Business Case
Enabling a Secure Data Zone

Part of the Energy Queensland Group

Executive Summary

The current communication and control connections for large scale generators are facilitated through a “hard-wired” solution into the nearest substation. Each solution is bespoke per connection and provides no flexibility for growth or change in operating parameters.

This ad-hoc connection process is increasingly problematic with growth in Distributed Energy Resources (DER) and increasing need for data flows to facilitate communication and control for customers. Energex and Ergon Energy need to create a safe separation of data for customers, enabling increased flexibility and availability of real-time data, while safeguarding cybersecurity. Two options for addressing this need have been evaluated in this business case:

Option 1 – Implement a new data security zone providing secure, flexible connection between DER providers, EQL and AEMO.

Option 2 – A counterfactual, ‘do nothing’ option, no measures are taken to address the increased demand for secure data communications.

Ergon Energy aims to minimise expenditure in order to keep pressure off customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety), customer reliability and security and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case the need to support customers adopting new technology is a strong driver, due to growing demand for secure data services which support DER.

To this end, Option 1 is the preferred option. It provides a cost-effective means of delivering secure data services to customers which want to participate in the grid through DER, and which are a feature of a modern electricity grid. The Net Present Value (NPV) of Option 1 is $-0.73M.

By contrast the counterfactual, Option 2, will increase the lifecycle management costs associated with substation maintenance as any work associated with the control system will need to take into consideration the hard-wired connection in terms of maintenance and upgrades. These costs will grow as the penetration of DER in the EQL network increases.

The direct cost of the program for each submission made to the AER is summarised in the table below. Note that all figures are expressed in 2018/19 dollars and apply only to costs incurred within the 2020-25 regulatory period for the preferred option.

Regulatory Proposal	Draft Determination Allowance	Revised Regulatory Proposal
$1M	N/A	$1M

Developing a Customer Zone within the current operational architecture will increase flexibility of data flows to the control room as well as other stakeholders (e.g. Australian Energy Market Operator (AEMO)), assisting with network stability and security and reducing the need for costly augmentation to manage capacity. It will decouple customers from substation operations (using IP instead of hard-wired), reducing impact throughout upgrades at substations, and reducing the risk of mal-operation. Finally, it will provide greater connection security as the relevant cybersecurity protections can be put in place to minimise risk to the power network from a compromise of the customer infrastructure.

This investment allows Energy Queensland to provide a common infrastructure that will support and benefit all medium/large DER connections. Individual customer projects will continue to fund their connection requirements specific to their projects, however, this infrastructure will allow the process to occur more flexibly and at a lower cost to the customer. Customers, typically DER providers, will benefit from simpler, secure and more flexible data connections to Energy Queensland and onwards to AEMO.

Contents

1 Introduction

With an increasing move towards Distributed Energy Resources (DERs), Energy Queensland is faced with an increasing number of embedded generation customers requiring flows of data into and out of Energy Queensland's systems for control and communication purposes. The existing "ad-hoc" approach to creating these connections involves a "hard-wired" solution into the nearest substation. The lack of standardisation involves significant effort and cost for customers. This proposal seeks to enable a standardised solution that better delivers on customer's needs, while also providing safeguards against heightened cyber security risks.

1.1 Purpose of document

This document recommends the optimal capital investment necessary for enabling a secure data zone for customers.

This is a preliminary business case document and has been developed for the purposes of seeking funding for the required investment in coordination with the Energex Revised Regulatory Proposal to the Australian Energy Regulator (AER) for the 2020-25 regulatory control period. Prior to investment, further detail will be assessed in accordance with the established Energy Queensland (EQL) investment governance processes. The costs presented are in $2018/19 direct dollars. This document should be considered in conjunction with Energy Queensland's Future Grid Roadmap and Intelligent Grid Technology Plan.

1.2 Scope of document

This document lays out the requirement for measures to address and upgrade current inflexible connection methodologies with modernised and flexible systems capable of managing changing generator needs. This document will outline the rationale, benefits, and drivers for the business case, as well as present options for system upgrade. These options, their associated risk assessments, delivery timeframes and project costs will be outlined to provide a recommendation that minimises risk and optimises cost efficiency.

1.3 Identified Need

Ergon Energy aims to minimise expenditure in order to keep pressure off customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety), customer reliability and security and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case the need to support customers adopting new technology is a strong driver, due to growing demand for secure data services which support DER.

The current communication and control connections for large scale embedded generation are facilitated through a "hard-wired" solution into the nearest substation. Each solution is bespoke for a particular connection and provides no flexibility for growth or change in operating parameters. The ad-hoc nature of this connection process is becoming increasingly problematic with the continuing growth of DERs. The historic and predicted growth in photovoltaic (PV) generation capacity across Queensland is shown in Figure 1 below. While this represents total PV generation, a significant portion will come from large and medium scale solar farms, which are of relevance to this proposal.

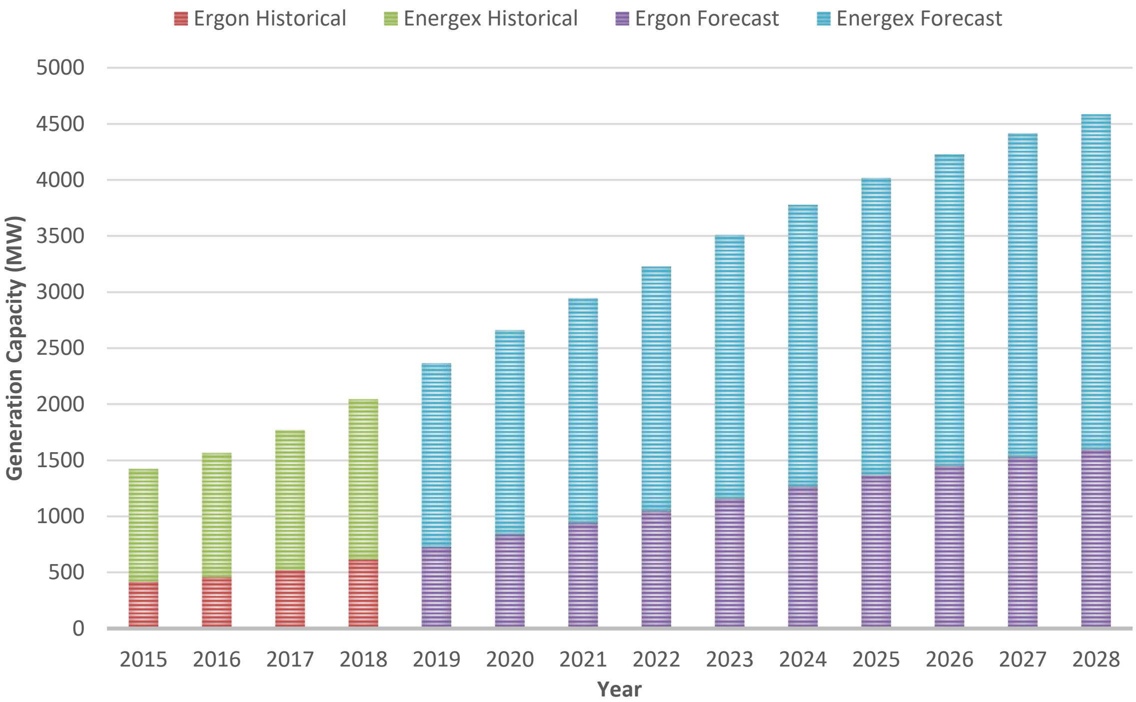

Figure 1: Energy Queensland historical and forecast PV DER Uptake

The Australian Energy Market Operator (AEMO) is recognising that they can no longer continue to operate “blind” to these generators in the distribution network and inevitably they will request distribution network service providers (DNSPs) to provide more real-time data around these connections. This requires Energex and Ergon Energy to develop a solution to meet this need.

Customers (such as Solar Farms) are requesting more operational flexibility, where the DNSP dynamically rates the hosting capacity of the network and manages these signals via Distributed Energy Resource Management Systems (DERMS). This allows them to maximise their revenue opportunities into the market. In their recent review on integration of DERs (AEMC, 2019) The Australian Energy Market Commission (AEMC) has recognised the need for DNSPs to facilitate greater access to data for customers in order to optimise the use of existing and future DERs.

By developing a Customer Zone within the operational architecture, this will allow greater flexibility of data flows to the control room as well as other interested parties (e.g. AEMO). This data will assist in helping maintain network stability and security and reduce the need for costly augmentation to manage capacity.

It will also logically decouple the customer from the substation operations so that there is less impact through lifecycle changes in the substation. It is expected that the average solar farm will have an operational life of 20 years. During this time both the DNSP and the solar farm will have to upgrade their control and monitoring technology. By decoupling the connection (using Internet-Protocol (IP) instead of hard-wired) this simplifies these upgrades and reduces the risk of mal-operation.

Finally, it will also provide greater security of the connection. By setting up a dedicated customer zone, the relevant cybersecurity protections can be put in place to minimise the risk to the power network from a compromise of the customer infrastructure.

This investment allows Energy Queensland to provide a common infrastructure that will support and benefit all medium/large DER connections. Individual customer projects will continue to fund their connection requirements specific to their projects, however, this infrastructure will allow that to occur more flexibly and at a lower cost to the customer.

Customers, typically DER providers, will benefit from simpler, secure and more flexible data connections to Energy Queensland and onwards to AEMO.

This proposal aligns with the CAPEX objectives and criteria from the National Electricity Rules as detailed in Appendix C.

1.4 Energy Queensland Strategic Alignment

Table 1 details how Secure Data Zones contribute to Energy Queensland's corporate and asset management objectives. The linkages between these Asset Management Objectives and EQL's Corporate Objectives are shown in Appendix D.

Table 1: Asset Function and Strategic Alignment

Objectives	Relationship of Initiative to Objectives
Ensure network safety for staff contractors and the community	This initiative contributes to maintaining security of network supply which contributes to network safety for staff, contractors and the community.
Meet customer and stakeholder expectations	The initiative simplifies connection upgrade processes and reduces the risk of mal-operation which improves processes and experiences for customers and stakeholders.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	This initiative works toward helping maintain network stability and security by allowing greater flexibility of data flows.
Develop Asset Management capability & align practices to the global standard (ISO55000)	This business case is consistent with ISO55000 objectives and promotes a continuous improvement environment.
Modernise the network and facilitate access to innovative energy technologies	This business case is directly related to modernising the network as it relates to updating and implementing newer technologies.

1.5 Applicable service levels

Corporate performance outcomes for this asset are rolled up into Asset Safety & Performance group objectives, principally the following Key Result Areas (KRA):

- Customer Index, relating to Customer satisfaction with respect to delivery of expected services
- Optimise investments to deliver affordable & sustainable asset solutions for our customers and communities

Corporate Policies relating to establishing the desired level of service are detailed in Appendix D.

Under the Distribution Authorities, EQL is expected to operate with an 'economic' customer value-based approach to reliability, with "Safety Net measures" for extreme circumstances. Safety Net measures are intended to mitigate against the risk of low probability vs high consequence network outages. Safety Net targets are described in terms of the number of times a benchmark volume of energy is undelivered for more than a specific time period. EQL is expected to employ all reasonable measures to ensure it does not exceed minimum service standards (MSS) for reliability, assessed by feeder types as

- System Average Interruption Duration Index (SAIDI), and;
- System Average Interruption Frequency Index (SAIFI).

Both Safety Net and MSS performance information are publicly reported annually in the Distribution Annual Planning Reports (DAPR). MSS performance is monitored and reported within EQL daily.

1.6 Compliance obligations

Table 2 shows the relevant compliance obligations for this proposal.

Table 2: Compliance obligations related to this proposal

Legislation, Regulation, Code or Licence Condition	Obligations	Relevance to this investment
Distribution Authority for Ergon Energy or Energex issued under section 195 of *Electricity Act 1994* (Queensland)	Under its Distribution Authority: • The distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services. • The distribution entity will ensure, to the extent reasonably practicable, that it achieves its safety net targets as specified. • The distribution entity must use all reasonable endeavours to ensure that it does not exceed in a financial year the Minimum Service Standards (MSS)	This proposal will improve flexibility of data flows helping to maintain network security and stability and providing greater security of connection, aligning with good electricity industry practice.

1.7 Limitation of existing assets and process

The current connection methodology treats the generator as a “fixed” connection. These technical connections are developed as a “set and forget” with no flexibility for operation of the generator other than when the connection agreement is established.

This has allowed a simple direct connection from the customer controller/ Remote Terminal Unit (RTU) to the Energex or Ergon RTU in the substation, effectively treating the generator as additional input/output points in the substation. Up to the current level of DER penetration, this connection type allowed for resonable control of cybersecurity risk as it is serially based and focused on a specific protocol – Distributed Network Protocol (DNP3).

From an economic perspective, as the number of solar farms increase the number of network constraints will grow, and without a flexible operating model these constraints will significantly impact approvals. This will see a reduction in size and number of solar farms connecting to the network.

Additionally, the operational requirements for these generators are changing for a number of reasons:

- Growth in renewables in the distribution networks means the original network parameters that the generator was approved under may no longer be valid
- Economic drivers for the generator to offer more capacity and flexibility in operation (e.g. variable output) which brings associated control and communication requirements
- AEMO requesting significantly more real-time operational data for the purposes of network modelling and stability studies
- Distributed Energy Resources Management System (DERMS) integration which will require an active data and control connection to the generator

This requires a different methodology in the way that Energex and Ergon Energy currently connects for control and communication purposes to these generators. Due to the requirements around fault tolerance, a local connection to the substation will still be needed, however, this will need to be an IP based connection to allow multiple protocol interactions and transfer significantly larger data sets.

The methodology is to set up a “customer zone” within the operational systems in the substation and the broader Operational Technology environment. This will allow a cybersecurity solution to inspect the data and protect the DNSP infrastructure. It will also allow a separate data collection/storage /transmission system to other parties such as AEMO. Currently, this is being achieved in a limited way using the existing EQL management platform and a data link to Powerlink and does scale as required.

2 Counterfactual Analysis

2.1 Purpose of asset

Currently, control and communication systems of large-scale embedded generation are connected as a “hard-wired” solution into the nearest substation. Each connection solution is tailored for that connection and there is no flexibility for growth or change in operating parameters. As additional connections are needed, extra consideration and costs are necessary for any control system assets that are upgraded.

The current connection methodology treats the generator as a ‘fixed’ connection with only the need for emergency signalling instructions, such as ‘Ramp Down’ and ‘Disconnect from the Network’. This has allowed a simple communication from the customer controller to the substation, enabling reduced cybersecurity risk as it is focussed on a specific protocol – Distributed Network Protocol 3 (DNP3).

2.2 Business-as-usual service costs

The business as usual (BAU) service costs are related to management costs associated with substation maintenance. These costs are expected to increase under a BAU case as any work associated with the control system will need to take into consideration the hardwired connection in terms of maintenance and upgrades. Additionally, extra consideration and cost will be required for any control system assets that are upgraded. These have not been explicitly costed in this case.

2.3 Key assumptions

It is assumed that solar farms and other medium–large scale generators will continue to connect to the network at the existing rate.

This project relies on the organisation continuing the current security models (zones) as per the architecture principles already adopted by both Energex and Ergon Energy.

The counterfactual is assumed as the ‘Do Nothing’ business as usual case.

2.4 Risk assessment

This risk assessment is in accordance with the EQL Network Risk Framework and the Risk Tolerability table from the framework is shown in Appendix E.

Table 3: Counterfactual risk assessment

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Unable to cost-effectively meet medium/large DER customer data requirements securely	Customer	4 *(Adverse national media attention, loss of public trust, disruption to multiple large businesses or essential services)*	4 *(Likely)*	**16** ***(Moderate Risk)***	2019
Current communication and control connections for large scale generators are unable to meet f**uture technology** plans (intelligent grid); leading to **EQL being unable to deliver on a strategic initiatives and additional business costs $>1 million**.	Business	4 *(Unable to meet strategic initiative’s resulting in additional business costs $>1 million)*	3 *(Unlikely)*	**12** ***(Moderate Risk)***	2025

Further Details of the risk ratings and descriptions can be found in Energy Queensland's Network Risk Framework.

The preferred option (Creation of a Secure Data Zone for large DER connections) is the right option to reduce these risks, as it provides the right balance of additional security with data performance at the lowest cost to assist in actively managing the medium-large DER connections. This solution removes the current fixed and hard-wired solutions that do not evolve to meet the changing needs of the network.

Risk Assessment Outcome:

The network (business) risk the organisation would be exposed to if the project was not undertaken is not deemed to be as low as reasonably practicable (ALARP). Addressing the risks as detailed below through implementation of the preferred option will reduce Energy Queensland's risk exposure.

2.5 Retirement or de-rating decision

This business case refers to current connection services rather than a particular asset so there is no applicable retirement or de-rating decision.

3 Options Analysis

3.1 Options considered but rejected

None identified.

3.2 Identified options

Option 1: Implement New DER Security Data Zone (Recommended)

Implement a data security zone that provides a secure and flexible connection for DER providers to connect to EQL and onwards to AEMO.

This option consists of:

- Development of a new DER connection architecture
- Selection of technology
- Field validation
- Establishment of standard designs for customer connections.

Option 2: Do Nothing

This option will increase the lifecycle management costs associated with substation maintenance as any work associated with the control system will need to take into consideration the hardwired connection in terms of maintenance and upgrades.

3.3 Economic analysis of identified options

3.3.1 Cost versus benefit assessment of each option

The Net Present Value (NPV) of the program has been determined by considering costs and benefits over the program lifetime from FY2020/21 to FY2024/25, using EQL's standard NPV analysis tool. The tool incorporates any residual value for assets at the end of the program lifetime into the NPV analysis. The Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62% has been applied as the discount rate for this analysis (as per EQL's Standard NPV Tool)

Table 4: Estimated NPV for business case for both Ergon Energy and Energex works

Option Name	NPV ($ 000s)
Implement New DER Security Data Zone	-$730

Table 5 and Table 6 outline the estimated direct costs for both Ergon Energy and Energex to implement the new security data zone. These combine for a total of $1M CAPEX required for the 2020-2025 regulatory control period.

Table 5: Energex Direct Cost Summary

ENERGEX	FY2020/21	FY2021/22	FY2022/23	FY2023/24	FY2024/25	Total FY20/21-24/25
Labour	-	-	-	$80,000	$100,000	**$180,000**
Material	-	-	-	$120,000	$100,000	**$220,000**
Grand Total:	-	-	-	**$200,000**	**$200,000**	**$400,000**

Table 6: Ergon Energy Direct Cost Summary

ERGON ENERGY	FY2020/21	FY2021/22	FY2022/23	FY2023/24	FY2024/25	Total FY20/21-24/25
Labour	-	-	-	$120,000	$150,000	**$270,000**
Material	-	-	-	$180,000	$150,000	**$330,000**
Grand Total:	-	-	-	**$300,000**	**$300,000**	**$600,000**

3.4 Scenario Analysis

3.4.1 Sensitivities

The key sensitivities to this project are the capital costs and timing of project works. Any changes in estimated capital will increase the NPV while deferment of projects will decrease the relative NPV.

3.4.2 Value of regret analysis

As only one alternate option has been identified the value of regret is the additional cost and risk incurred through inaction in the 'Do Nothing' case.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

Table 7 details the advantages and disadvantages of the options considered.

Table 7: Assessment of options

Option	Advantages	Disadvantages
Option 1: Implement New DER Security Data Zone	• Reduced CAPEX and open for substation maintenance requirements • Improved cybersecurity • Increased flexibility for DER operability • Contribute to easing access for connection of large-scale generators • Decoupling of customer from substation allows for less impact during lifecycle changes • Easier access to data for AEMO, customers and network operators	• CAPEX and OPEX requirements brought forward compared to Do Nothing
Option 2: Do Nothing	• Deferred CAPEX and OPEX	• Extra consideration and cost for control systems assets that are upgraded • Projects attempting an IP connection will introduce cybersecurity risk • Contribute to difficulties in connecting more and larger solar farms • Increased lifecycle management costs associated with substation maintenance

3.5.2 Alignment with network development plan

A number of elements of the Electricity Network Transformation Roadmap relate to this initiative. The first is Intelligent Networks and Markets. The expectation is that in the 2020-2025 period, Energex and Ergon have a suite of grid intelligence and control architectures to automate distributed energy resources markets as well as providing system security. The second is Customer Orientated Electricity where it is expected that collaboration with customers and market actors will create new value with streamlined connections. The third is Power System Security where distribution networks provide visibility of DER and potentially enable Frequency Controlled Ancillary Services (FCAS) and other delegated balancing services through real-time communications and controls.

This is provided in more detail in the Future Grid Roadmap document.

3.5.3 Alignment with future technology strategy

This initiative is based on the strategies defined in the Future Grid Roadmap and the Intelligent Grid Technology Plan. From these strategies, a technology solution and its associated costing and benefits have been described to deliver on these strategic aims. Its delivery is essential to the delivery of these strategies and will form the foundation for the future Digital Platform of Energy Queensland, enabling data analytics and collaboration.

3.5.4 Risk Assessment Following Implementation of Proposed Option

Table 8: Risk assessment showing risks mitigated following Implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Unable to cost-effectively meet medium/large DER customer data requirements securely	Customer	*(Original)* *4* *(Adverse national media attention, loss of public trust, disruption to multiple large businesses or essential services)* (Mitigated) 4 (As above)	*4* *(Likely)* 2 *(Very Unlikely)*	***16*** ***(Moderate Risk)*** **8** ***(Low risk)***	2019
Current communication and control connections for large scale generators are unable to meet f**uture technology** plans (intelligent grid); leading to **EQL being unable to deliver on a strategic initiatives and additional business costs $>1 million**.	Business	*(Original)* *4* *(Unable to meet strategic initiative's resulting in additional business costs $>1 million)* (Mitigated) 4 (As above)	*3* *(Unlikely)* 2 *(Very Unlikely)*	***12*** ***(Moderate Risk)*** **8** ***(Low risk)***	2021

4 Recommendation

4.1 Preferred option

The recommended option is to implement a new DER security data zone in order to improve flexibility, access to information and cybersecurity for customers and network operators.

4.2 Scope of preferred option

The scope consists of the following items:

- Development of a design of a customer zone with the Energex and Ergon Energy Operational Technology Environment (OTE);
- Design of an interface to AEMO;
- Design of an interface to DERMs;
- Development of a security architecture;
- Review and trial of technology to enable connectivity, security, data and control from within the substation;
- Implementation of all relevant solution components (e.g. changes to zoning, telecommunications, SCADA etc to enable solution);
- Test and Trial on a number of solar farms; and,
- Implement as a standard with Energex and Ergon Energy.

The customer zone is expected to be operational around the middle of the regulatory period along with the implementation of the Intelligent Grid Enablement program. However, it may need to be brought into the earlier part of the period depending on pressure from AEMO to deliver the capability sooner.

It will be delivered as a staged approach across the 2020-2025 period with initial forecasts towards the middle of the period, but potentially moved to the 2020/21 period if pressured by AEMO and customers.

Appendix A. References

Note: Documents which were included in Energy Queensland's original regulatory submission to the AER in January 2019 have their submission reference number shown in square brackets, e.g. Energy Queensland, *Corporate Strategy [1.001], (31 January 2019).*

AEMC, *Integrating Distributed Energy Resources for the Grid of the Future, Economic Regulatory Framework Review,* (26 September 2019).

Energy Queensland, *Asset Management Overview, Risk and Optimisation Strategy [7.025]*, (31 January 2019).

Energy Queensland, *Corporate Strategy [1.001],* (31 January 2019).

Energy Queensland, *Future Grid Roadmap [7.054],* (31 January 2019).

Energy Queensland, *Intelligent Grid Technology Plan [7.056],* (31 January 2019).

Energy Queensland, *Network Risk Framework*, (October 2018).

Appendix B. Acronyms and Abbreviations

The following abbreviations and acronyms appear in this business case.

Abbreviation or acronym	Definition
$M	Millions of dollars
$ nominal	These are nominal dollars of the day
$ real 2019-20	These are dollar terms as at 30 June 2020
2020-25 regulatory control period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As Low as Reasonably Practicable
AMP	Asset Management Plan
BAU	Business as Usual
CAPEX	Capital expenditure
BESS	Battery Energy Storage System
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management Systems
DMS	Demand Management System
DNP3	Distributed Network Protocol
DNSP	Distributed Network Service Provider
DSO	Distribution System Operator
ENA	Energy Networks Association
ENTR	Electricity Network Transformation Roadmap
EQL	Energy Queensland
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FCAS	Frequency Controlled Ancillary Services
HV	High Voltage (35kV – 230kV AC)
IP	Internet Protocol
KRA	Key Result Areas
MSS	Minimum Service Standard
NEL	National Electricity Law
NEM	National Electricity Market

Abbreviation or acronym	Definition
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
NPV	Net Present Value
OTE	Operational Technology Environment
PCBU	Person in Control of a Business or Undertaking
Previous regulatory control period or previous period	Regulatory control period 1 July 2010 to 30 June 2015
PV	(Solar) Photovoltaic System
RIN	Regulatory Information Notice
RTU	Remote Terminal Unit
RTS	Return to Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
WACC	Weighted average cost of capital

Appendix C. Alignment with the National Electricity Rules (NER)

The table below details the alignment of this proposal with the NER capital expenditure requirements as set out in Clause 6.5.7 of the NER.

Table 9: Alignment with NER

Capital Expenditure Requirements	Rationale
6.5.7 (a) (2) **The forecast capital expenditure is required in order to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services**	Our alignment to regulatory obligations or requirements is demonstrated in this proposal, whereby CAPEX is required in order to maintain compliance and electrical safety through alignment with the QLD Electrical Safety Act 2002 and the QLD Electrical Safety Regulation 2006, as well as maintain levels of data and network security.
6.5.7 (c) (1) (i) **The forecast capital expenditure reasonably reflects the efficient costs of achieving the capital expenditure objectives**	The Unit Cost Methodology and Estimation Approach sets out how the estimation system is used to develop project and program estimates based on specific material, labour and contract resources required to deliver a scope of work. The consistent use of the estimation system is essential in producing an efficient CAPEX forecast by enabling: • Option analysis to determine preferred solutions to network constraints • Strategic forecasting of material, labour and contract resources to ensure deliverability • Effective management of project costs throughout the program and project lifecycle, and • Effective performance monitoring to ensure the program of work is being delivered effectively. The unit costs that underpin our forecast have also been independently reviewed to ensure that they are efficient (Attachments 7.004 and 7.005 of our initial Regulatory Proposal).
6.5.7 (c) (1) (ii) **The forecast capital expenditure reasonably reflects the costs that a prudent operator would require to achieve the capital expenditure objectives**	The prudency of this proposal is demonstrated through the options analysis conducted and the quantification of risk and benefits of each option. The prudency of our CAPEX forecast is demonstrated through the application of our common frameworks put in place to effectively manage investment, risk, optimisation and governance of the Network Program of Work. An overview of these frameworks is set out in our Asset Management Overview, Risk and Optimisation Strategy (Attachment 7.026 of our initial Regulatory Proposal).

Appendix D. Mapping of Asset Management Objectives to Corporate Plan

This proposal has been developed in accordance with our Strategic Asset Management Plan. Our Strategic Asset Management Plan (SAMP) sets out how we apply the principles of Asset Management stated in our Asset Management Policy to achieve our Strategic Objectives.

Table 1: "Asset Function and Strategic Alignment" in Section 1.4 details how this proposal contributes to the Asset Management Objectives.

The Table below provides the linkage of the Asset Management Objectives to the Strategic Objectives as set out in our Corporate Plan (Supporting document 1.001 to our Regulatory Proposal as submitted in January 2019).

Table 10: Alignment of Corporate and Asset Management objectives

Asset Management Objectives	Mapping to Corporate Plan Strategic Objectives
Ensure network safety for staff contractors and the community	EFFICIENCY ***Operate safely as an efficient and effective organisation*** Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations.
Meet customer and stakeholder expectations	COMMUNITY AND CUSTOMERS ***Be Community and customer focused*** Maintain and deepen our communities' trust by delivering on our promises, keeping the lights on and delivering an exceptional customer experience every time
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	GROWTH ***Strengthen and grow from our core*** Leverage our portfolio business, strive for continuous improvement and work together to shape energy use and improve the utilisation of our assets.
Develop Asset Management capability & align practices to the global standard (ISO55000)	EFFICIENCY ***Operate safely as an efficient and effective organisation*** Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations.
Modernise the network and facilitate access to innovative energy technologies	INNOVATION ***Create value through innovation*** Be bold and creative, willing to try new ways of working and deliver new energy services that fulfil the unique needs of our communities and customers.

Appendix E. Risk Tolerability Table

Network Risks - ***Risk Tolerability Criteria and Action Requirements***

Risk Score	Risk Descriptor	Risk Tolerability Criteria and Action Requirements			
30 – 36	***Intolerable*** *(stop exposure immediately)*				
24 – 29	***Very High Risk***	***ALARP** Risk in this range managed to As Low As Reasonably Practicable	**Executive Approval** (required for continued risk exposure at this level)	May require a full Quantitative Risk Assessment (QRA) Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments	**SFAIRP** Risks in this area to be mitigated So Far as is Reasonably Practicable
18 – 23	***High Risk***		**Divisional Manager Approval** (required for continued risk exposure at this level)	Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments	
11 – 17	***Moderate Risk***		**Group Manager / Process Owner Approval** (required for continued risk exposure at this level)	Introduce new or changed risk controls or risk treatments as justified to further reduce risk Periodic review of the risk and effectiveness of the existing risk treatments	
6 – 10	**Low Risk**				
1 to 5	***Very Low Risk***		No direct approval required but evidence of ongoing monitoring and management is required	*Periodic review of the risk and effectiveness of the existing risk treatments*	

Figure 2: A Risk Tolerability Scale for evaluating Semi-Quantitative risk score

Appendix F. Reconciliation Table

Reconciliation Table Conversion from $18/19 to $2020	
Business Case Value	
(M$18/19)	$1.00
Business Case Value	
(M$2020)	$1.04