y(i))\ (1+r)^{-T(i)}\ \ln(1+r) \tag{4.13}$$

BOX 4.6 VARIABLES FOR EQUATIONS 4.11 TO 4.13

T is a vector of project timings $T(i)$ with an arbitrary reference time. Values of time before the present are considered invalid. T may be referenced to the current time as zero. The resulting values of T are constrained $T > T_0$ where T_0 is a vector of the earliest service date for each project having regard to lead time

x is a vector of peak demands defined at locations either in MVA or kVA as required

A is a matrix of coefficients which define the sensitivity of timing to peak demand. These coefficients are derived from the peak demand forecast probabilistic planning

[10] In Victoria, the timing of network upgrades to peak demand changes is fairly linear over moderate periods of time. In practice, project timing is discrete and uncertain due to influences of network performance and patterns of demand growth. Marginal methods smooth project timing for convenience.

[11] The 'project timing' function could also be represented as a matrix of functions for multiple projects in a network area.

approach.

B is a vector of constants influenced by the initial peak demand at each location

$Z(i)$ is the present value network cost related to a specific network project (i) and its timing

$X(i)$ is the capital cost of the project i,

$Y(i)$ is the present value real future operating cost of the project i, if installed at time zero

r is the annual real discount rate with time $T(i)$ measured in years

$a(i)$ is the peak demand coefficient in the time equation 4.11 for the ith project. It should also be noted that when x is the change in peak demand, the coefficients $a(i)$ are negative, so the marginal cost with respect to peak demand is positive

$V_{marginal}$ is the marginal value of distributed generation at the ZSS (in $/kW)

Each network project at a specific location produces a value according to equation 4.13. The values from multiple projects over the period of analysis can be summed to give the total marginal value for a reduction in peak demand at that location.

This approach can be replicated for each ZSS using the project costs and impact of distributed generation systems unique to that ZSS. Equation 4.13 provides a capitalised network value for a unit of distributed generation added to the existing system. This capitalised value can be annuitised over an assumed life of a distributed generation system to represent an annual value (refer to section 3.2.2).

It should be noted that the impact on the cost of changes in unserved energy is excluded in the 'project cost' function described in this staff paper.[12]

[12] Based on the observations of costs in figure 4.7, unserved energy costs move in an opposite way to project costs, i.e. if distributed generation causes a network project to be delayed, the unserved energy cost will increase as a result. This relationship, in present value calculations, results in negative changes in costs that are mostly cancelled out by the positive changes of distributed generation on unserved energy costs in years when there is no project to delay. For simplicity, unserved energy cost impacts have not been incorporated into equation 4.12 for the 'cost function'.[12]

FURTHER CONSIDERATIONS FOR MARGINAL METHODS

In addition to the methodologies described in section 4.6.1, the marginal valuation methods require additional assumptions as follows:

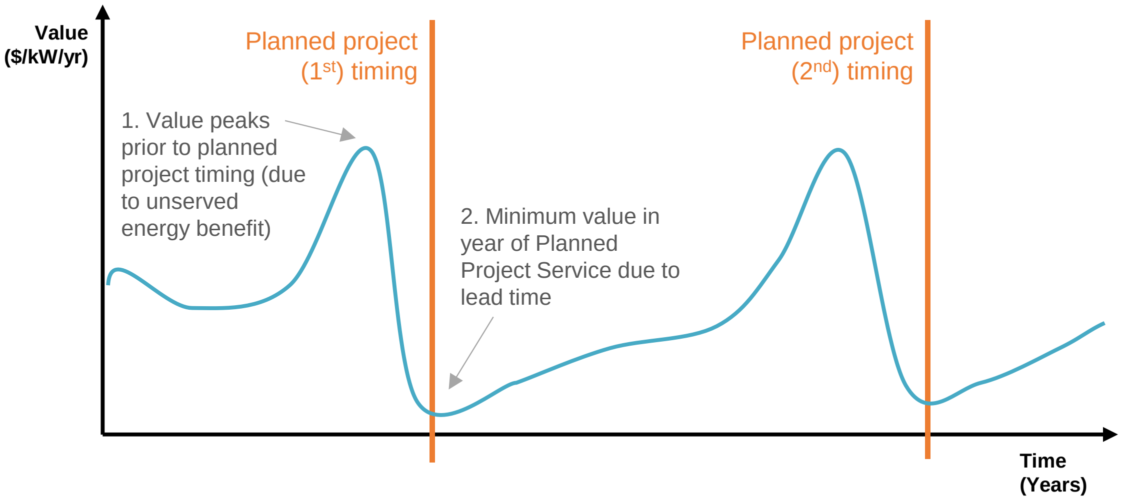
- **Project lead time.** Project lead times are typically 1 to 2 years for distribution projects, and 2 to 3 years for transmission projects. We have considered project lead time for marginal methods to capture the dynamic relationship between the cause (distributed generation) and effect (delayed project investment). If a change in peak demand is too late to influence the timing of a network project, it should not be included in the cost function (equation 4.9). It is also assumed that changes in distributed generation occurring within project lead-time does not impact project timing and only impacts unserved energy during that time.
- **Lifetime of distributed generation assets.** When estimating the present value of future impacts, it was assumed that distributed generation assets (being solar PV) have a 20 year life. Network projects beyond 20 years in the future are ignored on the basis that the existing distributed generation assets would have been retired.

4.6.2 FEATURES OF MARGINAL METHOD VALUES

The features of values under the marginal method ('cost-curve' approach) are shown in figure 4.9. The application of the 'differential of functions' approach also has similar features. This example assumes moderate linear demand growth.

FIGURE 4.9 FEATURES OF THE MARGINAL METHOD (USING THE 'COST-CURVE' APPROACH) VALUE OVER TIME

Capital values



Source: ESC

With reference to the numbered items in figure 4.9:

1. The value peaks just prior to the timing of the planned project because of project lead time being considered. The value from avoided unserved energy value has its maximum present value at this time.
2. The value falls to its lowest level immediately after a planned project. Between projects, the value depends on the future projects in the long-term planning horizon.

It can also be observed that under high peak demand growth, the pattern of value can become quite variable. It should also be noted that when capitalised values are converted to annualised values, a similar pattern can be observed (section 3.2.2).[13]

[13] This is because there is a constant ratio between these two values based on the annuitising factor.

5 OBSERVATIONS ON VARIABILITY OF NETWORK VALUE

5.1 INTRODUCTION

This chapter describes results from applying the valuation methods described in chapter 0 of this staff paper. As described in the findings in the Network Value Final Report, we observed significant variability of annual value across ZSSs in Victoria and over time. In this chapter, we provide further observations outlining a range of factors that can cause network value to vary from year to year. Consistent with the Final Report, these factors are summarised as follows:[1]

- **Location** – Network value varies based on the distributed generator's location within the network, specifically its proximity to areas of the network that are congested, or nearing congestion. In this chapter, we describe how peak demand growth and reserve margin at a ZSS varies by location, which leads to variability of network value.
- **Asset life-cycle** – Network value varies based on when in the network operator's cycle of upgrade projects the value is being measured. Network value varies year-on-year, subject to the timing of network upgrade projects, as well as the supply and demand for energy in the area of the network to which it is connected.

  In this chapter, we describe the following observations related to asset lifecycle:

  - the threshold effect on project timing
  - the leverage effect of distributed generation and
  - multiple projects forecast to occur within an analysis period.

[1] ESC 2017, *Final Report into the Network Value of Distributed Generation*, February, pp. 43

- **Methodology-specific –** Network value may also vary as a result of specific methodologies. The application of certain methodologies can impact network variability due to:
  - the outlook period for analysis and
  - the smoothing effect of marginal methods.

Examples using data from sample Victorian ZSSs are used to demonstrate these observations in this chapter.

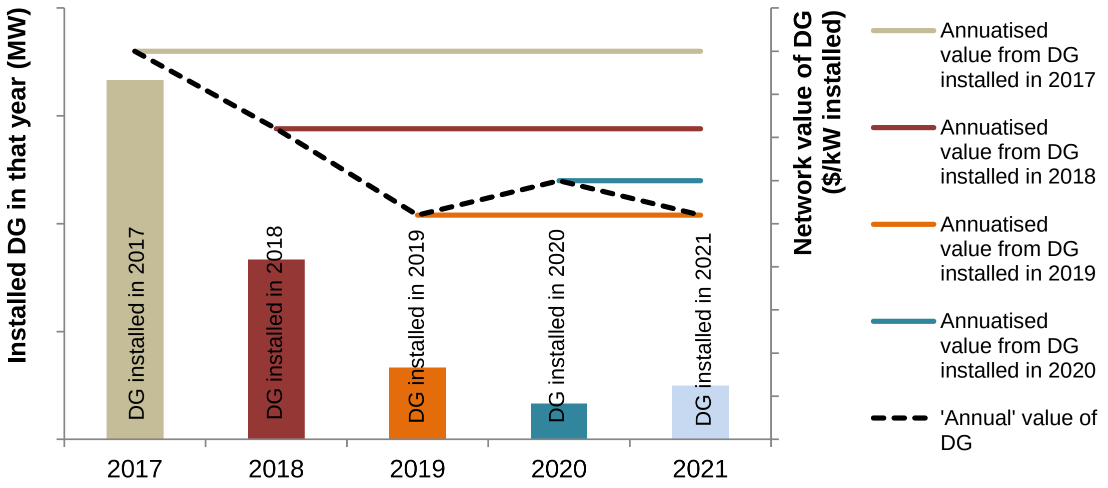
ASSUMPTIONS FOR ANALYSIS IN THIS STAFF PAPER

Several assumptions were made for the analysis undertaken in this chapter. These were necessary given limitations in data and are as follows:

- **Level of analysis.** The analysis was only conducted for the value of reduced network congestion at zone sub-station assets.
- **Demand and distributed generation growth.** When considering valuations beyond 2020, an average linear growth rate for demand and annual distributed generation installations based on DNSP forecasts for 2016 to 2020 was applied.
- **Distributed generation profiles and system types.** Valuation methods were conducted for either dispatchable or solar PV systems. Rather than apply hourly generation profiles for solar PV, the analysis calculates the value of network peak demand reduction, then applies a ratio relative to a certain amount of installed solar PV capacity. The ratio was derived using hourly profiles provided by Jacobs for the Network Value Final Report – an average ratio of 30.9% (refer to section 3.3.4).
- **Use of 'trend analysis' for expected unserved energy based on historical data.** Expected unserved energy functions were derived from Jacobs load and generation profile data and analysis. This technique is described in section 3.3.5.
- **Impact of network project lead time.** Certain methods consider network project lead time in determining when the change in project timing would be achieved. We assumed an eighteen-month lead time in our modelling of the marginal methods.

Additionally, for long-run average growth and marginal methods, 'annual values' represented in this staff paper are the annuitized values in the year that distributed generation is installed – this is depicted as the dotted black line in figure 5.1.

FIGURE 5.1 ANNUATISED VALUES REPRESENTED AS 'ANNUAL VALUES'



Source: ESC

5.2 NETWORK VALUE VARIES BY LOCATION

In Victoria, there are 224 zone sub-stations, 30 terminal stations and hundreds of sub-transmission feeders. Distributed generation may reduce network congestion at any number of these assets. Network value varies by location because it depends on whether that location is or will be network congested in the future.

We observed two factors that could suggest that network congestion is occurring in a given location – demand growth and the reserve margin at a network asset. The variability of network value can depend on the interaction of these two factors.

5.2.1 THE INFLUENCE OF CHANGES IN DEMAND GROWTH AND RESERVE MARGIN

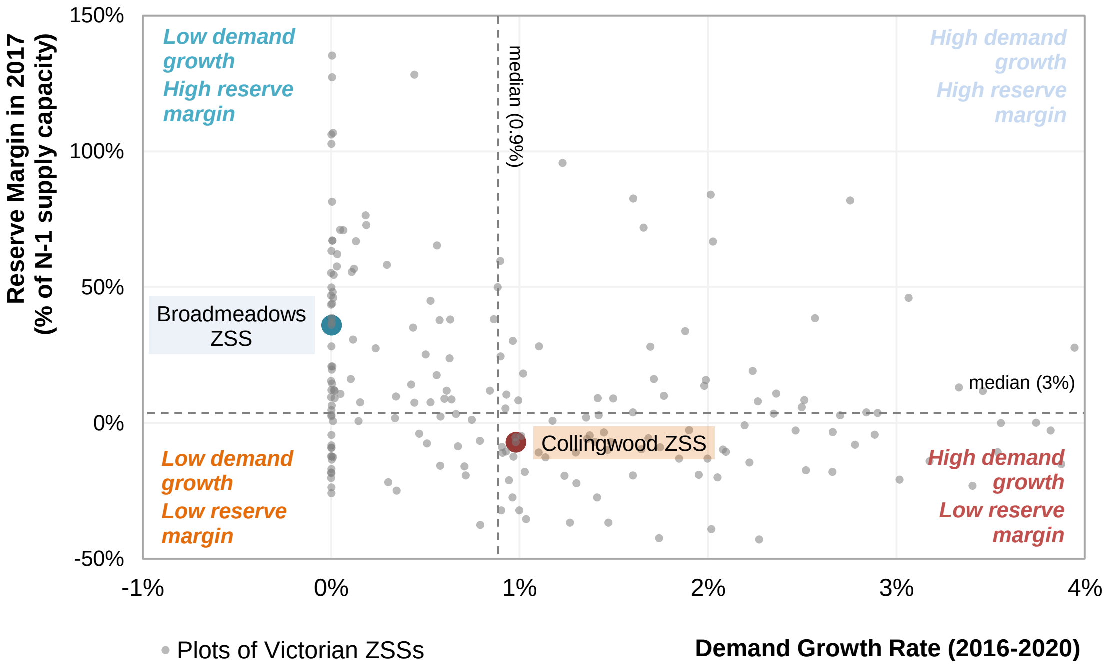
Growth in demand affects the variability of network value predominantly through its impact on project timing. Network assets experiencing high demand growth will tend to experience more variable value. Assets that also have low reserve margins may lead to higher network values from distributed generation. Each ZSS in Victoria experiences different levels of reserve margin and different rates of demand growth.

As a case-study, we compared two ZSSs with different levels of demand growth[2] and reserve margin[3], as follows:

- Collingwood ZSS with high forecast demand growth (0.5 MW per year) and low reserve margin (-7%) and
- Broadmeadows ZSS with low forecast demand growth (0.001MW per year) and high reserve margin (50%).

In figure 5.2, the demand growth rates and reserve margins of all ZSSs in Victoria are plotted. The two example ZSSs are plotted on opposing quadrants of the chart.

FIGURE 5.2 RESERVE MARGIN VS DEMAND GROWTH
Using data based ZSSs in Victoria



Note: For graphical purposes, 29 ZSSs lie outside the bounds of the displayed plot.

Source: ESC analysis for this staff paper

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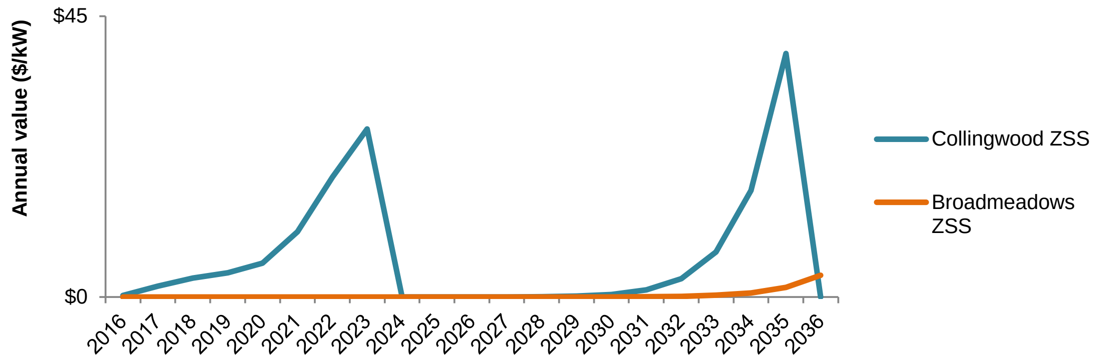
[2] Average load growth from 2016 to 2020.

[3] Reserve margin as peak demand compared to N-1 capacity.

The results from the two ZSSs when applying the counterfactual incremental method is shown in figure 5.3. Network values are more variable for Collingwood ZSS for the next twenty years. However, Broadmeadows ZSS is shown to have zero value until 2033.

FIGURE 5.3 COUNTERFACTUAL INCREMENTAL METHOD – INFLUENCE OF DEMAND GROWTH AND RESERVE MARGIN EXAMPLE

Example ZSSs using data based on Collingwood and Broadmeadows ZSSs, annual value, solar PV



Note: Collingwood ZSS values are from avoiding expected unserved energy rather than project deferrals.

Source: ESC analysis for this staff paper

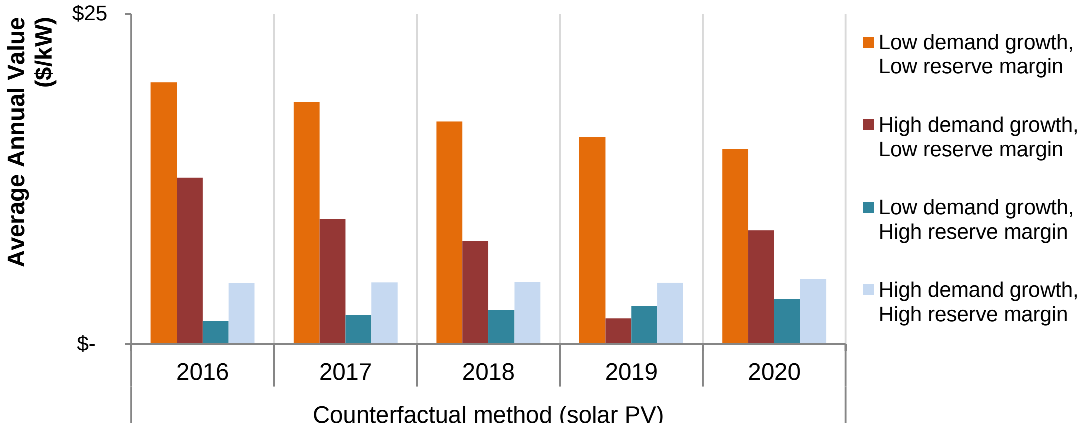
Network areas with high growth and low reserve margins generally have at least one network project forecast in the long-term. For counterfactual methods, these areas experience spikes of network value nearing each network project over time. But each ZSS in Victoria will experience individual trends in variability.[4] Some locations like Broadmeadows ZSS may not have any network value for over twenty years, as network project upgrades are not forecast due to low demand growth.

A comparison of average annual values across all Victorian ZSSs by reserve margin and demand growth categories is shown in figure 5.2. The average annual values between 2016 and 2020 reinforce the findings shown in figure 5.4. ZSSs that have low demand growth and reserve margins will have the highest average counterfactual

[4] Thomastown ZSS also shows variability in value over ten years, as is shown in figure 5.5, as it is forecast to have moderate demand growth of 1.3MW per year and a low reserve margin of 11% (similar to Collingwood ZSS).

values. ZSSs with high reserve margins, regardless of growth, will have consistently low counterfactual values.

FIGURE 5.4 COUNTERFACTUAL METHOD – INFLUENCE OF DEMAND GROWTH AND RESERVE MARGIN EXAMPLE
Average of ZSSs in category, average annual values (2016-2020), using data based on Victorian ZSSs



Source: ESC analysis for this staff paper

5.3 NETWORK VALUE VARIES YEAR ON YEAR BASED ON ASSSET LIFECYCLE

The network value of distributed generation also varies based on when in the network operator's cycle of upgrade projects the value is being measured. The operator's investment profile is determined, at least in part, by the extent to which different parts of the network are nearing congestion. We observed the following related factors that can impact network value variability:

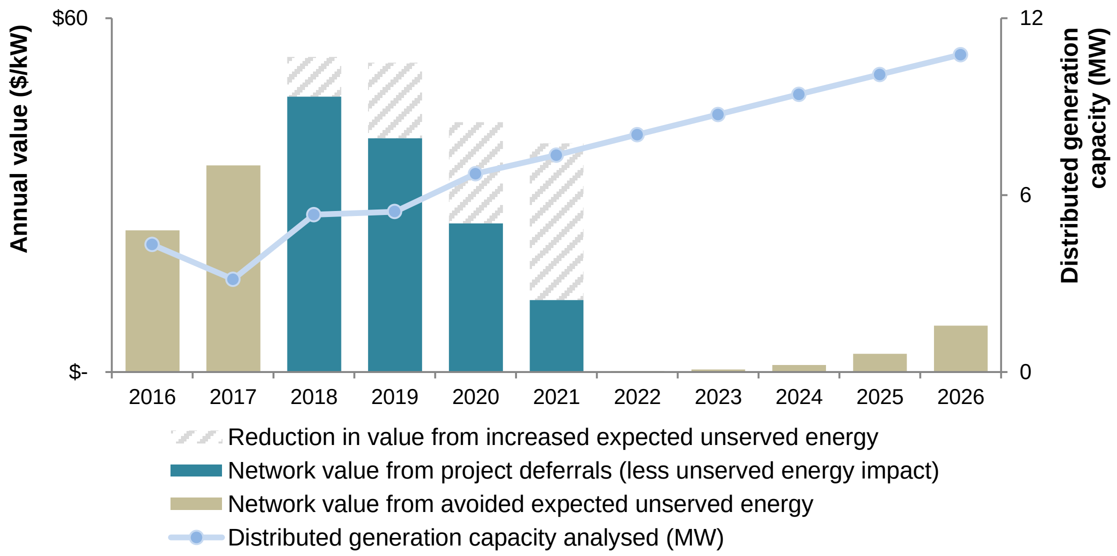
- the threshold effect on project timing
- the leverage effect of distributed generation and
- multiple projects forecast to occur within an analysis period.

5.3.1 THRESHOLD EFFECTS ON PROJECT TIMING

In section 3.2.1 we showed that a certain amount of distributed generation is required to have sufficient influence on deferring the timing of network projects to create value. This effect is termed the ‘threshold effect’.

Value can significantly change because of this effect. As shown in figure 5.5 for Thomastown ZSS, network value from project deferrals only occurs from 2018 when the forecast installed capacity of distributed generation reaches around 6MW. Prior to 2018, the calculated network value is only attributed to reductions in expected unserved energy.

FIGURE 5.5 COUNTERFACTUAL METHOD – THRESHOLD EFFECT EXAMPLE
Example ZSS using data based on Thomastown ZSS, annual value, existing and forecast solar PV



Source: ESC analysis for this staff paper

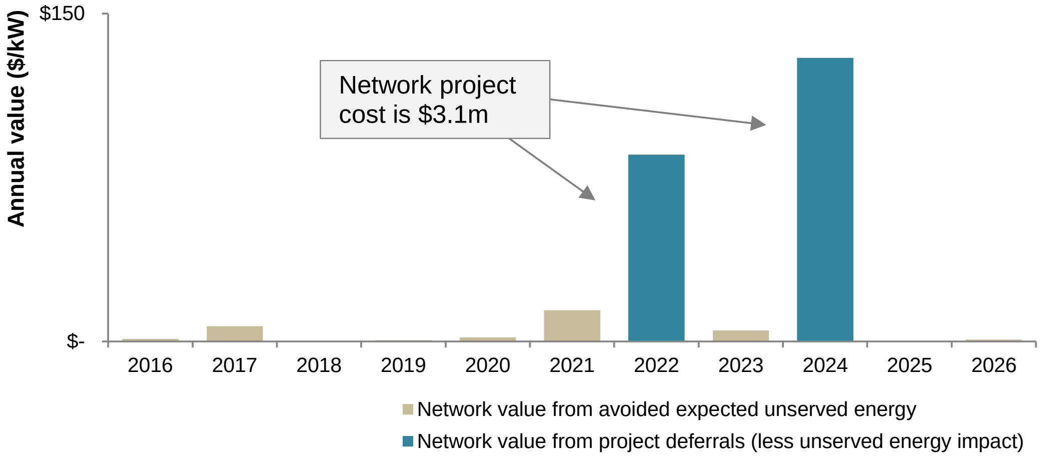
The Turvey incremental and long-run growth incremental methods specifically employ the threshold effect as part of its valuation approach – specifying an amount of distributed generation that defers projects by one year, or deferring network projects indefinitely by matching an amount with demand growth. The threshold effect is also observable in counterfactual methods as it analyses a specific amount of installed distributed generation. Marginal methods avoid the threshold effect by smoothing the relationships between network project timing and installed distributed generation.[5]

5.3.2 LEVERAGE OF DISTRIBUTED GENERATION

Under certain circumstances, a relatively small amount of distributed generation could provide high amounts of value for a short period of time – a leverage effect. In ZSSs experiencing low demand growth, low reserve margin and high avoidable project cost, a small amount of distributed generation could have a leverage effect.

An example of the leverage effect can be shown in figure 5.6 for Richmond ZSSs using the Counterfactual incremental method. The chart shows that a 1MW increase in distributed generation in 2022 and 2024 could provide high network value by deferring a $3.1 million network project for one year.

FIGURE 5.6 COUNTERFACTUAL INCREMENTAL METHOD – LEVERAGE OF DISTRIBUTED GENERATION EXAMPLE
Example ZSS using data based on Richmond ZSS, annual value, firm dispatchable DG



Source: ESC analysis for this staff paper

[5] For marginal methods, the 'cost curve' approach recognises the threshold effect in building the network project cost-curve to support its valuation. However, the smoothing of the cost curve effectively removes the discrete nature observed by the threshold effect. The smoothing effect is described in section 5.4.2.

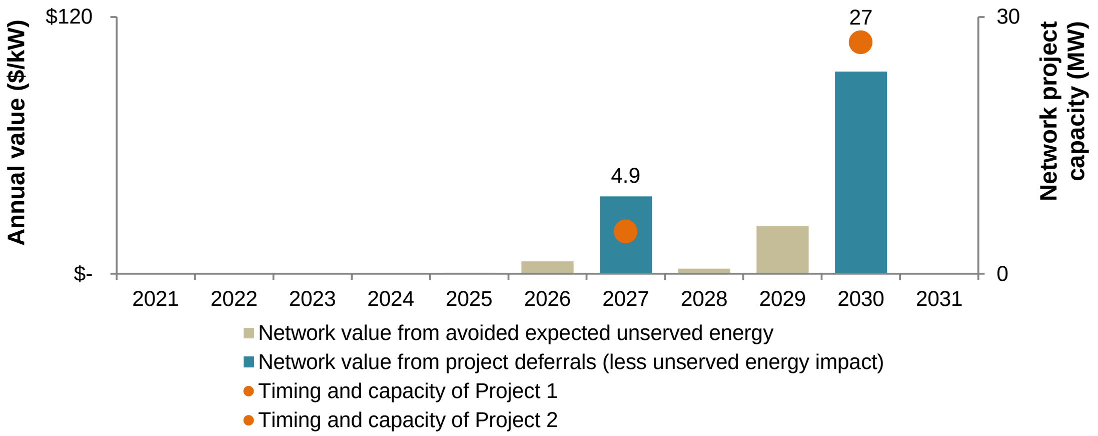
These leverage conditions can produce very high values for short periods of time. High values could be sustained for a longer period, only if demand growth is very low and reserve margin remains very close to a level that would not trigger the need for a network project. This effect also tends to be more pronounced in the counterfactual method because the avoided net project cost is divided by the quantity of distributed generation being assessed (refer to equation 4.1).

5.3.3 MULTIPLE PROJECTS OF DIFFERENT SIZES

Variability in value also occurs in ZSSs that are forecast to have multiple network projects of different sizes over the analysis period. This is because the avoided cost (or deferral value) of a network project is directly related to the size of the network project. An example is shown in figure 5.7 for Pakenham ZSS using the Turvey incremental method. Annual value varies considerably between 2016 and 2036, depending on the size of the project being deferred. In the example, a smaller network project sized at 4.9MW is required in 2027 and a larger network project of 27MW is required in 2030.

FIGURE 5.7 TURVEY INCREMENTAL METHOD – MULTIPLE PROJECTS EXAMPLE

Example ZSS using data based on Pakenham ZSS, annual value, firm dispatchable DG



Source: ESC analysis for this staff paper

5.4 METHODOLOGY-SPECIFIC OBSERVATIONS ON THE VARIABILITY OF NETWORK VALUE

Network value can also vary depending on how certain methodologies conduct their valuation. We observed that depending on the methodology, the selected outlook period for valuation can cause spikes in network value, and that the smoothing of costs applied for marginal methods can also affect network value. We describe these two methodology-specific observations in this section.

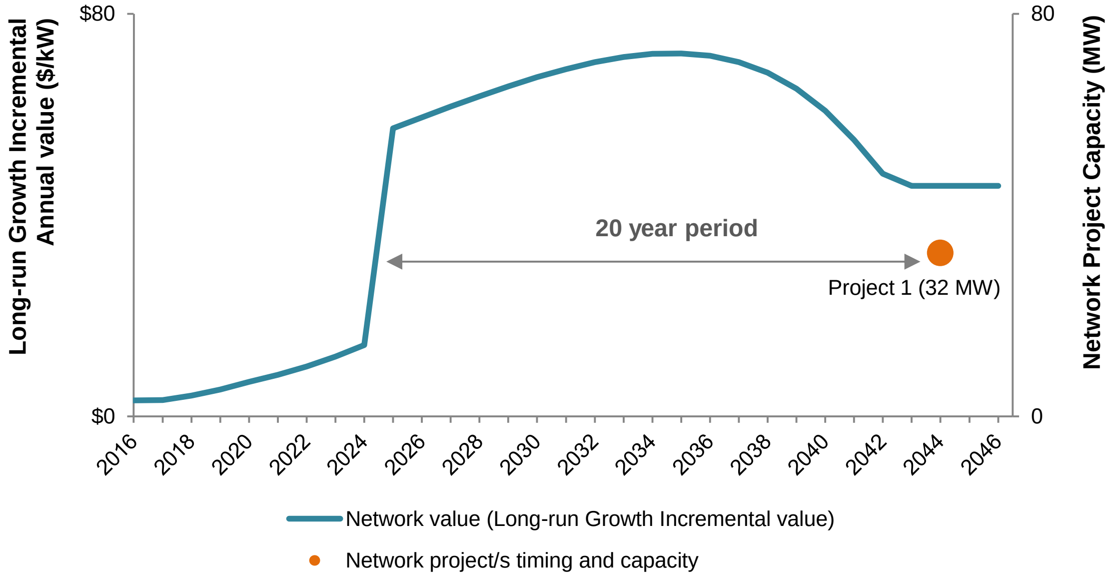
5.4.1 OUTLOOK PERIOD FOR ANALYSIS

For some methodologies the outlook period for the analysis could have a bearing on spikes in network value. This occurs in instances where a network project is initially outside the outlook period of the analysis (the nominated 20 year life of distributed generation), but eventually comes into the evaluation after a number of years.

This effect is illustrated in figure 5.8 for Geelong ZSS, particularly for the Long-run Growth Incremental method. Between 2016 and 2024, the valuation method only considers network projects twenty years from those years, and the value remains relatively low. The sudden jump in the value in 2024 arises because the network project is required in 2044, which enters into the 20-year analysis period at 2024.

FIGURE 5.8 LONG-RUN GROWTH INCREMENTAL – EFFECT OF OUTLOOK PERIOD EXAMPLE

Example ZSS using data based on Geelong ZSS, annual value, firm dispatchable DG



Source: ESC

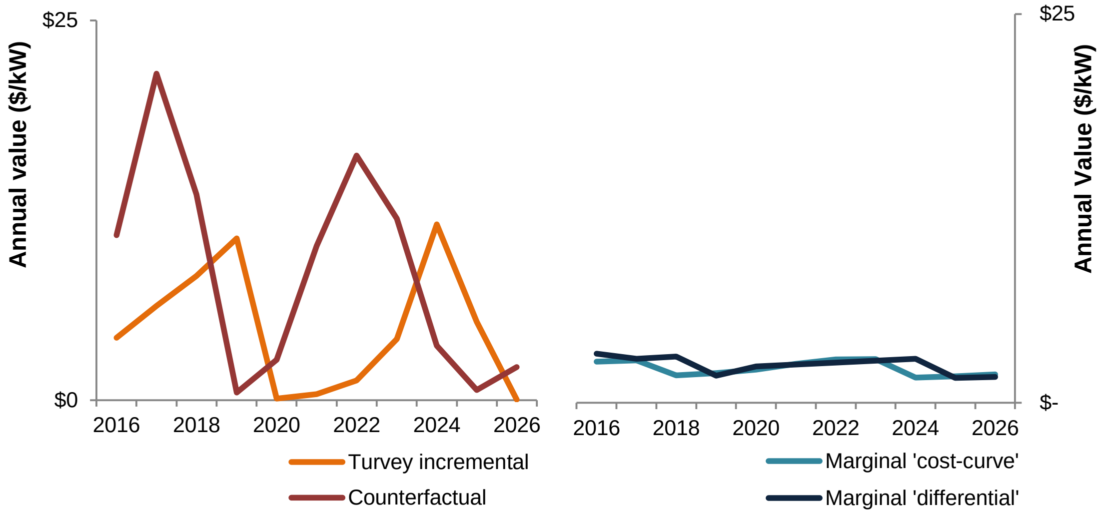
This effect has the potential to influence the variability of value particularly for long-run growth incremental and marginal valuation methods. The effect does not occur for counterfactual and incremental methods, as the period of interest is limited to the year of analysis.

5.4.2 SMOOTHING EFFECT IN MARGINAL METHODS

The previous sections described how a number of effects and factors can lead to variability in annual values – this variability can occur in any of the valuation methods described in this staff paper. However, as discussed in section 4.6.1, marginal methods have been developed by assuming smooth functions of network costs and project timing. The effect of this approach to smoothing can be shown in figure 5.9, which contrasts four different methods for Werribee ZSS.

FIGURE 5.9 SMOOTHING EFFECT IN MARGINAL METHODS

Example ZSS using data based on Werribee ZSS, annual value, firm dispatchable DG



Note: lead-time effect has been removed from the marginal ‘cost-curve’ analysis for the purposes of comparison.

Source: ESC

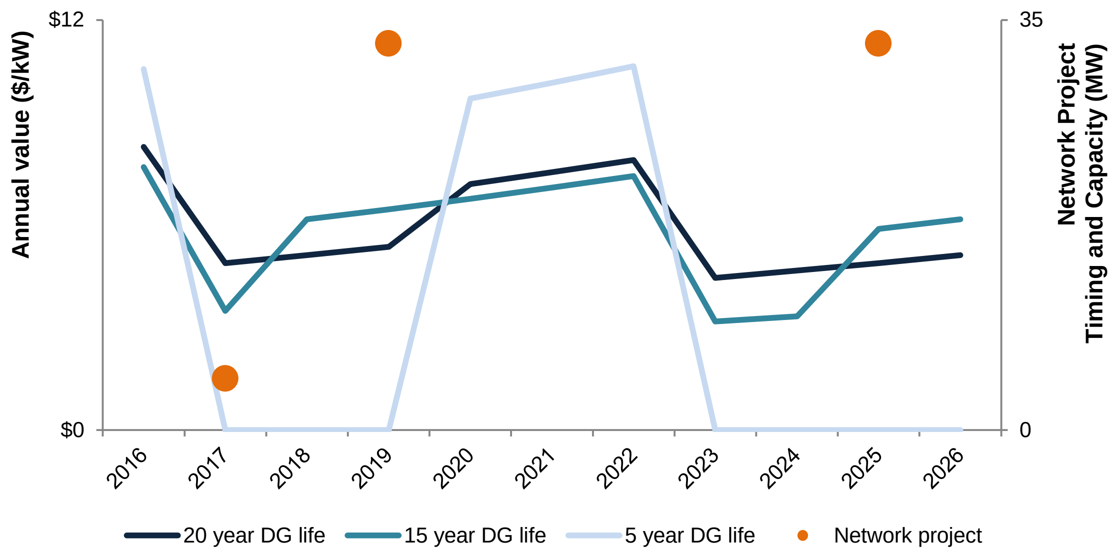
The Turvey incremental and counterfactual methods clearly show the discrete nature of project costs and timing, whilst the marginal methods smooth this variability of value as a necessary feature for deriving a marginal value. Using the data from Werribee ZSS as an example, the results illustrate that incremental and counterfactual methods tend to be more variable over time than marginal methods. This is because they only take into account values within one year, whilst marginal methods average network costs over a longer period of time (20 years).

EFFECT OF ASSUMPTIONS ON DISTRIBUTED GENERATION SYSTEM LIFE ON MARGINAL METHODS

Marginal methods analyse the value that distributed generation can provide over the lifetime of the system. The analysis in this staff paper assumed a twenty-year life for distributed generation systems. This is in contrast to the counterfactual methods, which do not consider system life as they conduct an analysis in one specific year. We considered the sensitivity of the marginal ‘differential’ method to the assumed life of distributed generation systems. In figure 5.10, we compare the impact of distributed generation system lives of 5, 15 and 20 years. The results show that the longer the assumed life, the less variable the annual value.

FIGURE 5.10 LONG-RUN 'DIFFERENTIAL' METHOD – EFFECT OF DG LIFE

Example ZSS using data based on Werribee ZSS, annual value, firm dispatchable DG



Source: ESC

For marginal methods, assuming a longer life of distributed generation systems captures more future network projects and therefore produces higher values that are less variable. Assuming shorter lives of distributed generation systems will lead to variable value as depicted in other methods. In the Werribee ZSS example, the short five-year period results in only one network project being captured in the valuation.

6 THE CHOICE OF THE COUNTERFACTUAL METHOD FOR THE INQUIRY

6.1 INTRODUCTION

As outlined in the previous sections the commission identified six methods by which the network value of distributed generation could be calculated. This section details why the ESC chose to use the counterfactual methodology to calculate the network value of distributed generation for the purposes of this inquiry.

6.2 THE PURPOSE OF THE VALUATION METHOD

The terms of reference for the inquiry required a valuation method that could “examine the value of distributed generation for the planning, investment and operation of the electricity network”. In our inquiry, we found that distributed generation currently provides benefits to the network in reducing network congestion that avoids the need for network expenditure and also reduces changes in expected unserved energy. The purpose of the valuation exercise should then represent, in monetary terms, the benefit provided by distributed generation that is currently (or forecasted to be) installed in the network.

We examined a range of methodologies that could calculate a value of distributed generation in providing network benefits. However, not all methodologies could address the context of the terms of reference for this inquiry. We describe briefly these methodologies below.

COUNTERFACTUAL

This methodology is based on the probabilistic planning approach commonly used by network companies and gives a network value for the current year. It calculates the value of distributed generation installed, and forecast to be installed in the current year. It calculates the value by setting the value of distributed generation to zero, estimating the additional annual network costs required to meet demand, and comparing this cost to the network cost incurred with the distributed generation installed.

COUNTERFACTUAL INCREMENTAL

This is based on the Counterfactual methodology but calculates the network value of 1MW of distributed generation additional to the current and forecast distributed generation used for the Counterfactual calculation.

TURVEY INCREMENTAL

This method starts with the existing network – installed and forecast distributed generation – and calculates the cost of any network upgrades required. It then calculates the amount (and cost incurred) of distributed generation needed to offset the network upgrade by one year.

LONG-RUN GROWTH INCREMENTAL METHOD

This method calculates the incremental cost of peak demand growth. It does not explicitly consider the value of distributed generation. It infers a value of a particular amount of *additional* distributed generation to avoid any future investments to upgrade the network. It is also a long-term valuation methodology looking 15-25 years into the future.

The valuation method also assumes a particular amount of additional distributed generation capacity to avoid the need for network projects to meet demand growth. This is different to an assessment of the value of existing installations of distributed generation systems.

MARGINAL METHODS

Marginal method approaches look at the long-term relationship between network costs and distributed generation to analyse the impact a small change in distributed generation has on peak demand and network costs. Smoothing of network project costs and timing are required for applying these methods.

The ESC explored considered two approaches to marginal methods; a ‘cost-curve’ and ‘differential of functions’ approach. The ‘cost-curve’ approach creates a table of network costs (a cost curve) to estimate the marginal effects in changes to peak demand. The ‘differential of functions’ approach applies mathematical differentiation on an equation of network costs.

6.3 THE COUNTERFACTUAL METHOD FOR THE INQUIRY

In context of the terms of reference for the inquiry, the valuation method should aim to identify the value of the benefits provided by distributed generation that is currently (or forecasted to be) installed in the network. The ESC concluded that the counterfactual methodology was the most appropriate for this purpose.

The counterfactual method calculates the value of benefit provided by the amount of distributed generation that is connected and forecast in a part of the network. The method can also specifically calculate the value of distributed generation connected to the network in 2017.

As described in the Final Report, the focus of this inquiry is not to determine the long-term value of distributed generation. The other methods described in this paper provide this type of valuation in various ways. New mechanisms may emerge in the future, like a market for grid services, where these other valuation methods may be suitable for applications such as pricing grid services. It should also be recognised that our observations of network value being highly variable and location-specific is true whichever method is chosen (as described in chapter 5).

APPENDIX A – REFERENCES

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