Smart Meter Data Acquisition

Business Case

19 November 2024

Part of Energy Queensland

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1 SUMMARY

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This case addresses several needs - the need to improve outage response times, the need to provide a safe network and the need to reduce where possible, the cost of replacing network assets The rollout of smart meters provides us with the opportunity to utilise the available engineering data for our LV networks. The benefits that will flow from this include:
Reliability – improved reliability from identifying and responding more quickly for service line and distribution transformer failures.
CECV – better visibility allows us to set less conservative operating envelopes for export.
Safety – obtaining data will allow us to identify and respond to broken neutrals on our LV service lines.
Environmental – better visibility allows us to set less conservative operating envelopes for export and reduce emissions by utilising distributed energy resources (DER) rather than alternative fuel sources for our energy mix.
Financial – monitoring our LV service population will allow us to time our replacements more effectively, reducing replacement costs.</td></tr>
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2 CHANGES SINCE THE REGULATORY PROPOSAL

Following the submission of our Regulatory Proposal, we identified an error in our cost benefit analysis (CBA) modelling. We rectified this mistake and re-submitted our Smart Meter Data Acquisition business case in May 2024. The error in our CBA modelling did not change our preferred option, Option 4. This option was to capture data from all the service lines in our network, with 25% of data from our overhead network being captured near real-time and 10% of our underground network near real-time. The remaining data was captured on what we had assumed would be a 6-hourly basis. There have been several changes that we have made to our Smart Meter Data Acquisition business case since the Regulatory Proposal (RP), which we outline below.

2.1 Australian Energy Market Commission (AEMC) Draft Decision

Since the submission of our RP, the AMEC has released its final decision on *Accelerating smart meter data deployment*. There were several clarifications in the final decision that required us to alter our inputs to our CBA modelling. Specifically:

- **6-hourly data:** The AEMC's final decision proposes that basic power quality data be made available to distribution networks every 24-hours, potentially on a 6-hourly rotational basis. This is a significant change, where we had assumed that free basic data would enable us to monitor the network every 6 hours, we now can only rely on free data every 24 hours. This substantially changes the difference in value between paying for near real-time data and relying on the free data that comes in every 24 hours. As we outline through the business case, this change has informed the differences in benefits between acquiring near real-time and 24-hour data.

[redacted]

- **Timing change**: The Draft Decision also included a delayed start date for free data to be available to distribution businesses. This means that for the first year of the 2025-2030 regulatory period we would need to purchase both near real-time and 24-hour data.

2.2 AER Release of Valuing Emissions Reduction Final Guidance

Following the submission of our RP, the AER released its *Valuing emissions reduction final guidance*, which outlined the carbon emissions pricing that we should utilise to value the reduction in emissions from the efficient integration of distributed energy resources (DER). We had estimated a carbon price well below this final guidance, as was noted in the AER's Draft Decision. We have since updated this input in our modelling, which has increased the benefits of smart meter data acquisition as it relates to near real-time data and DER integration.

2.3 Changes in response to AER and EMCa feedback

The AER and EMCa questioned some of the inputs and assumptions in the CBA modelling. Their concerns and our adjustments are summarised below.

2.3.1 Cost of data acquisition

[redacted]

2.3.2 Safety reduction benefits reliability improvement

In our original business case, we assumed that near real-time data acquisition would be able to identify 90% of neutral integrity and other service line safety issues prior to causing a safety concern for our customers and the community. This was based on our best judgement at the time. EMCa and the AER had concerns that the conversion rate was too high.

Since the RP, we have been collecting data from our current smart meter data acquisition trials. From a population of 45,000 service lines, we have identified 45 neutral integrity issues. When comparing this to our overall population of service lines and associated failures, this shows that our smart meter data acquisition is detecting around half of the asset failures that you would expect in the population. Over the next year we will be continuing to calibrate our detection algorithms and expect to be able to at least detect 60% of network faults from smart meter data. Our data also shows that around 36% of shocks occur within the first day of a neutral integrity issue, with 25% within 1-3 days. As a result of this data, we have adjusted our detection rate of a fault prior to a safety incident to 60% for near real-time data, and 36% for 24-hour data.

2.3.3 Reliability improvement benefits

Our modelling also includes an improvement in reliability that will result from being able to detect outages more quickly through access to near real-time data. This was for both individual service line faults affecting a single customer and distribution transformer faults which typically affect multiple customers. We had originally also included a 90% improvement from near real-time data, however in line with the above analysis we have reduced this to 60%. This figure is conservative given near real-time data provides direct and immediate insight into the outage, but we acknowledge that this is a new functionality and have adopted a lower anticipated improvement in the modelling. We have modelled no improvement in reliability through access to data once per day.

2.4 Preferred Option – Option 4 changes to Option 2

Following the incorporation of feedback from the AER and EMCa and adjusting our assumptions for the final decision from the AEMC, our preferred option has changed to Option 2. This option reduced the volume of smart meter data that we are proposing to acquire as outlined below:

- **Overhead service line 24-hour data:** 75% of our network. No change from RP.
- **Overhead service line near real-time data:** 25% of our network. No change from RP.
- **Underground service line 24-hour data:** 0% of our underground network. This is a change from our RP where we proposed to collect data on 90% of our underground network. The change in our modelling means there is not sufficient value for our customers to collect this data.
- **Underground service line near real-time data:** 10% of our underground network. No change from RP.

As outlined above, this is a reduction in the level of data we are proposing to acquire in the 2025-2030 regulatory period.

3 BACKGROUND

The benefits of smart meter data and services delivering value through the energy transition are well documented. The Australian Energy Market Commission's Final Report on the "Review of The Regulatory Framework for Metering Services" states:

> *"Better information can improve efficiency of operation, use and planning of networks. This can reduce costs and unlock greater CER hosting capacity — allowing customers increased export limits. Smart meters also create indirect system-wide benefits to households via DNSPs, retailers and AEMO.*
>
> *Further, the data and information provided by smart meters can also allow DNSPs to improve their management of customer outages. Smart meters can also offer a dependable and uniform pathway for near-real-time data delivery and control services. Finally, smart meters can improve safety outcomes — such as through detection of neutral integrity failures, which can cause hazardous voltages to be present in accessible areas, and detection of over or under voltages, which can cause equipment failure."*

Victorian DNSPs, benefitting from the early deployment of smart meters, have reported numerous benefits:

- Track power supply for life support customers and prioritise them during outages.
- Maximise customer investment in solar by managing exports to reduce trips of your system.
- Prevent electric shocks by using data to identify neutral integrity issues that can allow electrical current to pass through pipes.
- Detect faults on the network faster and organise asset replacements before problems occur.

- Correct low voltage network models including customer to transformer mapping and phase connectivity.
- Inform distribution transformer load forecasting and network planning.
- Proactive voltage management through identification of quality of supply issues.
- Detection of DER installation non-compliance.
- Electricity theft detection.
- Improved reliability and asset management, particularly relating to distribution transformers.

These benefits are dependent on the network having access to engineering data, also called power quality data, from smart meters but also on the data latency – the delay between when the data is recorded in the meter and received by the network.

In the case of detecting neutral integrity issues to prevent electric shock, United Energy, has adopted an as low as reasonably practicable approach to the safety risks arising from its electricity network. To this end, they are transmitting engineering data from all smart meters every 15 mins.

Multiple industry projects and analyses have affirmed that effectively integrating DER into the NEM will deliver benefits including avoided costs along the electricity supply chain such as generation investment, system balancing, and network investment, with associated reductions in consumer costs and accelerate the net zero transition[1]. Project EDGE also recommended that DNSPs consider "…focusing on investment to uplift monitoring and management of their LV networks and connected DER. This will require DNSPs to invest in monitoring systems and digital platforms to increase visibility and control. These investments will be critical to supporting the increased utilisation of network assets and allowing more of the expanding volume of DER to be brought to market." Our DER Integration Strategy Cost Benefit Analysis presented the high grid-visibility option as delivering the greatest net present value.

This business case addresses both the grid visibility benefits of near real-time smart meter data, as well as the improvement in safety and reliability of our overhead service line and distribution transformer populations. The following sections provide an outline of these asset populations, their condition, and their asset performance.

3.1 Asset Population

3.1.1 Service Lines

Energex overhead services provide a connection for electricity between the Energex overhead low voltage (LV) mains line and designated points of connection owned by individual customers. These overhead services are considered low-cost assets and are typically managed based on population, using regular inspections and systematic performance reviews to identify and address any issues or concerns. Energex currently manages approximately 600,900 services as detailed in Figure 1.

[1] Project EDGE Final Report, AEMO-Project-EDGE-Final-Report.pdf (arena.gov.au), Oct 2023.

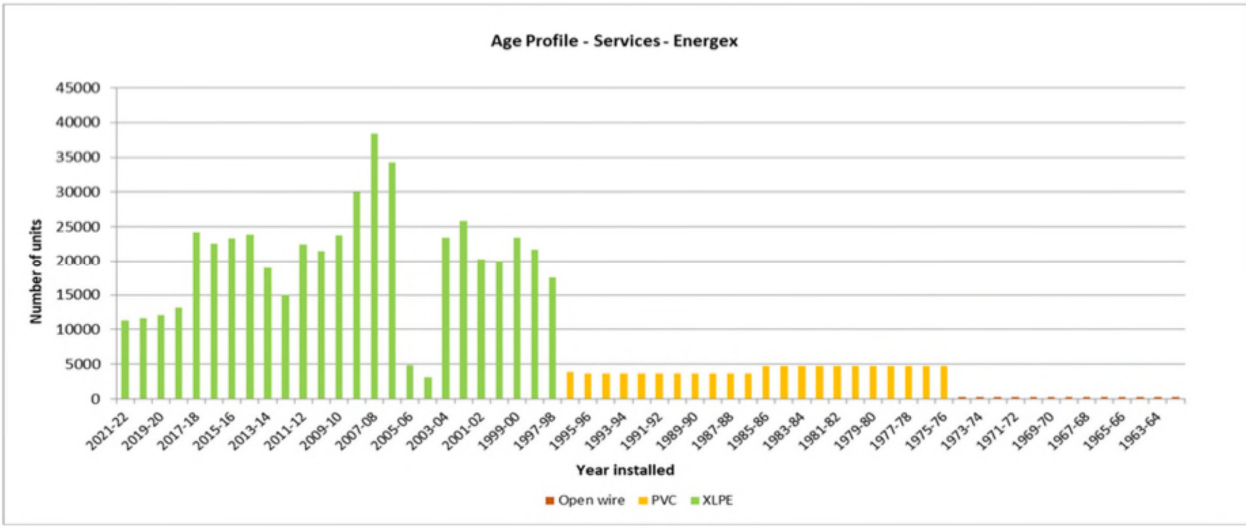

Figure 1 – Service Line Age Profile

3.1.2 Distribution Transformers

Energex's Distribution Transformer asset class population consists of Ground and Kiosk Mounted Transformers, Pole Mounted Transformers, Distribution Regulators, SWER Isolation Transformers, Pole-Mounted Reactors, Substation Earthing Transformers and Substation Service Transformers.

The Distribution Transformer asset class provide capabilities to complete a variety of functions including voltage conversion, voltage regulation, reactive load management and earthing. Transformers, regulators, and reactors are essential components of electrical networks as they allow for the use of cost-effective infrastructure to achieve efficient transportation of electricity across large distances. An age profile of all distribution transformer assets is shown in Figure 2. This age profile distribution reflects that we have 839 assets are over 50 years, and 92 assets are over 70 years across the asset class.

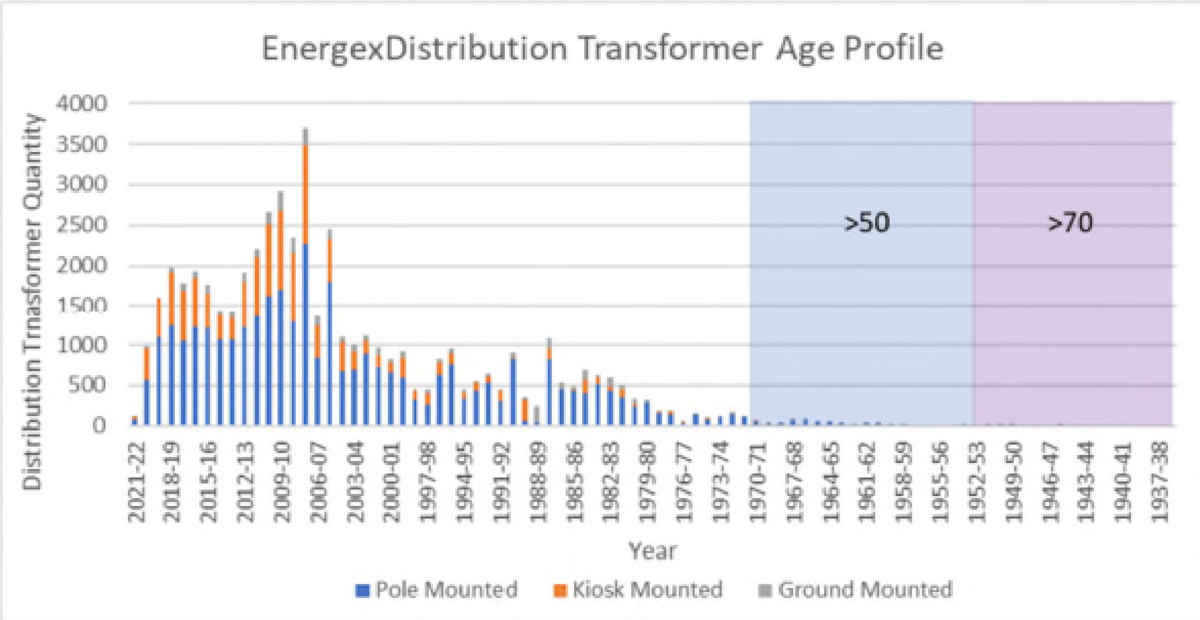

Figure 2 – Distribution Transformer Age Profile

3.1.3 Smart Meters

Energex currently has an extremely limited data acquisition capability on our LV networks, and virtually no network visibility beyond the distribution transformer. This lack of network data has historically been due to a lack of technology to be able to detect the sorts of issues that would provide benefit to customers. With both the Australian Energy Market Commission and the Queensland Energy and Jobs Plan committing to a high penetration of smart meters, there is now the capability available to monitor our LV network through acquiring metering data.

Metering at the customer premises is the responsibility of the retailer. As such, our access to smart meter data will be through agreement and purchase from the metering providers. In addition to the roll-out of smart meters, communications and monitoring equipment advances in recent years mean we are now able to have the technology to install devices on our LV network to provide the same data as a smart meter.

We have had discussions with Metering Providers to determine the costs and delivery parameters of data that is acquired from smart meters. For the purposes of this business case, we have assumed that daily (24-hour) delivery of data would constitute basic data, with near real-time delivery of data being advanced data. In our discussions, we have determined the likely costs for acquiring the data:

[redacted]

[redacted]

4 IDENTIFIED NEED

The identified need is a requirement to improve visibility of our LV networks.

The benefits that this data acquisition offers our customers comes from us being able to proactively manage our network, delivering Reliability, Safety, Export and Financial benefit streams from an effective grid visibility strategy. The opportunities for this investment include:

- **LV service in-service faults:** LV visibility for a single service cable allows us to respond to faults on our LV service cables more quickly, which reduces reliability issues that arise from faulty service lines and importantly improves safety through our ability to respond more quickly to potentially life-threatening conditions such as a faulty neutral connection.
- **Distribution Transformer in-service faults:** Widespread LV visibility coverage (where we don't already have a transformer monitor) allows us to respond to faults on our distribution transformers given we can more easily and quickly identify an outage to an area. This will reduce the reliability issues following a distribution transformer outage.

- **DER integration:** Near real-time data on our network will enable us to better manage our dynamic operating envelopes, decreasing the level of curtailment across our network and better targeting investment in increasing capacity.
- **Service line replacement deferral:** by having a more active monitoring of our service lines, we will be able to defer the proactive replacement of the service line we are monitoring.
- **Grid planning improvements:** increased availability of engineering data on our network allows us to understand loads and export requirements for these networks, informing better demand and energy forecasts at the LV level, in turn reducing the future labour requirements in our forecasting and planning teams.
- **Electricity theft:** power quality data down to the household level allows us to identify where customers have bypassed the meter and therefore paying a reduced network charge.

4.1 Discussions with customers

We discussed our approach to Smart Meter Data Acquisition with our Reset Reference Group to guide the way we considered the benefits that flowed to customers from this investment. Their feedback was clearly that we should invest based on the highest cost benefit option, without bias to technology or timing of costs. To this end, we have undertaken a cost benefit analysis and sensitivity analysis to determine which of the options we have considered maximises the benefits to our customers and the community.

4.2 Counterfactual analysis

4.2.1 Summary

The counterfactual for this business case is based on not acquiring any smart meter data. In understanding the risks and calculating the benefits attributable to a more active monitoring capability of our network, we have split some of our risk costs into a “per service” framework by age, which means that we have calculated the existing risk level for a single service cable or distribution transformer of each age from 1 to 73. This simplifies the understanding of the benefits of a single monitoring device where the benefit will be attributable to a single asset.

We have then modelled those benefits that can be attributed to monitoring capability at scale, such as distribution transformer reliability and DER integration at more of a system level, with the benefits of this capability being shared across our network, rather than only by the single service line asset.

4.2.2 Costs

The counterfactual case has no costs associated with it given there is no investment in data acquisition.

4.2.3 Risks

Service line Safety and Reliability risk costs

To simplify the analysis, we have provided an assessment of the risk cost of the counterfactual and then we have applied a saving/reduction factor to the reliability and safety because of smart metering. The assessment is based on 15-year horizon across the range of the age of our service cables. That is, we have calculated the present value of the risk benefit in the safety and reliability for a single service aged 1 to 73 over the 15-year period. The following assumptions have been utilised in developing the per service line risk costs:

- **Probability of Failure (PoF):** as part of our Service Lines Replacement business case, we calculated a Weibull distribution to represent the PoF for a service line. This incorporates both service failures and service defects. The parameters of this are beta of 2.5 and gamma (characteristic life) of 34. Figure 3 shows our actual failure data and the associated modelled Weibull distribution.
- **Likelihood of Consequence (LoC) - Reliability:** 100% of defects and failures result in a network outage. The assumptions around these outages are:
  - 2-hour outage for a service failure
  - 2-hour outage for a service defect
  - 1kW average consumption for a service line
  - VCR rate of $54.75/ kWh
- **LoC – Safety:** utilising historic data and industry experience we have determined the LoC following a failure or defect for service lines to be:
  - 0.02% of service failures result in a fatality.
  - 0.0003% of service defects result in a fatality.

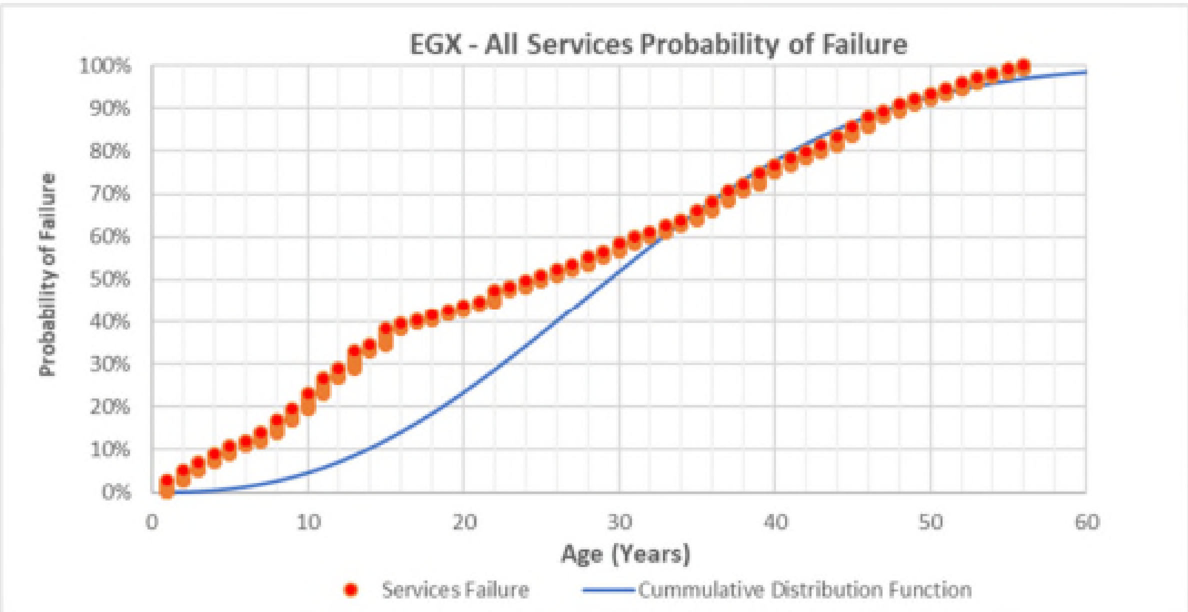

Figure 3 – Service Line Failure and Defect Weibull Distribution

As can be seen from Figure 3, our Weibull distribution tends to underestimate the PoF for a service line below 30 years but provides a very accurate representation of failure above this age. We have utilised this curve in assessing the counterfactual risk associated with our service cable failures.

Service line replacement deferral risk cost

Active monitoring of LV services will allow us to have a lower volume proactive replacement program for our service lines assets. To simplify the analysis for this business case, rather than factoring in our entire replacement program as a cost and then factoring in these reduced costs as a benefit, Figure 4 shows the present value of a two-year deferral of a service line replacement over time. This factors in a replacement value of $1070 / service and a cost of capital of 3.5% demonstrates that over the next 10 years, a two-year deferral of a service cable replacement represents between $40 - $70 in risk cost.

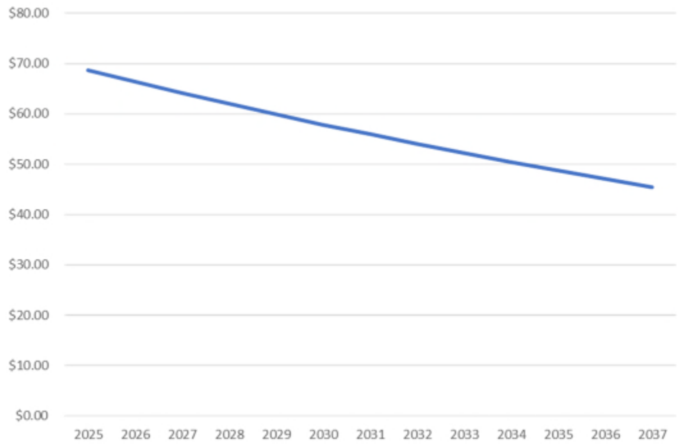

Figure 4 – Present Value of a Two-Year Deferral of a service line replacement

Distribution Transformer Reliability risk costs

Broader visibility on our LV network also gives us the capability to respond to an outage of a distribution transformer faster. As such, below is the modelling of the total reliability risk associated with our distribution transformers. We haven't modelled the safety risk associated with transformers given that smart meter data doesn't provide a safety benefit related to distribution transformers. shows the level of risk cost on our service lines by age.

- **Probability of Failure (PoF):** as part of our Distribution Transformer Replacement business case, we calculated a Weibull distribution to represent the PoF for a distribution transformer. The parameters of this are beta of 2.2 and gamma (characteristic life) of 33. Figure 5 shows our actual failure data and the associated modelled Weibull distribution.
- **Likelihood of Consequence (LoC) - Reliability:** 100% of failures result in a network outage. It is important to note that for networks with no or limited visibility, we require customers to notify us of asset failures resulting in outages. AS such, the timeframe for restoration is dependent on the level of information that customers can provide, and the volume of customer calls so that we can determine where the fault in the network is. The assumptions around these outages are:
    - 3-hour outage for a transformer failure.
    - 350kW average consumption for a distribution transformer
    - VCR rate of $54.75/ kWh

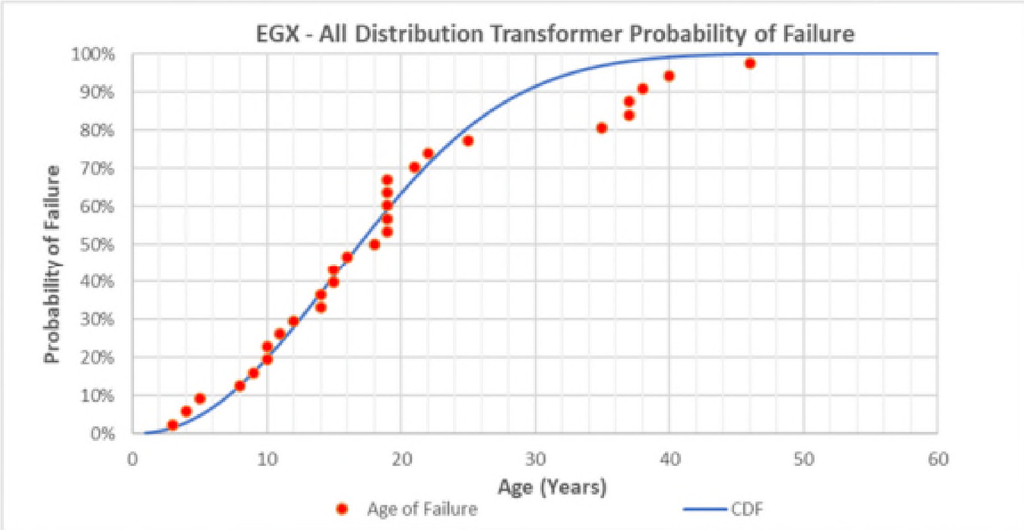

Figure 5 – Distribution Transformer Weibull Distribution

As can be seen from Figure 5, our Weibull distribution tends to underestimate the PoF for a service line below 30 years but provides a very accurate representation of failure above this age. We have utilised this curve in assessing the counterfactual risk associated with our transformer failures.

DER Integration risk costs

The benefits of access to near real-time data have been calculated, with a detailed explanation contained in our DER Integration Strategy. In simple terms, better data for our LV network visibility would allow us to optimally calculate dynamic operating envelopes and increase the capacity for export that customers can utilise on our network, as well as ensuring our investments in increasing hosting capacity for DER are more efficient than would otherwise be the case. As part of the Strategy, we calculated that the difference between a DoE with access to sufficient near real-time data and a more basic DoE has a present value of $16.0m in benefits.

Grid planning and forecasting functionality

Our current limited visibility on LV networks makes forecasting minimum and maximum demands and energy use on our networks difficult. As a result, our planning and forecasting teams require much more effort to correctly forecast this demand and coming up with the associated projects and programs to respond to any identified needs. As our network becomes more complex and load flows in both directions at different times of the day, network data will become more valuable, and increasing the data capture across our network will result in a lower level of effort than would have otherwise been the case. Although we aren’t forecasting that data capture would reduce our current planning and forecasting effort, we are forecasting that there will be a reduction in the level of effort required in the planning and forecasting areas than otherwise would have been the case.

Electricity theft

With limited data on our LV networks, electricity theft is difficult for us to detect. Greater visibility of the customer connection arrangement and power quality data at their premises will enable us to determine where this may be occurring. The current rate of theft is difficult for us to determine.

However, we have estimated that full visibility would be able to prevent theft from 40 customers / year.

5 OPTIONS ANALYSIS

5.1 Option 1 – Only Overhead Service and only 24-hour data

This option focuses on acquiring data about overhead service lines to capture the safety and reliability benefits, as well as a deferral of service lines replacement. This option will also result in an improvement in our distribution transformer failure response. This option results in data being captured for around 40% of our overhead service lines.

5.1.1 Assumptions

The following assumptions have been factored into the analysis:

- **Data acquisition timeframe –** this option assumes 24-hour data is captured from smart meters.
- **Ratio of data capture** – this option assumes that we capture the smart meter data that is available for our overhead network.
- **Service line safety improvement** – using 24-hour data will prevent 36% of the safety incidents on our LV service lines. This likely under-represents the success of this program in identifying incidents on our network.
- **Service line reliability improvement** – using 24-hour data will not prevent any customer outages related to service line failures.
- **Distribution transformer reliability improvement** –
    - Using 24-hour data will not prevent any customer outages related to transformer failures.
    - 23,897 pole-mounted transformers will have improved reliability should they fail in service. This equates to all pole-mounted transformers above 60kVA.
    - We have utilised the existing age profile of our distribution transformer population in combination with the Weibull distribution to determine the benefits attributable.
- **DER Integration** – no benefits are factored into this analysis for DER integration as the approach only considers 24-hour data, which does not provide a material uplift in capacity for export.
- **Service line replacement deferral** – we have factored in a present value benefit of $14.10 for a deferral in replacement because of having more active monitoring available.
- **Grid planning uplift** – we have forecast that because of an improved level of data capture, we will save around 80 hours of effort in planning the network at $112 / hour.
- **Electricity Theft** – we have estimated a reduction of theft from 10 customers / year, and assumed an annual use of 4,000kWh at a prevailing rate of $0.3 / kWh
- **Investment horizon** – this has been assumed to be 15 years.

5.1.2 Costs

The cost of this option once the final uptake is at scale is:

Opex

[redacted]

5.1.3 Benefits

A summary of the benefits attributable to improved LV visibility are listed in Table 2.

Table 2 Benefits overview for Option 1

Benefit Type	Benefit Description	Value
Benefit Type	Benefit Description	NPV
Service line safety and reliability - 24-hour data	Improvement in fault and defect detection to improve safety and reliability of our network.	**$25.2m**
Distribution transformer reliability – 24-hour data	Improvement in network reliability for customers due to greater visibility throughout our network.	**$0.0m**
Service line replacement deferral	Ability to defer the replacement of a service line by two years.	**$8.5m**
DER Integration	Ability to orchestrate DER more accurately on our network	**$0.0m**
Grid Planning uplift & Theft	Ability to better plan the network through access to LV data and ability to detect when a customer has by-passed the meter	**$0.2m**

The NPV of benefits is shown in Figure 6.

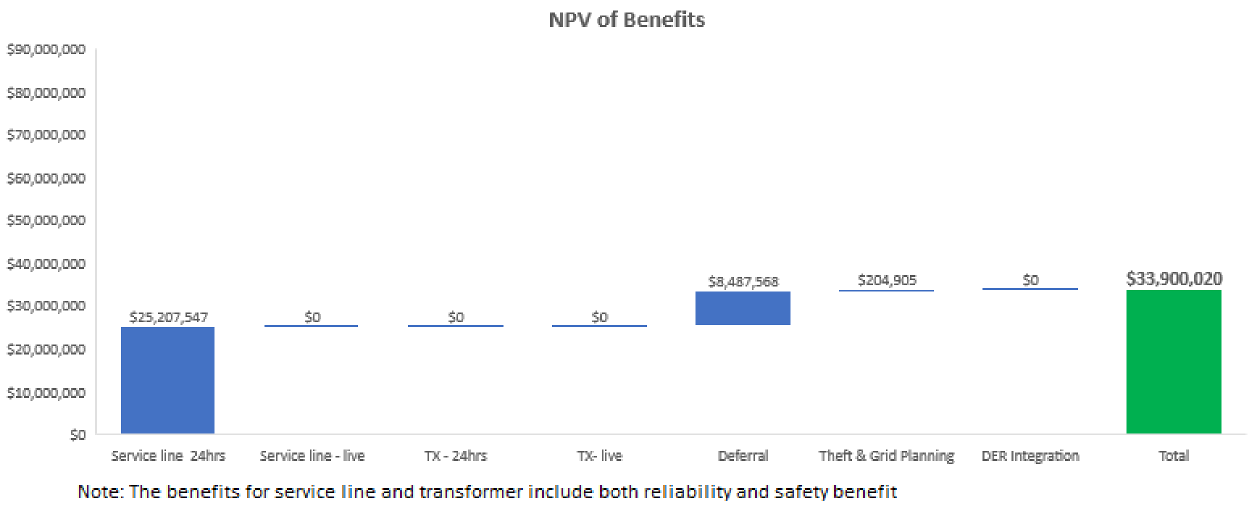

Figure 6 – NPV of Benefits for Option 1

5.2 Option 2 – 75% 24 hourly data for overhead services and 25% of live data for overhead services and 10% underground services

This option acquires a mixture of data for overhead and underground service lines to capture the safety and reliability benefits, as well as a deferral of service lines replacement. This option will also result in an improvement in our distribution transformer failure response. To capture the benefits associated with DER integration, this option captures 25% of our overhead network and 10% of our underground network as near real-time data, from either smart meters to enable highly efficient operating envelopes to be calculated. This option results in data being captured for around 60% of our LV network.

5.2.1 Assumptions

- **Data acquisition timeframe –** this option assumes near real-time data is utilised for 25% of our OH service lines, 10% of our UG service cables, with the data for the remaining OH services being captured every 24-hours.
- **Ratio of data capture** – this option assumes that we capture the smart meters that are available for our overhead network.
- **Service line safety improvement** – using near real-time data will prevent 60% of the safety incidents on our LV service lines. For those with 24-hour data capture, 36% of our incidents will be captured. This likely under-represents the success of this program in identifying incidents on our network.
- **Service line reliability improvement** – using near real-time data will reduce 60% of our reliability incidents by 1.8 hours, while those with 24-hour data will not prevent any customer outages related to service line failures.
- **Distribution transformer reliability improvement** –
    - We have 23,897 pole-mounted transformers and 3,772 ground mounted transformers above 60kVA in size. These transformers will have improved reliability should they fail in service.
    - Using a near real-time data capture will prevent around 60% of the customer outages related to transformer failures on all 27,669 transformers identified above. This translates to 1.92 hours saving on all outages where near real-time data has been captured. This assumes a mixture of near real-time data across all transformers in our network.
    - We have utilised the age profile of our distribution transformer population to determine the benefits attributable.
- **DER Integration** – the benefits of the uplift described in our DER Integration Strategy from the basic DoE to the highly accurate DoE have been attributed to this business case. The resultant improvement is entirely attributable to obtaining the critical mass of near real-time data.
- **Service line and cable replacement deferral** – we have factored in a present value benefit of $14.10 for a deferral in replacement because of having more active monitoring available.
- **Grid planning uplift** – we have forecast that because of an improved level of data capture, we will save around 640 hours of effort in planning the network at $112 / hour.
- **Electricity Theft** – we have estimated a reduction of theft from 20 customers / year, and assumed an annual use of 4,000kWh at a prevailing rate of $0.3 / kWh
- **Investment horizon** – this has been assumed to be 15 years.

5.2.2 Costs

The cost of this program is:

<u>Opex</u>

[redacted]

5.2.3 Benefits

A summary of the benefits attributable to improved LV visibility are list below. These are summarised to yearly figures as the final uptake rate in 2030 as we achieve close to full penetration of smart meters.

Table 3 Benefits overview for Option 2

Benefit Type	Benefit Description	NPV
Service line safety and reliability – 24-hour data	Improvement in fault and defect detection to improve safety and reliability of our network.	**$18.9m**
Service line safety and reliability – near real-time data	Improvement in fault and defect detection to improve safety and reliability of our network.	**$17.3m**
Distribution transformer reliability	Improvement in network reliability for customers due to greater visibility throughout our network.	**$9.9m**
Service line replacement deferral	Ability to defer the replacement of a service line by two years.	**$8.5m**
DER Integration	Ability to orchestrate DER more accurately on our network	**$16.0m**
Grid Planning uplift & Theft	Ability to better plan the network through access to LV data and ability to detect when a customer has by-passed the meter	**$0.9m**

The NPV of benefits is shown in Figure 7.

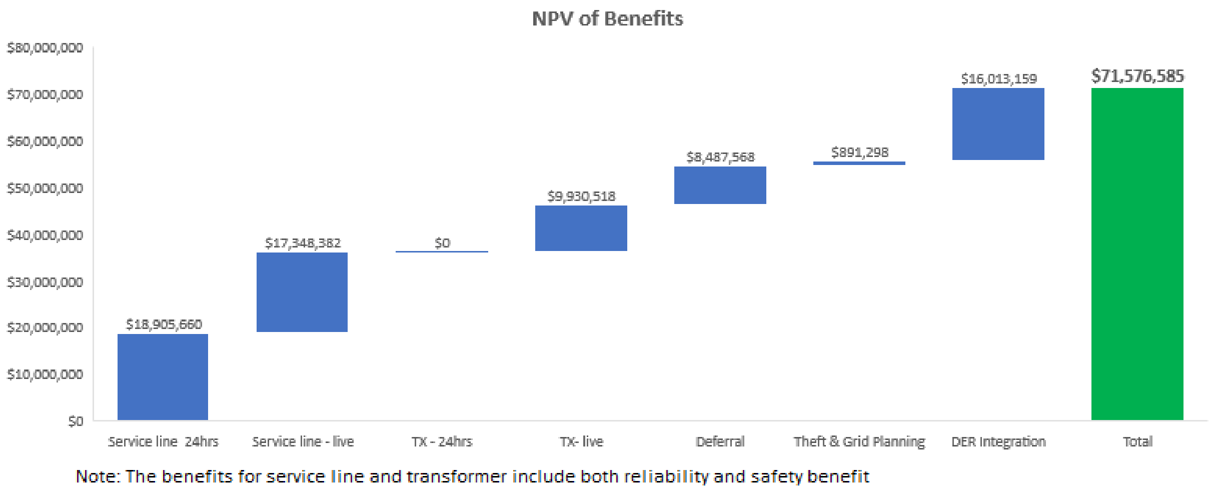

Figure 7 – Option 2 NPV of Benefits

5.3 Option 3 – 75% 24 hourly data and 25% of live data for overhead services, no data for underground services

This option acquires data for overhead service lines only, in capturing the safety and reliability benefits, as well as a deferral of service lines replacement. This option will also result in an improvement in our distribution transformer failure response. To capture the benefits associated with DER integration, this option requires 25% of our overhead network, from smart meters to enable highly efficient operating envelopes to be produced. This option results in data capture for around 40% of our overhead service lines.

5.3.1 Assumptions

- **Data acquisition timeframe –** this option assumes near real-time data is utilised for 25% of our OH service lines with data for the remaining OH services being captured in 24-hour windows.
- **Ratio of data capture** – this option assumes that we capture the smart meter that is available for our overhead network.
- **Service line safety improvement** – using near real-time data will prevent 60% of the safety incidents on our LV service lines. For those with 24-hour data capture, 36% of our incidents will be captured. This likely under-represents the success of this program in identifying incidents on our network.
- **Service line reliability improvement** – using near real-time data will reduce 60% of our reliability incidents by 1.8 hour, while those with 24-hour data will not prevent any of the customer outages related to service line failures through being unable to respond earlier to faults. This is due to the lag in data reaching our network operations centre.
- **Distribution transformer reliability improvement** –
  - We have around 23,897 transformers that are pole-mounted that will have their reliability improved should they fail in service. This is equal to all pole-mounted transformers above 60kVA in size.
  - Using a near real-time data capture will reduce around 60% of the customer outages related to transformer failures on 27,669 transformers identified above. This translates to 1.92 hour saving on all outages where near real-time data has been captured. This assumes a mixture of near real-time data across all transformers in our network.
  - We have utilised the age profile of our distribution transformer population to determine the benefits attributable.
- **DER Integration** – $5.3m benefits of DER integration due to the critical mass of near real-time data acquired.
- **Service line and cable replacement deferral** – we have factored in a present value benefit of $14.10 for a deferral in replacement because of having more active monitoring available.
- **Grid planning uplift** – we have forecast that because of an improved level of data capture, we will save around 160 hours of effort in planning the network at $112 / hour.
- **Electricity Theft** – we have estimated a reduction of theft from 10 customers / year, and assumed an annual use of 4,000kWh at a prevailing rate of $0.3 / kWh

- **Investment horizon** – this has been assumed to be 15 years.

5.3.2 Costs

The cost of this program is:

Opex

[redacted]

5.3.3 Benefits

A summary of the benefits attributable to improved LV visibility are list below. These are summarised to yearly figures as the final uptake rate in 2030 as we achieve close to full penetration of smart meters.

Table 4 Benefits overview for Option 3

Benefit Type	Benefit Description	NPV
Service line safety and reliability – 24-hour data	Improvement in fault and defect detection to improve safety and reliability of our network.	**$18.9m**
Service line safety and reliability – near real-time data	Improvement in fault and defect detection to improve safety and reliability of our network.	**$17.3m**
Distribution transformer reliability	Improvement in network reliability for customers due to greater visibility throughout our network.	**$9.9m**
Service line replacement deferral	Ability to defer the replacement of a service line by two years.	**$8.5m**
DER Integration	Ability to orchestrate DER more accurately on our network	**$5.3m**
Grid Planning uplift & Theft	Ability to better plan the network through access to LV data and ability to detect when a customer has by-passed the meter	**$0.3m**

The NPV benefits is shown in Figure 8

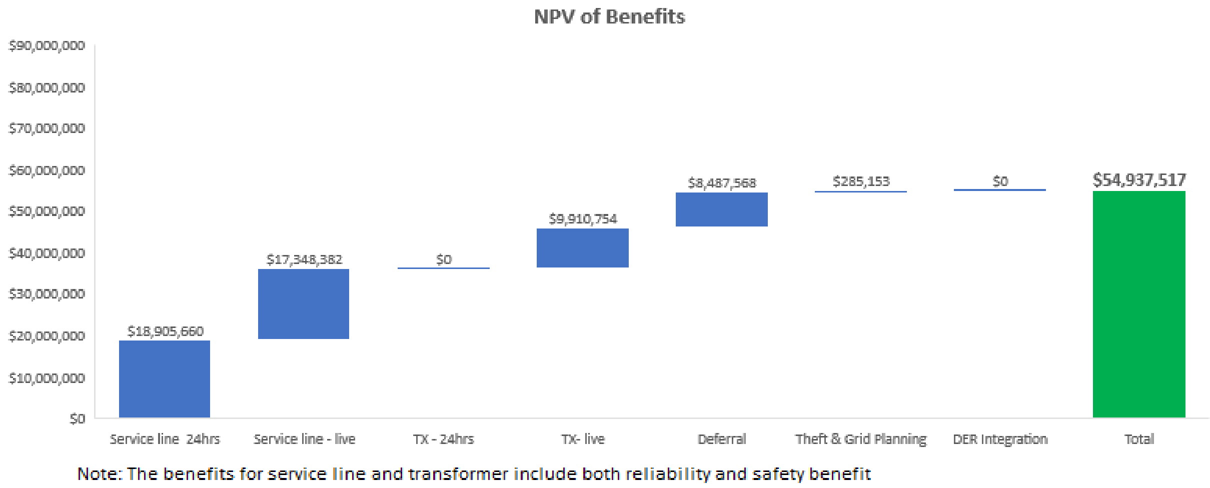

Figure 8 – Option 3 NPV of Benefits

5.4 Option 4 – All services, with capture of live data for 25% for overhead and 10% for underground

This option acquires data for overhead and underground service lines. This captures the safety and reliability benefits, as well as a deferral of service lines replacement, while also resulting in an improvement in our distribution transformer failure response for both overhead and underground areas with the acquisition of near real-time data. This also captures the benefits associated with DER integration to enable highly efficient operating envelopes to be produced. This option results in data being captured for around 80-90% of our LV services.

5.4.1 Assumptions

- **Data acquisition timeframe –** this option assumes near real-time data is utilised for 25% of our OH and 10% for UG service lines, with the remaining services captured as 24-hour data
- **Ratio of data capture** – this option assumes that we capture the smart meters that are available for our overhead and underground network.
- **Service line safety improvement** – using near real-time data will prevent 60% of the safety incidents on our LV service lines. For those with 24-hour data capture, 36% of our incidents will be captured. This likely under-represents the success of this program in identifying incidents on our network.
- **Service line reliability improvement** – using near real-time data will reduce 60% of our reliability incidents by 1.8 hours for service line failure, while those with 24-hour data will not prevent any customer outages related to service line failures through being unable to respond earlier to faults.
- **Distribution transformer reliability improvement** –
  - We have factored in an improvement in the failure response to all 27,669 transformers in our network above 60kVA.

- o We have utilised the age profile of our distribution transformer population to determine the benefits attributable.

- **DER Integration** – the benefits of the uplift described in our DER Integration Strategy from the basic DoE to the highly accurate DoE have been attributed to this business case. The resultant improvement is entirely attributable to obtaining the critical mass of near real-time data for both our overhead and underground networks.
- **Service line and cable replacement deferral** – we have factored in a present value benefit of $14.10 for a deferral in replacement because of having more active monitoring available.
- **Grid planning uplift** – we have forecast that because of an improved level of data capture, we will save around 640 hours of effort in planning the network at $112 / hour.
- **Electricity Theft** – we have estimated a reduction of theft from 20 customers / year, and assumed an annual use of 4,000kWh at a prevailing rate of $0.3 / kWh
- **Investment horizon** – this has been assumed to be 15 years.

5.4.2 Costs

The cost of this program is:

<u>Opex</u>

[redacted]

5.4.3 Benefits

A summary of the benefits attributable to improved LV visibility are list below. These are summarised to yearly figures as the final uptake rate in 2030 as we achieve close to full penetration of smart meters.

Table 5 Benefits overview for Option 4

Benefit Type	Benefit Description	NPV
Service line safety and reliability – 24-hour data	Improvement in fault and defect detection to improve safety and reliability of our network.	**$18.9m**
Service line safety and reliability – near real-time data	Improvement in fault and defect detection to improve safety and reliability of our network.	**$17.3m**
Distribution transformer reliability	Improvement in network reliability for customers due to greater visibility throughout our network.	**$9.9m**
Service line replacement deferral	Ability to defer the replacement of a service line by two years.	**$8.5m**
DER Integration	Ability to orchestrate DER more accurately on our network	**$16.0m**
Grid Planning uplift & Theft	Ability to better plan the network through access to LV data and ability to detect when a customer has by-passed the meter	**$0.9m**

The NPV benefits is shown in Figure 9.

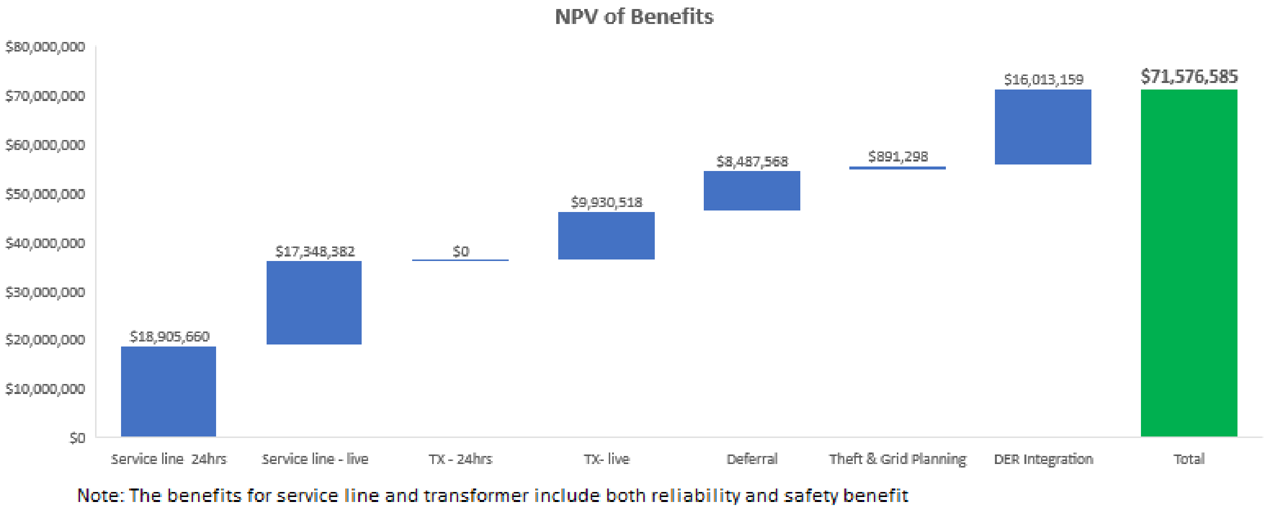

Figure 9 – Option 4 NPV of Benefits

5.5 Economic Analysis

5.5.1 Cost summary 2025-30

Table 6 shows the costs for each option for the 2025-2030 period. These have been broken up into Opex and Capex to ensure the step change value can be separately reported from the capex implications of the program.

Table 6 – Cost summary 2025-30 2022-23 $M

Option	Expenditure Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025-30
Option 1	Opex	2.01	0.56	0.58	0.60	0.63	4.38
Option 2	Opex	3.14	2.39	2.72	3.05	3.36	14.67
Option 3	Opex	2.53	1.65	1.85	2.06	2.26	10.35
Option 4	Opex	5.5	2.6	2.9	3.2	3.5	17.6

5.5.2 NPV analysis

The NPV of all options has been calculated, with the results shown in Table 7.

Table 7 – NPV analysis $M

Option	Net Present Value	Present Value of Costs	Present Value of Benefits
Option 1	**26.23**	7.67	33.90
Option 2	**37.18**	34.39	71.58
Option 3	**36.69**	23.53	60.22
Option 4	**33.73**	37.85	71.58

As can be seen from Table 7, Option 2 maximises the value to our customers, with benefits of obtaining greater visibility on our network outweighing the costs associated with obtaining it.

5.5.3 Sensitivity analysis

We have undertaken sensitivity analysis to test a few key variables, and the results are in the below table.

Sensitivity Analysis									
Variable to be Tested		**Base Case**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**	**Scenario 5**	**Scenario 6**	**Scenario 7**
% of Outage Reduction Time Through Metering	24 hourly Data	0%	5%	0%	10%	0%	0%	0%	0%
	Live Data	60%	70%	50%	90%	60%	60%	60%	60%
% Safety Incident Reduction Through Metering	24 hourly Data	36%	36%	36%	40%	20%	36%	36%	36%
	Live Data	60%	60%	60%	60%	40%	60%	60%	60%
Smart Meter Installation Ramping Rate		As Per Assumpoionn in the Model	As Per Assumpoionn in the Model	As Per Assumpoionn in the Model	As Per Assumpoionn in the Model	As Per Assumpoionn in the Model	As Per Assumpoionn in the Model	As Per Assumpoionn in the Model	AEMC's Accelerating smart meter deployment
Cost of 24 hourly Data		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Live Data		$12.00	$12.00	$12.00	$8.50	$8.50	$10.00	$15.00	$8.50
NPV		**Base Case**	**Scenario 1**	**Scenario 2**	**Scenario 2**	**Scenario 4**	**Scenario 5**	**Scenario 6**	**Scenario 7**
Option 1		$26,227,995	$28,072,361	$26,227,995	$32,717,566	$15,024,641	$26,227,995	$26,227,995	$26,104,357
Option 2		$37,183,270	$39,260,708	$35,265,867	$45,356,178	$28,780,754	$37,183,270	$37,183,270	$35,849,171
Option 3		$36,693,233	$38,770,671	$34,775,830	$44,866,141	$28,290,718	$36,693,233	$36,693,233	$35,823,027
Option 4		$33,726,320	$35,803,758	$31,808,917	$41,899,228	$25,323,804	$33,726,320	$33,726,320	$32,381,094

6 RECOMMENDATION

Option 2 is the recommended option. This includes obtaining all data for overhead service with 25% being near real-time and 10% of our underground services with near real-time data.

Table 8 Options Analysis Scorecard

Criteria	Option 1 – 24-hour data for OH	Option 2 – Mixture of data for OH and 25% for underground	Option 3 – Mixture of 24-hour and near real-time data for OH	Option 4 – All customer data, 25% near real-time
Net Present Value	$26.2M	$37.1M	$36.7M	$33.8M
Investment cost (Opex)	$4.38M	$14.67M	$10.35M	$17.60M
Detailed analysis – Benefits	Provides an improvement in safety and reliability for our OH services network.	Provides safety benefits for our OH services network. Provides reliability benefits for our services and transformer network across all our network.	Provides safety benefits for our OH network. Provides reliability benefits to our OH network.	Provides the highest overall benefits to customers.
Detailed analysis – Risks	Does not provide any reliability benefits for transformer failures.	Provides slightly less grid planning visibility than option 4.	Does not provide any benefits for our customers connected to the underground networks.	Provides the most benefits to our customers.

APPENDICES

Appendix 1: Alignment with the National Electricity Rules

Table 9 Recommended Option's Alignment with the National Electricity Rules

NER capital expenditure objectives	Rationale
A building block proposal must include the total forecast capital expenditure which the DNSP considers is required in order to achieve each of the following (the capital expenditure objectives):	
6.5.7 (a) (1) meet or manage the expected demand for standard control services over that period	This business case seeks to meet our obligations to provide a safe and reliable network and improve our ability to respond to asset failures.
6.5.7 (a) (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;	We have a regulatory obligation to operate our network safely and undertake expenditure that is proportionate to the risk involved. We have demonstrated a positive cost-benefit analysis for this expenditure.
6.5.7 (a) (3) to the extent that there is no applicable regulatory obligation or requirement in relation to: (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent: (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services	This business case is supported by positive cost benefit analysis.
6.5.7 (a) (4) maintain the safety of the distribution system through the supply of standard control services.	This business case proposes the use of smart meter data to detect asset failures that could result in public safety issues.
NER capital expenditure criteria	**Rationale**
The AER must be satisfied that the forecast capital expenditure reflects each of the following:	
6.5.7 (c) (1) (i) the efficient costs of achieving the capital expenditure objectives	The costs of this initiative are proportionate to the risks we have identified.
6.5.7 (c) (1) (ii) the costs that a prudent operator would require to achieve the capital expenditure objectives	This business case has a positive cost-benefit analysis, demonstrating prudency.
6.5.7 (c) (1) (iii) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives	The costs associated with this initiative have been worked through with suppliers of data and analytics tools.

Appendix 2: Reconciliation Table

Table 10 Reconciliation

Expenditure	DNSP	2025-26	2026-27	2027-28	2028-29	2029-30	2025-30
Opex in business case $M, direct 2022-23	Energex	$3.14	$2.39	$2.72	$3.05	$3.36	**$14.67**
Escalation to $2024-25	Energex	1.067	1.067	1.067	1.067	1.067	
Opex (as outlined in RRP) $M, direct June 2025	Energex	$3.35	$2.55	$2.91	$3.26	$3.59	**$15.66**