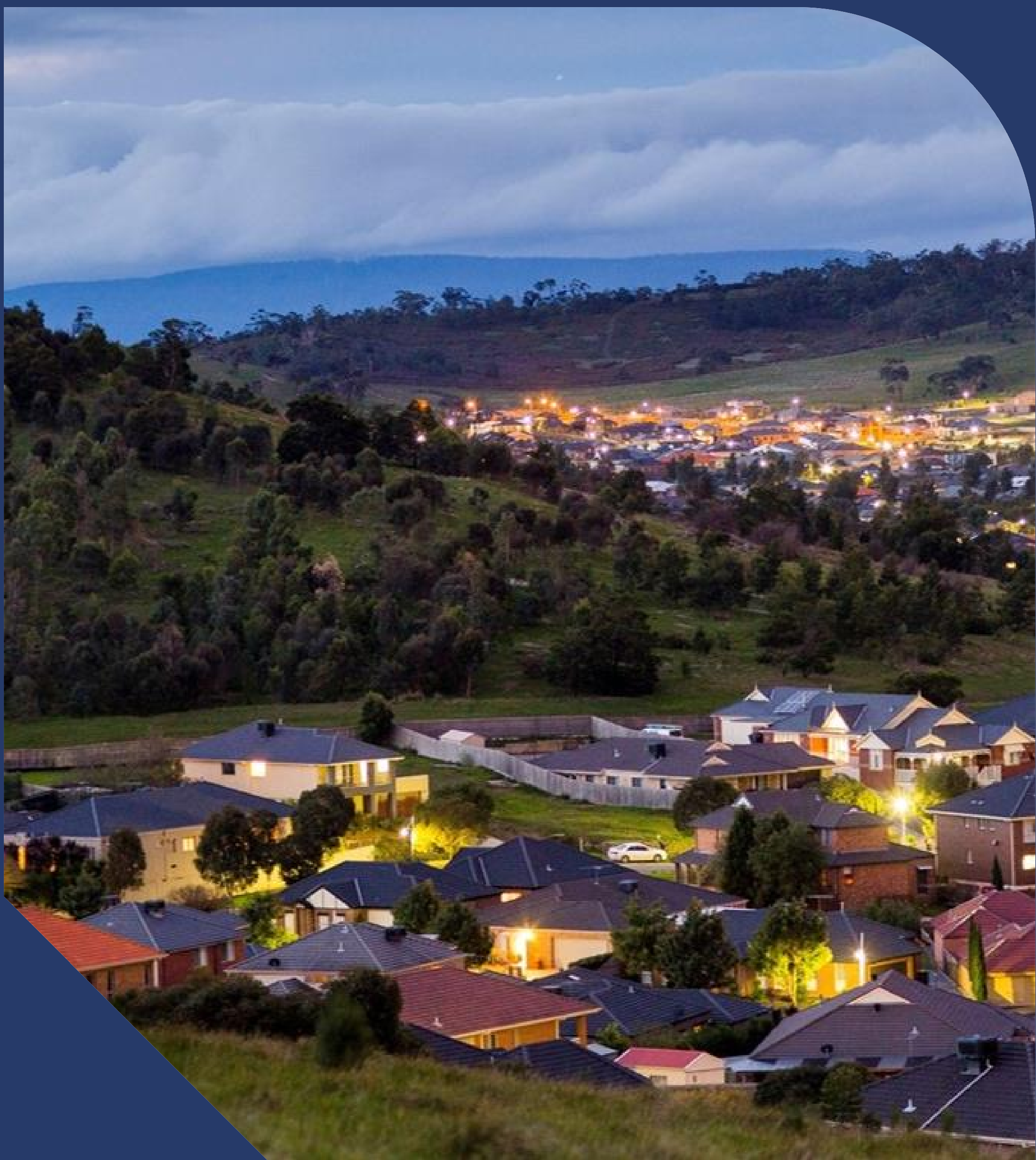
AusNet

Electricity Distribution Price Review (EDPR 2026-31)

Supply security of Wonthaggi, South Gippsland business case

Date: 31 January 2025



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1. Executive summary

AusNet Services is a regulated Victorian Distribution Network Service Provider (DNSP) that supplies electrical distribution services to more than 800,000 customers. Our electricity distribution network covers eastern rural Victoria and the fringe of the northern and eastern Melbourne metropolitan area.

As expected by our customers and required by the various regulatory instruments that we operate under, AusNet Services aims to maintain service levels at the lowest possible cost to our customers. To achieve this, we assess the requirements, identify emerging constraints, evaluate options to mitigate constraints and develop plans that aim to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

This Executive Summary provides an overview of the proposed investment in the electrical distribution network in Wonthaggi, South Gippsland. It discusses the underlying need, the key drivers, the options considered to address the identified need, and the recommended solution. The body of the document covers these aspects in detail.

Identified need

Customers' energy requirements are changing due to the ongoing energy transition. Both individual customers and businesses are increasingly inclined to shift away from gas, embrace low-emission transportation and heating choices, and amplify the effectiveness of their household appliances and the presence of distributed energy resources (DERs) such as solar photovoltaic (PV) installations. Continued investments in DER to offset electricity from the grid don't eliminate the need for network capacity augmentations, as the maximum generation or demand typically occurs at different times. The electricity demand growth over the next decade is predicted to occur at a faster pace. This growth is primarily attributed to three key factors:

- population growth,
- decarbonisation through the electrification of transport, and
- the gradual transition from using gas to using electricity in homes and industries.

By 2053, the population growth in Wonthaggi and surrounding areas including Inverloch and San Remo will ultimately result in approximately 4,500[1] new residential dwellings and 70 hectares of employment land comprise industrial and commercial developments - town centres, schools, community facilities, and future commercial spaces. When fully developed beyond 2053, it is expected that the development areas in Wonthaggi and surrounding areas, including Inverloch and San Remo, will result in a new load in the order of 44 MVA being added to AusNet Services' electricity network in South Gippsland. Several connection inquiries for connecting industrial/commercial loads have been already received, and applications to increase the capacity of the existing loads in the abovementioned areas have been made.

The basis for this business case is the combined growth in demand from existing (brownfield) and newly developed (greenfield) sites in the Wonthaggi, South Gippsland, for initial stages of the Wonthaggi development area, for which AusNet Services have strong and credible forecast. The future stages, likely to be required after 2031 will be covered in a separate business case when the need or trigger arises.

The town of Wonthaggi and surrounding areas including Inverloch and San Remo are predominately serviced by 66/22kV Wonthaggi (WGI) zone substation (ZS) established in the mid-1960s. Currently it has three, aged 10/13.5 MVA transformers in deteriorating conditions and seven 22kV feeders with outdoor 66kV and 22kV switchgear in an un-switched configuration. The station has enough room to allow it to be developed to have three 20/33 MVA transformers and indoor 22 kV switchgear arranged in three buses with twelve 22 kV feeders. The WGI21 22kV feeder connects the Wonthaggi wind farm.

AusNet Services has identified a need to increase the ability of the WGI station to supply the forecast demand in the Wonthaggi, South Gippsland and manage the increasing risk of involuntary load shedding (National Electricity Rules (NER) 5.17.1(c)(4)(ii) of the customers supplied by the WGI station beyond 2029. In addition to the risk of unserved energy to existing customers, the lack of capacity of the WGI station will prevent connecting new customers to AusNet Services' network in the area supplied by WGI station. This would directly violate AusNet Services' obligation to provide connection services (Section 5.10 of the NER). There are also substantial reputational risks and stakeholder dissatisfaction if AusNet Services cannot meet supply requirements for this high-growth area. An investment into additional electrical capacity in this area is required to reduce these risks.

Options considered

Based on gathered credible growth information, there is a definite need for a long-term increase in WGI station's capacity supplying in the abovementioned area. Increasing the WGI capacity requires investment in infrastructure, which:

[1] Source: 2019-04-18-Wonthaggi-Structure-Plan-and-Discussion-Paper-FINAL.PDF (basscoast.vic.gov.au)

- enables new customer connections,
- finds the right balance between short-term and long-term needs, and
- provides the choices (network or non-network) for future growth of electricity infrastructure.

As a result, various network topologies based on the ultimate demand were tested, and the costs and benefits of these ultimate configurations were compared over a sensible time horizon (i.e., what is likely to be the demand within 10-15 years). Table 1 below summarises the options that were considered to address the identified need.

Based on the performed quantitative and qualitative analysis (Table 1), the preferred option is **Option 1A (Replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx)** as it has the most significant economic benefit being Net Present Value (NPV) positive **$41.9 Million**. This option provides the greatest benefit by providing the most significant reduction in unserved energy, allowing more capacity at the station level and the greatest number of customers to connect. As a result, Option 1A will provide more long-term benefits than all other options considered.

Table 1: Cost Benefit Analysis (CBA) of credible options

Option	Description	Solution Type	PV Benefits[2] ($M)	PV Cost[3] ($M)	NPV[4,5] ($M)	Rank	Qualitative Assessment
0	No proactive intervention	Base case	-52.9	-	-52.9	5	Non-preferred as will lead to unacceptable risk and higher customer costs.
1	Replace 3 x 10/13.5 MVA Tx with 3 x 20/33 MVA Tx	Network solution	48.0	21.0	26.9	2	Non-preferred as it will not deliver the highest net economic benefits.
1A	**Replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx**	**Network solution**	**50.6**	**8.7**	**41.9**	**1**	**Preferred long-term option as it will deliver the highest net economic benefits and provide the right balance between medium and long-term needs.**
2	Construct 2x 20/33MVA zone substation in Inverloch	Network solution	43.0	35.9	7.1	4	Non-preferred as it will not deliver the highest net economic benefits.
2	Contract network support services to defer network investment	Non-network and new-technology solution	31.7	21.2	10.6	3	Non-preferred as it results in high operating costs and low net benefits from deferring investment in a network solution.

[2,3,4] **Notes:**
2: PV of total quantified benefits, both risks mitigated, and any forecast decrease in Capex or Opex arising from undertaking the investment.
3: PV of total costs, both capital expenditure (Capex) and operational expenditure (Opex).
4: NPV represents the difference between PV Benefits and PV Investment Costs.
5: The breakdown of PV is based on the parameters specified for the base case (Section 3.1).

2. Identified Need

2.1. Strategic Context

Wonthaggi is located approximately 135 kilometres southeast of Melbourne following the main transit corridor, the Bass Highway. The AusNet Services' network supplies approximately 23,008[2] customers in the Wonthaggi area, including Inverloch and San Remo (Figure 1). It represents the largest town within Bass Coast Shire and the municipality's regional centre. The town has the employment, shopping, and business environment of a regional centre, with multiple supermarkets, national chain store retail, and independent traders. State government population forecasts indicate that there will continue to be significant population growth for Bass Coast Shire in the next 20 years.

The population of Bass Coast Shire is expected to grow from 33,311 in 2016 to 46,429 in 2036, a growth of 39% in the next twenty years. Given that many services, including electricity, are planned and consumed per household (dwelling) rather than for individuals, the Department of Transport and Planning for Future Urban Development has estimated the number of dwellings needed to house the population. By 2053, the population growth in Wonthaggi and surrounding areas including Inverloch and San Remo will ultimately result in approximately 4,500[3] new residential dwellings and 70 hectares of employment land comprise industrial and commercial developments - town centres, schools, community facilities, and future commercial spaces. With the growing real-estate value in Australia, it is highly probable that development projects decide to increase their yield by increasing the total number of dwellings and commercial spaces available to maximise the projects' Return on Investment (ROI). This tendency has been observed more frequently, especially in the past years.

When fully developed beyond 2053, it is expected that the development areas in Wonthaggi and surrounding areas including Inverloch and San Remo will result in a new load in the order of 44[4] MVA is being added to AusNet Services' electricity network in South Gippsland. Several connection inquiries for connecting industrial/commercial loads have been already received, and applications to increase the capacity of the existing loads in the abovementioned areas have been made.

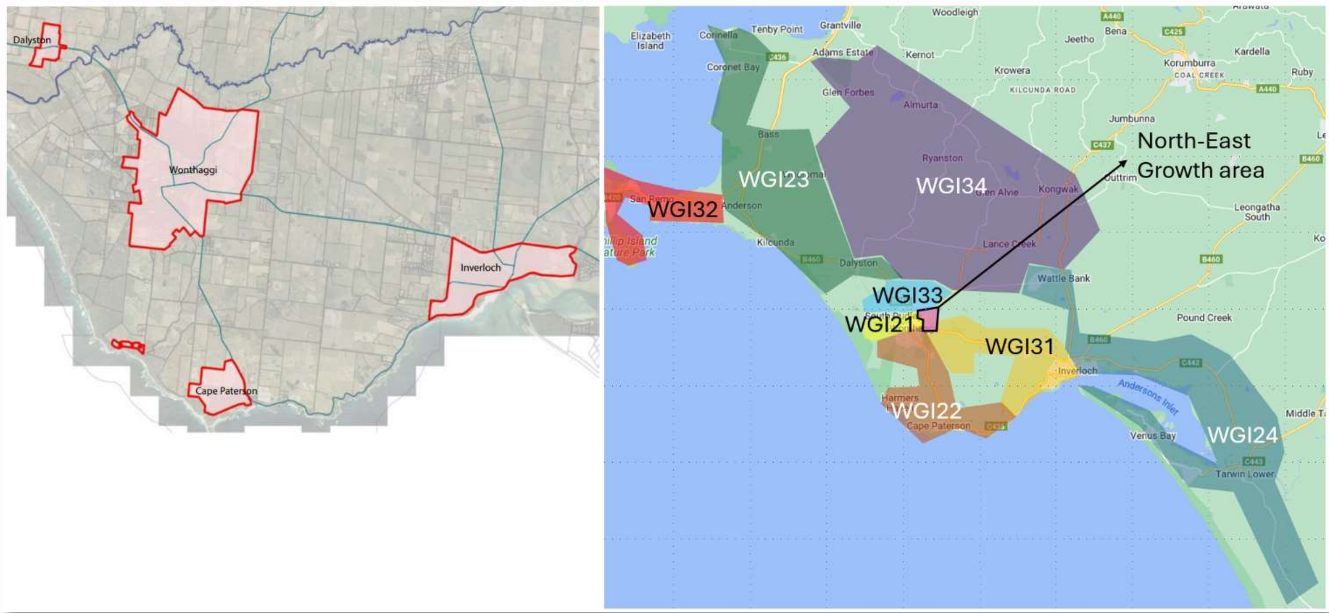

Figure 1: Areas supplied by the key 22kV feeders – WGI21, WGI22, WGI23, WGI24, WGI31, WGI32, WGI33, WGI34

As the population grows, so does the demand for electricity from the existing (brownfield) and new customer connections (greenfield). However, customer energy requirements are changing due to the ongoing energy transition. Both individual customers and businesses are increasingly inclined to shift away from gas, embrace low-emission transportation and heating choices, and amplify the effectiveness of their household appliances and the presence of distributed energy resources. Continued investments in DER to offset electricity from the grid don't eliminate the need for network capacity augmentations, as the maximum generation or demand typically occurs at different times. The electricity demand growth over the next decade is predicted to occur at a faster pace. This growth is primarily attributed to three key factors:

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[2] Source: Extract from the AusNet's internal customer database.
[3] Source: 2019-04-18-Wonthaggi-Structure-Plan-and-Discussion-Paper-FINAL.PDF (basscoast.vic.gov.au)
[4] 5.4kVA per dwelling is adopted for dwellings. 6MVA per km² is adopted for industrial load and 12MVA per km² for commercial load. The employment lands are expected to have 67% of the industrial load and 33% of the commercial load. Supply of residential lots is 30 years.

- population growth,
- decarbonisation through the electrification of transport, and
- the gradual transition from gas to electricity in households and industry.

All these factors combined will increase electricity demand, adding extra load to the electricity network in the South Gippsland supplied by AusNet Services.

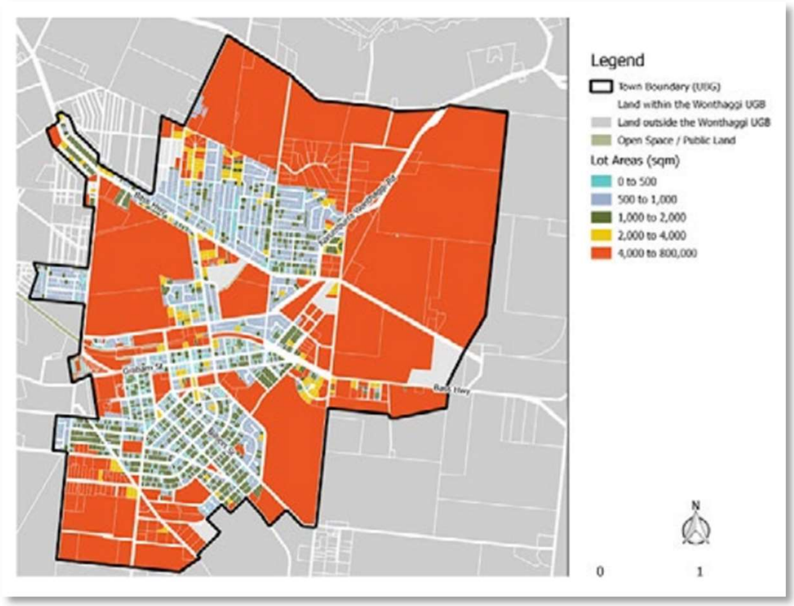

Figure 2: Key growth areas

2.2. Existing supply arrangements

The town of Wonthaggi and surrounding areas, including Inverloch and San Remo, are predominantly serviced by the 66/22kV Wonthaggi (WGI) zone substation (ZS) established in the mid-1960s. Currently, it has three aged 10/13.5 MVA transformers in deteriorating conditions and seven 22kV feeders with outdoor 66kV and 22kV switchgear in an un-switched configuration (Figure 3).

The No.1 transformer has been in service since 1976 while the No.2 and 3 date back to 1962. The No.1 transformer was refurbished in 2019 with a replacement of a tap changer and 66kV bushings. When the station was rebuilt, the switchyard was laid out to facilitate transformer replacement in sequences No.3, No.2, and No.1. The station has enough room to allow it to be developed to have three 20/33 MVA transformers and indoor 22 kV switchgear arranged in three buses with twelve 22 kV feeders.

The zone substation capacity consists of a nameplate rating of 40.5 MVA and 'N' and 'N-1' cyclic ratings of 45 MVA and 30 MVA, respectively.

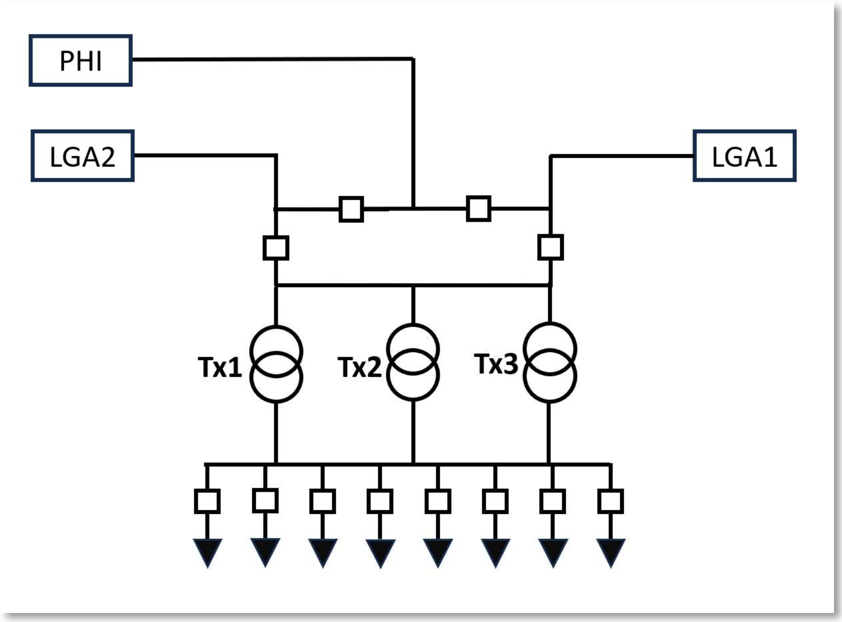

Figure 3: The high-level diagram of the existing WGI station

The WGI21 22kV feeder connects the Wonthaggi wind farm with a 12MW installed capacity. The wind farm is operated approximately 60% of the time.

2.1. Demand forecast

Based on this load demand growth information of future economic trends in the area, including information from government agencies regarding identified growth areas and other factors, 50% probability of exceedance (POE) and 10% POE maximum demand forecasts for the WGI station are produced and shown in Table 2 and Table 3.

Table 2: 90%, 50%, 10% POE Maximum Demand Forecast (MVA) - Winter

MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2053
P90%	32.6	33.5	34.4	35.4	36.3	37.3	38.4	39.5	40.6	41.7	42.7	43.9	45.0	46.1	46.1	46.1
P50%	36.0	36.9	37.9	39.0	40.0	41.1	42.2	43.4	44.6	45.7	47.0	48.3	49.4	50.6	50.8	50.8
P10%	41.4	42.5	43.6	44.7	45.8	47.0	48.2	49.5	50.8	52.0	53.2	54.4	55.6	56.9	57.1	57.1
Transfers	4.0	3.9	3.8	3.7	3.6	3.5	3.4	3.3	3.2	3.1	3.0	2.9	2.8	2.7	2.6	2.6
Emb gen	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Total P90%	21.4	22.4	23.4	24.5	25.5	26.6	27.8	29.0	30.2	31.4	32.5	33.8	35.0	36.2	36.3	36.3
Total P50%	24.8	25.8	26.9	28.1	29.2	30.4	31.6	32.9	34.2	35.4	36.8	38.2	39.4	40.7	41.0	41.0
Total P10%	30.2	31.4	32.6	33.8	35.0	36.3	37.6	39.0	40.4	41.7	43.0	44.3	45.6	47.0	47.3	47.3

Table 3: 90%, 50%, 10% POE Maximum Demand Forecast (MVA) - Summer

22kV feeder	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2053
P90%	36.7	37.3	38.0	38.6	39.3	40.2	40.9	41.7	42.5	43.3	44.1	44.9	45.7	46.4	46.7	46.7
P50%	40.9	41.5	42.2	43.0	43.7	44.5	45.4	46.3	47.2	48.1	49.0	49.9	50.8	51.6	52.1	52.1
P10%	45.6	46.4	47.3	48.2	49.0	49.9	50.9	51.9	52.9	53.8	54.8	55.8	56.7	57.6	58.0	58.0
Transfers	4.0	3.9	3.8	3.7	3.6	3.5	3.4	3.3	3.2	3.1	3.0	2.9	2.8	2.7	2.6	2.6
Emb gen	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Total P90%	25.5	26.2	27.0	27.7	28.5	29.5	30.3	31.2	32.1	33.0	33.9	34.8	35.7	36.5	36.9	36.9
Total P90%	29.7	30.4	31.2	32.1	32.9	33.8	34.8	35.8	36.8	37.8	38.8	39.8	40.8	41.7	42.3	42.3
Total P90%	34.4	35.3	36.3	37.3	38.2	39.2	40.3	41.4	42.5	43.5	44.6	45.7	46.7	47.7	48.2	48.2

2.2. Limitations of existing infrastructure

The zone substation capacity, consisting of a nameplate rating of 40.5 MVA and 'N' and 'N-1' cyclic ratings of 45 MVA and 30 MVA respectively, coupled with the age and condition of the existing transformers, is insufficient to reliably supply the forecast maximum demand, meaning that the current level of supply to the customers is expected to diminish if proactive intervention is not undertaken. The capacity of the existing station at times of maximum demand will be entirely utilised by 2024 under 'N-1" operating conditions, which will result in a load at risk from 2024 onwards (Table 4 and Figure 4). Extreme weather events and associated incidents, including periods of extreme heat or cold, may cause an exceedance of this capacity earlier than expected.

The annual service level risk due to these factors is forecast to increase from $0.2 million in 2024 to $1.3 million by 2031 (Table 5). In addition to the risk of unserved energy to existing customers, this will prevent new customers from connecting to AusNet Services' network in the area. This would directly violate AusNet Services' obligation to connect customers as per the National Electricity Rules (NER). There are also substantial reputational risks and stakeholder dissatisfaction if AusNet Services cannot meet supply requirements for this high-growth area. An investment into additional electrical capacity in this area is required to reduce this risk.

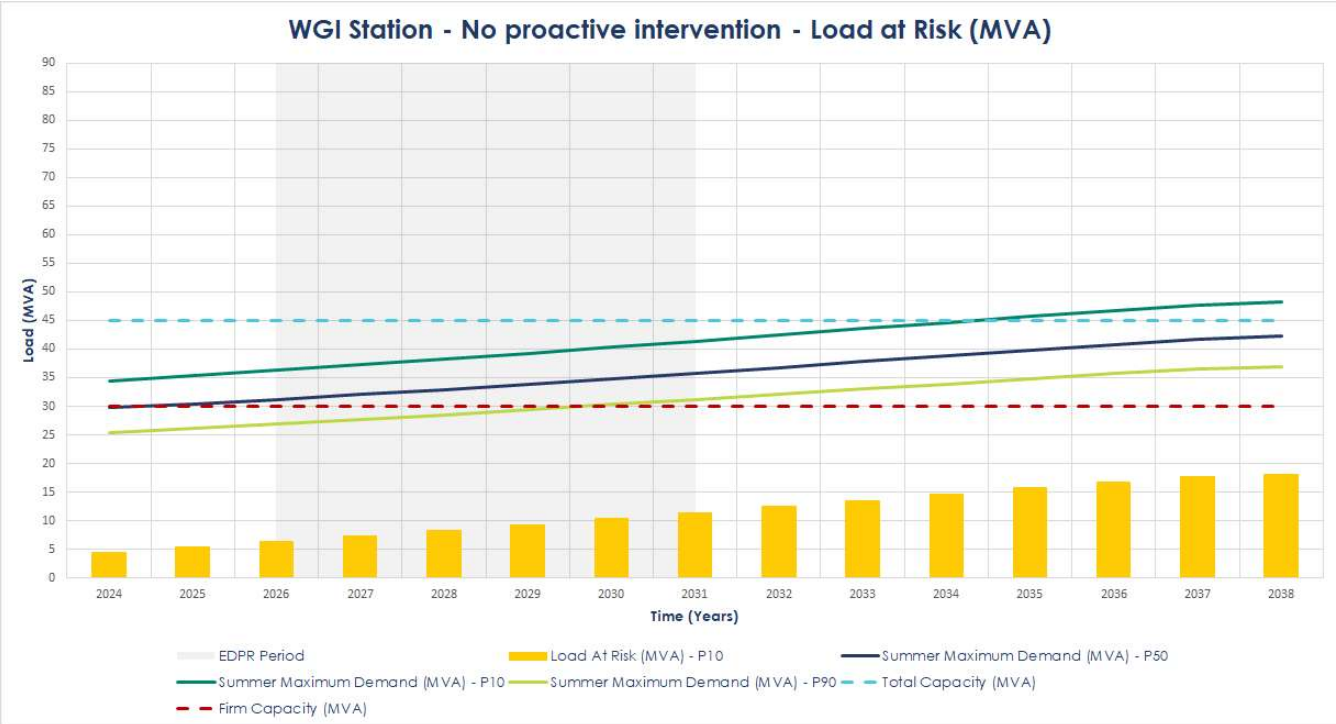

Figure 4: WGI station - Load @ Risk (MVA) - Graphical view

Table 4: WGI - Load @ Risk (MVA) - Tabular view

Timeline	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038		2053
Total P90%	25.5	26.2	27.0	27.7	28.5	29.5	30.3	31.2	32.1	33.0	33.9	34.8	35.7	36.5	36.9		36.9
Total P90%	29.7	30.4	31.2	32.1	32.9	33.8	34.8	35.8	36.8	37.8	38.8	39.8	40.8	41.7	42.3		42.3
Total P90%	34.4	35.3	36.3	37.3	38.2	39.2	40.3	41.4	42.5	43.5	44.6	45.7	46.7	47.7	48.2		48.2
Total Capacity (MVA)	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0		45.0
Firm Capacity (MVA)	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0		30.0
Load @ Risk POE 10 (MVA)	4.4	5.3	6.3	7.3	8.2	9.2	10.3	11.4	12.5	13.5	14.6	15.7	16.7	17.7	18.2		18.2

2.3. Summary of identified need

AusNet Services has identified a need to increase the ability of the WGI station in South Gippsland to supply the forecast demand and manage the increasing risk of load shedding beyond 2024. The forecast service level risk driving the identified need to invest is primarily caused by existing transformers' capacity limitations, age and condition, which can require load reduction to maintain network loading within network capabilities to avoid damaging assets and risking personnel and public safety.

Meeting this identified need is expected to result in an increase in producer and consumer surplus (a net economic benefit to all those who produce, consume and transport electricity in the NEM), primarily by reducing the cost of expected unserved energy by more than the proposed preferred solution's cost, including implementation, operating and maintenance costs. Consequently, the investment in increased capacity will deliver the market benefit by reducing the amount of involuntary load shedding in line with Section 5.17.1 of the NER. The Expected Unserved Energy (EUE) and community cost are described in Section 3.2.

3. Options considered

This section outlines the options that were considered in the long-term interests of consumers, including a "no proactive intervention" counterfactual option to assist overall comparison. These include all substantially differing commercially and technically credible options, including non-network and new technology solutions. Credible options (or a group of options) are those that meet the following criteria:

- addresses the identified need,
- is (or are) commercially and technically feasible and
- can be implemented in sufficient time to meet the identified need.

The forecasted load requirements and limitations of existing infrastructure necessitate the investigation of additional supply options to address the loading of assets above their ratings in the West Gippsland area.

The options analysed to address distribution feeder exceeding planning design ratings are as follows:

- Option 0: No proactive intervention
- Option 1 - Replace 3 x 10/13.5 MVA Tx with 3 x 20/33 MVA Tx
- Option 1A - Replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx
- Option 2 - Construct 2x 20/33MVA zone substation in Inverloch
- Option 3 - Contract network support services to defer network investment

Each credible option is further elaborated in the subsequent chapter.

3.1. Assessment approach

The NER states that quantifiable economic market benefits include changes in involuntary load shedding. The quantified costs and benefits described in this section included this benefit in determining the best option. AusNet Services Distribution Network Planning Standards and Guidelines were used to estimate the involuntary load shedding that can be prevented by proactive action. The estimated involuntary load shedding was utilised by the cost-benefit analysis (CBA) along with a Value of Customer Reliability (VCR) to calculate a market benefit. The VCR is an estimation of the value that customers place on a reliable electricity supply. This value is equivalent to the cost to consumers of having their electricity supply interrupted for a short time. No other identified risks were included in the CBA.

The key assumptions used in the CBA for the base case are:

- A study period of 30 years, with FY2024 being the first year of analysis and base year for dollar inputs.
- The commercial discount rate was set to 5.56% based on the average of 4.11% and AEMO's IASR central scenario discount rate of 7%
- A VCR of $36,300 per MWh was used in the analyses, comprising 61% residential, 29% commercial and 4% industrial and 6% agricultural loads. This estimation is based on the WGI energy usage profile in the last calendar year (i.e. CY2023).
- Asset life is assumed to be 45 years and battery life 15 years.
- The benefits of options are based on the avoided expected unserved energy.

- NPV is based on the parameters specified for the base case.

3.2. Option 0: No proactive intervention

This chapter analyses the risks and benefits of taking no proactive interventions or maintaining the status quo. The option connects the proposed loads to the existing WGI station and analyses the impact on network capacity and unserved energy. The consequence of not proceeding with any investment in the area supplied by the WGI station will result in significant unserved energy due to the existing station being constrained and incapable of supplying the forecast demand, as shown in Figure 5 and Table 5.

In terms of risk/cost assessment, the no proactive intervention option provides a base case where the risks are valued by applying a VCR to the forecast expected unserved energy.

Without proactive intervention, a risk of unserved energy will remain, as shown in Figure 5 and Table 5, resulting in AusNet Services being unable to provide supply security in Wonthaggi and surrounding areas including Inverloch and San Remo. In addition to the risk of unserved energy to existing customers, the option of no proactive intervention will also prevent connecting new customers to AusNet Services' network. This would directly violate AusNet Services' obligation to connect customers as per the NER. There are also substantial reputational risks and stakeholder dissatisfaction if AusNet Services cannot meet supply requirements for this high-growth area.

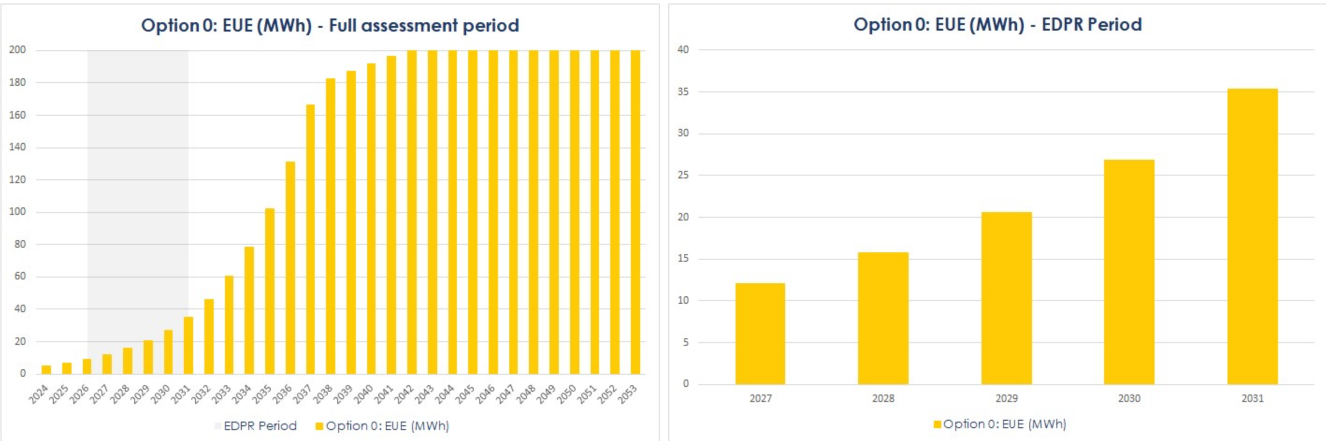

Figure 5: EUE as a result of no proactive intervention – Graphical view

Table 5: EUE as a result of no proactive intervention – Tabular view

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038		2053
EUE (MWh)	5.2	6.9	9.2	12.0	15.7	20.5	26.8	35.3	46.1	60.3	78.7	102.1	131.3	166.5	182.8		182.8
EUE Value ($M)	0.2	0.3	0.3	0.4	0.6	0.7	1.0	1.3	1.7	2.2	2.9	3.7	4.8	6.0	6.6		6.6

3.3. Option 1: Replace 3 x 10/13.5 MVA Tx with 3 x 20/33 MVA Tx

3.3.1. Scope

Option 1 proposes replacing existing transformer units with new, larger units - 3 x 20/33 MVA, which will provide a total capacity of 85 MVA and firm substation capacity of 57 MVA by 2033 as per optimal timing analysis. A high-level diagram of this option can be found on Figure 6.

Primary works within WGI will include but are not limited to the design, procurement, installation/modification, testing and commissioning of the following:

- 66kV Switchyard & Transformers
- HV cables

Secondary works within WGI will include but are not limited to the design, procurement, installation/modification, testing and commissioning of the following:

- Protection and Control
- SCADA
- Metering
- AC & DC Supplies

REFCL Works include REFCL re-commissioning and REFCL engineering.

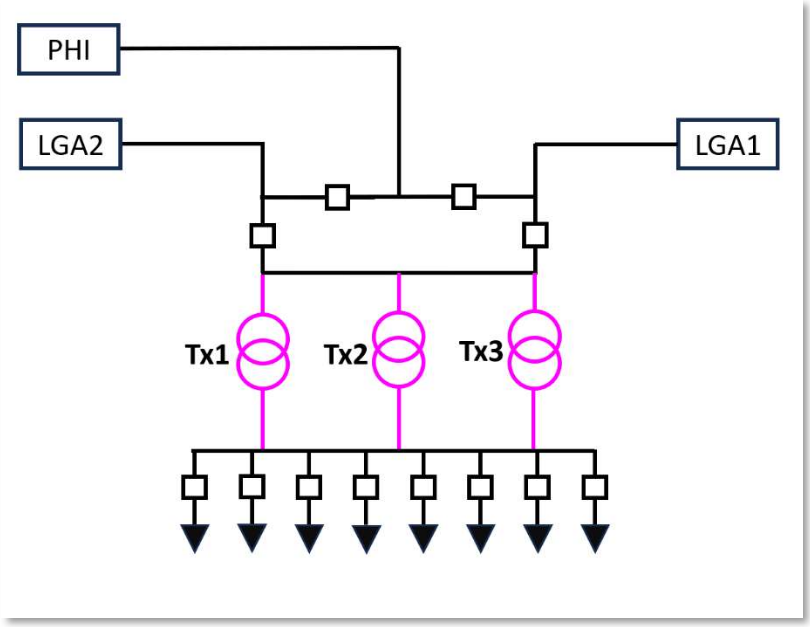

Figure 6: High-Level diagram for Option 1. New assets in magenta.

Figure 7 and Figure 8 presents how this option will reduce the unserved energy compared to the base case (no proactive intervention). While this option reduces the unserved energy compared to the base case, unserved energy is still expected from 2024 until the optimal timing of commissioning the works under this option, which is 2033.

In summary, Figure 10 and Table 11 present a cumulative impact of the investments proposed under this option on expected unserved energy compared to the base case (no proactive intervention).

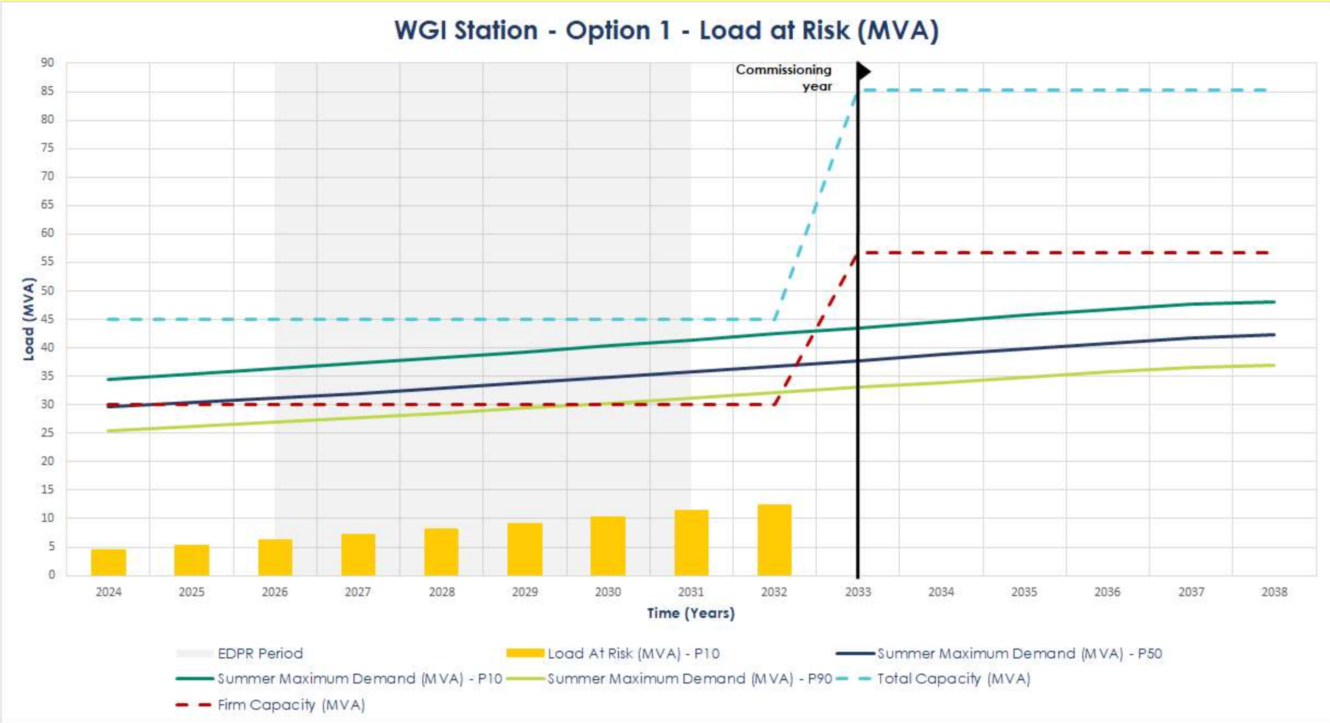

Figure 7: Option 1 - Load @ Risk (MVA) - Graphical view

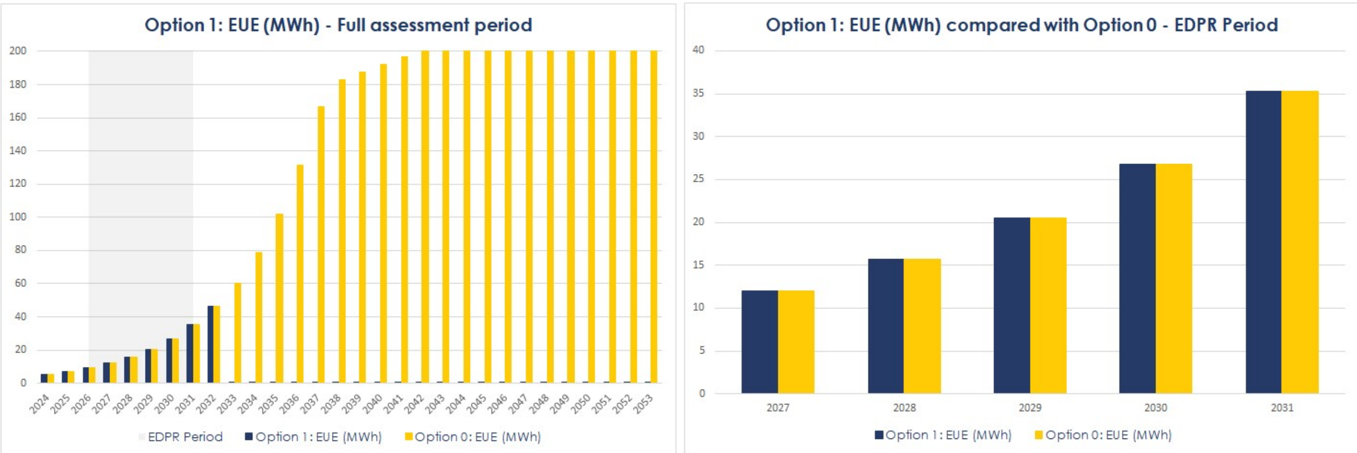

Figure 8: Option 1 - EUE results compared with no proactive intervention – Graphical view

Table 6: EUE as a result of Option 1 intervention – Tabular view

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038		2053
Option 1 - WGI EUE (MWh)	5.2	6.9	9.2	12.0	15.7	20.5	26.8	35.3	46.1	0.1	0.2	0.2	0.4	0.5	0.6		0.6
Option 1 - WGI EUE Value ($M)	0.2	0.3	0.3	0.4	0.6	0.7	1.0	1.3	1.7	0.00	0.01	0.01	0.01	0.02	0.02		0.02

3.3.2. Cost

The total estimated value of the capital cost of Option 1 is **$32.4M**. The cost is spread over three years to align with construction timelines and is based on estimates provided by the estimating team. Commissioning of new equipment from Option 1 is planned for FY33. A summary of the capital cost can be found in Table 7.

Table 7: Capital cost summary (undiscounted, real June 2024 dollars)

Year	FY31	FY32	FY33	FY34	FY35
Option 1	$10,800,000	$10,800,000	$10,800,000	-	-

3.3.3. Benefits

The quantifiable economic market benefits include changes in involuntary load shedding. Unserved energy was used to estimate the involuntary load shedding that can be prevented because of the proactive action provided by this option.

The total present value of benefits for Option 1 for the entire assessment period is **$48.0M**.

3.3.4. Summary of CBA assessment

A summary of the cost-benefit assessment is provided in Table 8:

Table 8: CBA outputs

Option	PV Cost ($M)	PV Benefits ($M)	NPV ($M)
1	21.0	48.0	26.9

3.4. Option 1A: Replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx

3.4.1. Scope

Option 1A proposes replacing the existing transformer unit Tx3 with new, larger units - 1 x 20/33 MVA, which will provide a total capacity of 63 MVA and firm substation capacity of 57 MVA by 2029 as per optimal timing analysis. A high-level diagram of this option can be found on Figure 6.

Primary works within WGI will include but are not limited to the design, procurement, installation/modification, testing and commissioning of the following:

- 66kV Switchyard & Transformer no 3
- HV cables

Secondary works within WGI will include but are not limited to the design, procurement, installation/modification, testing and commissioning of the following:

- Protection and Control
- SCADA
- Metering
- AC & DC Supplies

REFCL Works include REFCL re-commissioning and REFCL engineering.

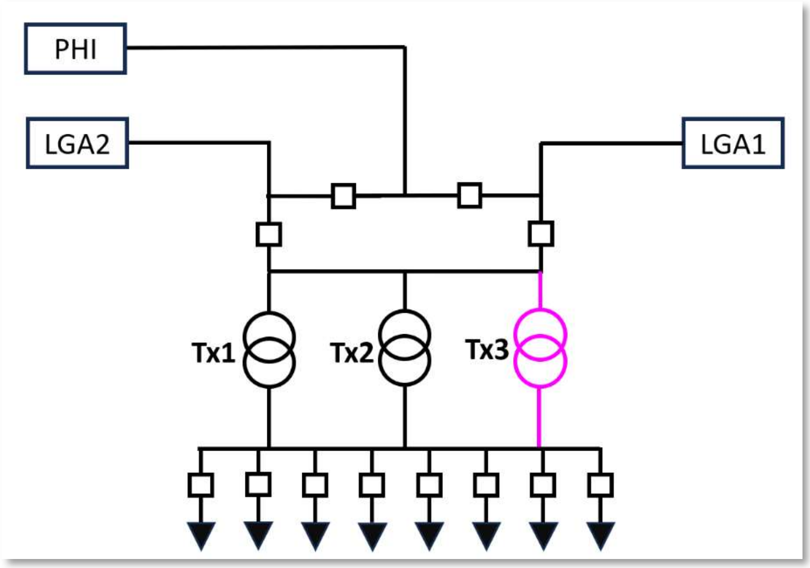

Figure 9: High-Level diagram for Option 1A. New assets in magenta.

Figure 10 presents how this option will reduce the unserved energy compared to the base case (no proactive intervention). While this option reduces the unserved energy compared to the base case, unserved energy is still expected from 2034 onwards. However, it provides a staged approach to the accounting for the uncertainties in the load forecast materialisation.

In summary, Figure 10 and Table 11 present a cumulative impact of the investments proposed under this option on expected unserved energy compared to the base case (no proactive intervention).

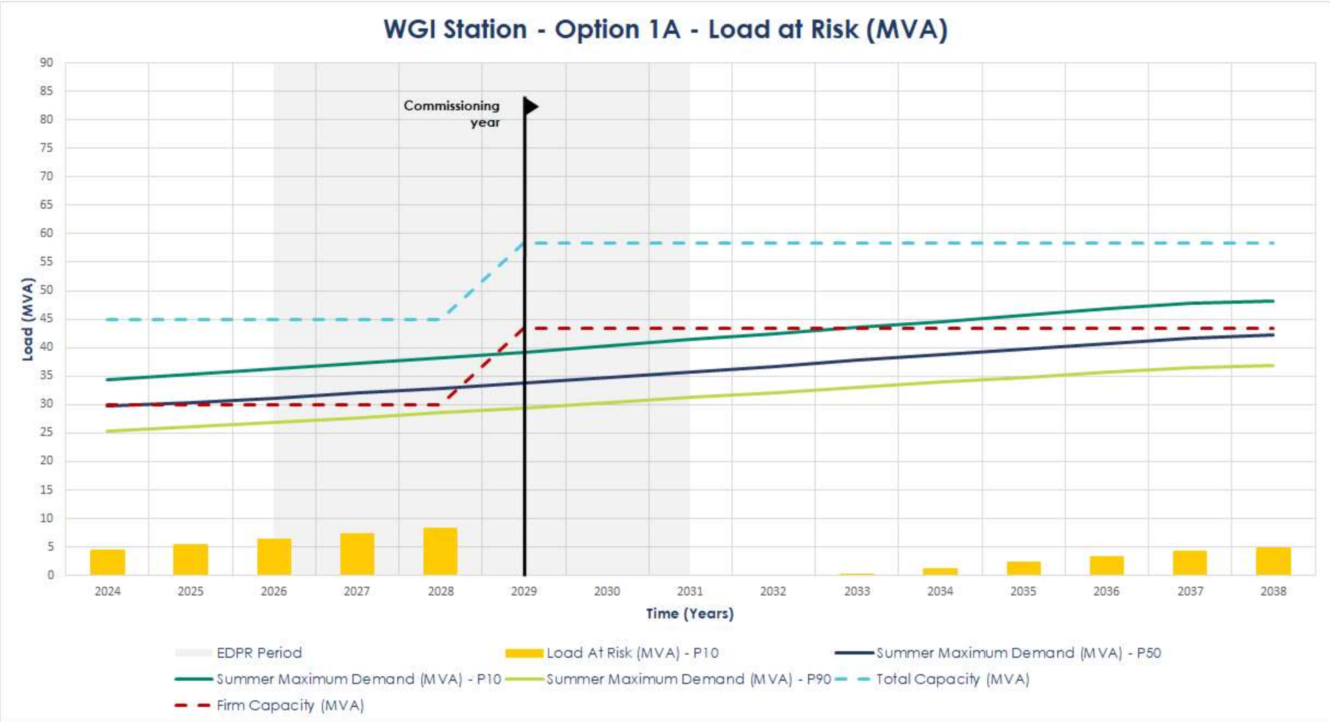

Figure 10: Option 1A - Load @ Risk (MVA) - Graphical view

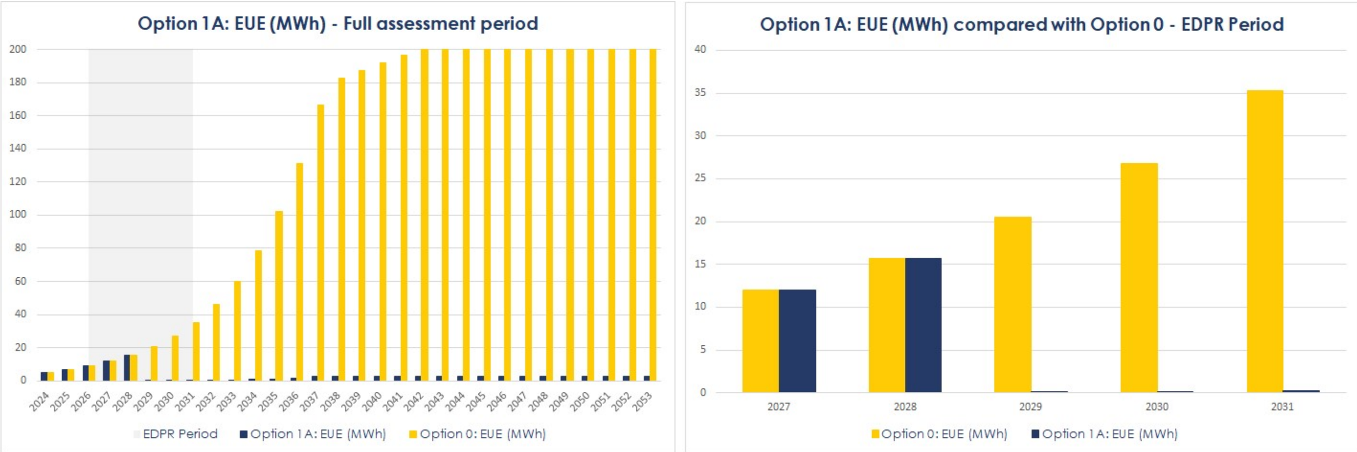

Figure 11: Option 1A - EUE results compared with no proactive intervention – Graphical view

Table 9: EUE as a result of Option 1A intervention – Tabular view

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038		2053
Option 1A - WGI EUE (MWh)	5.2	6.9	9.2	12.0	15.7	0.1	0.1	0.2	0.4	0.6	0.9	1.3	1.9	2.6	3.0		3.0
Option 1A - WGI EUE Value ($M)	0.2	0.3	0.3	0.4	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1		0.1

3.4.2. Cost

The total estimated capital cost of Option 1A is **$10.9M**. The cost is spread over three years to align with construction timelines and is based on estimates provided by the estimating team. Commissioning of new equipment from Option 1A is planned for FY29. A summary of the capital cost can be found in Table 7.

Table 10: Capital cost summary (undiscounted, real June 2024 dollars)

Year	FY27	FY28	FY29	FY30	FY31
Option 1A	$3,600,000	$3,600,000	$3,600,000	-	-

3.4.3. Benefits

The quantifiable economic market benefits include changes in involuntary load shedding. Unserved energy was used to estimate the involuntary load shedding that can be prevented because of the proactive action provided by this option.

The total present value of benefits for Option 1A for the entire assessment period is **$50.6M**.

3.4.4. Summary of CBA assessment

A summary of the cost-benefit assessment is provided in Table 8:

Table 11: CBA outputs

Option	PV Cost ($M)	PV Benefits ($M)	NPV ($M)
1A	**8.7**	**50.6**	**41.9**

3.5. Option 2: Construct 2x 20/33MVA zone substation in Inverloch

3.5.1. Scope

This option proposes to establish a new zone substation in Inverloch with 2x 20/33 MVA transformers, which will provide additional capacity in the supply area and more transfer capability. Based on optimal timing analysis, this option will provide additional capacity by 2036, resulting in unserved energy between 2024 and 2036.

This option proposes the following equipment to be installed:

- land in Inverloch
- 2 x 20/33 MVA 66/22 kV transformers,
- 2 x transmission feeder bays,
- 2 x 66 kV bus sections and
- 2 x 22 kV switchboards.

Figure 12 and Figure 13 presents how this option will reduce the unserved energy compared to the base case (no proactive intervention). While this option reduces the unserved energy compared to the base case, unserved energy is still expected from 2024 until the optimal timing of commissioning the works under this option, which is 2036.

In summary, Figure 10 and Table 11 present a cumulative impact of the investments proposed under this option on expected unserved energy compared to the base case (no proactive intervention).

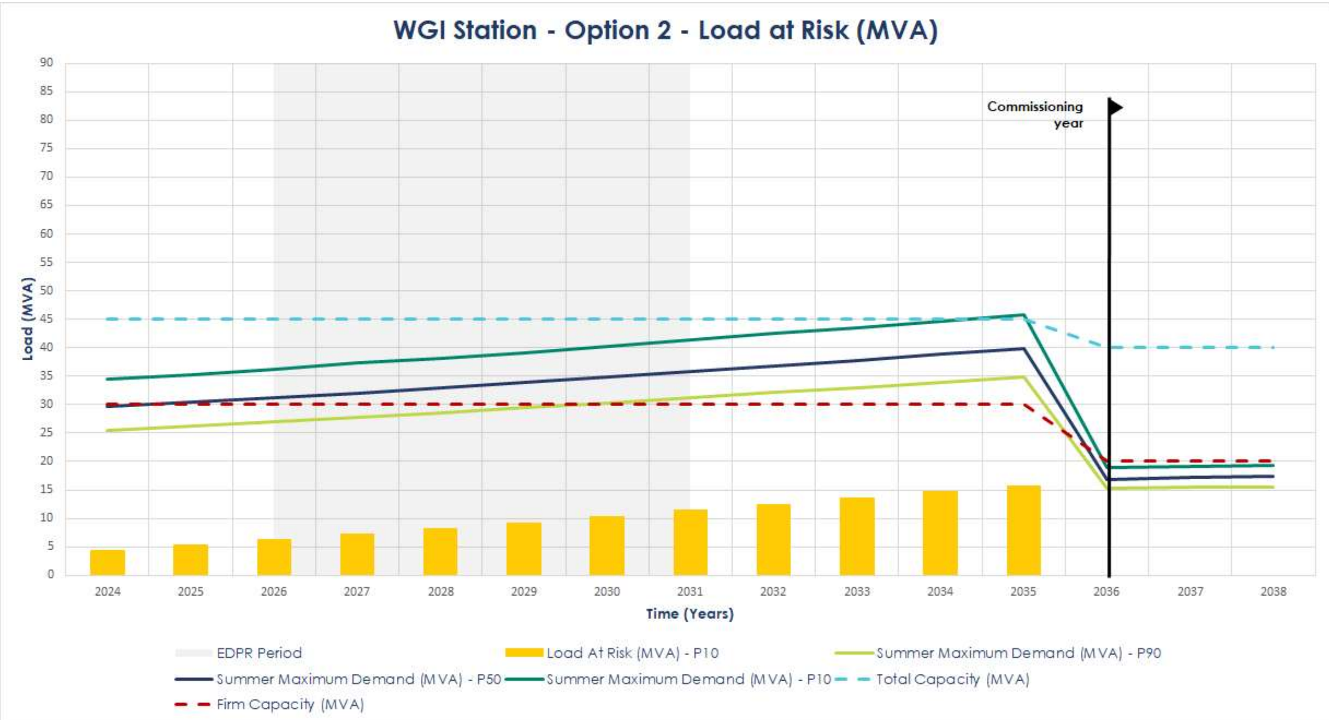

Figure 12: Option 2 - WGI - Load @ Risk (MVA) - Graphical view

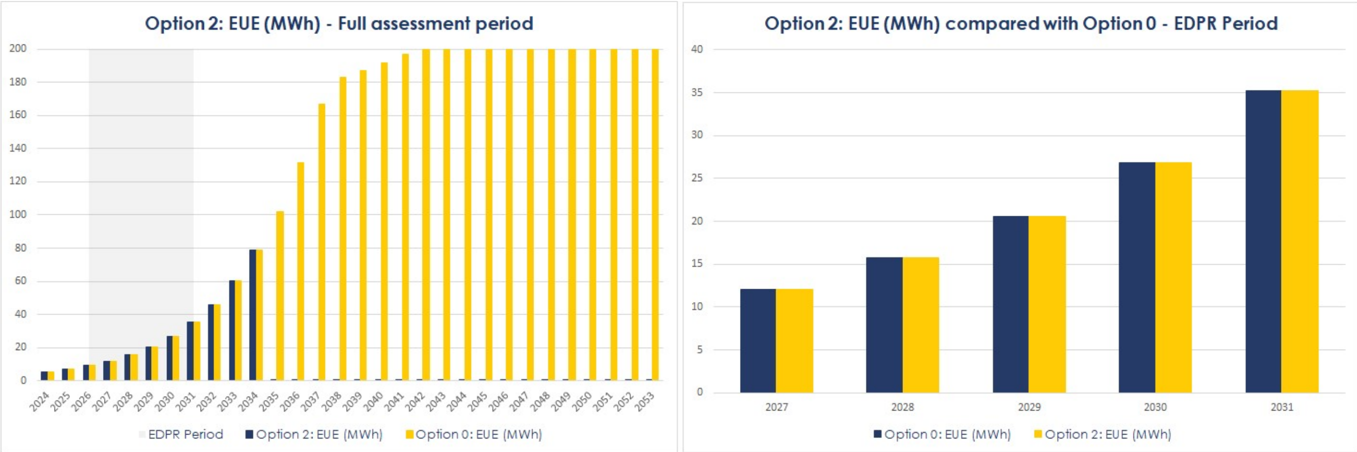

Figure 13: Option 2 -EUE results compared with no proactive intervention – Graphical view

Whilst the battery will be able to provide network support to mitigate load at risk in the short-term, existing regulations and ring-fencing guidelines prevent AusNet Services from accessing the same revenue stack as external unregulated businesses.

Figure 14: EUE as a result of Option 2 intervention – Tabular view

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2053
Option 2 EUE (MWh)	5.2	6.9	9.2	12.0	15.7	20.5	26.8	35.3	46.1	60.3	78.7	102.1	-	-	-	-
Option 2 EUE Value ($M)	0.2	0.3	0.3	0.4	0.6	0.7	1.0	1.3	1.7	2.2	2.9	3.7	-	-	-	-

3.5.2. Cost

The total estimated capital cost of Option 2 is **$65M**. The cost is spread over three years to align with construction timelines and is based on estimates provided by the estimating team. Commissioning of new equipment from Option 2 is planned for FY36. A summary of the capital cost can be found in Table 12.

Table 12: Capital cost summary (undiscounted, real June 2024 dollars)

Year	FY32	FY33	FY34	FY35	FY36
Option 2	-	-	$21,666,667	$21,666,667	$21,666,667

3.5.3. Benefits

The quantifiable economic market benefits include changes in involuntary load shedding. Unserved energy was used to estimate the involuntary load shedding that can be prevented because of the proactive action provided by this option.

The total present value of benefits for Option 2 for the entire assessment period is **$43.0M**.

3.5.4. Summary of CBA assessment

A summary of the cost-benefit assessment is provided in Table 13:

Table 13: CBA outputs

Option	PV Cost ($M)	PV Benefits ($M)	NPV ($M)
2	**35.9**	**43.0**	**7.1**

3.6. Option 3: Contract network support services to defer network investment

3.6.1. Scope

The NER require DNSPs to investigate non-network and new-technology options by utilising a consultation process as part of planning for major network augmentations. A credible non-network and new-technology option are those that meet the following criteria:

- able to form a credible stand-alone option (i.e., without being combined with a network solution), or
- able to defer the network investment.

3.6.1.1. Requirements that a non-network option would need to satisfy

This section outlines the technical characteristics of the identified need that a non-network and new technology solution via network support services would be required to deliver, along with an indication of the maximum fee that AusNet Services could pay to a network support proponent to mitigate the identified risks. The specific network support requirements are presented in the Table, which outlines the following:

- Average expected network support response (MWh), which is the average volume of support that is expected to be required each year.
- Potential value of network support ($M), which is based on the probability-weighted annualised service level risk cost of each limitation and represents the maximum fee that AusNet Services could pay to a network support proponent, completely mitigating the associated service level risk.

Table 14: Network support requirements for WGI capacity risk mitigation

Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038		2053
Average expected network support (MWh)	2.1	2.8	3.7	4.8	6.3	8.2	10.7	14.1	18.5	24.1	31.5	40.8	52.5	66.6	73.1		73.1
Potential value of network support ($M)	0.1	0.1	0.1	0.2	0.2	0.3	0.4	0.5	0.7	0.9	1.1	1.5	1.9	2.4	2.7		2.7

3.6.1.2. Qualitative assessment of specific non-network and new technology options

Table 15 summarises non-network and new technology options for meeting the requirements of Section 3.6.1.1. The analysis outlined in the following sections found at least two credible non-network options (BESS and Behavioural Demand Response). These options need to be further evaluated using the screening test in the RIT-D process. AusNet Services will issue a non-network options report before progressing with the Draft Project Assessment Report (DPAR) as part of the RIT-D process.

Table 15 - Non-network and new-technology solutions

Non-network and new-technology option	Potential outcomes	Qualitative assessment	Comments
Grid-Scale Storage (5 MW /10 MWh)	Potentially defers the network investment into the next regulatory cycle	✓	This option is feasible and should be investigated further as it could defer the network investment into the next regulatory cycle. However, this option requires a large capacity augmentation to enable

			connection to the NEM and commercial operation. This augmentation would have a similar cost to the network options. The operating life of the BESS (15 years) is much shorter than the life of the network asset (45 years). Moreover, new storage would likely need to acquire land to be situated on, which would further increase the cost and practical difficulties associated with these solutions.
Virtual Power Plant (VPP)	Defers the network investment by one year	✗	It is not feasible as this solution requires a large capacity and a significant storage uptake by 2029.
Residential BESS aggregation	Defer the network investment by two years	✗	This is not feasible as this solution will require a significant uptake of residential BESS by 2029.
Commercial Direct Load Control	Defer the network investment by two years	✗	This is not feasible as the area has 29% commercial and 4% industrial customers. Additionally, these programs are generally intended for large-scale industrial customers who possess building and process management systems that support a coordinated and controlled load conrol.
Behavioural Demand Response	Defer the network investment by one year	✓	Behavioural Demand Response could be a feasible option to defer network investment if there is sufficient participation from existing customers and should be investigated further. However, the deferred network investment may still fall within the FY27-31 regulatory cycle.

3.6.2. Benefits

The quantifiable economic market benefits include changes in involuntary load shedding. Unserved energy was used to estimate the involuntary load shedding that can be prevented because of the proactive action provided by this option.

The total present value of benefits for Option 3 for the entire assessment period is **$31.7M**.

3.6.3. Summary of CBA assessment

A summary of the cost-benefit assessment is provided in the following Table 16:

Table 16: CBA outputs

Option	PV Cost ($M)	PV Benefits ($M)	NPV ($M)
3	21.2	31.7	10.6

4. Recommended Option

Figure 15 below sets out the credible options considered together with the option Base Case - "no proactive intervention" to assist with the overall comparison. Option 1A represents the highest value (economic benefit), being NPV positive of **$41.9 Million** compared to other options, even with the sensitivity & scenarios considered in Section. This option allows AusNet Services to provide the most efficient, reliable, and safe supply services in the long-term interest of its customers. Hence, Option 1A is the preferred long-term network configuration for the project's overall scope.

Figure 15: CBA of credible options

Option	Description	Solution Type	PV Benefits[2] ($M)	PV Cost[3] ($M)	NPV[4,5] ($M)	Rank	Assessment
0	No proactive intervention	Base case	-52.9	-	-52.9	5	Non-preferred as will lead to unacceptable risk and higher customer costs if the opportunity is not captured.
1	Replace 3 x 10/13.5 MVA Tx with 3 x 20/33 MVA Tx	Network solution	48.0	21.0	26.9	2	Non-preferred as it will not deliver the highest net economic benefits.
1A	**Replace 1 x 10/13.5 MVA Tx with 1 x 20/33 MVA Tx**	**Network solution**	**50.6**	**8.7**	**41.9**	**1**	**Preferred long-term option as it will deliver the highest net economic benefits.**
2	Construct 2x 20/33MVA zone substation in Inverloch	Network solution	43.0	35.9	7.1	4	Non-preferred as it will not deliver the highest net economic benefits.
2	Contract network support services to defer network investment	Non-network and new-technology solution	31.7	21.2	10.6	3	Non-preferred as it results in high operating costs and low net benefits from deferring investment in a network solution.

[2,3,4,5] **Notes:**
2: PV of total costs, both capital expenditure (Capex) and operational expenditure (Opex).
3: PV of total quantified benefits, both risks mitigated, and any forecast decrease in Capex or Opex arising from undertaking the investment.
4: NPV represents the difference between PV Benefits and PV Investment Costs.
5: The breakdown of PV is based on the parameters specified for the base case (Section 3.1).

5. Sensitivity analysis

5.1.1. Sensitivity analysis

Sensitivity testing was undertaken to ensure that the NPV calculations of the options were robust to changes in key input parameters. This provides confidence that identifying the preferred option is the most prudent option for the project under changes to key variables.

The key variables included in the sensitivity analysis and shown below were:

- Discount rate used for the discounted cash flow in the evaluation
- Capital cost estimates
- VCR
- Asset unavailability rate

Sensitivity testing was conducted on each of the options assessed under the CBA. Three scenarios were tested around key cost and benefit values ranging from low, baseline, and high benefits cases. The cases differ from the baseline case by +/- percentage. The variables were selected to vary under the scenario due to some uncertainty around the forecast assumption and the importance of the parameter in the calculation.

A summary of the sensitivity investigated is provided in Table 17. The sensitivity assessment in Table 18 shows that when each scenario is run, the ranking remains the same, indicating that Option 1A is still preferred.

Table 17: Variables

Variable	Base case	Low case (low benefits)	High case (high benefits)
Capital cost	Estimated network capital costs	25% increase in the estimated network capital costs	25% decrease in the estimated network capital costs
VCR	$36,300/MWh	$45,006[5]/MWh	$53,425[5]/MWh
Discount rate	5.56% (WACC)	7.00%	4.11%
Asset unavailability rate	Probability of failure rates as provided by the Asset Management Group	10% decrease in the probability of failure rates provided by the Asset Management Group	10% increase in the probability of failure rates provided by the Asset Management Group

Table 18: Weighted NPV for credible options considered

Option	Base Case – NPV ($M)	Low Case – NPV($M)	High Case - NPV($M)	Option rank
1	26.9	16.2	91.0	2
1A	**41.9**	**32.2**	**104.7**	**1**
2	7.1	-3.4	71.2	4
3	10.6	8.8	23.0	3

5.1.2. Proposed Investment Timing

Optimal timing analysis is based on the 'crossover' method described by the Australian Energy Regulator (AER). The method identifies the optimal year as the first year when net operating benefits are more significant than the annualised cost of an option (i.e., the 'crossover'). The optimal timing where the value of unserved energy from the

[5] Based on the AusNet's Customer Willingness to Pay research.

'No Proactive Intervention' scenario exceeds investment costs for Option 1A is 2029, as per Table 19 and Figure 16. This timing aligns with the proposed commissioning date of Option 1A.

Table 19: Annualised cost and optimal commissioning year for Option 1A

Option	Annualised Cost	Optimal Year
1A	$658,136	**2029**

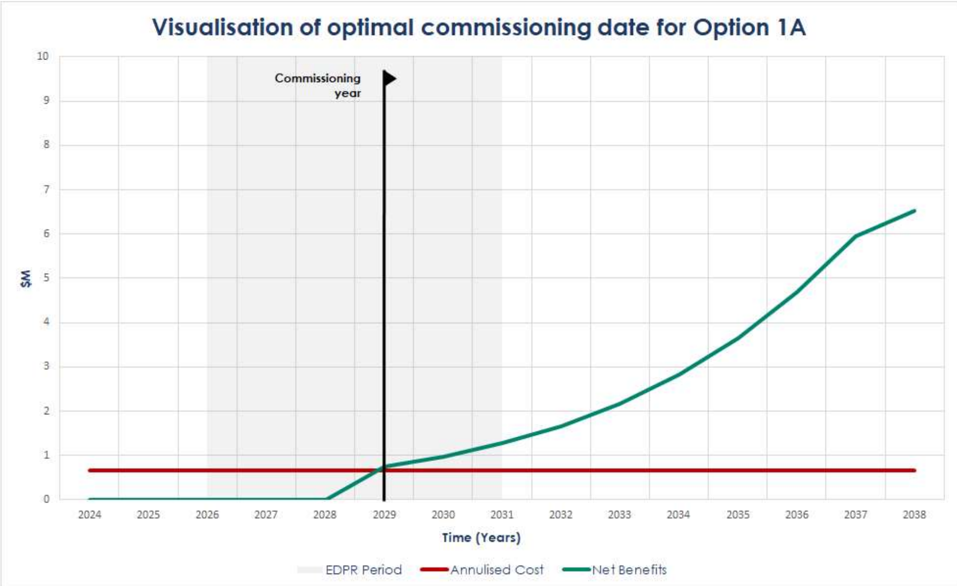

Figure 16: Visualisation of optimal commissioning year for Option 1A

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