Network Demand Management Plan

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Authorisations

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Review cycle	3 Years	

Responsibilities

This document is the responsibility of the Network innovation Team, Tasmanian Networks Pty Ltd, ABN 24 167 357 299 (hereafter referred to as "TasNetworks").

Please contact the Network Planning Leader with any queries or suggestions.

- Implementation All TasNetworks staff and contractors.
- Compliance All group managers.

Record of revisions

Section number	Details
0.1	DRAFT circulated for comment
0.2	DRAFT circulated for approval
1.0	Initial Issue

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Executive Summary

Demand management is an increasingly viable solution for managing network issues. These demand management solutions are often significantly cheaper than traditional network expansion. Demand management is often significantly more risky than traditional solutions. This is compounded by the fact that the properties of these solutions are often unknown. This risk is managed by taking a staged approach.

A non-exhaustive list of demand management projects that are being actively progressed by TasNetworks is given in Table 1.

Table 1: Current Projects

Project	Objective	Stage
Demand management process	• Define business procedures and resources that are required for demand management network support	Trial
Distributed energy storage	• Facilitate the deployment of customer-owned batteries • Develop systems to utilise customer batteries for network support	Trial
[redacted] embedded generation trial	• Develop a system to procure embedded generation as network support service (using the [redacted] generators as a test case)	Trial
Commercial and Industrial demand management	• Manage network demand by recruiting commercial and industrial customers for aggregate load controls	Feasibility
Bruny Island peak shaving generation	• Continue deploying mobile diesel generation for shaving peak load on the constrained submarine cables	Business as Usual
Irrigation load issues	• Develop solutions including network tariff, direct load control and energy storage to manage	Concept

	the irrigation loads	
Project	**Objective**	**Stage**
Tariff trial (with smart metering)	• Evaluate using cost-reflective network tariffs for demand management support	Trial
Electric vehicles	• Facilitate the ongoing use of electric vehicles by the public • Investigate the impacts of electric vehicle home charging on network issues • Investigate public charging and TasNetworks' role	Concept

1. Scope

The demand management plan sets out an alternative framework to avoid (or defer) network augmentation for managing emerging issues on the network.

It describes how TasNetworks will manage demand during high system load conditions to avoid network investment. In particular this includes:

- Control of customer demand;
- Control of customer generation (to address demand issues); and
- Use of energy storage.

This plan also considers how funding allocated under the Demand Management Incentive Scheme (DMIS) will be spent.

2. Strategic alignment

This plan will assist TasNetworks to meet the strategic goals identified in the 2015 TasNetworks Corporate Plan. The relevant objectives are presented in Table 2.

Table 2: Strategic alignment

Strategic goals	Strategic measures	Objectives
Customers We understand our customers by making them central to all we do	Customer net promoter score	Provide customer-centric demand management solutions
	Lowest sustainable prices	Avoid network build for increasing demand
One Business We care for our assets, delivering safe and reliable network services while transforming our business	Network service performance maintained	Utilise demand management for network support
	Sustainable cost reduction	Contribute to the business excellence framework, by running the network harder through demand management capabilities

3. Regulatory considerations

3.1 National Electricity Rules (Rules)

Clause 15.1.1 (d) (3) (ii) of the Rules requires TasNetworks to have regard to future demand side developments when analysing the future operation of its distribution network.

Clause 15.1.1 (f) of the Rules requires TasNetworks to consider the potential for non-network alternatives such as demand side and generation options when undertaking annual planning reviews in conjunction with the transmission planning.

Clause 15.1.1(d) (3) of the Rules requires that where analysis of the expected future operation of the transmission network or distribution network indicates that any relevant technical limits of the transmission or distribution systems will be exceeded; then TasNetworks must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test.

It is noted that the Australian Energy Market Commission (AEMC) has concluded its Review of National Framework for Electricity Distribution Network Planning and Expansion, and has prepared a Final Report and draft Rules which specify demand management requirements including the need for a *Demand Side Engagement Strategy*.

3.2 Regulatory Test

Promotion of economic efficient investment in the electricity network through the economic assessment of both network and non-network options to address network limitations is supported by clause 15.1.1 (3) of the Rules.

Clause 15.17.1 (b) states the purpose of the *regulatory investment test for distribution* is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the *National Electricity Market*.

3.3 Electricity Supply Industry Act 1995 (ESI Act)

TasNetworks' license, issued under the ESI Act, for the transmission and distribution of electricity within Tasmania requires the business to comply with the requirements of the TEC to safeguard the interests of Tasmanian consumers with regard to price, quality and reliability of electricity supply.

3.4 Tasmanian Electricity Code (TEC)

TasNetworks as a DNSP must submit to OTTER and publish annually, under clause 8.3.2 of the TEC, an Annual Planning Report that includes a description of feasible options for meeting forecast demand including opportunities for embedded generation and demand management.

TasNetworks as an NSP has an obligation under clause 8.6 of the TEC that the tariff applicable to a customer or an individual contract with a customer connecting to the distribution network provides that the customer must comply with various conditions as set out in the TEC. Those conditions include but are not limited to such things as: access, protection of TasNetworks owned equipment, safe condition, interference to other customers, protection co-ordination, power factor, load balance and limitation of voltage fluctuation. Clause 8.8 of the TEC sets out the information to be included in tariff or individual contract conditions that the customer must supply on request for the purpose of planning the distribution system. Details include but are not limited to such things as: existing load profile, forecasts of load growth, and anticipated new loads.

3.5 AER DMIS for TasNetworks

The AER, in accordance with clause 6.6.3 of the Rules, developed and published a Demand Management and Embedded Generation Connection Incentive Scheme (DMIS) applicable to TasNetworks for the regulatory control period commencing 1 July 2017. The AER initially applied DMIS to Aurora Energy and has transferred it to Tasnetworks through the business merger.

The role of the DMIS is to provide incentives for DNSP's to implement efficient non-network alternatives, or to manage the expected demand for standard control services in some other way.

4. The problem

Peak demand generally drives network expansion. Peak demand occurs only for short periods however. This is shown in Figure 1.

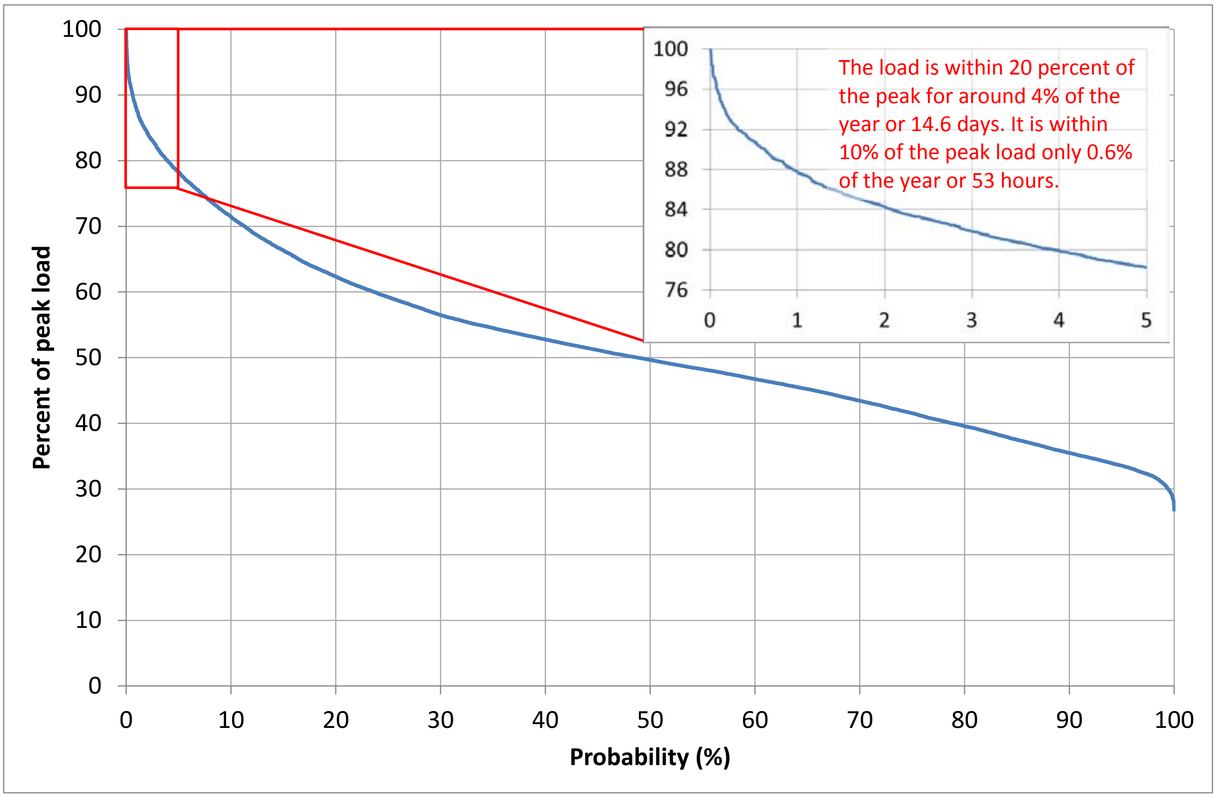

Figure 1: Load in Tasmania in 2014

Load is in the top 10th percentile of peak less than 1% of the time. The effect of the peak demand is compounded by solar generation. This has an effect of ‘hollowing’ the duration curve. This is because network-supplied energy is substituted during the traditionally low-load midday. This is shown in Figure 2.

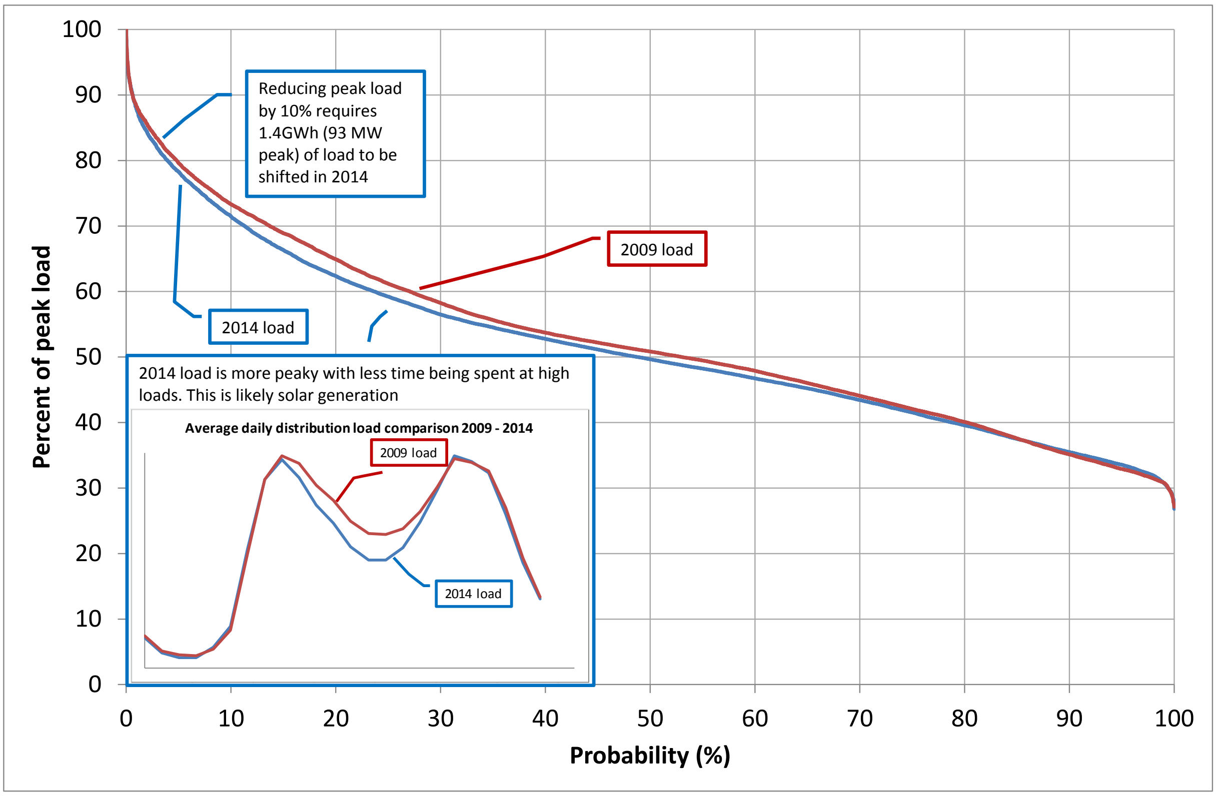

Figure 2: Change in loading patterns over recent years

The daily demand profile in Tasmania is different to other states in Australia in particularly because Tasmania is winter peaking and much of the load is industrial. The average daily demand shape is shown in Figure 3.

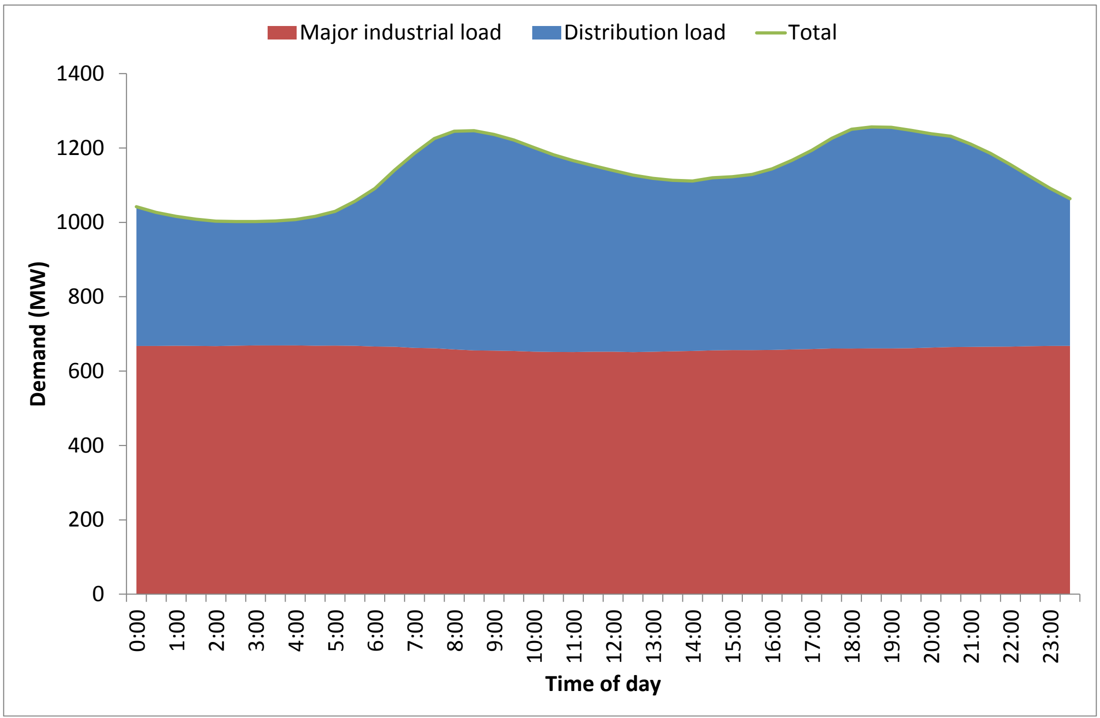

Figure 3: Average daily demand profile

The network generally has a (mostly) constant capability to supply load. Thus the 'ideal' load (from a network augmentation point of view) would be constant – i.e. no variation over a day. This allows the network to be sized exactly to meet average (as well as peak) demand. The real variation in load requires a network that is sized to meet peak, but with much of its capacity unused most of the time.

There are many uncertainties in predicting where and when peak demand will occur. Residential peaks are strongly correlated to the maximum daily temperature. That is, demand increases as temperature decreases. The correlation can be attributed to space and hot water loads.

Peak demand is also related to local developments. When a major change happens in an area (such as commissioning an irrigation scheme) the load growth in the area can be very rapid.

Electric vehicles, particularly if left uncontrolled, could change the nature of demand significantly again. If charging is uncontrolled they will add to especially the evening peak, forcing more network to be built.

4.1 What is demand management?

Demand management is in general an attempt at changing the load to more closely resemble the 'ideal' constant load. This is usually performed by:

- Either substituting the energy source of some load around the peak; or
- Shifting load from the peak to other times.

The effect of these methods on the load duration curve is shown in Figure 4.

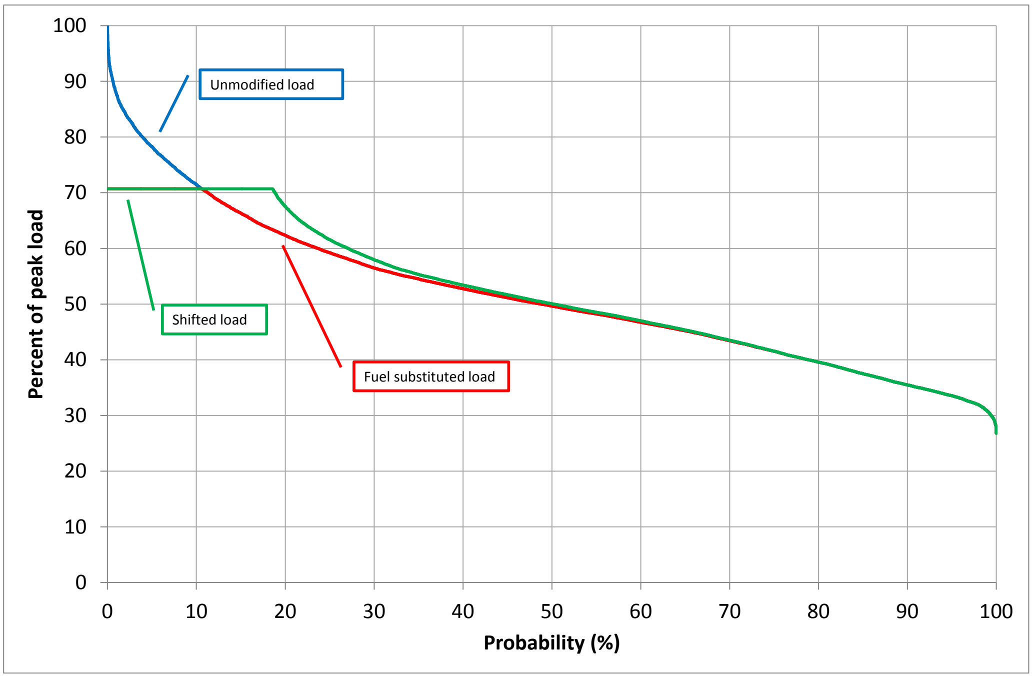

Figure 4: Effect of demand management on load

The effect of this demand management is to reduce the size of the network requirement to that required to supply the new, lower, peak.

4.2 Demand Management options

When considering demand management it is important to consider the target to be managed. Demand management can be targeted at a particular class of customer (i.e. industrial customers), and can be general or targeted at a specific area. This is shown in Table 3.

Table 3: Demand management options

	Targeted	**General**
Residential customers	• Active demand control • Network support such as home energy storage	• Tariffs • Education programs • Incentives for demand management technologies
Commercial and Industrial customers	• Network support agreement	• Tariffs
Embedded generation	• Network Support Agreement • Incentives to construct in an area	• Tariffs (Such as time of use feed in) • Operating in the NEM as a scheduled generator

Some of these network support services may be TasNetworks owned and operated (such as the fleet of mobile generation) or may be owned by a third party provider. TasNetworks is open to expressions of interest from these parties.

4.2.1 Commercial and Industrial

Industrial and commercial customers often have either backup generation or management systems that can modify demand. A recent survey[1] has indicated there is up to 40 MVA of demand that could be managed in Tasmania. The largest potential is from manufacturing load (16 MVA). Load reductions are split between the use of backup generators and the rescheduling or shutting down of processes.

The survey used an indicative cost of [redacted] of demand reduction during nominated times. Most businesses surveyed found this acceptable.

The larger commercial and industrial customers already have pricing signals to manage their demand:

- Irrigation customers (Tariff 75) have a time of use energy charge; and
- High voltage (Tariff 85) and low voltage (Tariff 82) business customers have a peak demand charge.

[1] See R0000139512

Smaller customers on Tariff 22 and Tariff 34 have no pricing signal encouraging them to reduce demand at certain times of the day. However, time-of-use demand tariffs will exist from 2017.

4.2.2 Residential

Residential hot water cylinder control is an option for demand management. Up to 30% of residential demand can be composed of hot water cylinders. Demand reductions of up to 15% are possible with simple timer control of hot water load[2]. However, a CSIRO study[3] indicated that Tasmanian customers are not currently receptive to the idea of demand side management. This can in part be attributed to the social economic situation in Tasmania.

Battery energy storage also holds promise as a form of residential demand management. This is inherently controllable. Aggregators are beginning to enter the market that can control large groups of battery storage that can appear to the network as if it is a single resource. This is being investigated with the Bruny Island distributed energy storage trial (see Section 6.1.2).

Only ‘pay as you go’ retail customers have a pricing signal to manage their demand. This is a relatively small proportion of customers. The upcoming changes as part of the ‘power of choice’ reviews may increase the number of tariffs available to customers.

4.2.3 Embedded Generation

Embedded generation does not reduce demand directly but it does supply some demand through alternative means, which appears to the network as a net demand reduction. This means it can be an effective alternative to network reinforcement.

While TasNetworks is yet to engage any demand management with customers, mobile generators are already used to manage peaks.

As well as providing for outages, generators are deployed regularly on Bruny Island. These generators aim to extend the life of the ageing 11 kV cables connecting Bruny Island to mainland Tasmania. Similarly backup generators are used at Strahan to avoid the need for a second feeder supplying the town.

There are currently no pricing signals on embedded generation to generate at particular times of the day. The nature of most embedded generators is that they are either baseload (i.e. on all the time) or intermittent (depending on fuel source availability). This means that even with pricing signals many can’t respond in a time frame that is helpful in terms of managing network issues.

There is however significant backup generation installed in Tasmania which could be used with appropriate pricing signals.

[2] See NW30473281
[3] See R0000139590

4.2.4 Aggregators

There are two business options to deploy demand management and embedded generation:

1. TasNetworks owns and/or operates the scheme and interacts directly with customers; and
2. TasNetworks engage third parties to provide the required services by dealing with the end-use customers. Such service providers are often referred to as aggregators.

Aggregators take distributed or disparate sources of network support and control them so that they appear to the network as a single source. This means that TasNetworks only needs to have an interface with one provider rather than many small ones. The function of an aggregator is shown in Figure 5

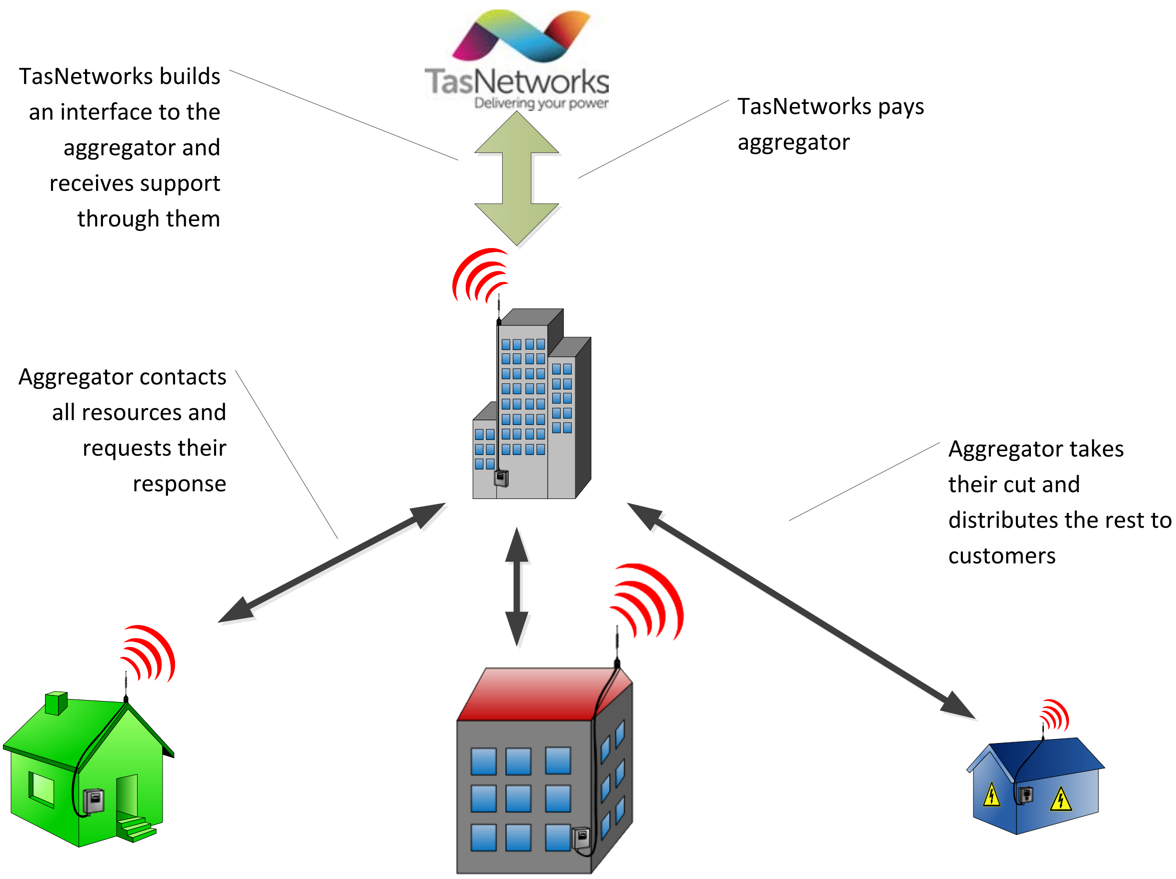

Figure 5: Aggregator function

Aggregators can provide benefit to TasNetworks when there are multiple sources of network support. This is particularly the case for residential support where many small support services must be added to generate a significant or meaningful level of support.

5. Demand Management Initiatives

When applying demand side solutions TasNetworks adopts a four stage approach. This approach lets TasNetworks explore the solutions with the minimum risk. The stages are illustrated in Figure 6. These stages are in line with the gated investment process.

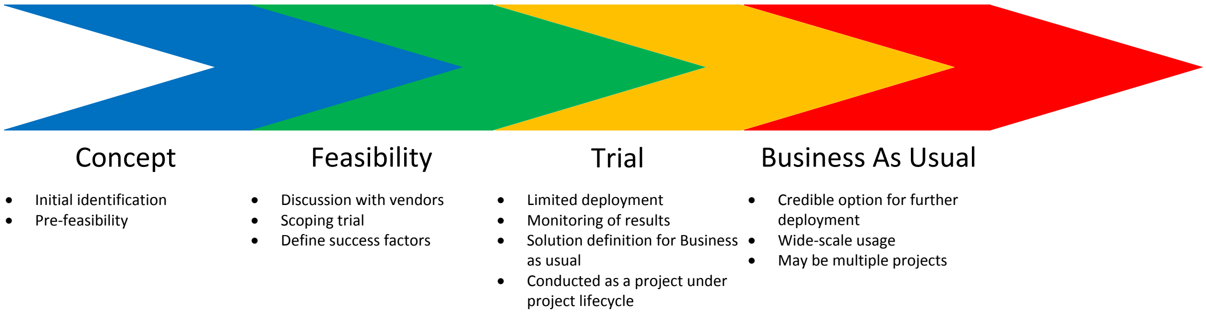

Figure 6: Stages of demand management deployment

Between each phase there is a hold point. This is where we decide whether an option displays sufficient merit to proceed to the next phase.

5.1 Project Status Summary

TasNetworks has been undertaking a wide range of demand management projects. Table 4 gives a summarised list of all past, present and future demand management projects.

Table 4: the list of demand management projects

Project	Stage	Status	Next steps/issues
Peak Performer Initiative (Residential Demand Management)	Feasibility	On Hold	• Survey results indicated uptake would be too low • Commercial and Industrial demand management shows greater promise • Implementation costs would have been high. • TasNetworks will monitor developments – particularly home energy storage • TasNetworks will also wait for Power of Choice implementation
[redacted] power system stabiliser	Feasibility	On Hold	• Tests results indicated promising results • Load in southern Tasmania is currently not sufficient to justify this project
Targeted demand management	Concept	Superseded	• Demand reductions have deferred most requirements • Other programs proposed in 6.1 supersede most of this work

Project	Stage	Status	Next steps/issues
Demand management process	Trial	In Progress	• Internal processes developed • Scoping of internal support systems in progress • Will be tested with first solution trial
Distributed energy storage	Trial	In Progress	• Application submitted to ARENA • Progress depends on outcome of application
[redacted] embedded generation trial	Trial	In Progress	• Generator controls installed • Will be progressed in coming years
Commercial and Industrial demand management	Feasibility	In Progress	• Awaiting suitable trial site • As required broader survey of smaller commercial and industrial customers
Demand Management Exchange	Concept	On Hold	• Specification to be developed during current trials
Bruny Island peak shaving generation	Business as Usual		• Generators currently deployed when high load is predicted on Bruny Island • TasNetworks has sufficient experience from this deployment to confidently use generation on other similar limitations
Irrigation load issues	Concept	In progress	• Currently under investigation
Power Factor Correction	Concept	In Progress	• Study benefits and costs of options • Determine economic costs of issues
Tariff trial	Trial	In Progress	• New metering coordinator role created • New smart meters provide additional data for a price
Electric vehicles	Concept	In Progress	• Investigations on issues introduced by electric cars • Identifying possible solutions • Trial of two TasNetworks Nissan Leaf electric vehicles

6. Current and future Programs

There are several demand management solutions that TasNetworks have deployed successfully to date. This chapter provides details on what TasNetworks is currently working on.

6.1 Demand management

There are several packages of work under the umbrella program of 'demand management'. These trials aim at using response from various groups of customers to manage network issues. There are currently four individual work packages under this umbrella:

- The first package will develop and trial internal processes for demand management;
- The second package will trial distributed energy storage as a solution to network issues;
- The third package will trial embedded backup generation in customer plant to reduce load on a feeder; and
- The fourth package will trial demand management from multiple commercial and industrial customers to reduce load on a part of the network. At least some of these customers will use means other than embedded generation.

There are also several other demand management work packages that will likely occur sometime after the first packages of work. Some of these are listed below.

- Active control of household demand such as hot water heaters;
- Targeted encouragement of fuel substitution with fuels such as gas; and
- Trail of controllable embedded generation such as natural gas fuel cells.

These trials are described in more detail below:

6.1.1 Demand management internal processes

Stage	Trial
Status	In progress
Next steps / issues	• Internal processes developed • Scoping of internal support systems in progress • Will be tested with first solution trial
DMIA Funding	Yes

This project will define business procedures and resources that are required for supporting demand management.

Generally operating network support is significantly more complex than operating the network. Demand response must generally be scheduled some time in advance of it being required and sometimes it may not be available.

This means that there is additional business processes required to operate it. In particular:

- Customer engagement is required to determine if it is an economic solution;
- Providers generally require notice their services will be needed; and
- Providers must be paid based on their actual use.

All of these steps require internal resources and a process to manage. This work develops these processes and internal support systems required to use network support.

There are five internal processes the have been developed. They are listed in Table 5.

Table 5: Demand management processes

Process	Link
Engagement	https://au.promapp.com/auroraenergy/Process/Minimode/Permalink/fzxoHv1Hf6P29bCQ3B3YP
Operation	https://au.promapp.com/auroraenergy/Process/Minimode/Permalink/r9Ille739N2QXlTDkJzR4
Validation	https://au.promapp.com/auroraenergy/Process/Minimode/Permalink/C8tuPokVWd1mQYCfy6NXKO
Review	https://au.promapp.com/auroraenergy/Process/Minimode/Permalink/E5GelS90ErKPia6EAoIhUN
Dispute	https://au.promapp.com/auroraenergy/Process/Minimode/Permalink/GuuZOOjxJoOB9KpTx9C2pw

A key outcome of this work is to define what the internal cost of managing network support is. This cost will be used when determining if network support is economic.

There will likely be additional tools required to manage this process. In particular tools will be required to:

- Record interactions with customers about network support;
- Record payments and analysis of support events; and
- Record outcomes of analysis for network support requirements.

For the trial these tools may be simple, or may be an expansion of existing tools.

The budget for the trial is in Table 6. Post-trial the operation costs are accounted on the solutions which use them.

Table 6: Budget for demand management process

Item	Description	Cost
Overhead costs Network support operation	Cost of operating network support • 2 hours per week (0.05 FTE)	[redacted]
Overhead costs – Billing and customer account management	Cost of paying providers and managing the contract • One day per month (0.03 FTE)	[redacted]
Operational systems	Operational systems that support use of network support such as: • Recording interactions with customers • Operation screens showing status of network support scheme • Tools for operations planning to assess future network support requirements Resourcing assumptions: • 4 weeks of work	[redacted]
Training	Training for all stakeholders in using new systems • One day of training for 7 people • 3 days for one trainer	[redacted]
Subtotal		[redacted]
30% Contingency		[redacted]
Total		[redacted]

The breakdown over the three years of the trial is given in Table 7.

Table 7: Distribution of costs

Item	15/16	17/18	18/19
Overhead costs Network support operation	[redacted]	[redacted]	[redacted]
Overhead costs – Billing and customer account management	[redacted]	[redacted]	[redacted]
Operational systems	[redacted]	[redacted]	[redacted]
Training	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

The trial budget will be covered by DMIS funding. It meets the DMIA criteria, because it refers to a cost of embarking demand management as an alternative to network augmentation.

After the trial is complete there will need to be some allowance for future system improvement and training. At this stage it is difficult to determine. Post-trial the overhead costs are no longer funded separately to the projects using network support. The operational systems and training however need to be budgeted separately.

For the purposes of this work it is assumed training and operational systems must be replaced every 5 years. This results in an annualised cost of these items of [redacted].

6.1.2 Distributed energy storage

Stage	Trial
Status	In progress
Next steps / issues	• Application submitted to ARENA • Progress depends on outcome of application
DMIA Funding	Yes

This project aims to support the deployment of customer-owned batteries and develop systems to utilise such batteries for demand management support.

Energy storage can resolve many network issues. It allows system peaks to be removed without effecting customer load.

Centralised energy storage owned by TasNetworks doesn't capture the full benefits of energy storage. TasNetworks can only consider the network expansion benefits. An energy storage system installed in a customers' house has many more benefits such as:

- Storing excess solar energy for use later;
- Avoiding blackouts;
- Ancillary services such as frequency control; and
- Providing a hedge to the retailer.

This is coupled with home energy storage being significantly cheaper per kwh than grid connected storage. A comparison based on recent experience is shown in Table 8.

Table 8: Energy storage costs

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

In other terms, if TasNetworks were to directly fund home energy storage systems (i.e. install them in homes for free) we could install [redacted] of storage for the same cost as [redacted] of grid-connected storage.

In reality (beyond a trial) TasNetworks would not pay the upfront cost of a home energy storage system. Customers would install these systems and TasNetworks would pay to use them as required.

There are two stages for this project:

- In the trial phase TasNetworks will pay for the batteries at a few sites, plus an operation cost; and
- In the business as usual stage TasNetworks will either not pay at all or only a small contribution to batteries, but will still pay an operation cost.

The trial is expected to occur in this revenue period.

Bruny Island Trial

The Bruny Island distributed energy storage trial is indented to deploy up to 200 kW of energy storage to reduce the time which the diesel must be deployed to the island. This trial, pending success of the application, will be partly funded by an Australian Renewable Energy Agency (ARENA) grant. [redacted]

[4] See R0000037942

[5] [redacted]

The spread of type and size of battery is to be determined at this stage, but the current proposed costs are shown in Table 9.

Table 9: Energy storage system cost

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Business as usual

Appendix B provides some analysis on the expected uptake levels for distributed energy storage. After the trial there is expected to be another 3 years where TasNetworks trials using energy storage added to the network due to natural uptake. The expected costs for this are shown in Table 13.

Table 13: Operation cost projections for distributed energy storage

Year	2018	2019	2020
Total batteries installed	3,571	6,046	12,410
Batteries that are used	150	254	521
Total used battery size	960	1,626	3,334
[redacted]	[redacted]	[redacted]	[redacted]

6.1.3 [redacted] embedded generation trial

Stage	Trial
Status	In progress
Next steps / issues	• Generator controls installed • Will be progressed in coming years
DMIA Funding	Yes

TasNetworks is trialling embedded generation as a source of network support with [redacted], [redacted] have recently commissioned a major upgrade to their [redacted] This increases their peak load significantly. [redacted] have also installed backup generation. This generation is intended to automatically start if the farm loses supply.

The [redacted] generation, as backup generation, has no grid connect capability with the standard controller. TasNetworks has paid the incremental cost of controllers with grid connect capability. Additionally TasNetworks will procure network support from the [redacted] generation on a trial basis. This support is not required on economic grounds. Its main purpose is to experience running a generator for network support.

Palmerston feeder 3 (the feeder to which the [redacted] generator is connected) has a capacity of around 13 MVA before it will experience issues. This is forecast to occur around 2025. This trail intends on artificially bringing that requirement forward some time so that network support may be tested as a solution to network issues. This will be done by assuming a feeder loading limit of 11 MVA. The Palmerston feeder 3 load forecast is shown in Figure 7.

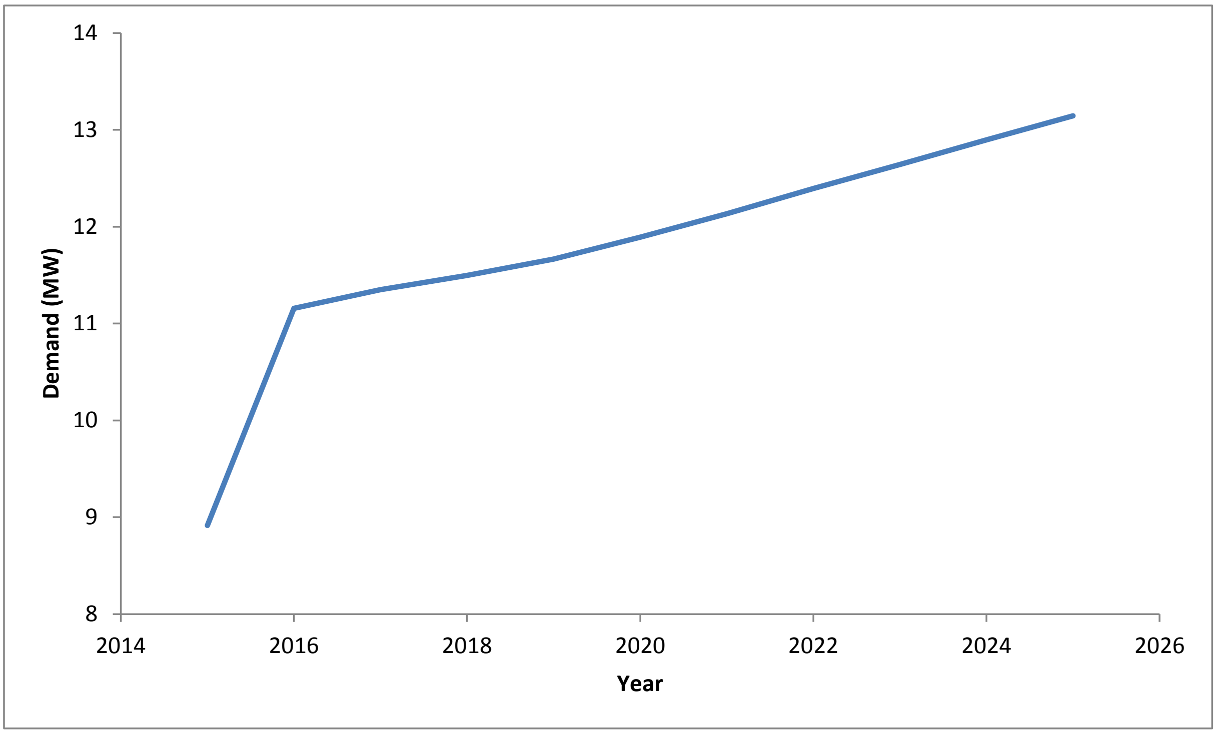


Figure 7: Palmerston 3 load forecast

The trial is expected to run form Summer 2016/17 to Summer 2018/19. Assuming that the generator will cost [redacted] to run the expected operational costs are shown in Table 14.

Table 14: Expected network support costs

Year	Load (MVA)	Injected energy (MWh)	Max injected power (MW)	Total cost	Number of days support is required	Longest event (hrs)
2016/17	11.3	1.8	0.4	[redacted]	2	3
2017/18	11.5	3.4	0.8	[redacted]	2	3
2018/19	11.7	4.8	0.8	[redacted]	4	4
			Total Cost	[redacted]		

The response of the generator on a typical event is shown in Figure 8. The generator output is limited so that only entire [redacted] W units are scheduled. It is unlikely to be practical to request the generator follow an exact load pattern. The two generators installed at the [redacted] site are sufficient to manage the loading issue for all three years of the network support agreement.

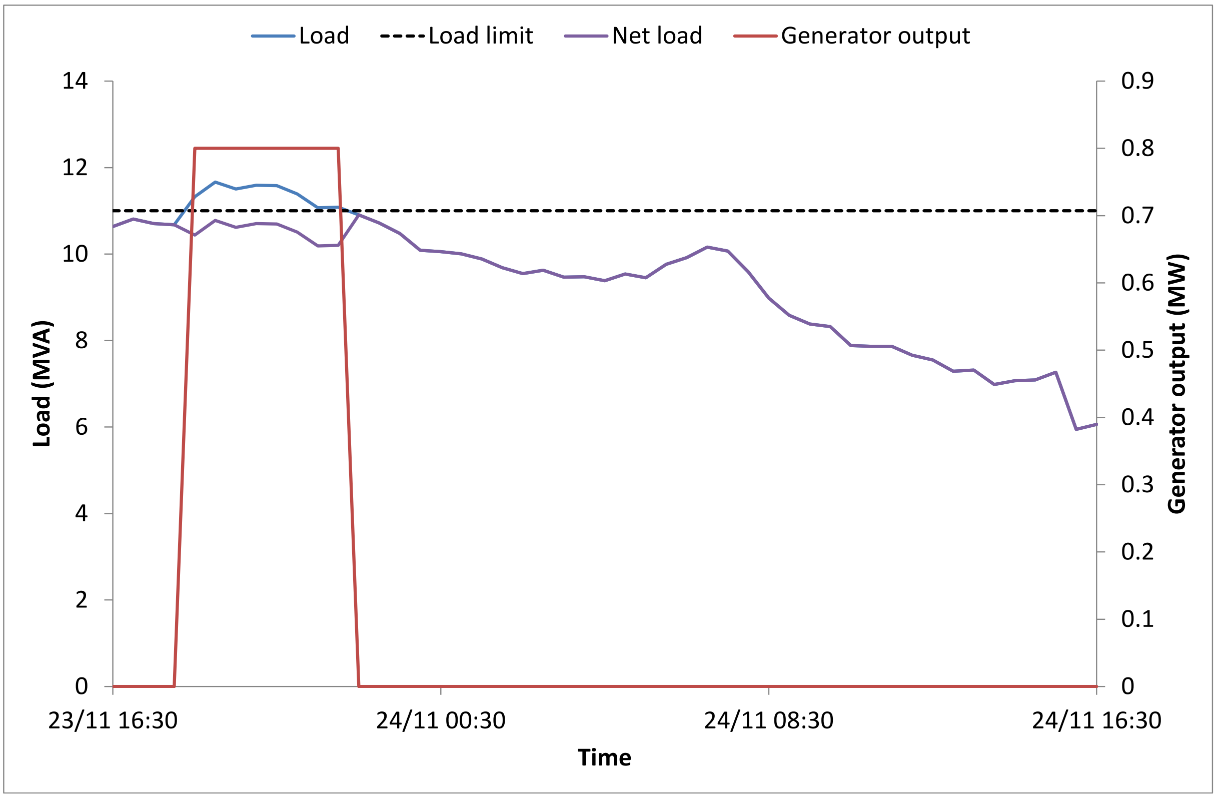


Figure 8: Predicted generator output

Internal costs need to be added to the cost of the network support itself. These costs are expected to be:

- [redacted] setup cost in the first year; and
- in subsequent years.

The total cost is shown in Table 15.

Table 15: Operation cost projections for the Petuna project

Year	2016	2017	2018
Network support costs	[redacted]	[redacted]	[redacted]
Management costs	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

6.1.4 Commercial and Industrial demand management

Stage	Feasibility
Status	In progress
Next steps / issues	• Awaiting suitable trial site • As required broader survey of smaller commercial and industrial customers
DMIA Funding	Yes

This project aims to trial demand management provided by commercial and industrial customers for network support.

Approximately 42 commercial and industrial (distribution connected) customers contribute nearly 150 MVA to Tasmanian peak load. These customers have the potential to significantly relieve congestion if their demand can be controlled.

In 2013 and 2014 Aurora energy conducted a survey these commercial and industrial organisations to determine:

- If they are willing to participate in demand management; and
- How much they can contribute.

The survey concluded that there is approximately 38 MVA of demand that could be shifted within this group. This capacity is scattered throughout Tasmania.

Beyond the [redacted] and distributed energy storage trial a further trial of network support is proposed. This trial will be aimed at testing:

- The demand side management engagement process;
- Aggregating multiple disparate sources of network support.

At this stage where this trial will be and which customers are involved is not known. At this stage Burnie or Devonport substations are likely first targets as they are nearing their capacity according to data analysis.

For this analysis the trial is assumed to occur at Burnie substation. There is 4.22 MVA of load reduction capacity at Burnie substation.

The peak load at Burnie substation in 2015 winter was 61.9 MVA. It is supplied through two 60 MVA transformers with an emergency rating of 72 MVA. The load is predicted to exceed that in 2026.

For the purposes of the trial demand at Burnie substation will be managed to 63 MVA. This is lower than the actual transformer rating. Similar to the [redacted] generation trial the primary purpose is to learn about demand management. This trial, in particular, will use multiple sources of demand management. This will provide experience in managing multiple disparate sources of demand management.

The predicted costs for this trial are shown in Table 16.

Table 16: Expected network support costs

Year	Load (MVA)	Injected energy (MWh)	Max injected power (MW)	Total cost	Number of days support is required	Longest event (hrs)
2018	63.8	0.4	0.8	[redacted]	1	1
2019	64.8	4.8	2.0	[redacted]	4	2
2020	66.0	13.0	3.2	[redacted]	9	2
			Total Cost	[redacted]		

The response of the demand management to a typical event is shown in Figure 9.

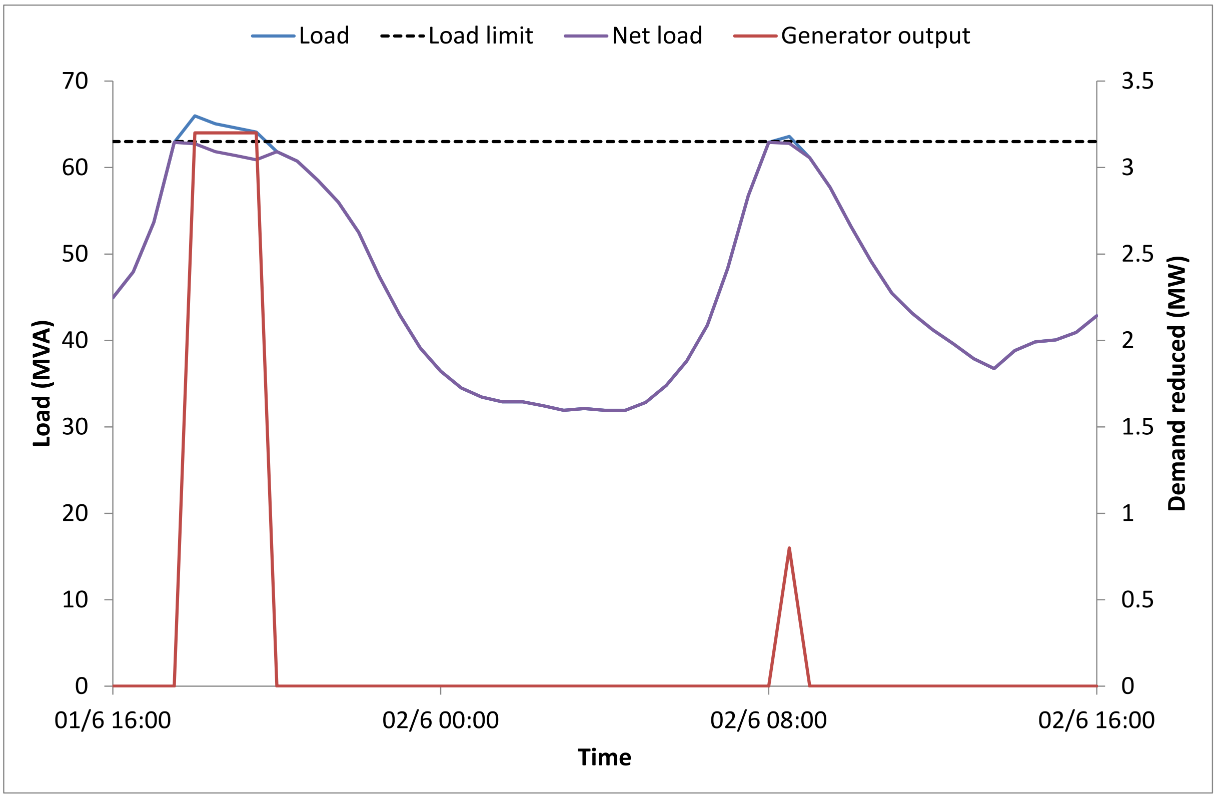


Figure 9: Response of demand management

This project also includes an allowance of [redacted] in the first year for the upfront works including marketing and recruiting customers, developing a dedicated system for load signalling and control, etc. The final distribution of costs is shown in Table 17.

Table 17: Operation cost projections for distributed energy storage

Year	2018	2019	2020
Network support costs	[redacted]	[redacted]	[redacted]
Management costs	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

6.1.5 Demand management exchange

Stage	Concept
Status	On hold
Next steps / issues	• Specification to be developed during current trials
DMIS Funding	N/A

The demand management exchange is a location for TasNetworks to source demand management serviced from external providers as they are required. It is intended to streamline the engagement process for smaller projects. In particular this targets projects which are too small to require the Regulatory Investment Test (RIT).

This concept will be developed further in the next revenue period. The proposed budget is shown in Table 18.

Table 18: Demand management exchange proposed budget

Expenditure profile	17/18	18/19
Setup costs	[redacted]	[redacted]
Network support payments	[redacted]	[redacted]

6.2 LED streetlight trial

Stage	Trial
Status	In Progress
Next steps / issues	• 4700 LED street lights installed • Current results promising
DMIA Funding	No

From January to May 2015 TasNetworks replaced approximately 4,700 80 W mercury vapour (MV) minor streetlights (approximately 15% of all lights of this type) with new energy efficient 18 W LED streetlights. Approximately a further 500 are due for replacement by the end of September 2015.

This was a major project, funded by the Federal Government in conjunction with Hobart/Glenorchy City Councils and TasNetworks. The main driver being the reduction of council's street lighting bills and replacing of old inefficient equipment. The system load of an 80 W streetlight is 95.8 W (AEMO Load Table), compared to an 18 W LED streetlight, the system load is 21.9 W (AEMO Load Table). This is a reduction of 73.9 W per light of load to the network. TasNetworks are in the process of rolling out the 18 W LED streetlight as our Business as Usual streetlight for minor roads (new installations and replacements of existing

80 W MV fittings). This is due by November/December 2015. In terms of major light LED installations and replacements (of 150 W, 250 W and 400 W fittings), this is still a 'work in progress' and is on the radar for further development and testing of the market to see what is available and how they will be incorporated into TasNetworks' network.

The LED trial is being managed under the metering program within TasNetworks.

6.3 Bruny Island diesel generation

Stage	Business as Usual
Status	Active
Next steps / issues	• Generators currently deployed when high load is predicted on Bruny Island • TasNetworks has sufficient experience from this deployment to confidently use generation on other similar limitations
DMIA Funding	No

Bruny Island is supplied by two 11 kV submarine cables. These cables were installed in 1949 and 1959. Both exceed their design lives. They are rated at 1.54 MVA and 1.86 MVA continuous and emergency respectively. Replacing one of these cables will cost approximately $2.5m.

There are also significant imbalance issues on Bruny Island. This reduces the actual transfer capacity to the island to about 1.2 MVA (that is well below the cable ratings in order to maximise the life of the cables)

Currently a mobile diesel generator is used to shave the peak load. This generator is deployed when the load is expected to exceed 1.2 MVA. This is usually Easter and Christmas holidays, although with load growth this number is expected to increase.

The ongoing running costs of this generator must be less than that of the annualised cost of a new cable to keep deploying the generator.

A new cable is expected to cost approximately $2.5m. With a WACC of 8% and a 60 year cable life the annualised cost is approximately $200k pa.

The ongoing cost of running the generator is made of several parts:

- Load on Bruny Island grows at approximately 1.1% pa consistent with 2014 load forecast. The forecast was corrected by the nominal temperature in place of the actual ones (being different for different years);
- Fuel cost (incl delivery approximately 40c more than pump price. Approx. $2/pl in 2014 increasing ~3c pl each year);
- Cost to transport generator to and from site ($2.5k each way);
- Share of the annualised cost of the generator (allocated pro rata with time spent on the island);
- Maintenance cost ($1.5k for each service, 2 per year, allocated pro rata); and
- Operator cost (on-call allowance plus cost to respond to calls, assigned $10 per hour generator is on island).

Figure 10 shows an estimate of the total cost (opex and annualised capex) of keeping the generator on the island for peak shaving.

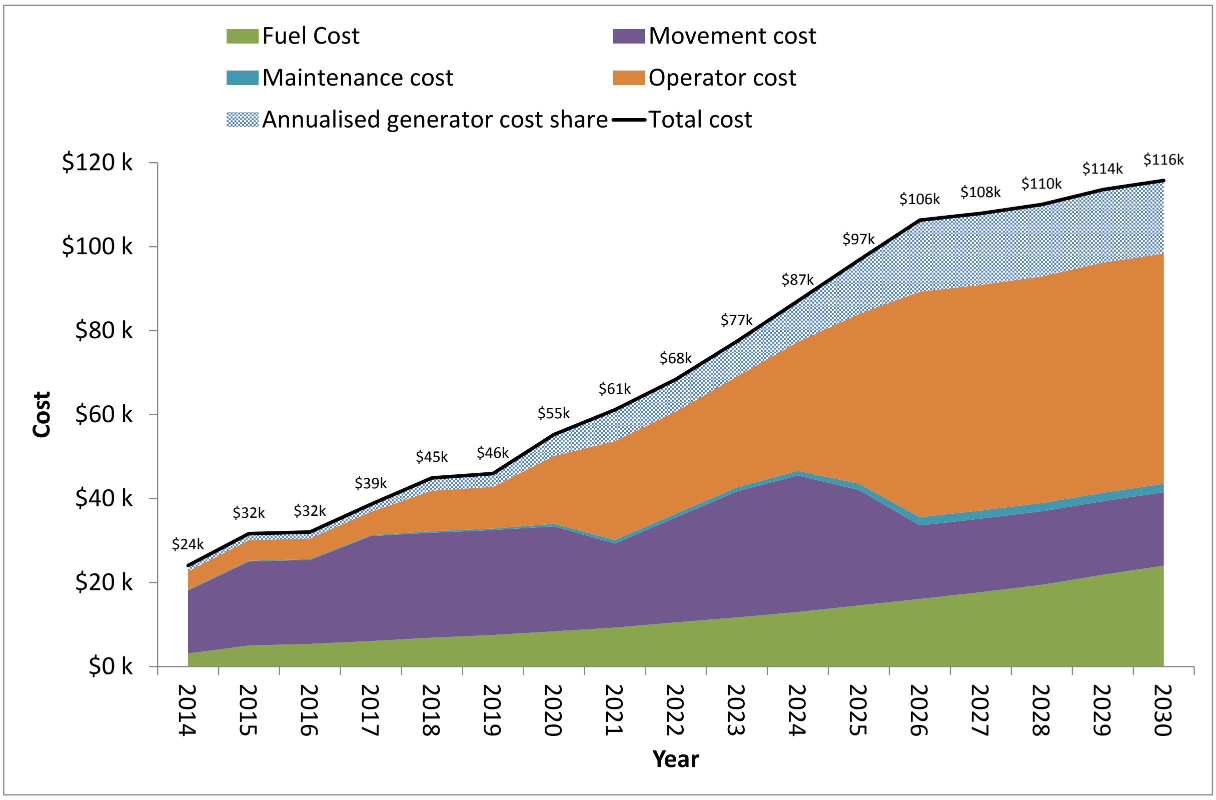


Figure 10: Expected operating and maintenance costs for Bruny Island generation

All of these operating costs are lower than the annualised cost of a new cable therefore the generator is the preferred option.

As the load on Bruny Island grows the amount of time the generator spends on the island grows. The approximate deployment schedule for the generator is shown in Figure 11. Note this schedule is automatically generated. It is just intended to provide an indication of the amount of time the generator is required to be on the island.

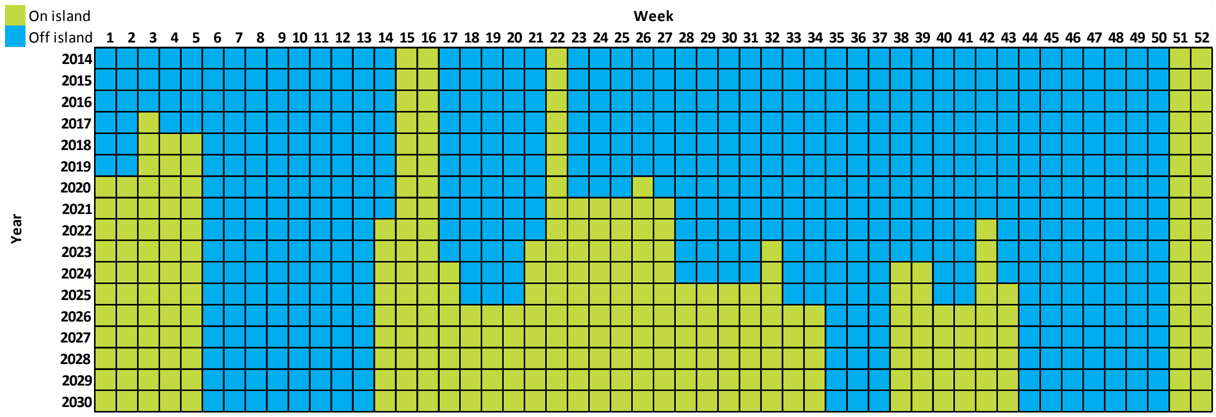


Figure 11: approximate generator deployment schedule for generator on island ('on island') and generator off island ('off island')

While the total cost increases over time the components that make up the cost vary considerably. The movement cost is the largest single cost initially. The generator is required to be on the island three times, and each round trip costs approximately $5k. As the amount of time the generator spends on the island increases the movement costs decline but the costs of providing an operator and fuel costs increase.

The operational expenditure required to run the generator does not include the depreciation share as that is part of the Regulated Asset Base (RAB). The estimated OPEX for the period to 2030 is shown in Table 19.

Table 19: Operational cost forecast

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Fuel Cost	$5k	$5k	$6k	$7k	$8k	$8k	$9k	$11k	$12k	$13k	$15k	$16k	$18k	$19k	$22k	$24k
Movement Cost	$20k	$20k	$25k	$25k	$25k	$25k	$20k	$25k	$30k	$33k	$28k	$18k	$18k	$18k	$18k	$18k
Maintenance cost	$0k	$0k	$0k	$0k	$0k	$1k	$1k	$1k	$1k	$1k	$1k	$2k	$2k	$2k	$2k	$2k
Operator cost	$5k	$5k	$6k	$10k	$10k	$16k	$24k	$24k	$26k	$31k	$40k	$54k	$54k	$54k	$55k	$55k
Total	**$30k**	**$30k**	**$37k**	**$42k**	**$43k**	**$50k**	**$54k**	**$61k**	**$69k**	**$77k**	**$84k**	**$89k**	**$91k**	**$93k**	**$96k**	**$98k**

TasNetworks intends to continue the generator deployment as required. Distributed energy storage (see 6.1.2) may change the dispatch of the generator somewhat. It is unlikely that enough storage will be deployed on the island to remove the need to deploy the generator in the next few years. The cost estimates here have made no allowance for storage, but if the energy storage trial is successful the cost is expected to drop.

6.4 Irrigation load issues

Stage	Concept
Status	In progress
Next steps / issues	• Currently under investigation
DMIA Funding	Yes

Irrigation load is a significant portion of the load connected to some feeders. Avoca feeder '4' is a prime example of this. The energy consumed by the various demand sectors for this feeder is shown in Figure 12.

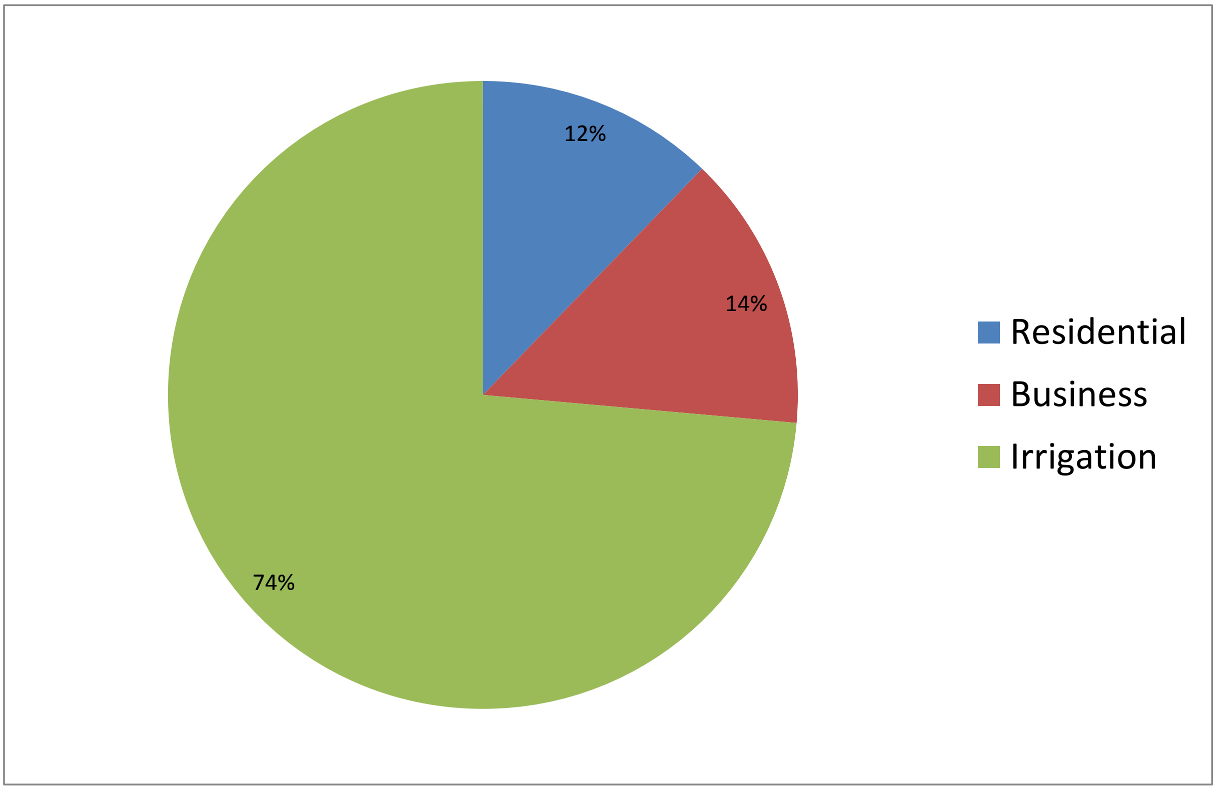


Figure 12: Avoca feeder 4 load types

Irrigation load is on a 'time of use' tariff. This tariff makes energy cheaper at certain times of the day. The current irrigation time of use tariffs and Avoca feeder 4 load are shown in Figure 13.

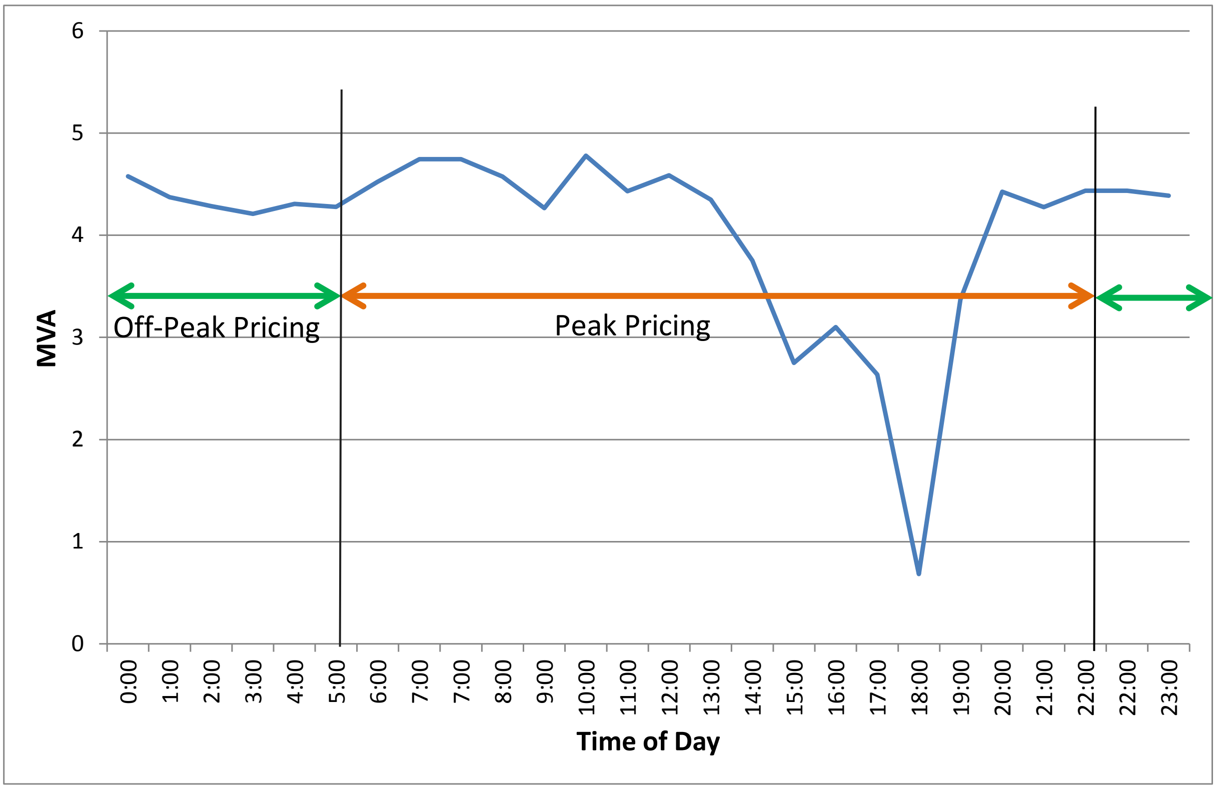


Figure 13: Time of use pricing for Irrigation and Avoca feeder 4 load

These tariffs encourage irrigation to run at night. Irrigation is a less time critical load in that all demand may be shifted to the off-peak window. This means that the peak on feeders with large amounts of irrigation such as Avoca 4 occurs during the off-peak period.

There are a number of possible solutions to this issue. Some of them are:

- Modify the tariff to encourage irrigators to come on at different times;
- Active control of irrigation pump staring;
- Other demand shifting technologies such as energy storage.

This issue is currently under investigation.

6.5 Power factor correction

Stage	Concept
Status	On hold
Next steps / issues	• Study benefits and costs of options • Determine economic costs of issues

The Tasmanian electricity code limits the power factor of customer installations to the levels shown in Table 20.

Table 20: Power factor requirements in the TEC[6]

Supply voltage (kV)	Power factor range for customer maximum demand and voltage					
	Up to 100 kVA		Over 100 kVA - 2 MVA		Over 2 MVA	
	Minimum lagging	Minimum leading	Minimum lagging	Minimum leading	Minimum lagging	Minimum leading
< 6.6	0.75	0.8	0.8	0.8	0.85	0.85
6.6 11 22	0.8	0.8	0.85	0.85	0.9	0.9
33 44 66	0.85	0.85	0.9	0.9	0.95	0.98

Low voltage customers less than 100 kVA make up the majority of TasNetworks customers. The low power factor presented by these customers causes voltage issues at the end of feeders.

There are several options to mitigate this:

- Provide a price signal for customers to increase their power factor;
- Modify the rules so that customers must present a higher power factor;
- Provide an incentive for customers to manage their power factor; or
- Add network elements to improve power factor (such as pole top capacitors).

Each one of these options has its own advantages and disadvantages. This work is currently in progress.

This project will be progressed slowly. Some allowance is included to allow TasNetworks to determine the scope of the issue and solutions.

Table 21: Power factor correction cost allowance

Expenditure profile	20/21	21/22	22/23
Consultancy budget	[redacted]		
Solution trial		[redacted]	[redacted]

[6] See http://www.energyregulator.tas.gov.au/domino/otter.nsf/elect-v/003

6.6 Tariff trial

Stage	Trial
Status	Active
Next steps / issues	• New metering coordinator role created • New smart meters provide additional data for a price

Currently TasNetworks maintains a fleet of accumulation meters. This function will in the future be provided by an external metering coordinator instead.

The standard accumulation data will be provided to TasNetworks as previously. The smart meters will be able to provide additional data. The data available will depend on the meter that is installed by the metering coordinator.

The Standing Council on Energy and Resources (SCER) has set out the standards that these meters can provide. They are listed below:

- De-energisation (turn electricity supply off remotely)
- Re-energisation (turn electricity supply on remotely)
- Meter read – on demand (obtained remotely as required by a retailer, customer or another authorised party)
- Meter read – scheduled (obtained remotely as per contracted dates and times)
- Meter installation enquiry (remotely obtaining energy information, meter status, and usage data)
- Meter Reconfiguration – (to remotely enable access to new tariffs and new arrangements, such as solar connections and energy demand tariffs)

Other advanced services may be available from particular metering coordinators depending on what meters are installed. The standard EDMI MK7a meters that TasNetworks installs currently on houses with solar generation can measure:

- Reactive power;
- Voltage;
- Current;
- Harmonics; and
- Some disturbance recording.

TasNetworks is currently investigating its role in metering in the future. It is possible that TasNetworks will become a metering coordinator, or partner with an existing metering coordinator to provide metering services. Similarly it may be most economic not to enter that market.

Whether TasNetworks is a metering coordinator or not the data will enhance our visibility of the network. In particular TasNetworks would expect to get the most value out of:

- Voltage performance of the LV network to improve tap settings and phasing on the LV network;
- Voltage and load relationship of customer load to improve models of performance to faults;
- Notification of outages as soon as they occur so power can be restored sooner; and
- Improve the accuracy of state estimation.

TasNetworks will need to analyse the relative benefits of each service to determine which are economic.

TasNetworks is undertaking a trial of tariffs and smart metering in 2015/16 and 2016/17. The expected cost of this trial is shown in Table 22.

Table 22: Tariff and smart metering trial cost allowance

Expenditure profile	15/16	16/17
Trial costs	[redacted]	[redacted]

6.7 Electric vehicles

Stage	Trial
Status	Active
Next steps / issues	• Investigations on issues introduced by electric cars • Identifying possible solutions • Trial of two TasNetworks Nissan Leaf electric vehicles
DMIA Funding	Yes (for the operating cost to run the trial)

The number of electric vehicles in Tasmania is predicted to grow. As much as 20% of the total fleet of electric vehicles could be electric by 2030[7]. This would be around 80,000 vehicles.

These electric vehicles are likely to increase demand in the network. While there is expected to be only a minor impact on the High Voltage (HV) network[7] the Low Voltage (LV) network could be strongly affected. This is particularly true where there is phase imbalance.

The key issue in the LV network occurs when too many vehicles attempt to charge at once. A very high penetration of electric cars can be sustained if their co-incidence is low. This is compounded by solar PV and phase imbalance.

[7] See R0000109563

TasNetworks have several packages of work in progress on electric vehicles:

- A trial in progress currently of two fully electric Nissan Leaf and two plug in hybrid Mitsubishi Outlander vehicles;
- An investigation of the impacts of electric vehicle home charging on network issues; and
- An investigation of public charging and TasNetworks role.

Electric Vehicle Trial

The electric vehicle trial involves the use of two fully electric Nissan Leaf and two plug in hybrid Mitsubishi Outlander vehicles.

The aim of this trial is to learn:

- If the operation and maintenance costs of the electric or hybrid vehicles is lower than their standard equivalents;
- How drivers use these vehicles and what factors into their acceptance;
- How these cars are charged;
- The capabilities of these vehicles to provide demand response; and
- The ability to use a high profile trial to influence customer perceptions of electric vehicles.

This trial is expected to run for 5 years and has the expenditure profile shown in Table 23.

Table 23: Electric vehicle trial costs

Year	2015	2016	2017	2018	2019
Electric Vehicle trial	$146,667				
Electric vehicle trial OPEX	$6,306	$6,306	$6,306	$6,306	$6,306

Home impacts of charging

Electric vehicles chargers are often large single phase loads. These loads can cause issues on the network when they all operate at once.

Recent studies have indicated that electric vehicle chargers when coupled with solar can cause issues in the network.

This plan includes an allowance to trial innovative solutions to the issues introduced by the larger home chargers, this is shown in Table 24.

Table 24: Electric vehicle charging management trial

Expenditure profile	16/17	17/18	18/19
Trial costs	[redacted]	[redacted]	[redacted]

This budget is to be covered by DMIS funding as it meets the DMIA criteria.

6.8 Education involvement

Education is important to enable the future generation of electricity customers to manage their own usage. This project is less an investment in managing demand today, more an investment in future demand management capability.

This work involves distributing learning materials to schools in Tasmania. These learning materials will include practical exercises that will raise understanding of energy conservation and peak demand.

7. Past work

TasNetworks has completed significant work to date. Much of the completed work has been in the concept or feasibility stages.

7.1 Peak Performer initiative / Hot Water control

Stage	Feasibility
Status	On Hold
Next steps / issues	• Survey results indicated uptake would be too low • Commercial and Industrial demand management shows greater promise • TasNetworks will monitor developments – particularly home energy storage and metering contestability
DMIA Funding?	Yes

The Peak Performer initiative aimed to use domestic hot water load control to reduce system peak size.

Residential load is one of the primary drivers of system peak load. Up to 30% of residential load is hot water heaters. In 2013 Aurora performed two work packages. The first one was to estimate the potential for hot water cylinder load reduction. The second was to survey customers to indicate how willing they are to have their hot water cylinders controlled voluntarily.

The first study indicated that up to 15% of load may be reduced controlling hot water cylinders. This reduction may be implemented using simple timer switches as well. This all would occur with only a slightly increased chance of running out of hot water (‘cold shower probability’). This must be tempered with the fact that all cold showers after this system is installed are likely to be blamed on the new system.

The second study indicated the uptake among customers may be as low as 13%. Customers were not receptive for TasNetworks to control their hot water cylinders. This was coupled with the ‘power of choice’ review which changes the responsibility of TasNetworks significantly.

With this in mind TasNetworks have decided to suspend the further investigation of this scheme until customers are more receptive.

Home energy storage may change the landscape significantly. It offers the promise of network support with no inconvenience for the customer.

While not doing any work at the moment TasNetworks intends on watching for opportunities as they arise.

The distributed energy storage trial (see Section 6.1.2) achieves a similar outcome using different means.

7.2 [redacted] power system stabiliser

Stage	Feasibility
Status	On Hold
Next steps / issues	• Tests results indicated promising results • Load in southern Tasmania is currently not sufficient to justify this project
DMIA Funding	No

Power system stabiliser is a technology used to provides supplementary excitation control used to damp generator mechanical oscillations in order to maintain the grid stability.

Transend had identified that there is a risk of instability in Tasmania if there is a double circuit fault between Palmerston and Waddamana substations. An $18m upgrade to an existing line would have rectified this issue.

[redacted] load is almost entirely the [redacted] that generate the [redacted] The [redacted] is generated using [redacted]. These [redacted] can respond quickly to a power target.

Transend investigated using this controllable load as a power system stabiliser (PSS)[8]. This would have quickly changed load to damp power swings. This would have allowed the deferral of the $18M project. A plot of the expected response of the power system stabiliser is shown in Figure 14.

[8] See D14/23038 [redacted] non-network option specification and summary'

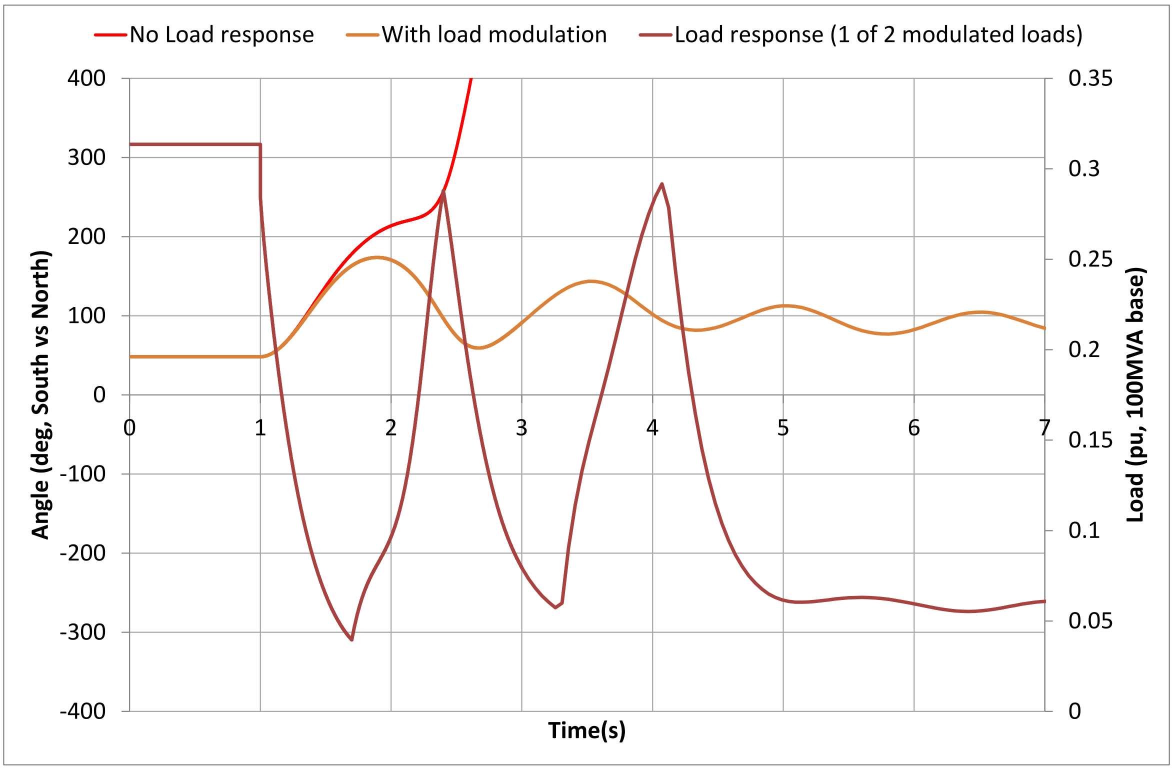


Figure 14: [redacted] PSS response

TasNetworks has not pursued this option further because southern Tasmanian load has not grown sufficiently to require it. TasNetworks intends on further testing this option when southern Tasmanian load gets closer to the point where it is required.

7.3 Time of Use tariffs (Energy)

Stage	Business as usual
Status	Complete
Next steps / issues	• Time of use network tariffs are available for retailer use • Retailer has not made energy tariffs available to customers • Will be superseded by new ‘cost reflective’ tariffs

Time of use tariffs provide a way of signalling to a customer when is the best time for them to consume energy. In this tariff energy costs more at certain times of the day.

Residential time-of-use network tariffs are available to retailers currently.

The recent ‘power of choice’ review requires TasNetworks to develop ‘cost reflective’ tariffs based on the long run marginal cost of the network. These new tariffs will supersede the time of use tariffs with demand tariffs.

7.4 Targeted demand management

Stage	Concept
Status	Various/Superseded
Next steps / issues	• Forecasted demand declined have deferred most requirements • Other programs proposed in Section 6.1 supersede most of this work

Targeted demand management refers to those programs that are designed to manage demand in localised network areas (as opposite to a state-wide program.)

At the beginning of the last revenue period demand management was proposed as a solution to several network limitations:

- Kingston substation;
- Wynyard area;
- Bridgewater substation;
- South Arm; and
- Bruny Island

The status of these issues are shown in Table 25.

Table 25: Targeted demand programs status

Area	Current status
Kingston Substation	• Kingston 33 kV connection point and Summerleas Rd substation has resolved issues • No further action proposed
Wynyard area	• Demand decline in Wynyard area has deferred need
Bridgewater Substation	• Demand decline in Bridgewater area has deferred need
South Arm	• Demand decline in South Arm area and commissioning of Howrah zone substation have deferred need
Bruny Island	• Peak shaving generation used to manage peaks (Section 6.3) • Distributed energy storage trial planned (Section 6.1.2)

8. Financial summary

The forecast operational and capital spend in this demand management plan is presented in Table 26. It is also presented graphically in Figure 15.

Table 26: Financial summary of demand management

Project	Funding Source	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Demand Management Internal processes trial	DMIS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Demand Management Internal processes	OPEX	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bruny Island energy storage trial	DMIS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distributed energy storage - other usage	DMIS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Petuna Seafoods network support trial	DMIS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
C&I network support trial	DMIS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bruny Island generation	OPEX	$30,100	$30,480	$36,860	$41,850	$42,800	$50,120	$53,690	$60,730	$69,050	$77,320	$83,940	$89,280	$90,890
Tariff trial	DMIS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Electric Vehicle trial	CAPEX	$146,667	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Electric vehicle trial OPEX	OPEX	$6,306	$6,306	$6,306	$6,306	$6,306	$0	$0	$0	$0	$0	$0	$0	$0
DM exchange	DMIS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Demand management of EV charging	DMIS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Future DMIS Projects	DMIS	$0	$0	$0	$0	$0	$431,375	$431,375	$431,375	$431,375	$431,375	$431,375	$431,375	$431,375
Future CAPEX Projects	CAPEX	$0	$0	$0	$0	$0	$45,583	$45,583	$45,583	$45,583	$45,583	$45,583	$45,583	$45,583
Future OPEX Projects	OPEX	$0	$0	$0	$0	$0	$29,333	$29,333	$29,333	$29,333	$29,333	$29,333	$29,333	$29,333
Total DMIS		**$730,000**	**$753,400**	**$399,400**	**$447,120**	**$196,955**	**$619,740**	**$431,375**	**$431,375**	**$431,375**	**$431,375**	**$431,375**	**$431,375**	**$431,375**
Total OPEX		**$48,766**	**$49,636**	**$56,116**	**$68,364**	**$69,424**	**$99,881**	**$103,551**	**$110,701**	**$119,131**	**$127,511**	**$134,311**	**$139,851**	**$141,641**
Total CAPEX		**$146,667**	**$0**	**$26,900**	**$26,900**	**$26,900**	**$72,483**	**$72,483**	**$72,483**	**$72,483**	**$72,483**	**$72,483**	**$72,483**	**$72,483**

[redacted]

Figure 15: Demand management cost profile

Appendix A Economic analysis for backup generator controls

There are many customers in Tasmania which have backup generation of significant size installed. These generators are usually not capable of grid infeed. They can only supply the customers' plant islanded form the grid.

The recent commercial and industrial demand survey revealed that there are around 22 (out of 102) customers over 4000 MWh with generation in Tasmania. This indicates that around 22% of customers this size have backup generation.

These generators can be a valuable source of network support in certain circumstances. Especially for cases where there is not enough network capacity.

It is generally cheaper to install grid connect controls to a generator during its construction rather than later. This analysis aims to determine:

- How many generators are installed each year which may be useful in the foreseeable future for network support;
- If it is economically viable install the controls when the plant is built instead of at the time the generation is required; and
- If generation from this source is likely to be generally economically viable (i.e. is there a case for these controllers at all).

The overall assumptions used in this analysis are:

- Weighted Average Cost of Capital (WACC): 3.8% (this is the current figure used by TasNetworks);
- Controls cost $30k to install when the backup generator is installed; and
- Controls cost $45k to install after the backup generator is installed.

A.1 Number of generators

On average there are approximately 10 new loads with a consumption of 4000 MWh pa installed per year in Tasmania. Based on the Commercial and Industrial demand management survey approximately 22% of these loads will have a backup generator. This means there are about 2.2 backup generators of significant size installed in Tasmania each year.

There are 174 feeders out of 418 total feeders where it is expected generation will be useful[9] by 2030. This means that there are around 0.9 generators per year that are in the right place for network support. TasNetworks should budget $26.9k pa if it proposes to install controls on all of these generators.

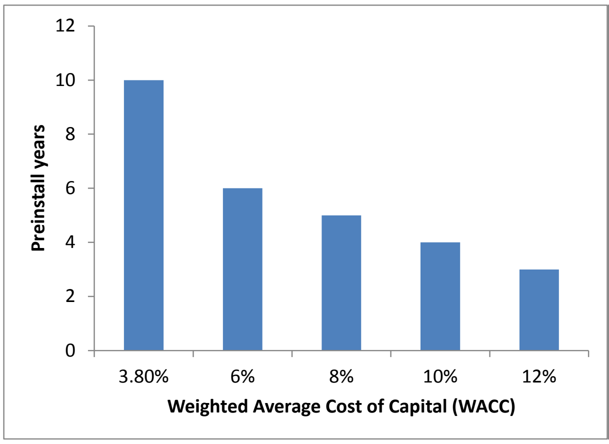
A.2 Preinstalling controls

The basic premise of installing controls on backup generation before it is required is that it is cheaper to do it now than later. In economic terms this means that the NPV of the cost of installing controls later is higher than the cost of installing them now.

[9] Feeders with either thermal issues, or load above firm at the supplying substation according to the 2015 Feeder Load Forecast

Using the general assumptions above, controls can be brought forward at most 10 years. Any longer than this and it is better to wait until the generation is needed.

An increased interest rate (WACC) tends to reduce the amount controls can be brought forward economically. Similarly change in install costs has a similar relationship. These relationships are shown in Figure 16.



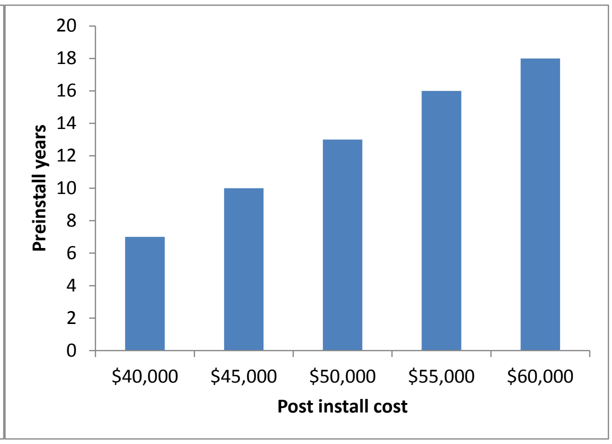


Figure 16: Control preinstall sensitivity

A cost of capital of 3.8% is very low in historical terms. The real risk that either the load growth does not occur or the generator is no longer there when it is required indicates a higher interest rate should be used.

To account for this care must be exercised if the identified need is toward the end of the 10 year period.

A.3 Grid connect economics

In reality it is impossible to predict when and where a backup generator will connect because this is the customer decision. This means that there is no way to prove that generation of this form is unequivocally required in the next period. Instead a reasonably representative sample is presented to determine if generation is preferred in some cases.

Bruny Island is the example used here. The specifics of Bruny Island substation is shown in Table 27.

Table 27: Bruny Island specifics

Peak Load	1664 kW in 2014
Capacity to island	Limited to 1500 kW
Weighted VCR[10]	$33.18/kwh

In reality TasNetworks deploys their own mobile generators to Bruny Island to manage system peaks (as discussed in 6.3). This example is mainly to determine if there is a use case for customer connected generation.

There is some expected unserved energy on Bruny Island currently.

Replacing a cable is expected to cost $2.5m.

The main aim of the economic analysis is to determine the action that minimises the total cost of:

- Unserved energy; and
- Augmentations installed to reduce unserved energy.

The results of this are shown in Figure 17. This makes the assumption that the generator is large enough to supply the network support.

[10] Weighted using usage and customer type statistics connected to St Marys

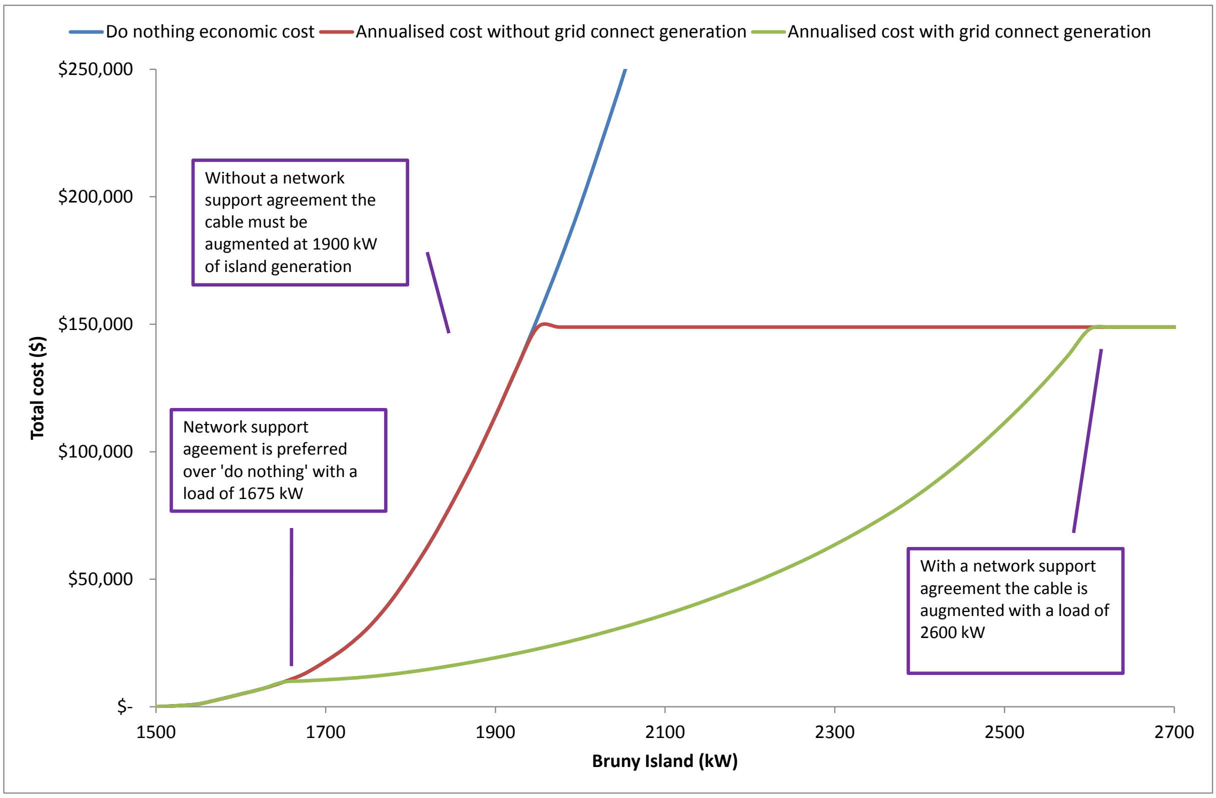


Figure 17: Network support agreement economics for Bruny Island

There is a significant domain where a network support agreement is preferred over both ‘do nothing’ and the cable.

A.4 Summary

This analysis has shown:

- There are around 0.9 backup generators installed per year where grid connect equipment would be worthwhile;
- Using the base assumptions grid connect controls should be installed a maximum of 10 years in advance. Extreme caution is advised if the identified need is more than 3 years in the future; and
- There are cases where customer installed backup generation can be the preferred option.

With this in mind, a CAPEX allowance of $26.9k/pa is proposed in 2017/18.

Appendix B Economic analysis for distributed energy storage

Based on the information provided by [redacted] for the Bruny Island distributed energy storage trial an estimate of future storage costs can be derived.

This chapter is made up of three sections:

- An estimate of the operation cost;
- Calculation of the breakeven usage for a grid connected battery; and
- An estimate of how much storage will be engaged.

B.1 Operation cost

[redacted]

B.2 Breakeven point

The breakeven point (per kwh) for a grid connected and distributed energy storage solution is shown in Figure 18.

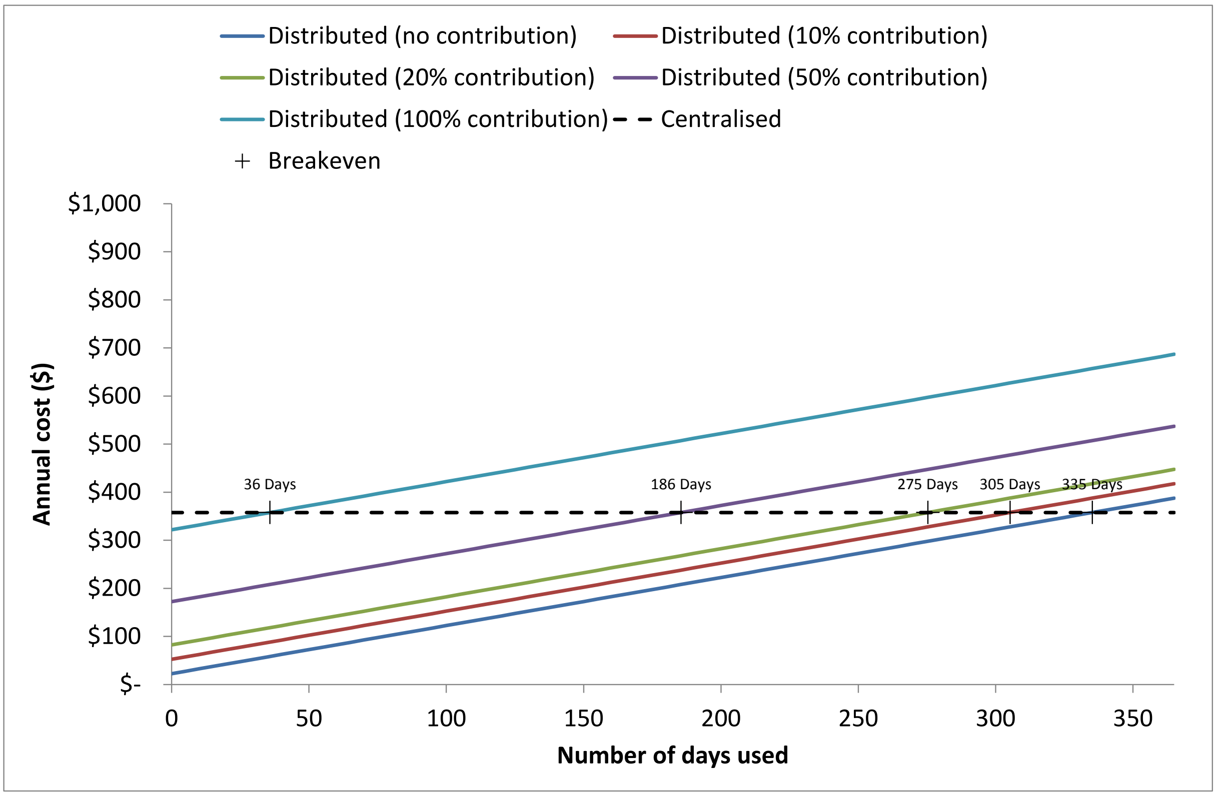


Figure 18: Centralised vs distributed storage

When either the storage can be installed with little contribution from TasNetworks or is only used rarely it is cheaper than a centralised battery.

Bruny island is the current most likely target for energy storage. Using the same assumptions as used to derive the generator operating cost (see6.3) a projection of energy storage usage is shown in Figure 19. Grid-connected energy storage is not more economic than distributed energy storage until 2041. Clearly there is some time where distributed energy storage makes more economic sense. This calculation assumes that TasNetworks pays 50% of the cost of the battery.

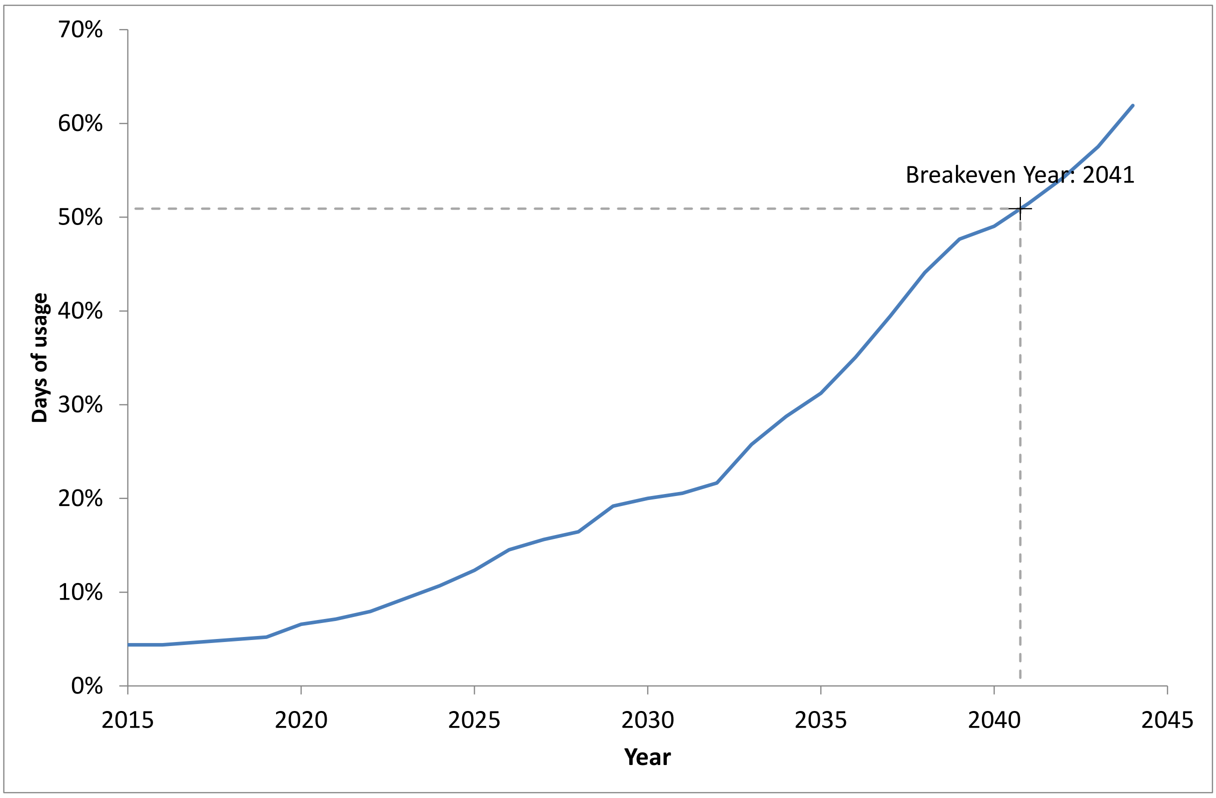


Figure 19: Breakeven time for Bruny Island batteries

B.3 Operation Allowance

Battery uptake rates are expected to be similar, but somewhat slower than solar uptake. The solar uptake rate in Tasmania historically is shown in Figure 20. Current battery installations are approximately one per week[11]. This means battery installations are at approximately the level that solar installations were in 2007. It is anticipated that the future battery uptake will tend to catch up with the solar uptake. The historical solar uptake is given in Figure 20.

[11] Based on discussions with solar connection people

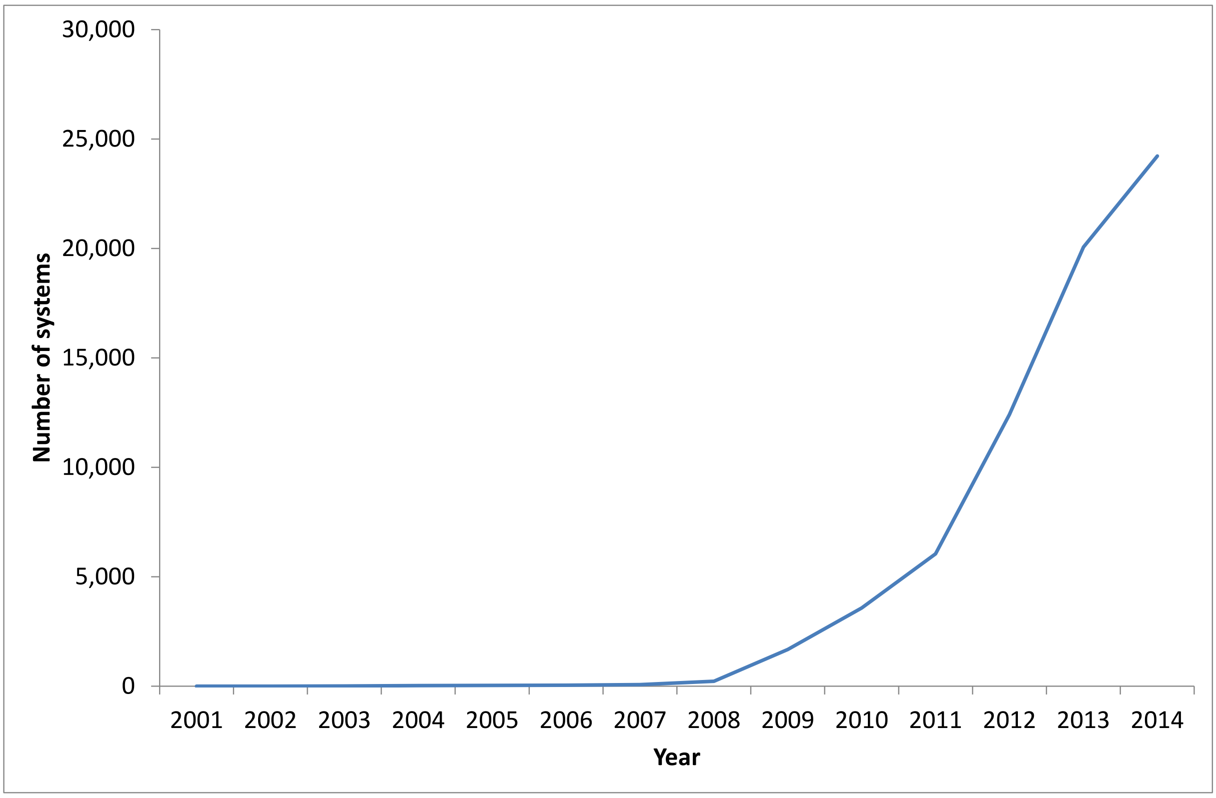


Figure 20: Solar uptake in Tasmania

Not all battery systems will be suitable:

- Some will be off-grid;
- Some will have no communications infrastructure;
- Some customers will not permit TasNetworks to use their batteries; and
- Some battery chemistries will be unsuitable.

To account for these factors this analysis assumes that 10% of installed batteries will be suitable for network support.

Based on the analysis in Appendix A around 42% of the storage systems are likely to be installed in places where it is useful (assuming they are evenly distributed across feeders). This gives a total of 4.2% of installed batteries that are used for network support. A table of the projected number of battery systems is shown in Table 28.

Table 28: Projected battery installations until 2030

Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Total batteries installed	69	230	1,682	3,571	6,046	12,410	20,068	24,225	24,610	16,270	18,348
Batteries that are used	3	10	71	150	254	521	843	1,017	1,192	1,367	1,541
Total used battery size (kWh)	19	64	454	960	1,626	3,334	5,395	6,509	7,629	8,749	9,862
Network support cost	[redacted]										

The cost of using these batteries depends on how often they are used. This analysis assumes that energy storage systems are used to reduce system peaks when loads are within 5% of the system peak. In 2014 this was 7 days, or 2% of the time.

These batteries will be used as an alternative to network expansion and thus their OPEX is justified under their own analysis.