Independent Pricing and Regulatory Tribunal
New South Wales

REVIEW OF THE ELECTRICITY DISTRIBUTION RELIABILITY STANDARDS

MODELLING APPROACH

Information Paper

May 2021

We estimated the long-term efficient levels of SAIDI for urban, short rural and long rural feeders to inform our recommendations and meet our terms of reference. The model we used to develop these estimates (the optimisation model) balances:

- The costs of owning, operating and maintaining feeder assets to achieve a given level of reliability, and
- The dollar value of the expected unserved energy (EUE) to customers at that level of reliability, based on the AER's value of customer reliability (VCR).

This Information Paper sets out:

- An overview of the optimisation model and a summary of the key inputs and assumptions we have used in this model.
- The formula we have subsequently applied to set the SAIDI standard for individual urban, short rural and long rural feeders based on feeder length.
- Additional analysis we undertook on the impact of rainfall on feeder standards. While we have not adopted a rainfall variable in our final recommendations, we intend to consider this in more detail in future reviews.

Overview of the optimisation model

The optimisation model was developed to investigate the relationship between network supply arrangements and life-time costs, where these costs include:

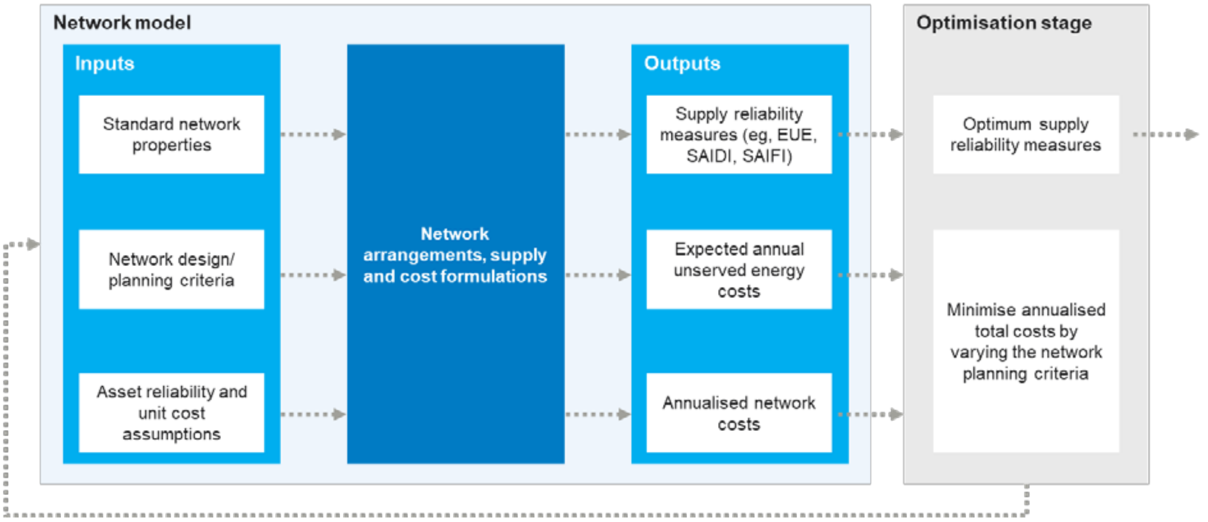
- the capital and operating costs associated with the network supply arrangements
- the economic value associated with the expected reliability of supply provided by the supply arrangements.

In this way, the optimum supply arrangements for elements of the distribution network are determined, based upon the design that minimises these total life-time costs. This in turn is used to provide the expected annual customer supply reliability provided by this optimal design.

The overall structure of the model is shown in the figure below, indicating the following two components of the model:

- the network model – calculates the reliability performance and costs for a specific network arrangement that is defined by a given set of network input assumptions
- the optimisation stage – finds the optimum network arrangements by varying the sub-set of the input assumptions, which specify design requirements, in order to search for the network arrangements that minimise the total costs (in present value terms).

Figure 1 Overview of model structure



The network model

We have developed a generic network model of a high-voltage (HV) distribution feeder. A HV distribution feeder represents the electricity lines (either overhead lines and/or underground cables) that emanate from zone substations (ZSS), and typically supplies a large number of customers along its length (e.g. a single HV feeder will typically supply hundreds or thousands of customers).[1]

We have focused our model on the distributors' HV feeders (rather than their low-voltage, LV, network and/or sub-transmission network) because we consider that this network component represents where variation in the network design and operation will have the greatest effect on the optimised performance of the network. The performance of this component of the distribution network typically contributes the most to customers' supply reliability.

The generic HV feeder model represents a single feeder. However, the feeder model is defined in a way that it enables us to analyse the typical variations in the arrangements across the distributors and feeder types (e.g. variations between urban and rural feeders). In this way, the generic model can be 'set-up' to represent an actual feeder through the selection of its input assumptions.

That said, it is important to note that it is not the aim that the model will represent actual arrangements in detail. Instead, it should broadly approximate the network performance and costs we could expect from feeders with similar characteristics.

1 The HV feeder typically supplies a number of distribution substations (DSS) along its length. The distribution substations then typically supply the distributors' low voltage (LV) network, which is used to provide the supply to individual customers. Depending on their size, some customers could be supplied directly from the DSS, the HV feeder or the sub-transmission system.

The generic HV feeder model is shown in Figure 2 below. It can be viewed as two security zones:

- The first is an N-1 zone, where the feeder supply has some form of backup via connections from adjacent feeders (or other backup capability, including non-network). It is assumed that some portion of any supply interruptions due to a feeder outage in this zone can be restored through this backup capability. Any supply not able to be restored via the backup is assumed to be restored following the repair of the outage.
- The second is a radial N security zone, which is immediately downstream of the N-1 zone. It is assumed that any supply interruptions due to feeder outages in this zone can only be restored following repair of the outage.

Box 1 The meaning of repair time in our modelling

Although we discuss here the restoration of all interruptions within the 'repair' time, it does not need to be assumed that this must be the actual time for the full repair of the outage and normal service. This time could include other techniques that typically allow all customer interruptions to be fully restored by the defined model 'repair time', for example through temporary arrangements. This distinction is important in appreciating the feasibility of the repair methods and costs assumptions discussed further below.

The extent of the N-1 zone can be varied such that a fully N-1 type feeder and a fully N type feeder can be defined via the input assumptions. For the feeder model, it is also assumed:

- there is a fault interrupting switch immediately downstream of the N-1 zone (i.e. any faults downstream of the N-1 zone will not interrupt customers in the N-1 zone)
- there is some form of switching in the N-1 zone such that a faulted feeder section in this zone can be isolated in order that all customers in this section can be restored provided there is sufficient backup capability.

The N zone is defined by:

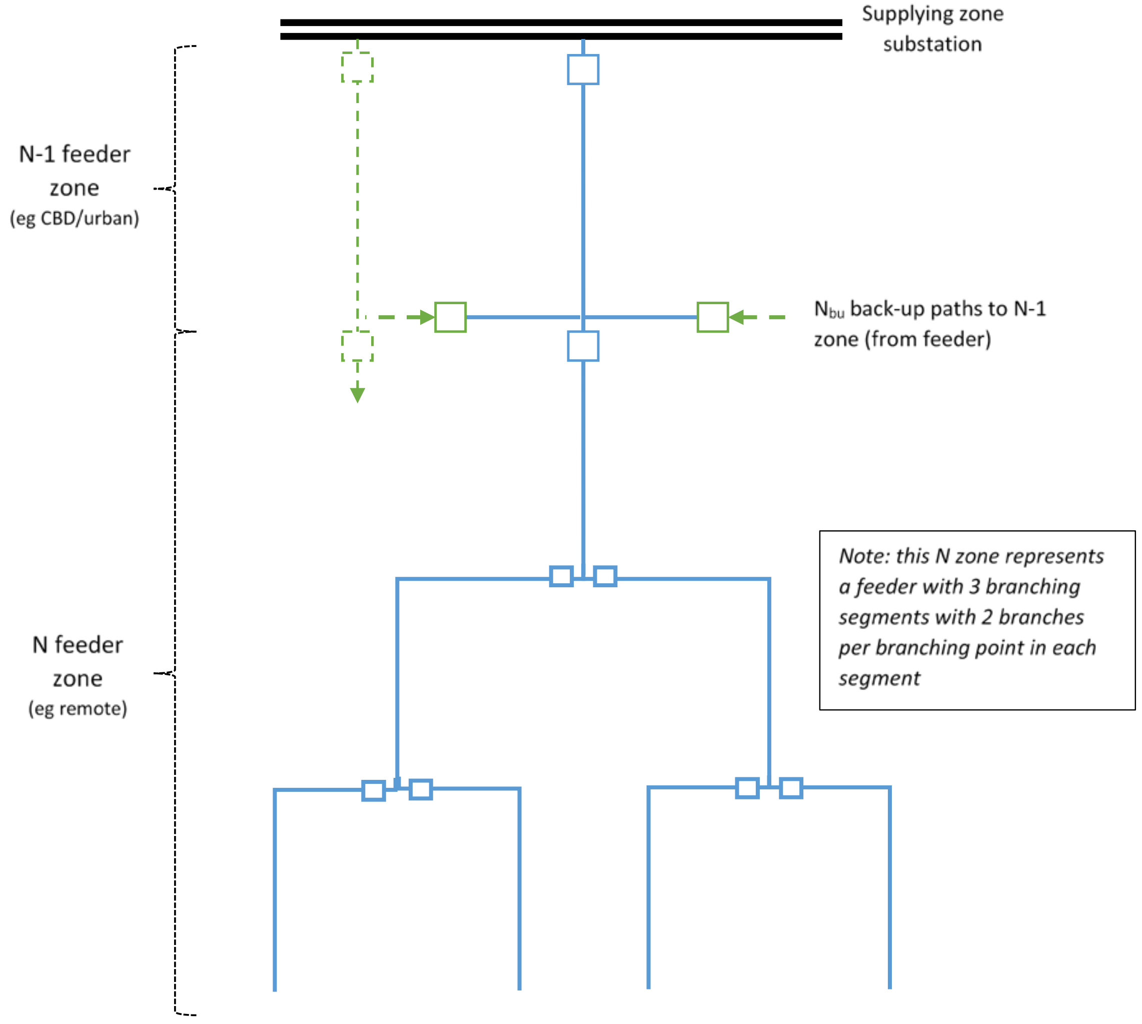
- the number of 'branching' segments along this zone (these are assumed to be equally spaced in the model)
- the amount of 'branching' that occurs at each branching point in the segment (the amount of branching is assumed to be same at each branching point in the model).

For example, in Figure 2 there are three branching segments in the N zone and the amount of branching is two.

The model distributes the customer load in terms of maximum demand (i.e. MW) and customer numbers along the length of the feeder. However, alternative loading patterns can be selected. These alternatives cover:

- Uniform distribution, where the proportion of the load is constant along the length of the feeder
- Inverse power law distributions, where the proportion of load reducing from the feeder exist is inversely proportional to the distance along the feeder, where distance is raised to a defined power (i.e. 1/distance, 1/distance^2, or 1/distance$^{1/2}$).

Figure 2 Feeder model supply arrangements



Overview of model inputs

The specific network arrangements are set via the model inputs. These inputs can be considered as three types, which reflect how they are used for defining specific feeder arrangements, namely:

- feeder properties
- feeder design and planning criteria
- asset reliability and unit cost assumptions.

Feeder properties

The feeder properties define the various characteristics of a specific feeder being modelled, which we consider will be fixed for the optimisation process. These properties cover:

- feeder load information, including:
  - the feeder category (i.e. urban, short rural, etc)
  - the maximum demand, annual energy supplied, load duration curve and load factor
  - the customer numbers
  - the load distribution model form
  - VCR (defined as $ per MWhr unsupplied)
  - feeder diversity/coincidence factor
- Feeder physical information, including:
  - feeder length
  - the proportion overhead and underground.

Feeder design and planning criteria

The network design and planning criteria define the various design and operating requirements of the feeder being modelled. These represent the criteria which we consider could be varied through the optimisation process – although for optimisation only a subset have been varied (this is discussed below).

The criteria are defined in a way that broadly reflects a classical deterministic planning approach. However, it is important to note that the model uses a 'probabilistic' planning approach (i.e. a formal quantitative risk-based cost-benefit analysis method) to optimise these criteria.

The criteria for each feeder cover:

- N-1 zone portion: the portion of feeder that must be secured via the N-1 requirements (i.e. the portion of the feeder in the N-1 zone as percentage of its length)
- load at risk: the portion of the maximum demand, which is at risk of being interrupted should an outage occur in the N-1 zone, after allowing for the available backup capability but before repair of the outage

- the number of back-up paths in the N-1 zone (i.e. how many adjacent feeders will provide the backup capability)
- restoration time: the time to restore the network to the relevant load at risk criteria using the back-up capability, which imposes design requirements on switching arrangements to make use of the defined back-up supply capability
- repair time: the time to fully restore supply to the normal service levels, which typically imposes requirements on the management of spares, asset procurement and repair and replacement protocols
- the number of branching segments and amount of branching in the N zone.

Asset reliability and unit cost assumptions

The asset reliability and unit cost assumptions are the underlying assumptions that we use, via the network formulations within the model, to calculate the output network costs and supply reliability for a given set of feeder properties and planning criteria inputs.

These assumptions define the various fixed data tables and other assumptions, which the optimisation process uses to calculate the outputs.

These assumptions cover:

- cost functions and assumptions:
  - feeder capital cost functions (i.e. cost per length and per rating)
  - restoration cost function (i.e. capital and operating cost as a function of restoration time)
  - repair cost function (i.e. capital and operating costs as a function of repair time)
  - maintenance cost rates (i.e. average annual maintenance as a percentage of capital cost)
  - asset lives
- existing feeder reliability assumptions:
  - feeder outage rate (i.e. unplanned outages per unit length per year)
  - average customer interruption duration due to an unplanned feeder outage
  - average proportion of feeder customers interrupted per unplanned feeder outage.

Overview of model outputs

The network model calculates various outputs for a given set of inputs. The key outputs can be considered as two types:

- various supply reliability measures, which are used to define the resulting reliability standards

- supply costs, which include the costs of constructing and operating the network and the economic cost of the supply reliability (which are required by the model's optimisation process).

Supply reliability measures

The model calculates various measures of the long-term average (i.e. expected) reliability performance of the feeder arrangements. These measures cover:

- EUE, which is the key metric being costed by the model using the VCR input. As noted above, the calculation of EUE in the model uses a similar methodology (often referred to as probabilistic planning) to that often used in the distribution industry for applying formal cost-benefit analysis to network investment planning and decision-making.
- SAIDI, SAIFI and CAIDI, as follows:
  - SAIDI is estimated from the EUE value using an average energy per customer minute conversion rate. This is used to convert the EUE to a value of customer minutes interrupted (CMI), which is then used to calculate SAIDI (where SAIDI = CMI / total customers). This method should reflect the usual method used in the industry to convert an EUE measure to the reported reliability measure.
  - SAIFI is calculated within the model by calculating customer interruption numbers from:
    i) the various inputs that define where the protection devices must be located along the feeder
    ii) the customers calculated to be downstream of these devices (i.e. the customers who will be interrupted if that device opens)
    iii) the number of outages that would be isolated by that operation of that device.
  - CAIDI is calculated as SAIDI divided by SAIFI, in line with the standard formula.

Supply costs

The model calculates the following two costs:

- annualised network cost, which is calculated as the annualised capital cost plus average operating costs of the network arrangements
- expected annual reliability cost, which is calculated as the EUE measure multiplied by an assumed VCR.

It is worth noting that the total annualised cost is used for optimisation purposes (where total annualised costs = annualised network costs plus expected annual reliability cost). The expected annual reliability cost and network operating costs are inherently calculated on this basis. Capital costs are transformed to this basis using an assumed asset life and discount rate, based on the following formula of the equivalent annual cost:

$$\text{Annualised capital cost} = d \ . \ \text{capital cost} \ / \ [(1-(1+d)^{-\text{Life}}) \ . \ (1+d)];$$

where d = discount rate.

Model network formulations

The network formulations calculate the various outputs, for the given set of inputs.

These formulations start by calculating various internal network parameters, including the network capacity, back-up capacity, the switching and restoration form, and the repair method. These parameters specify the network arrangements that are required to meet the given planning criteria for the given network properties. For example, the required capacity of the feeder and the required back-up capacity can be calculated, given the supplied maximum demand, the load-at-risk and the number of back-up paths.

These calculated internal network parameters are then used to calculate the output supply reliability measures, using the assumed asset failure frequencies, load durations curves and other network property assumptions. These calculations use typical formulations used for probabilistic planning of distribution networks, which rely on estimating the EUE from load durations curves, using network load limits (which are defined by the calculated capacity requirements) and asset unavailability probabilities (which are defined by the failure frequencies, and restoration and repair times).

Together, the calculated internal network parameters and reliability measures are then used to calculate the two key cost outputs, based on the various unit cost assumptions.

The optimisation stage

The optimisation stage adjusts the planning criteria inputs to determine the set that produces the minimum total annualised system cost. This 'optimum' input set will then define the economically optimum supply reliability measures for that feeder.

In this way, the optimum network arrangements can be understood both in terms of their specification as input design criteria and output supply reliability measures. Although output-based measures (e.g. SAIDI, SAIFI) will be used to define the reliability standard, the visibility of the equivalent input design criteria is useful in understanding the optimum results and the relevance of these on the network arrangements.

The specific planning criteria that we have varied through the optimisation process and the others we have assumed to be fixed are explained below.

Model inputs and assumptions

The following sections provide a comprehensive summary of the key inputs and assumptions we have applied for each distributor, including the basis of our derivation of these inputs and assumptions.

Existing reliability assumptions

As noted above, the model used the following three inputs to define the existing feeder reliability:

- Feeder outage rate (i.e. unplanned outages per unit length per year)
- Average customer interruption duration due to an unplanned feeder outage
- Average proportion of feeder customers interrupted per unplanned feeder outage.

The functions that define these inputs for each distributor have been derived from the interruption data reported by the distributor in their Category Analysis Regulatory Information Notices (RIN).

The following tables summarise the three functions we have used for each distributor.

Table 1 Feeder outage rate

Distributor	Feeder outage rate function
Endeavour	Feeder outages (for feeders >= 10% overhead length) = 0.126 + 0.0927 x feeder length (km) Or, Feeder outages (for feeders < 10% overhead length) = 0.135 + 0.0115 x feeder length (km)
Essential	Feeder outages (for feeders >= 10% overhead length) = 0.132 x feeder length (km) Or, Feeder outages (for feeders < 10% overhead length) = 0.018
Ausgrid	Feeder outages (for feeders >= 10% overhead length) = -0.2 + 0.084 x feeder length (km) Or, Feeder outages (for feeders < 10% overhead length) = 0.21
Limit assumptions	The model limits the outage rate given by these functions to be no lower than 0.0001.

Table 2 Average customer interruption duration

Distributor	Average customer interruption duration function
Endeavour	92.51 minutes for feeder length >0km and <= 10km 116.56 minutes for feeder length >10km and <= 20km 161.09 minutes for feeder length >20km and <= 50km 209 minutes for feeder length >50km
Essential	102.4 minutes for feeder length >0km and <= 10km 113.3 minutes for feeder length >10km and <= 20km 150.0 minutes for feeder length >20km and <= 40km 187.0 minutes for feeder length >40km and <= 200km 230.7 minutes for feeder length >200km and <= 1000km 320.8 minutes for feeder length >100km
Ausgrid	141.35 minutes for feeder length >0km and <= 20km 196.84 minutes for feeder length >20km and <= 50km 213.81 minutes for feeder length >50km and <= 160km 262 minutes for feeder length >160km

Table 3 Average proportion of customers interrupted

Distributor	Average proportion of feeder customers interrupted function
Endeavour	Feeder customer proportion = 1.09 – 0.19 x LN (feeder length (km))
Essential	Feeder customer proportion = 0.9 – 0.135 x LN (feeder length (km))
Ausgrid	Feeder customer proportion = 1.09 – 0.19 x LN (feeder length (km))
Limit assumptions	The model limits the proportion given by these function to be between 9% and 99%.

Model cost assumptions

Feeder capital cost model

Purpose: Estimate of the capitalised cost of a modelled feeder.

Coverage of costs: All direct constructions, installation and commissioning costs of the HV feeder, including overhead conductor, overhead structures, underground cable. Excludes:

- Switches associated with fault interruption and restoration (see calculations below)
- All DSS and LV network components (these are not covered by the feeder model).

Formulations: the cost of a feeder is estimated as a function of its length, rating, overhead/underground proportion, and load type, using the following formulas:

- feeder base cost = feeder length (km) . c . feeder rating (MVA) ^ b (i.e. power law)
- feeder cost = network type multiplier . feeder base cost

where:

- feeder length (km) is the total length of the feeder, or feeder segment being costed
- feeder rating (MVA) is the thermal rating of the feeder, or feeder segment being costed

- c and b are fixed parameters of the cost model that define the power law relationship (see below for basis)
- network type multiplier is used to scale the feeder base costs to reflect the properties of a specific feeder, including
  - proportion of overhead vs underground
  - whether CBD, Urban, Short Rural, Long Rural.

Basis of cost model parameters

We have used the 2018-19 RIN data of each distributor as the basis for estimating the parameters of its feeder cost model, as follows:

- average feeder unit costs (cost per km) have been calculated based on an estimate of the total replacement cost of all feeders and total length of all feeders.
- the total feeder replacement cost has been estimated separately for the overhead network and underground network using the relevant age profiles (i.e. asset quantities) in the 2018-19 Category Analysis RIN (template 2.5) and the AER benchmark unit costs it derived through its repex modelling exercise
- the total overhead and underground feeder length has been calculated from the feeder table in the 2018-19 Annual Reporting RIN
- to apportion total feeder costs to the urban and rural feeder types, we have assumed relative differences in the unit costs between categories as follows:
  - CBD is 200% of Urban
  - Short Rural is 70% of Urban
  - Long Rural is 90% of Short Rural
- we have assumed the b parameter of the power law to be 0.33 (i.e. the cost per unit length increase is the cubed root of the feeder rating)
- the c parameter of the feeder base cost power law has been set using the typical feeder ratings for the feeder types (as reported by the distributors in the Augex Model tables in their most recent Reset RIN) such that the average feeder unit cost provided by the power law for this rating matches the average feeder unit cost calculated from the RIN data.

Feeder cost model parameters

The tables below summarise the parameters of the three cost models developed for each distributor.

Table 4 Power law parameters

Distributor	Power law c . MVA ^ b ($millions per km	
	b parameter	c parameter
Endeavour	0.333	0.1671
Essential	0.333	0.1005
Ausgrid	0.333	0.1645

Table 5 Overhead multipliers

Distributor	CBD	Urban	Short Rural	Long Rural
Endeavour	na	1.00	0.71	0.73
Essential	na	1.00	0.82	0.71
Ausgrid	2.06	1.00	0.73	0.76

Table 6 Underground multipliers

Distributor	CBD	Urban	Short Rural	Long Rural
Endeavour	na	2.18	1.55	1.58
Essential	na	3.92	3.20	2.76
Ausgrid	3.78	1.84	1.34	1.40

Restoration cost model

Purpose: Estimate of the cost of the assets (e.g. switches and associated control/communication) required to restore customer supply following an outage in the N-1 security zone and the costs of performing the restoration (per outage event) for a given restoration time.

Note that this reflects the costs necessary to restore customer supply via methods such as switching and load transfers (prior to the repair of the outage). As such, these costs are only relevant to the N-1 security zone.

Coverage of costs

Capitalised costs covering all direct design, construction, installation and commissioning of the asset equipment, facilities necessary to perform the restorative network switching following outages on the modelled feeder. This allows for the feeder level switching and any associated communications, control and SCADA costs necessary to achieve different switching methods, covering manual/field switching, remote or automatic switching.

Operating costs covering all direct operating costs associated with performing the restoration, following an outage event (i.e. unit operating costs per outage). This would include the costs of field activities necessary to perform manual switching and any office/control room activities to plan and manage the restoration.

Note that it is recognised that actual operating costs will vary depending on the specific circumstances of any outage and the customers interrupted. The unit operating costs used in the model should approximate the average unit cost for the modelled feeder.

Formulations

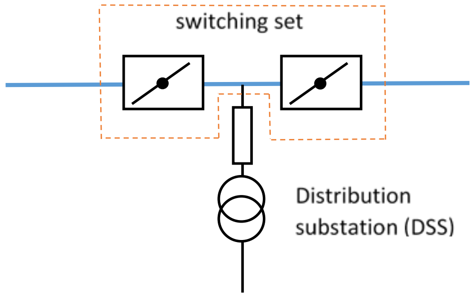
The formulations for calculating the capital and operating costs are based upon two unit-cost functions, which define the capital and operating unit cost as a function of the restoration time.

The two unit-cost functions are defined by fitting a curve based upon the estimated costs and restoration times for three restorative switching methods and assumed times:

- fully manual: assuming the restoration will occur in 180 minutes
- fully remote: assuming the restoration will occur in 30 minutes
- fully (fast) automatic: assuming the restoration will occur in 1 minute.

The capital unit-cost function defines the capital cost per switching set. The model assumes that all load in the N-1 zone can be restored, provided there is sufficient backup capacity. Consequently, a switching set allows for two 3-phase switches, in order that, following a fault on the HV feeder, supply to any distribution substation (DSS) and associated downstream LV network can be restored via switching, while still allowing for the isolation of the faulted feeder section, as shown in the figure below.

Figure 3 N-1 zone restoration switching set example diagram



The number of switching sets for the modelled feeder are estimated based upon another function (switching sets function). The switching sets function defines a relationship between the number of switching sets in the N-1 zone and the customer demand, customer numbers and length of feeder in this zone. In this regard, this function reduces the number of switching sets as customer density increases. This function can be considered to represent the effect of the change in the typical DSS size (in kVA terms) in the N-1 zone as customer density increases, whereby we would expect the average DSS size to increase as the density increased.

The switching sets function is constructed as follows:

- number of switching sets = maximum demand in N-1 zone / (average DSS size x 60%)
- where the average DSS size = L1 x L2, where both L1 and L2 are linear functions, as follows:
  - L1 can be viewed as a base DSS size, which increases linearly from 75kVA to 350kVA as the customers per km (in the N-1 zone) increases from 20 to 100 – the function is 'clipped' between these bounds
  - L2 can be viewed as a scaling of the base DSS, which increases linearly from 1 to 5 as the maximum demand per customer (in the N-1 zone) increases from 2 kVA to 100 kVA – the function is 'clipped' between these bound

- and the 60% is an assumed typical DSS utilisation factor
- in addition, the number of switching sets must be no greater than the number of customers.

In this way, number of switching sets calculated by the switching sets function is then input to the capital cost function, along with the restoration time, to calculate the capital cost of the assets to achieve this restoration time.

The operating unit-cost function defines the operating cost per outage events (affecting the N-1 zone). The number of outage events are calculated by the model, based on the network arrangements and feeder outage rates.

Restoration cost assumptions

The feeder restoration capital unit costs are shown in the table below.

Table 7 Feeder restoration capital unit costs

Switching method	Restoration time	Capital unit cost (per switch set)	Cost basis
Manual	180 minutes	$5,000	The manual switch cost allows for a simple switch/disconnector, without any remote monitoring or control facilities. We have assumed a unit cost of $12,000 per pole mounted switch to produce a total switching set cost of $24,000. However, this total cost is reduced by $19,000 to allow for the poles, fittings and disconnectors that are necessary irrespective of whether the DSS is in the N-1 or N zone.
Remote	30 minutes	$141,000	The remote switch allows for a switch type and associated facilities that can be remotely monitored and controlled from the network control room, where the costs include any necessary measuring/monitoring, communication and control, at both the feeder-level and control room to facilitate a remote restoration methodology. We have assumed a unit cost of $80,000 per pole mounted switch to produce a total switching set cost of $160,000. However, similar to the manual switch, this total cost is reduced by $19,000 to allow for the poles, fittings and disconnectors that are necessary irrespective of whether the DSS is in the N-1 or N zone.
Fast automatic	1 minute	$191,000	The automatic switch allows for a switch type and associated facilities that can be remotely monitored and controlled from the network control room, but also has the appropriate dedicated monitoring and control system to automatically switch and restore supply, where the costs will include those of the remote switch type and any additional costs to allow for an extensive automated feeder restoration scheme for the N-1 zone, including design, testing and commissioning and associated dedicated communication/control hardware and software. We have assumed a unit cost for the switch installation will be similar to the remote switch, as this will require similar hardware.

Switching method	Restoration time	Capital unit cost (per switch set)	Cost basis
			This estimate assumes any necessary ADMS and SCADA system is in place. However, we have assumed an additional $50,000 per switching set to allow for the automation design, testing, and commissioning, including any software/system upgrades.

In addition, an uplift of 20% is applied to these costs to reflect the increase in costs we expect when ground mounted / kiosk switching associated with predominantly underground feeders is necessary. This uplift on costs is applied when less than 30% of the feeder by length has been reported by the distributor to be overhead construction.

The feeder restoration operating unit costs (per outage event) are shown in the table below.

Table 8 Feeder restoration operating unit costs

Switching method	Restoration time	Operating unit cost (per switch set)	Cost basis
Manual	180 minutes	$1,800	The manual operating costs assume on average 18 hours of labour, allowing for direct field, control room and other office activities, with an average direct labour rate of $100 per hour.
Remote	30 minutes	$600	The remote operating costs assume on average 6 hours of labour, allowing for direct control room and other office activities, with an average direct labour rate of $100 per hour.
Fast automatic	1 minute	$300	The automatic operating costs assume on average 3 hours of labour, allowing for direct control room and other office activities, with an average direct labour rate of $100 per hour.

Outage repair cost model

Purpose: Estimate of the cost of the assets, equipment and field activities required to repair the network (per outage event) for a given repair time (where 'repair time' is the time from the commencement of the outage to all supply interruptions being restored).

Note that it is recognised that actual repair costs will vary depending on the specific circumstances of any outage. The unit costs used in the model should approximate the average repair cost for the modelled feeder and given repair time.

Furthermore, as discussed above, although we label these 'repair' costs here, these costs could include techniques that allow customer supplies to be fully restored by the defined 'repair time' through temporary arrangements, while the actual repair is being performed (e.g. temporary line bypass arrangements or temporary alternative supply/generation). This distinction is important in appreciating the feasibility of the 'fast' repair methods and costs discussed below.

Coverage of costs

The cost model covers two components:

- Asset costs: the direct costs associated with the assets, equipment, facilities necessary to perform the repairs and restorations for the given repair time. This should allow for any specialised assets and equipment necessary to perform faster repairs and/or restoration than usual. It is assumed that the use of these assets, equipment and facilities will be spread across the network, and will not be specific to the feeder being modelled. Therefore, these costs are treated as a type of service cost in the model, rather than a capitalised cost.
- Operating costs: the operating costs directly associated with any specific repair for the given repair time. This would include the costs of the field activities necessary to perform the repair/restoration and any office activities to plan and manage the repair.

Formulations

The formulations for calculating the two cost components are based upon two cost functions, which define the unit costs (cost per repair event) as a function of the repair time.

The two unit-cost functions are defined by fitting a quadratic curve based upon the assumed costs and repair times for the following three repair methods:

- very fast repair – assumes an average repair time of 4 hours and requires specialist assets, equipment and facilities to enable this rapid repair time, and enhanced operating/field activities
- fast repair – assumes an average repair time of 6 hours and requires specialist assets, equipment and facilities to enable this fast repair time, and enhanced operating/field activities
- normal repair – assumes a repair time of 8 hours with no specialist assets or equipment and usual operating/field activities.

Repair cost assumptions

The asset investment capital costs necessary to significantly reduce repair times could cover a broad range of options, including:

- increased emergency spares
- temporary line arrangements

- mobile generation and mobile substations
- non-network support services
- increased/enhanced fault location detection devices and/or systems.

The best solution would likely include a range of these options and others. The best make-up of these options, including the quantities and depot locations necessary to reduce average repair times, will be specific to the distributor.

We have assumed an indicative aggregate cost, which we consider is a reasonable amount to purchase a selection of the above options (or others) that could be used to reduce average repair times in the order suggested.

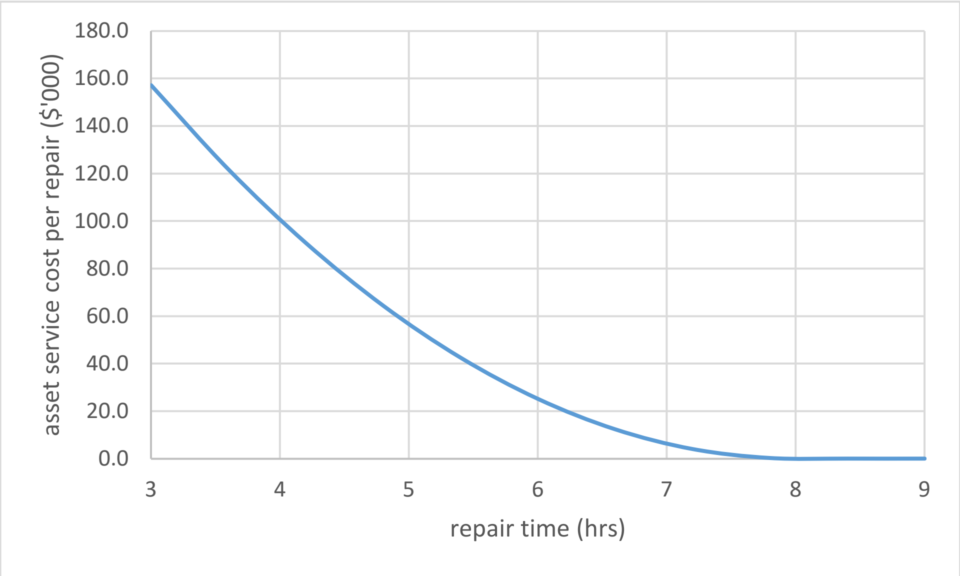
The repair capital unit cost assumptions used in the model and the associated cost function are shown in the table and figure below.

Table 9 Repair capital unit cost assumptions

Repair method	Repair time	Asset investment	Service cost (per repair event)[a]
Very fast	4 hours	$200 million	$100,600
Fast	6 hours	$50 million	$25,100
Normal	8 hours	-	-

a This assumes the specialist assets have a 15-year life, the service provides 5% return, and assets have a 50% utilisation.

Figure 4 Cost function for repair capital unit-cost



Similarly, the operating unit costs for enhanced repair methods could cover a range of factors, including:

- increased response and repair crew sizes
- specialist and more costly skill sets
- increased control room and/or depot staff levels.

For similar reasons to those discussed above on our capital costs assumptions, we have not attempted to develop a bottom-up estimate of operating unit costs. Instead, we have assumed an indicative aggregate cost which we consider is a reasonable amount to allow for a selection of the above options (or others) that could be used to reduce average repair times.

The normal operating cost assumption has been set to broadly align with the average emergency response cost we could estimate from the emergency response operating costs the distributors have reported in their 2018-19 Category Analysis RIN. The relative difference in the normal repair cost is used to scale the costs for the two enhanced repair methods. With regard to this scaling, we are assuming that these differences are due largely to uncontrollable factors affecting these costs, and so do not reflect any inherent inefficiency between distributors.

The repair operating unit cost assumptions used in the model are shown in the table below.

Table 10 Operating unit cost (per repair, $'000)

Repair method	Repair time	Endeavour	Essential	Ausgrid
Very fast	4 hours	60	60	120
Fast	6 hours	30	30	60
Normal	8 hours	15	15	30

Maintenance cost rate

Purpose: Estimate of the maintenance costs of the feeder assets.

Coverage of costs: The direct costs of the maintenance of the assets that form the feeder or directly affect the service of the feeder. This would include the costs of the field activities necessary to perform the maintenance and any office activities to plan and manage the maintenance activities.

Formulations

The maintenance costs are estimated using constant maintenance cost rates that define the average annual maintenance costs as a proportion of the feeder capital costs. In this way, the annual feeder maintenance cost = maintenance cost rate x feeder capital cost.

Two maintenance cost rates have been calculated, covering the overhead network and the underground network (noting we would expect these to have significantly different maintenance rates).

Maintenance rate assumptions

We have derived the rates from the maintenance costs reported in the 2018-19 Category Analysis RINs (templates 2.1.2 and 2.8.2) and total network replacement costs we estimated to calculate the feeder unit capital costs discussed above.

The maintenance cost rates we have calculated for each distributor are shown in the table below.

Table 11 Maintenance rates (as % of capital cost)

Distributor	Overhead	Underground
Endeavour	1.75%	0.36%
Essential	1.02%	0.35%
Ausgrid	1.67%	0.34%

Other model assumptions

Individual feeder properties

The feeder properties for each individual feeder being modelled have been taken from the following sources:

- Feeder total length (km), the proportion overhead (%), the maximum demand (MVA), customer numbers and the current feeder category (i.e. urban, short rural, etc) have been taken directly from the 2018-19 Annual RIN of the relevant distributor.
- The feeder load duration curve and load factor have been assumed to be equivalent to the supplying ZSS. We have calculated the supplying ZSS load duration curve and load factor from substation load profiles published by the distributors.
- The total customer energy supplied by the feeder is calculated, based upon the feeder maximum demand and the assumed load factor, discussed above.
- Estimates of feeder-specific VCR using information provided by the distributors.

Design and planning criteria

We have varied the following four planning criteria through the optimisation process:

- portion of feeder (by length) in N-1 zone
- load at risk (of outage in N-1 zone)
- restoration time
- repair time.

The number of back-up paths in the N-1 zone is assumed to be 2 for all feeders as this reflects the typical number of adjacent feeders it could be expected will provide back-up capability to a feeder. The number of 'branching' segments in the N zone and the amount of 'branching' at each branching point in the segment has been set based upon the assumptions in the table below.

These branching assumptions were estimated from actual distributor interruption data (Ausgrid) by estimating the parameters for feeders in the defined length ranges, where the distribution of the proportion of customers interrupted by each outage given by the model best represented the actual distribution we calculated from the actual data. A length relationship was used as we considered it reasonable to assume that length was the most significant factor, in general, influencing the extent of branching in the N zone (i.e. we would expect that as the length of a feeder increased there would tend to be a greater number of branching points and branches in the feeder).

Table 12 Branching assumptions

Length range		Overhead		Underground	
lower	upper	segments	branches	segments	branches
0	5	1	1	1	1
5	10	1	2	1	1
10	15	1	2	1	2
15	20	1	2	1	2
20	30	2	2	2	2
30	40	3	2	3	2
40	60	3	2	3	2
60	80	3	2	3	2
80	120	2	3	2	3
120	150	2	4	2	4
150	200	3	3	3	3
200	500	3	3	3	3
500	3000	4	4	4	4

Other general assumptions

The table below summarises the other assumptions that we have applied in the model.

Table 13 Other modelling assumptions

Model parameter	Value
Feeder coincidence factor	95%
Feeder N-1 zone backfeed portion[a]	30%
Discount rate	3.0%

a This represent the amount of additional feeder that is constructed to provide the backfeed capability.

Derivation of formulae for SAIDI and SAIFI single-feeder standards

The proposed new standards are based on formulae for the upper limits on SAIDI and SAIFI for an individual feeder in any year. Whenever a feeder exceeds either of these limits in a reporting year, the distributor would need to notify IPART and participate in an investigation of the reasons for that non-compliance.

The formulae express the upper limits as a function of feeder length. We determined that feeder length[2] is the most important determinant of SAIDI and SAIFI performance through statistical analysis of past interruption data. The formulae are:

$$Upper\ limit\ SAIFI = 3.1 + 0.44\sqrt{length} + MIN\left(0.65, \frac{21}{length}\right)$$

$$Upper\ limit\ SAIDI = 262 + 108\sqrt{length} + MIN\left(160, \frac{5500}{length}\right)$$

Each of these upper limits is set to ensure the probability of an individual feeder exceeding it is about 1% in any year on average. That implies an expectation that approximately 1% of feeders should be non-compliant with each upper limit in any year.

The coefficients in the formulae were established by analysing actual performance data for the years 2014-15 through 2018-19. If future performance deteriorates relative to that past performance, then the proportion of feeders that are non-compliant would be higher than 1%.

The rest of this section explains how we established the functional form and the coefficients of these formulae.

Interruptions affecting the customers on a feeder can originate from an event on one of four parts of the electricity supply system:

- outside the distributors' network (exempt from the standard)
- the distributors' sub-transmission network (not reflected in these formulae)
- the high-voltage part of the feeder (HV)
- the low-voltage part of the feeder (LV).

Only HV and LV events are reflected in the formulae.

2 The coefficients in the formulae below are based on length measured in km units.

Distinguishing between HV and LV events

Ausgrid provided interruption data that separately identified HV and LV events. Using this data, we examined a range of heuristic rules that could be used to classify interruptions as HV or LV. For each candidate rule, we could compare the resulting classifications with the actual HV/LV breakdown. Our aim was to find a rule that would minimise the effect of any classification errors on our estimates of customer interruptions (CI, used for SAIFI) and customer-minutes of interruption (CMI, used for SAIDI).

Based on expert engineering advice and discussions with the distributors, we examined rules based on the proportion of customers affected by a given interruption. The intuition was that LV faults tend to affect a smaller proportion of customers (only those on an LV spur) than HV faults (which affect everyone downstream).

We determined that an LV-cutoff function of the following form would yield a useful classification of faults into HV and LV categories:

$$Maximum\ proportion\ of\ customers\ affected\ by\ an\ LV\ fault\ =\ MIN\left(1, \frac{A}{feeder\_length}\right)$$

Using trial and error, we determined a value for the parameter "A" that minimised misclassification errors in numbers of interruptions, CI, CMI and average duration for the Ausgrid data. We applied the same LV-cutoff formula for Endeavour to classify their faults as HV or LV.

Essential provided information that enabled us to distinguish between HV and LV faults for the last four years in our sample (FY16 – FY19). We used that data to derive the HV fault rate for Essential. The new fault rate calculation for Essential also excluded feeders longer than 500 km because the relationship between fault rate and length appeared to break down for these extremely long feeders. We have done some exploratory analysis that suggests a relationship between rainfall and fault rates for Essential feeders, and possibly that is the explanation of this problem for extremely long feeders (which tend to extend far into low rainfall, low fault rate parts of the state).

The resulting fault rate of 0.132 unplanned interruptions per feeder-km per year was significantly higher than the fault rate of 0.074 we had used in our draft report. The calculations presented in this final report have been updated to reflect this new fault rate for Essential.

HV upper limits

We found that historical actual levels of SAIFI for HV interruptions increased with the square root of feeder length. We found that the HV SAIFI upper limits corresponding to a 1% probability of exceedance were well described by a linear function of the actual HV SAIFI. Combining these two results yielded the intercept and the square root coefficient in the SAIFI formula above.

As documented above, we used an optimisation model to determine the HV SAIDI values that minimised the expected total social costs for each feeder. We found that these optimal SAIDI values also increased with the square root of feeder length. We found, as for SAIFI, that the HV SAIDI upper limits corresponding to a 1% probability of exceedance were well described by a linear function of the optimal HV SAIDI. Combining these two results yielded the intercept and the square root coefficient in the SAIDI formula above.

The upper limits for SAIFI and SAIDI were calculated using the single-feeder statistical model.

LV upper limits

LV faults are more prevalent on feeders of shorter length. That is to be expected since our LV-cutoff function is proportional to the inverse length (i.e. 1/length). While LV fault data tends to exhibit greater variability (i.e. noise) than HV fault data, we observed a statistically significant relationship between LV SAIFI and the inverse length function. We observed a similar significant relationship for LV SAIDI. We judged statistical significance in this case by the t-values for the inverse length coefficients, which were above 4 (for SAIDI) and 8 (for SAIFI).

By trial and error, we found a coefficient B for a 1% probability of exceedance cut-off function of the form B/length for each of LV SAIDI and LV SAIFI. These B values are used in the above formulae for the single feeder standards.

The effect of rainfall on reliability

Our modelling is based on the relationship between reliability and feeder length. There are many more factors that drive electricity distribution reliability, including storms (lightning), vegetation and animal interference and flooding. The impact of these, particularly severe weather, is likely to be growing as the climate changes.

Capturing the impact of these different factors in our modelling is important, but difficult. We would need to have a reliable measure of each factor for each different feeder across the three NSW networks. We could then consider the impact of each of these on the level of reliability and assess the importance of including them in our modelling. For many of these factors there is simply not enough good data available.

We have considered whether the use of a simple measure, rainfall, could be used instead. Greater rainfall may be correlated with more storms and flooding, and also with greater vegetation and a higher capacity to support animals. The Bureau of Meteorology collects and publishes detailed data over time that can be used in our modelling.

We have undertaken some preliminary analysis, which supports the inclusion of rainfall in explaining the level of reliability, particularly across the very diverse Essential Energy network. For Endeavour and Ausgrid, our analysis shows that including rainfall does not improve the explanatory power of the model. On the other hand, it does not reduce it either. Over the period we modelled, rainfall across Essential Energy's network varied more than it did across Endeavour and Ausgrid's networks, which may explain why the impact on Essential's modelled reliability was so much greater.

As this analysis has not yet been published and consulted on, we have not adopted a rainfall variable in our final recommendations. However, we intend to consider this in more detail in any future reviews.

Why rainfall?

This section explains how we could incorporate a rainfall variable in estimating fault rates for DNSP feeders in NSW. The motivation for this is the observation that parts of the state that experience higher than average fault rates per kilometre of feeder length tend to have higher than average rainfall, and vice versa.

We consider the merits of using rainfall in conjunction with feeder length as an explanatory variable in a statistical model of DNSP feeder fault rates.

We expect rainfall to be highly correlated with events known to be key contributors to feeder outages:

- lightning
- vegetation interference
- animal interference
- flooding.

Rainfall is objectively measurable, and reliable records exist for many locations in the state over long periods of time. The Bureau of Meteorology (BOM) publishes monthly rainfall for approximately 5,000 weather stations in NSW.

How much rain falls on an individual feeder?

A feeder is a linear asset, possibly 500 km long or more. Rainfall is measured at point locations. It would be impractical to identify all the BOM weather stations on or near an individual feeder and create a composite rainfall time series.

Instead, we find the BOM weather station closest to the ZSS of an individual feeder. We calculate 12 monthly rainfall totals for that station for each fiscal year from FY15 to FY19. We create two new variables:

- annual rainfall x feeder length
- annual rainfall x (feeder length)^2

We regress the number of unplanned interruptions within each 12-month period for each feeder against these two variables.

This regression model produces an estimate of the rainfall exposure of a given feeder: how much of the feeder length is exposed to how much rainfall. The second variable (with the square of the feeder length) allows for the rainfall to change from the near end of the feeder (where the ZSS is) to the far end. For networks west of the Great Dividing Range, a rainfall drop-off is expected because long feeders tend to have their far ends further from the coast than their near ends. For networks East of the range, we would expect rainfall to increase as we move away from the ZSS, as the far end of the feeders is more likely to be at a higher altitude and experience higher levels of orographic precipitation.

How do we choose the weather station for each feeder?

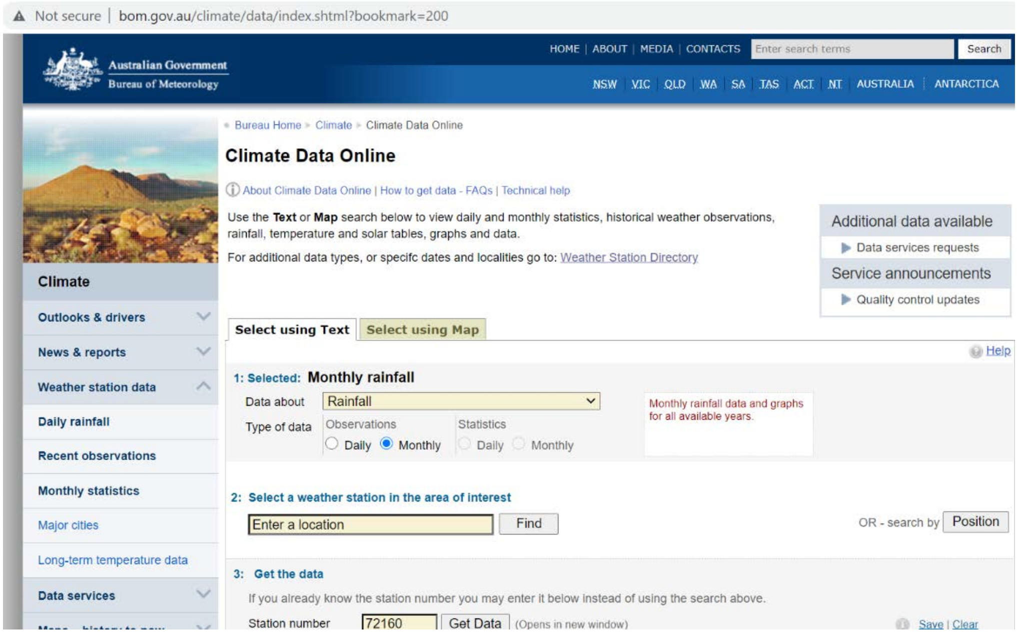
Each feeder has a ZSS. We create a list of the unique ZSS for each DNSP. We try first to match the ZSS names to the BOM weather station names automatically. However, if automated matching fails, or if an unsuitable weather station is chosen by the matching algorithm, some manual intervention may be required.

Manual intervention will also be required if the chosen weather station has missing data. Ideally we would like a complete record of monthly rainfall between July 2014 and June 2019. If a small number of individual months' data are missing, it can be estimated by taking the average rainfall for the same month from the other years in the sample. However, if there is too much missing data within our target date range, we must choose a different weather station within (ideally) 20 km of the ZSS.

How do we get the monthly rainfall data for the chosen weather station?

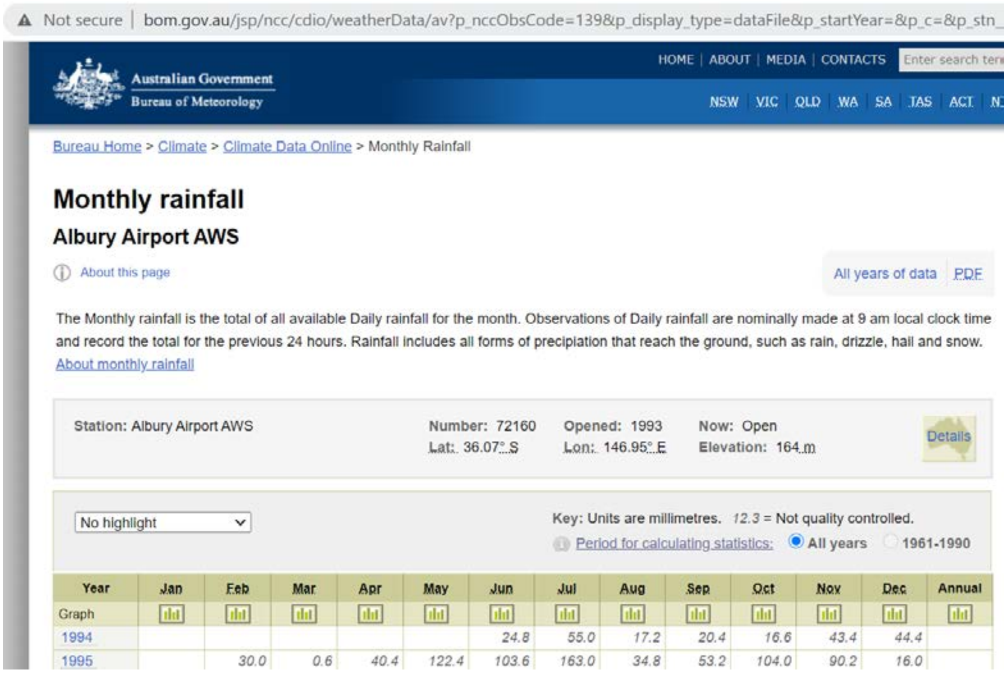
We extracted the monthly rainfall data from the Bureau of Meteorology (BOM) website using the BOM station number. Select Monthly rainfall. In this example, station 72160 (Albury airport) has been selected. Press the "Get Data" button next to the station number.

Figure 5 Screenshot of BOM webpage for extracting monthly rainfall data



Data source: Bureau of Meteorology (www.bom.gov.au)

Figure 6 Screenshot of BOM webpage showing monthly rainfall



Data source: Bureau of Meteorology (www.bom.gov.au)

To extract the data, select "All years of data" in the upper right hand corner. That will cause a download of a zip file: "IDCJAC0001_72160.zip". The last five digits of the file name are the station number.

The zip file contains a CSV file named IDCJAC0001_72160_Data12.csv which contains monthly rainfall records for all available years for that weather station.

Copy the worksheet to the file (in our model, "ESS_locations.xlsx" or "END_locations.xlsx" or "AG_locations.xlsx", depending on which network it is for).

In our analysis, we kept the first row, but deleted rows for all years except 2014 – 2020. We replaced any null monthly rainfall totals with the averages of rainfall for the same month in the remaining years (in our model these are highlighted in yellow to show that the original data has been modified). We then copied the formulae in cells A11:H17 from one of the other tabs in "ESS_locations.xlsx" to those cells in the new tab "IDCJAC0001_072160_Data12". In our model, the annual rainfall totals in columns H:L in tab "ZSS" automatically update to reflect those calculations for this new weather station.

What happened when we tried this?

The new regression model shows a much better statistical correlation to fault rates for Essential than pure length. It captures most of the issues that Essential raised with us in a logical, objective, implementable way.

To expand on our motivation for employing this type of regression model, note that for very long feeders, the rainfall at the ZSS may be quite different to rainfall at other places along the feeder. For NSW, the likely pattern is that rainfall drops off the further you get from the ZSS because you are most likely getting further from the coast. If we assume rainfall drops off linearly with length, then we would expect to see fault rates following this pattern:

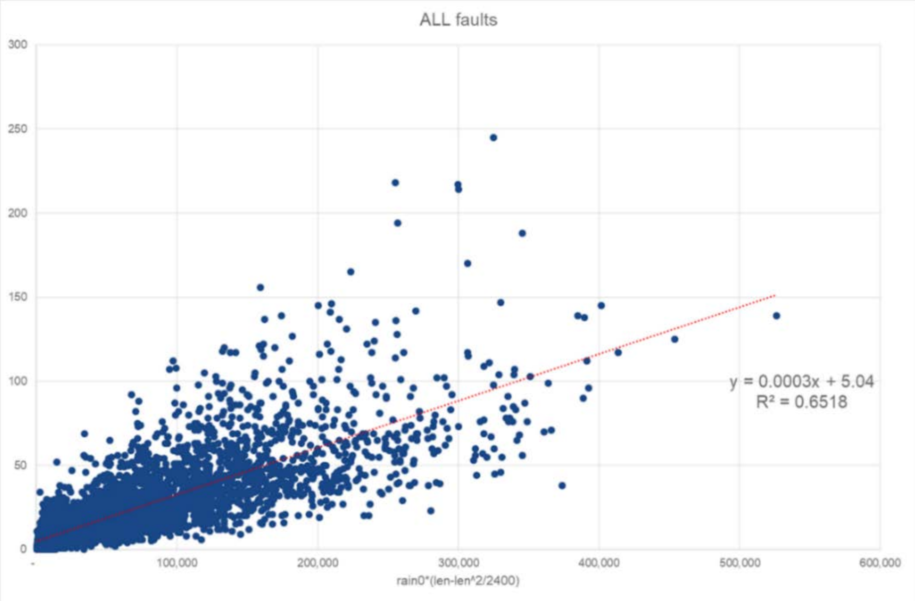
$$\text{Fault rate} = \text{constant} + A\ \text{len} \times \text{rain} - B\ \text{len} \times \text{len} \times \text{rain}$$

We estimated the best fit parameters for the above equation (in our model, tab "ALL_v_rainlen_lenrainlen"). This model had a good R squared (65%) and represents the data on all faults quite well. The dataset includes even the extremely long feeders > 500km.

The new rainfall variables give a better predictor of both total faults and HV faults than the length variable (in the model you can see this by comparing to tab 'ALLfaults_v_len'). In each case, using the rain-related variables improved the F value, R squared, standard error, and also halved the intercept value (which you would expect to be zero on theoretical grounds—a feeder of zero length has no exposure to the environment).

Figure 7 is a scatter plot of the actual fault rate against the variable rain x len (A – B x len).

Figure 7 Actual fault rate plotted against the new variable based on rainfall and length



Data source: IPART calculations

We estimated the model for HV faults using the same equation.

Results for Ausgrid and Endeavour

We replicated the above analysis for the other two networks. The results are tabulated below.

Table 14 Results of rainfall analysis for each of the three distributors

		Essential	Endeavour	Ausgrid
HV v len				
	Intercept	6.3	0	0.05
	Coef len	0.0705	0.094	0.085
	R2	32%	59%	64%
HV v rain terms				
	Intercept	1.7	0.16	0.15
	Coef len x rainfall	2.0e-4	8.9e-5	6.9e-5
	Coef len2 x rain	-8e-8	2.1e-7	2.7e-7
	R2	45%	57%	60%
ALL (HV+LV) v len				
	Intercept	11.4	1.3	2.7
	Coef len	0.084	0.18	0.20
	R2	43%	57%	51%

		Essential	Endeavour	Ausgrid
ALL v rain terms				
	Intercept	5.04	1.6	1.7
	Coef len x rainfall	2.8e-4	1.8e-4	3.2e-4
	Coef len2 x rain	-1.2e-7	3.1e-7	-2e-7
	R2	65%	54%	54%
Effect of rain terms	on HV	Better fit	Similar fit	Similar fit
	on ALL	Better fit	Similar fit	Similar fit

Source: IPART calculations

All coefficients had highly significant t-values. This means there is a very low probability that the signs are wrong. The 95% confidence interval for these coefficients is narrow, indicating that the estimates are not subject to much uncertainty.

For Essential Energy, the inclusion of rainfall terms leads to a significantly better fit to the data, both for HV faults and faults overall. The negative sign of the coefficient for the length squared x rainfall variable indicates that rainfall is lower at the far end of feeders than at the end near the ZSS. This is what you'd expect for a network that is mainly west of the Great Dividing Range.

For Ausgrid and Endeavour Energy, the inclusion of rainfall terms does not improve the fit, although it doesn't make the fit significantly worse, either. The positive sign of the coefficient for the length squared x rainfall variable indicates that rainfall is higher at the far end of feeders than at the end near the ZSS. This is also to be expected for a network that is mainly east of the range.

Given the high t-values of the rainfall-related terms, rainfall is clearly important. However, rainfall across all feeder-years was much more variable for Essential Energy than for the other two networks. Rainfall variability is tabulated below. Each feeder-year combination was one observation. As rainfall was in a narrower range for Endeavour Energy and Ausgrid, including it would not add much to the model's explanatory power, compared to Essential Energy.

Table 15 Rainfall variation across the distribution area of each distributor

Rainfall (mm) all f-y s	Essential	Endeavour	Ausgrid
Min	77	252	249
Max	2,363	2,051	1,824
Median	642	831	1,106
Mean	782	848	1,070
Std deviation	427	302	321