Demand Management Incentive Scheme Annual Report FY2022 (update)

AusNet Electricity Services Pty Ltd

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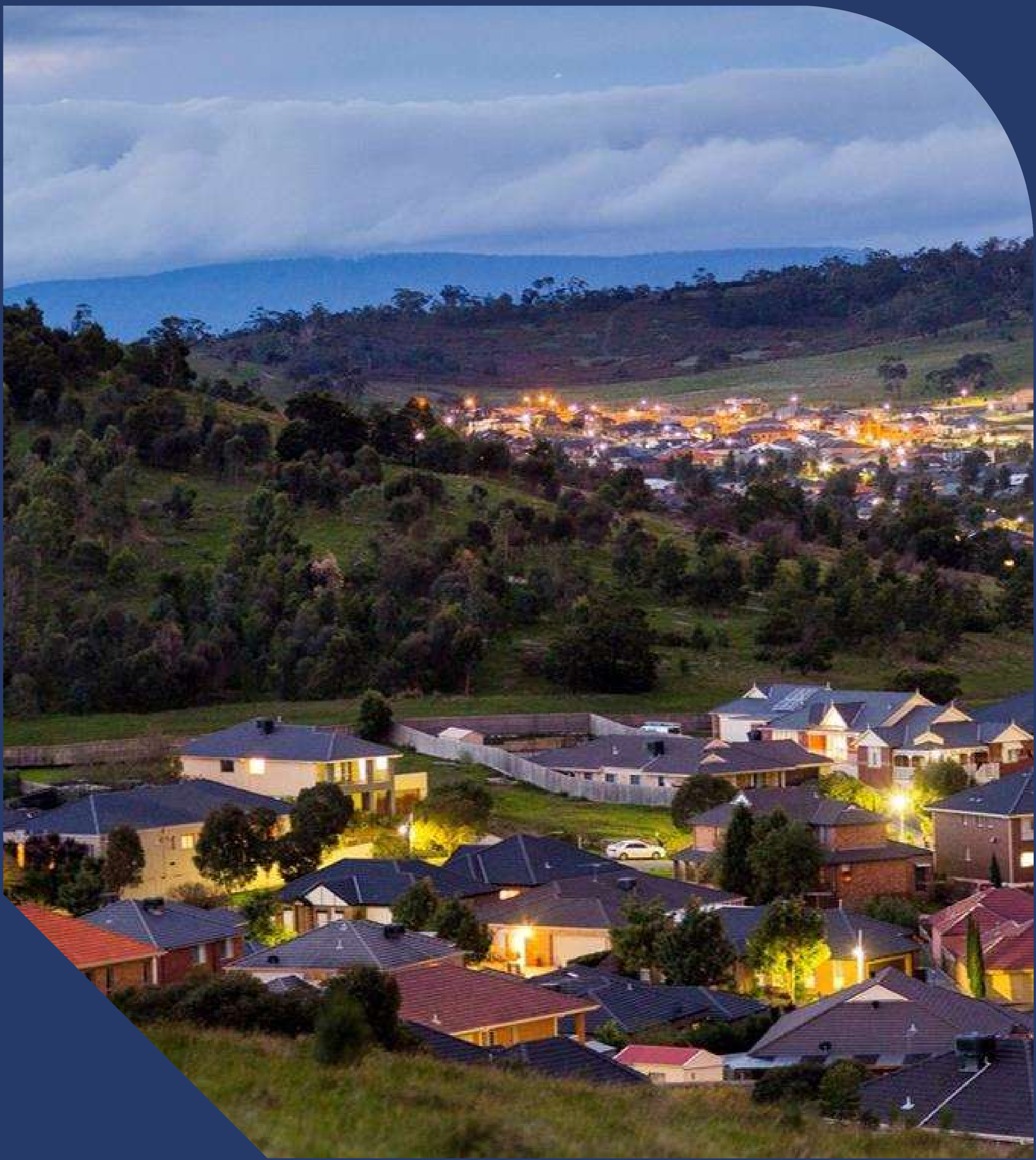

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1. Introduction

This report has been prepared pursuant to the AER's Demand Management Incentive Scheme (DMIS) for electricity distribution network service providers (DNSPs). The DMIS was introduced by the AER in 2018 and applied to AusNet on 1 January 2019. Accordingly, this is the fourth DMIS compliance report submitted by AusNet. For clarity, AusNet's annual reporting obligations under the Demand Management Innovation Allowance Mechanism (DMIAM) are satisfied through a separate report submitted to the AER.

In accordance with section 2.4 of the DMIS, DNSPs are required to submit a DMIS compliance report to the AER no later than 4 months after the end of each regulatory year. The regulatory year for AusNet transitioned to the Australian financial year effective 1 July 2021, and as such this is the first full year report aligned to the Australian financial year.

Each compliance report must include two parts—Part A and Part B. Part A includes information on committed projects and Part B contains information on projects that the distributor has identified as eligible projects.

AusNet confirms that, as of 30 June 2022, it has two committed projects. Information has been provided in accordance with section 2.4, paragraph 5 of the DMIS.

2. Compliance Report – Part A

2.1. Doreen Non-Network Solution

Project Status

Network Support Agreement executed.

Project Description

The DRN11 22 kV feeder out of Doreen zone substation supplying the precincts of Mernda, Doreen and South Morang was forecast to exceed thermal ratings by December 2020.

The network option to address this emerging constraint was a new 22 kV feeder out of Doreen zone substation which would be installed by November 2023. Options undertaken to manage this energy-at-risk in the meantime include transfers of load to adjacent feeders and demand-side response.

This network option does not address emerging zone substation energy-at-risk as this new feeder would be supplied by the existing Doreen zone substation assets.

The project involves engaging an existing customer to operate their embedded generation facility at times of feeder peak demand. Up to 7 MW of generation capacity is available and would defer network augmentation until 2027, as well as address emerging zone substation energy-at-risk during the intervening years. AusNet has entered into a demand management contract known as a Network Support Agreement (NSA) with the customer. This NSA stipulates required capacity and likely timing of demand management services required to address the identified need of reducing feeder peak demand. AusNet requests the demand management services via telephone request from the Customer & Energy Operations Team (CEOT) control room. The NSA specifies that AusNet will pay the customer up to [C – I – C] per annum to ensure generation output is maintained upon request.

[C – I – C]

This project was reported as a committed project in AusNet's 2020 and 2021 DMIS reports.

Project details

> *(4) Each **compliance report** must include the following information in Part A:*
>
> *(a) The volume of **demand management** delivered by **committed projects** in that **regulatory year** (that is, the **kVA** per year of demand that a **distributor** controlled (either directly or indirectly) by means of **committed projects** in that **regulatory year**).*

The customer will be requested to generate during periods as required by AusNet, to cater to loads at a POE50 (50% probability of exceedance) level, forecasted in 2019 for summer 2020/21 and beyond. The volume of demand management supplied in the period 1 July 2021 to 30 Jun 2022 was zero. This is due to a delay in completion of network augmentation works required to connect the generator to the constrained distribution network feeder. It is expected that these works will be completed in October 2022.

> *(b) The **distributor's** estimate of the benefits realised from the **demand management** delivered by **committed projects** in that **regulatory year**.*

Demand management was not delivered by this committed project during the period 1 July 2021 to 30 June 2022.

However, AusNet anticipates that up to 7,000 kVA of network support may be requested during a single dispatch event when required following connection of the generator to the constrained feeder from October 2022.

Nonetheless, the committed project has deferred the construction of more extensive feeder works out of Doreen zone substation from 2023 until 2027 and manage network risk throughout this period. This is the preferred credible option with a net benefit of $28.1M.

> *(c) The **total financial incentive** that the **distributor** has assessed that it is able to claim in accordance with clauses 2.2, 2.3 and 2.5 of this **scheme**, for that **regulatory year**.*

The incentive payment of $36,550 was claimed for this committed project in the 2020 DMIS report.

Table 1: Accrual of project incentives

	2020	Jan – Jul 21	2021/22	2022/23
Doreen Non-Network Solution	$36,550			
Total incentive accrued to projects	$36,550			
1% AR cap	$6,460,000			
Total accrued (up to cap)	$36,550			
Incentive to be paid (2.5-year lag)				$36,550

2.2. West Gippsland Non-Network Solution

Project Status

Network support agreement executed. BESS commissioning expected to take place in February 2023.

Project Description

The 22 kV feeders out of Warragul zone substation supplying precincts of Drouin, Bunyip and Longwarry are forecast to exceed thermal ratings beyond December 2023.

The network option to address this emerging constraint is a new 22 kV feeder out of Warragul zone substation which would have been constructed by June 2023.

The feeder augmentation option would not address emerging zone substation energy-at-risk as this new feeder would still be supplied by the existing Warragul zone substation assets (i.e., it would only address energy at risk on the 22 kV feeder). Conversely, a non-network solution on the 22 kV feeder would act to reduce load on both the feeder and upstream zone substation.

The proposed non-network project is to strategically locate distributed energy resources (e.g., embedded generation, demand response or energy storage) in the Longwarry area which, in conjunction with load transfers from two of the three 22 kV feeders, would achieve a reduction in peak demand on all three feeders across the summer period until 2029/30. The project would defer a new 22 kV feeder until beyond 2029/30.

AusNet has entered into a demand management contract known as a Network Support Agreement (NSA) with the customer. This NSA stipulates required capacity and likely timing of demand management services required to address the identified need of reducing feeder peak demand. AusNet may request the demand management services via an automated means. The NSA specifies that AusNet will pay the customer [C – I – C] per annum to ensure generation output is maintained upon request up to 120 MWh of support per billing period.

This project was reported as an eligible project in AusNet's CY2020 and HY2021 DMIS report.

Project Details

> *(4) Each **compliance report** must include the following information in Part A:*
>
> *(a) The volume of **demand management** delivered by **committed projects** in that **regulatory year** (that is, the **kVA** per year of demand that a **distributor** controlled (either directly or indirectly) by means of **committed projects** in that **regulatory year**).*

The customer will be required to generate during periods as requested by AusNet, to achieve a reduction in peak demand across the summer periods until 2029/30. The volume of demand management supplied in the period 1 July 2021 to 30 June 2022 was zero. This is because the customer generation site has not yet been energised. It is expected that this will be completed in February 2023.

> *(b) The **distributor's** estimate of the benefits realised from the **demand management** delivered by **committed projects** in that **regulatory year**.*

Demand management was not delivered by this committed project during the period 1 July 2021 to 30 June 2022 as the Network Support Agreement has not yet commenced.

AusNet anticipates that up to 3,000 kVA of network support may be requested during a single despatch event when required following the completion of the connection of the generator to the constrained network and relevant commissioning tests by February 2023.

This committed project has deferred the construction of a new feeder from the Warragul Zone Substation until beyond 2029/30 and will manage network risk throughout this period. This is the preferred credible option with net benefit of $1.8 million ($1.4 million in PV terms).

> *(c) The **total financial incentive** that the **distributor** has assessed that it is able to claim in accordance with clauses 2.2, 2.3 and 2.5 of this **scheme**, for that **regulatory year**.*

Applying Equation 1:

$$PV\ incentive_i \leq \max\{dv \times E\ [PV\ DMcost_i - S_i]\ ,0\}$$

Subject to the constraint:

$$d_v \times E[PV\ DMcost_i] \leq E[NPV_i]$$

The expected demand management cost when the project became a committed project was $527,366.

The expected total subsidies when the project became a committed project were $0.

The expected relevant net benefit was $1.8 million ($1.4 million in PV terms).

Therefore, per equation 1, $PV\ incentive_i$ = MAX (0.5 * $527k,0) = $263,683.

Therefore, the constraint is satisfied as the calculated incentive of $263,683 is below the expected net benefit of $1.8 million ($1.4 million in PV terms). The claimed incentive is also below 1% of AusNet's annual smoothed revenue requirement.

Table 2: Accrual of project incentives

	2021/22	2022/23	2023/24	2024/25
West Gippsland Non-Network Solution	$263,683			
Total incentive accrued to projects	$263,683			
1% AR cap	$6,907,862			
Total accrued (up to cap)	$263,683			
Incentive to be paid (2-year lag)			$263,683	

2.3. Deferred or Cancelled Committed Projects

Not applicable.

3. Compliance Report – Part B

3.1. West Gippsland Non-Network Solution

Project Status

Network support agreement executed. BESS commissioning expected to take place in February 2023.

Project Description

The 22 kV feeders out of Warragul zone substation supplying precincts of Drouin, Bunyip and Longwarry are forecast to exceed thermal ratings beyond December 2023.

The network option to address this emerging constraint is a new 22 kV feeder out of Warragul zone substation which would have been constructed by June 2023.

The feeder augmentation option would not address emerging zone substation energy-at-risk as this new feeder would still be supplied by the existing Warragul zone substation assets (i.e., it would only address energy at risk on the 22 kV feeder). Conversely, a non-network solution on the 22 kV feeder would act to reduce load on both the feeder and upstream zone substation.

The proposed non-network project is to strategically locate distributed energy resources (e.g., embedded generation, demand response or energy storage) in the Longwarry area which, in conjunction with load transfers from two of the three 22 kV feeders, would achieve a reduction in peak demand on all three feeders across the summer period until 2029/30. The project would defer a new 22 kV feeder until beyond 2029/30.

Project Details

(5) For each eligible project that a distributor identifies as a preferred option in a regulatory year, Part B of the compliance report relating to that regulatory year must include the following information about that eligible project:

(d) In PV terms, the expected costs and benefits that the distributor determined, in accordance with clause 2.2, that the eligible project would deliver to electricity consumers.

The preferred option was to engage a third-party to provide a non-network solution and defer the construction of a new feeder (i.e., the network solution) by eight years.

The estimated costs and net benefits associated with the preferred option are as follows:

PV Expected Costs	Network support payments of $527,366 - [C – I – C] and deferred capital cost of $2,138,709. Total PV expected costs = $2,666,075.
PV Expected Net Benefits	$1,428,516 (or $1,804,595 in undiscounted terms) (compared to the "Do Nothing" option)

An additional benefit of reduced zone substation energy-at-risk (up to $401,021 by 2029/30) was not included in the calculation of the maximum network support payment. This is due to the calculation of network support payments being based on deferral of financial costs only, with financial costs of the network option comprising the construction cost of a new feeder in 2022/23.

*(e) A description of the responses that the **distributor** received to either its **RIT–D** or its **request for demand management solutions** under the **minimum project evaluation requirements** (as relevant) including, for each response:*

A request for demand management solutions via a public Expression of Interest was communicated on the corporate website in April 2020 and communicated directly to Providers listed on AusNet's Demand Side Engagement Register.

The service provider was selected in August 2020 and is working to install a grid-scale battery storage solution, connected to a 22 kV feeder. The battery storage solution is expected to be connected to the network in February 2023.

(i) a short description of the proposed project;

This project engaged non-network service providers on AusNet's Demand Side Engagement Register to propose suitable solutions to reduce peak demand on 22 kV feeders supplied out of Warragul zone substation.

The aim of the project was to defer construction of a new 22 kV feeder from the zone substation for at least eight years, or until firm underlying growth trends emerge.

The solution provider selected will be installing a battery energy storage system (BESS) that will provide the requested 3 MW / 6 MWh of network support for summer periods until 2029/30.

*(ii) the proposed costs and deliverables put forward in the response to the **request for demand management solutions**; and*

The network support payment made available to service providers was calculated at [C – I – C] per annum (nominal). This figure was stated in the request for demand management solutions, with service providers asked to propose fee structures for any additional (ad-hoc) demand management services requested by AusNet.

*(iii) for any response that proposed a potential **credible option**, the **distributor**'s estimate of that project's **relevant net benefit**.*

Solution providers that responded to the request for proposals issued by AusNet accepted the fixed [C – I – C] fee for the provision of up to 120 MWh of network support across a summer period. From 3.1.2(d), the relevant net benefit is $1.8 million ($1.4 million in PV terms) and assumes no additional (ad-hoc) network support payments are made across the eight-year agreement period.

*(f) Identify whether, if the **distributor** decides (or has decided) to proceed with the project as a **committed project**, it is likely that this will occur via a **demand management contract**, or whether this is likely to occur via a **demand management proposal**. If the former, the **compliance report** must also identify the proposed party or parties to the **demand management contract**.*

AusNet has negotiated a Network Support Agreement with the selected service provider. This Agreement stipulates the required capacity and timing of demand management services that will address the identified need of reducing feeder peak demand.

*(g) The expected costs of delivering **demand management**, by means of the **eligible project**, that the **distributor** used as an input into its assessment, under clause 2.2, that the project is an **efficient non-network option** in relation to **demand management**.*

See response to clause 5(d) above. The business case to determine the expected costs / maximum demand management costs payable to the Provider was based on the estimated annual deferral value of the proposed network option of feeder augmentation. To ensure the non-network solution would be the most efficient option, the network support payment was capped at 70% of this annual deferral value, which is the return on capital and regulatory depreciation for the relevant year the network solution is deferred from.

*(h) the **kVA** per year of network demand that the **distributor**:*

*(i) would be able to call upon, influence, dispatch or control if the project is implemented (that is, the **kVA** per year of **demand management** capacity); and*

AusNet is requesting up to 3 MW of network support during a single dispatch event. This is equal to 3 MVA at unity power factor[1].

(ii) expects to call upon, influence, dispatch or control, based on its probabilistic assessment of future demand, if the project is implemented.

[1] Power Factor is the ratio of Active Power (kW) to apparent power (kVA) and is used to represent the electrical demand requirements, in vector sum of kW and KVAR, to support customer demand. At Unity Power Factor 1 kW is equal 1 kVA).

Up to 6 MWh is expected per dispatch event and a total annual dispatch allowance of 120 MWh is requested. This is to achieve a reduction in the feeder peak demand across summer periods until 2029/30. AusNet will negotiate additional costs for dispatch over and above this 120 MWh allowance.

> *(6) Where a **distributor** decides, in a **regulatory year**, to defer or not proceed with an **eligible project** that it has previously decided (either in that **regulatory year** or in a previous **regulatory year**) to proceed with as a **committed project**, the **distributor** must identify that decision and project in its **compliance report** for that **regulatory year**.*

Not applicable.

3.2. Phillip Island Non-Network Solution

Project Status

Business case approved; service provider engaged. Civil works completed with commissioning expected in late 2022.

Project Description

The Phillip Island (PHI) zone substation is supplied by a long 66 kV line emanating out of Wonthaggi zone substation, approximately 40 kms to the east. A 22 kV feeder from Wonthaggi also crosses over the water at San Remo and provides a secondary supply of up to ~ 5 MVA to the island in the event of either a full outage at PHI zone substation or an issue with the 66 kV line into the zone substation. Peak demand on Phillip Island can reach up to 25 MVA during holiday periods- e.g., New Year's Eve, long weekends, and major event weekends.

The project engaged the market to provide a non-network solution that would provide firm support to reduce the energy-at-risk carried by the zone substation and to support the existing 5 MVA transfer capacity onto the existing 22 kV feeder out of Wonthaggi. By bolstering this transfer capacity with a non-network solution, the availability of this second supply into Phillip Island to support customer demand during an upstream outage would be increased.

A network support agreement (demand management contract) will be entered to pay the solution provider [C – I – C] per annum to provide network support across the summer months and maintain availability to dispatch under contingency conditions during other holiday weekends and major event weekends.

Project Details

> *(5) For each **eligible project** that a **distributor** identifies as a **preferred option** in a **regulatory year**, Part B of the **compliance report** relating to that **regulatory year** must include the following information about that **eligible project**:*
>
> *(d) In PV terms, the expected costs and benefits that the **distributor** determined, in accordance with clause 2.2, that the **eligible project** would deliver to electricity consumers.*

The preferred option was to engage service providers listed in AusNet's Demand Side Engagement Register and via the public website to provide a non-network solution that would supplement the existing load transfer capacity from Wonthaggi zone substation, thereby improving resilience of supply to Phillip Island. A battery energy storage system was selected due to its ability to be dispatched to support the network during days of peak demand and its firmness of response.

The estimated costs and benefits associated with the preferred option are as follows:

PV Expected Costs	$428,000 (OPEX) total, [C – I – C], excluding any emergency / ad-hoc support dispatch requests.

PV Expected Benefits	~$336,000 (PV) reduction in energy-at-risk carried by Phillip Island zone substation, compared to the "Do Nothing" option, by the fifth year of operation (2024/25). ~$252,600 (PV, OPEX) avoided cost of temporary generator deployment for summer network support or planned zone substation outages (~$53 k / annum). ~$1,017,000 (PV) reduction in STPIS penalties associated with outages that affect Phillip Island zone substation, which would now be able to be addressed at least 89% of the year.
PV Expected Net Benefits	After accounting for ~$428 k (PV) of network support payments, net benefit compared to the "Do Nothing" option = PV expected benefits less PV expected costs = ($336,000 + $252,600 + $1,017,000) – ($428,000) = $1,177,600

*(e) A description of the responses that the **distributor** received to either its **RIT–D** or its **request for demand management solutions** under the **minimum project evaluation requirements** (as relevant) including, for each response:*

A request for non-network solution proposals was communicated on the corporate website in November 2020 and communicated directly to Providers listed on AusNet's Demand Side Engagement Register. Three service providers submitted responses and attended meetings with a project evaluation panel to discuss their proposals.

The preferred service provider was selected in February 2021 and the grid-scale battery storage solution connected to one of the 22kV feeders in Phillip Island is expected to be commissioned in late 2022.

(i) a short description of the proposed project;

Phillip Island is served by three 22 kV feeders out of the Phillip Island zone substation, which in-turn is supplied by a radial 66 kV sub-transmission line emanating from Wonthaggi. An additional 22 kV feeder from Wonthaggi also supplies the island and serves as a contingency measure that can only support a portion of the entire island's demand, particularly during peak holiday periods.

The project seeks to engage the non-network solutions market to improve the overall resilience of energy supply on the island, by providing additional capacity on the island during times of sub-transmission outages, zone substation outages or limitations, during planned outages and during times of holiday peak demand. Over the last few years, temporary diesel generators have been connected at the zone substation to bolster capacity during these periods.

By supplementing the load transfer capacity on the island, zone-substation or sub-transmission outages can be addressed for a greater portion of the year, and without the need for the use of temporary generators. Planned zone substation and sub-transmission outages can also be catered to due to the improved ability to utilise the existing transfer back to the Wonthaggi feeder, thereby reducing outage times and improving customer service.

*(ii) the proposed costs and deliverables put forward in the response to the **request for demand management solutions**; and*

The avoided costs of deploying network support generation during summer and other holiday periods, along with the reduction in energy at risk carried by Phillip Island zone substation due to the connection of a dispatchable energy storage solution was used to determine the maximum annual network support payment.

The Request for Proposals issued publicly and directly to service providers on AusNet's Demand Side Engagement Register offered an annualised network support payment of [C – I – C]. Additional payments will be made for requests for network support over and above 300 MWh.

> *(iii) for any response that proposed a potential **credible option**, the **distributor**'s estimate of that project's **relevant net benefit**.*

The estimated relevant net benefit includes avoided generator deployment expenditure, reduction in energy at risk carried by the Phillip Island zone substation, and estimated STPIS benefit through the ability of the solution to support transfer capacity provided by the 22 kV feeder from Wonthaggi.

Per 3.1.3 (d), the relevant net benefit of this solution is estimated at $1,177,600.

> *(f) Identify whether, if the **distributor** decides (or has decided) to proceed with the project as a **committed project**, it is likely that this will occur via a **demand management contract,** or whether this is likely to occur via a **demand management proposal**. If the former, the **compliance report** must also identify the proposed party or parties to the **demand management contract**.*

AusNet will engage the customer through a demand management contract, in the form of a network support agreement. The network support agreement will stipulate required capacity and likely timing of demand management services required to address the identified need of supporting transfer capacity during zone substation or sub-transmission faults. AusNet would request the demand management services via telephone request from the Customer and Energy Operations Team (CEOT), or through an automated dispatch trigger via remote telemetry unit (RTU).

> *(g) The expected costs of delivering **demand management**, by means of the **eligible project**, that the **distributor** used as an input into its assessment, under clause 2.2, that the project is an **efficient non-network option** in relation to **demand management**.*

See response to clause 5(d) above. The business case to determine the expected costs / maximum demand management costs payable to the Provider was based on the estimated reduction energy-at-risk carried by Phillip Island zone substation and savings made from avoided generator deployment for summer network support / planned outages. To ensure the non-network solution would be the most efficient option and allow for occasional ad-hoc / emergency dispatches, the fixed component of the network support payment was capped so that the Total PV Cost of the project was no greater than 80% of the "Do Nothing" scenario.

> *(h) the **kVA** per year of network demand that the **distributor**:*

> *(i) would be able to call upon, influence, dispatch or control if the project is implemented (that is, the **kVA** per year of **demand management** capacity); and*

AusNet is requesting up to 4.95 MW (at unity power factor) of network support during a single dispatch event.

> *(ii) expects to call upon, influence, dispatch or control, based on its probabilistic assessment of future demand, if the project is implemented.*

Up to 10 MWh is expected per dispatch event and a total annual dispatch allowance of 300 MWh is requested. It is likely that dispatch will be required with at least 24 hours' notice for a summer peak day or at less than 24 hours' notice in the event of an extended sub-transmission or zone-substation outage. AusNet will negotiate additional costs for dispatch over and above this 300 MWh allowance, or outside of the normal summer peak demand period, such as during holidays and major events.

> *(6) Where a **distributor** decides, in a **regulatory year**, to defer or not proceed with an **eligible project** that it has previously decided (either in that **regulatory year** or in a previous **regulatory year**) to proceed with as a **committed project**, the **distributor** must identify that decision and project in its **compliance report** for that **regulatory year**.*

Not applicable.

3.3. Deferred or Cancelled Eligible Projects

This section contains previously reported eligible projects that have been deferred or cancelled.

3.3.1. Euroa Non-Network Solution

The Euroa non-network solution was deferred in 2021 following a review of the identified need.

The project scope and benefits will be reassessed when the identified need is clarified.

4. Information Requirements Checklist

The following checklist has been requested to be completed by the AER[2] in addition to the DMIS report from 2020 onwards.

DMIS clause	Description	AusNet response
For each committed project		
	A. The identified need for the project	
2.2.1(4)	(a) A description of the **identified need** that the distributor is seeking to address (b) Technical information about the **identified need**, including the load at risk, energy at risk, duration and load curves, the annual probability and frequency of relevant events, and the expected value of energy at risk. The expected value of energy at risk must be based, as a minimum, on the average volume of energy at risk, the weighted probability of the energy at risk event occurring, and the relevant value of customer reliability for a given regulatory year (c) The location of the **identified need** and a description of the affected classes of customers and network area	**West Gippsland NNS:** Please refer to PDF file **EOI for Longwarry Non-Network Solution (PUBLIC).pdf** and Section 3.1 of this DMIS report.
	B. Identifying and selecting the efficient non-network option	
2.2.1(2)	Where an **identified need** on its distribution network could be fully or partly addressed by a demand management solution, state whether the distributor issued a **request for demand management solutions** to the following parties: (a) Persons registered on its demand side engagement register (b) Any other parties the distributor may identify as having or potentially having the capabilities to provide a demand management product, service or solution to either fully or partly form a credible option to address the identified need on the distribution network.	**West Gippsland NNS:** AusNet issued a request for demand management solutions via a public EOI communicated on the corporate website as well as communicated directly to providers listed on AusNet's Demand Side Engagement Register. Please see Section 3.1 of this DMIS report.
2.2.1(3)	State whether the **request for demand management solutions** included a request for a quote.	**West Gippsland NNS:** AusNet calculated the annual network support payment and stated this in the request for demand management solutions and invited the respondents to propose a payment structure for dispatch of network support including pricing for ad-hoc or emergency dispatch and beyond the annual network support allowance.
2.2.1(4)	Demonstrate that, as part of the **request for demand management solutions**, the distributor provided the following information: (a) A description of the **identified need** that the distributor is seeking to address (b) Technical information about the **identified need**, including the load at risk, energy at risk, duration and load curves, the annual probability and frequency of relevant events, and the expected value of energy at risk. The expected value of energy at risk must be based, as a minimum, on the average volume of energy at risk, the weighted probability of the energy at risk event occurring, and the relevant value of customer reliability for a given regulatory year	**West Gippsland NNS:** Please refer to PDF file **EOI for Longwarry Non-Network Solution (PUBLIC).pdf**

[2] AER 2021, AusNet Services 2020 DMIS incentive payment assessment (letter, via email), 29 July.

DMIS clause	Description	AusNet response
	(c) The location of the **identified need** and a description of the affected classes of customers and network area (d) If the distributor has already identified an initial preferred option to meet the **identified need** on the distribution network, a description of its initial preferred option (e) Other information that is sufficient to enable the parties receiving the **request for demand management solutions** to provide an informed response in presenting an alternative potential **credible option**, including, to the extent relevant, the information that a distributor is required under the NER to provide in a **non-network options report**.	
2.2.1(5)	Demonstrate that, in the **request for demand management solutions,** the distributor required the provision of the following information from responding parties: (a) A description of the proposed demand management product, service or solution that is put forward as a credible option, or as part of a credible option, to address the identified need on the distribution network (b) Where the proposed demand management product, service or solution is put forward as part of a credible option (but not as the whole of a credible option), a description of the other elements of the credible option. A reasonable estimate of: i. The proposed product, service or solution's expected outputs, including the amount of network demand (based on a specified kVA per year) that the party responding to the **request for demand management solutions** expects to be able to manage (either at its influence, request or control). ii. The expected payments that the distributor would be required to make to the responding party if the distributor were to enter into a contract with the responding party for the responding party to provide that product, service or solution to the distributor. (c) Any other information relevant to determining whether the proposed product, service or solution would be a credible option, or part of a credible option, to address the identified need on the distribution network.	**West Gippsland NNS:** Please refer to PDF file **EOI for Longwarry Non-Network Solution (PUBLIC).pdf**
2.4(5)	(d) A description of the responses that the distributor received to either its **RIT–D** or its **request for demand management solutions** under the **minimum project evaluation requirements** (as relevant) including, for each response: i. a short description of the proposed project ii. the proposed costs and deliverables put forward in the response to the **request for demand management solutions; and** iii. for any response that proposed a potential **credible option**, the distributor's estimate of that project's **relevant net benefit**. (e) Identify whether, if the distributor decides (or has decided) to proceed with the project as a **committed project**, it is likely that this will occur via a **demand management contract**, or whether this is likely to occur via a **demand management proposal**. If the former, the **compliance report** must also identify the proposed party or parties to the **demand management contract**.	**West Gippsland NNS:** Please see Section 3.1 of this DMIS report under 'Project Details'
2.2.2	For each **committed project**, provide a copy of the **demand management contract** or the **demand management proposal.**	**West Gippsland NNS:** Please refer to PDF file of the Network Support Agreement
	C. Cost-benefit analysis	
2.3(5)	Demonstrate that the distributor carried out a cost–benefit analysis to calculate the expected **relevant net benefit** for project *i* referred to in clause 2.3(2)(b) and equation 1. As part of	**West Gippsland NNS:**

DMIS clause	Description	AusNet response
	this cost–benefit analysis, the distributor must estimate project *i*'s net benefit relative to 'the base case', being, in most cases, where the distributor does not implement a **credible option** to address the **identified need**. The exception to this 'base case' is that, where the **identified need** is for reliability corrective action, the distributor will use a **credible option** that has the second highest net benefit as the base case.	Please see Section 3.1 of this DMIS report under 'Project Details'.
2.3(4)	Demonstrate that the expected value of project *i*'s demand management costs used for the purposes of clause 2.3(2)(a) and equation 1 are consistent with: (a) The payments, or potential payments, for the demand management solution under the **demand management contract** or in the **demand management proposal** (as relevant); and (b) The distributor's reasonable expectation of the frequency and duration on which it will call on or utilise the capability to control network demand under the **demand management proposal** or the **demand management contract** (as relevant). In order to determine this expectation, the distributor must probabilistically determine the amount of network demand that it expects to request, control or influence.	<u>**West Gippsland NNS:**</u> Please see Section 3.1 of this DMIS report under 'Project Details'.
2.2(4)	Demonstrate that, in determining by means of the **minimum project evaluation requirements** whether a project is an **efficient non-network option**, including when estimating the NPV of the net economic benefit of a project as part of that process, the distributor included: (a) Costs and benefits of a kind that accrue to consumers via the distribution network, and (b) To the extent they exist and may affect the distributor's identification of the **preferred option**: i. costs and benefits of a kind that accrue to consumers via parts of the **relevant market** other than the **distribution network**, and ii. benefits that consist of option value.	Please refer to the supporting spreadsheet provided.

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