Enabling an Emergency Backstop Mechanism

Consultation Paper

1 September 2022

Part of Energy Queensland

Enabling an Emergency BackStop Mechanism

CONTENTS

Ergon Energy Corporation Limited ABN 50 087 646 062 | Energy Queensland Limited ABN 96 612 535 583 | Energex Limited ABN 40 078 849 055

Enabling an emergency backstop mechanism

EXECUTIVE SUMMARY

This paper seeks feedback from stakeholders on a proposal to introduce an emergency backstop mechanism in Queensland. The proposal has been developed in consultation with the Australian Energy Market Operator (AEMO), Powerlink Queensland and the Department of Energy and Public Works (DEPW), and aims to support the National Electricity Market (NEM) and electricity security of supply in Queensland.

The emergency backstop mechanism would give Energex and Ergon Energy Network the ability to curtail the output of inverters, in new connections 10kVA and above and selected replacement/upgraded systems, at the direction of AEMO, for any electricity system emergencies should this be required to reduce any load shedding that might otherwise be required. An emergency backstop mechanism would be used to help maintain grid stability and prevent widespread power outages and support the continued safe uptake of roof top solar photovoltaic (PV) systems.

The emergency backstop would only be implemented as a last resort and after all other available options to maintain power system security have been exhausted. This includes AEMO calling for a market based response and taking all available 'system' level actions such as the curtailment of large scale generators or the cancelling of line maintenance where ever possible. These steps are taken via AEMO's Contingency and Minimum System Load Framework – a three stage approach to maintaining system security. Under this framework AEMO issues Market Notices seeking any available market-based responses to support the power system, moving to the system level actions and then finally application of the emergency backstop if these measures have not addressed the risk to system security.

The demonstrated need for this mechanism is outlined in AEMO's 2021 Electricity Statement of Opportunities (ESOO) [1], which highlights declining demand and credible system security risks in Queensland, resulting from the ongoing connections of distributed energy generation without any capability to be managed. The large volumes of distributed energy systems, mainly roof top solar, can create circumstances where the entire Queensland electricity demand is so low that it presents a risk to the ability to keep the power system stable, this is known as minimum system load. This capability will also support AEMO, Energex and Ergon Energy Network in managing risk of rooftop solar systems unexpectedly disconnecting in aggregate, that when combined with the unexpected loss of a large scale generating unity, could occur at levels that exceed the level of generation supplies held in reserve to manage the unexpected tripping of generating plant both large and small. This is detailed on AEMO's Power System Operation web page [2].

A range of other supporting measures, such as dynamic connection standards and repurposing existing load control are also being implemented to help address the risks associated with minimum system load. The combination of measures will enable the emergency backstop mechanism to be used as a last resort and help provide a safe and reliable electricity network, whilst allowing more distributed generation to be connected to the Queensland electricity network.

Enabling an emergency backstop mechanism

ABOUT OUR CONSULTATION

Purpose of consultation

Energex and Ergon Energy Network are consulting with industry stakeholders on implementing an emergency backstop mechanism for inverter energy systems (IES) customer connections (like solar PV systems) 10kVA and above to:

- Explain the rationale and justification for introducing an emergency backstop mechanism;
- Explain the proposed application of the emergency backstop mechanism to new and selected existing IES connections;
- Provide industry guidance and clarity on the installation and operation of Generation Signalling Devices (GSD) required to be installed to enable the emergency backstop mechanism; and
- Seek feedback on any specific challenges or concerns with the installation and operation of GSDs with IES.

Consultation Information

Submissions due by:	**7th October 2022**
Options for submission	Email: emergencybackstop@energyq.com.au Website form: www.talkingenergy.com.au/emergencybackstop
Webinar	Thursday 15th September, 9:00am – 10:00am. To register for the webinar, send an email to emergencybackstop@energyq.com.au
Response	Questions are provided at the end of the consultation paper.

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MINIMUM SYSTEM LOAD

The challenge of increased distributed generation and minimum system load

Energex and Ergon Energy Network have a long history of supporting the connection and integration of Distributed Energy Resources (DER) on Low Voltage (LV) networks. In Queensland, roof-top solar now represents the single largest generation source, with > 4.2 gigawatts (GW) of total generation capacity. This is greater than Gladstone power station which at 1.68 GW is Queensland's largest individual coal fired power station.

Customers continue to connect new generation in large quantities, with an average of 5,800 solar PV systems connecting to the distribution systems of Ergon Energy Network and Energex each month in 2020/21. This adds around 50 megawatts (MW) of distribution generation capacity each month, or the equivalent of 600 MW per year. Unlike large traditional generating units that can have their output directly managed by the plant operators or AEMO, rooftop solar PV is largely uncoordinated from a network management perspective.

In order to maintain the security and stability of electricity networks, it is important that the supply of electricity is properly managed to align with the demand from customers. However, the widespread uptake of distributed generation has caused the demand for electricity from the grid to drop dramatically, particularly in the middle of the day. Whilst increased levels of distributed generation can be beneficial to customers in terms of reducing power bills and carbon emissions, it is also proving to be a significant challenge for network operators in terms of ensuring a secure and reliable electricity system in times of system contingencies.

Each year AEMO produces an Electricity Statement of Opportunities (ESOO) which provides technical and market data for the NEM over a 10-year period to inform the planning and decision-making of market participants, new investors, and jurisdictional bodies. The 2021 ESOO also includes operational consumption and maximum and minimum demand forecasts over a 30-year period (until the end of the 2050-51 financial year) across a range of scenarios to assist with longer-term planning studies. Based on Queensland's present assets, these longer-term forecasts indicate the minimum operational demand threshold for synchronous generation (e.g. electricity supplied by Queensland's large coal-fired generators) must remain on-line during all system normal periods, so as to ensure system strength is adequately maintained in Queensland.

When demand for electricity falls below this minimum threshold level, it is known as 'minimum system load'. As minimum system load continues to decrease, particularly at certain times of the year, this creates a considerable risk to Queensland's electricity system, particularly if this occurred when the interconnector between Queensland and New South Wales was offline causing Queensland to operate in island' mode. As noted in the ESOO [1] (pages 83-84):

> *To operate Queensland as an island, in addition to maintaining sufficient units online to deliver the necessary levels of system strength, there must be sufficient assets operating to deliver the levels of frequency control required in the island... approximately 1.6 GW to 3.4 GW of operational demand is required to maintain the secure operation of Queensland as an island and deliver all the required services…If Queensland is operating as an island and operational demand falls below these minimum operational demand thresholds, it will become increasingly difficult to provide the necessary levels of frequency control to meet the Frequency Operating Standards following credible contingencies.* ***Minimum operational demand is projected to start to fall into this range in 2021****, indicating that operational flexibility at low demand times is already becoming challenging, if Queensland is operating as an island. During 2023 and 2024, in the Central projection, operational demand is forecast to fall below the lower parts of this threshold. This will mean* ***shedding***

***of whole consumer feeders in reverse flows may become necessary to securely operate a Queensland island**, if a separation event occurred in a low demand period.*

Records show that in the last 10 years, Queensland has operated in island mode once every two years on average. If the interconnector is offline for planned or unplanned outages and operational demand falls below these minimum operational demand thresholds, it will become increasingly difficult to control the power system frequency, which in turn places risks on overall system security. An expected response to these events may be to disconnect or 'shed' at least some parts of the network, particularly those areas that experience 'reverse flow' due to high solar generation, meaning that customers on those parts of the network will lose their electricity supply.

Energex and Ergon Energy Network have for some time supported customers installing distributed generation to supply their electricity needs, and continues to do so. However, many customers' solar generation greatly exceeds their daytime electricity usage, resulting in more power being exported to the grid than is used on-site by the customer. Energex and Ergon Energy Network do not wish to prevent or limit customers from connecting rooftop solar PV, however, to avoid the risks associated with minimum system load (noted above) it is prudent to implement measures that will allow this to happen in a manner that ensures the network can still be operated safely and securely.

Potential solutions to minimum system load

A range of potential solutions exist to address minimum system load over the short to long term. Energex and Ergon Energy Networks have been working closely with DEPW, Powerlink Queensland and AEMO, along with participating in the Energy Security Board (ESB) DER integration working groups, to ensure that all credible options are identified and implemented as quickly as possible. Some of the options that have been considered include:

- Direct control of inverters as an emergency backstop mechanism;
- Connections being able to access new markets through the use of dynamic operating envelopes;
- Encouraging customers to optimise the use of their systems by using their appliances more during the daytime to 'soak up' their solar generation;
- Optimising the use of the existing fleet of appliances on load control tariffs to 'soak up' excess solar generation (within existing tariff rules);
- Support for electric vehicles and electrification of industries;
- Support for, and installation of, grid scale batteries for storing electricity generated during the day in customer or network scale batteries;
- Large scale energy storage in pumped hydro schemes; and
- Economic development supporting daytime demand growth.

The above initiatives would all contribute to helping manage minimum system load and ensure the power system continues to operate securely, reliably, safely and affordably. Progressing all these changes require the collaboration of AEMO, market bodies, governments, industry, and consumer advocates.

An emergency backstop mechanism has been identified as a critical no-regret mechanism for system operators to manage risks associated with minimum system load in the short term. In its

Enabling an emergency backstop mechanism

Post-2025 market design final advice to energy ministers, the ESB made the following recommendation [3]:

> *To support system security and improved transparency at times of minimum system load, the ESB recommends Energy Ministers adopt a jurisdictional Ministerial lever for emergency backstop mechanisms, as an immediate reform.*

To enable an emergency backstop, Queensland is in a unique position to leverage the same control mechanism that has been used in the network for more than 60 years, and more recently as part of load control tariffs. This enables a faster implementation timeframe for this important network security mechanism.

DEMAND RESPONSE VIA AS/NZS 4755 DEMAND RESPONSE STANDARD

Demand response refers to the ability for enabled 'smart devices' to respond to communications sent to the device instructing it to alter its output or use of energy from the grid. The AS/NZS 4755 series covers a range of demand response capable appliances, including:

- DER such as solar PV;
- air conditioners;
- pool pumps;
- electric hot water storage heaters;
- batteries; and
- electric vehicle supply equipment.

As an example, Ergon Energy Network and Energex have successfully delivered the PeakSmart program since 2014. This is a voluntary demand management program, utilising customer air conditioners that have been enabled for demand response via AS/NZS 4755.3. The demand response is enabled through the installation of a device into individual air conditioners. The device can trigger the air conditioner to enter one of three demand response modes (DRM 1,2,3) when it receives a signal from the network. Communication to the device is through an Audio Frequency Load Control (AFLC) system, which is sent as a ripple signal via powerlines.

To date, over 130,000 air conditioners across Queensland have had demand response enabling devices installed. These devices are typically activated less than 5 times per year and only during peak network conditions (e.g. in the middle of summer).

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Example of Demand Response Signalling Device

EMERGENCY BACKSTOP

Inverter management

Inverters connected to the grid in Queensland are all compliant with *AS/NZS 4777.2 Grid connection of energy systems via inverters, Part 2: Inverter requirements*. These inverters have an inbuilt capability to disconnect from and reconnect to the electricity network by operating a disconnection device within the inverter when it receives a signal. This utilises what is known as the Demand Response Mode 0 (DRM0) function of an inverter, which is a demand response function compliant to *AS/NZS 4755.3 Demand response capabilities and supporting technologies for electrical products.*

We propose to utilise this existing DRM0 capability for the emergency backstop mechanism. To utilise DRM0 functionality, an IES will require the installation of a GSD, which is an AFLC based demand response enabling device designed specifically for use in IES, like solar PV.

For the proposed solution, the GSD will be connected to each inverter, utilising the existing connection available for the demand response mode function. Connection may vary depending on inverter manufacturer but is typically via the RJ45 port or 8 pin round communications port. In some cases, the settings in the inverter may also need to be configured to ensure it is enabled for DRM0 mode.

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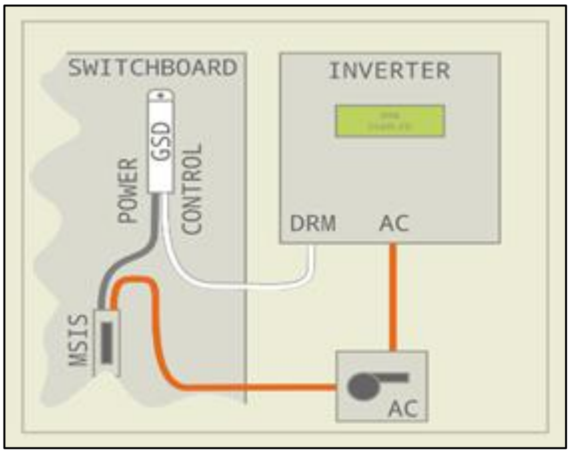

Simple wiring diagram showing connection of Generation Signalling Device

Example of Demand Response Mode Port – RJ45 connection

In Queensland, Energex and Ergon Energy Network:

- have proven experience with using demand response modes functions via AFLC for demand management purposes;
- manage a large fleet of customer air conditioners, hot water systems and pool pumps via this technology; and
- are exploring how they can leverage new technology being introduced as part of dynamic customer connections, using SEP2 (IEEE 2030.5), to support an emergency backstop mechanism for the Queensland jurisdiction in the future.

The requirement for emergency backstop mechanism

To support the Queensland electricity grid for short periods on days when rooftop solar generation exceeds demand, Ergon Energy Network and Energex are only looking to introduce this for customers connecting larger systems. It is proposed that from November 2022, an emergency backstop mechanism will be required where a customer is connecting or altering an IES connection with an aggregate capacity of 10 kVA or above. The requirement will apply equally to systems that are approved for full export, partial export, or nil export. For further details, please see Appendix 1.

As an example, an emergency backstop mechanism will be required for:

- new connections with an aggregate installed nameplate capacity of 10kVA or above;
- for a replacement inverter, not under warranty, where the aggregate installed capacity is 10kVA or above, for example:
    - Scenario 1 – where a 10kVA IES system has a single 10kVA inverter which is being replaced, it must be replace with an inverter that is compliant with our current standards and fitted with a GSD;
    - Scenario 2 – where a customer has a 10kVA IES system that has 2 X 5kVA inverters and replaces one of the inverters with a new 5kVA inverter. The replacement 5kVA inverter must be compliant with our current standards and fitted with a GSD. The inverter which is not being replaced is not required to have a GSD fitted;
- when adding IES capacity to an existing IES system and this results in the total capacity being 10kVA or above, all the new inverters being added (regardless of their size/capacity) must be compliant with our current standards and fitted with a GSD. The pre-existing inverters are not required to have a GSD retrofitted.

As our AFLC infrastructure does not service the entire Energex and Ergon Energy Network, certain areas where there is no AFLC coverage will be exempt from having to comply with the requirement to install a GSD. Exempted areas include:

- Ergon Energy isolated network communities;
- Single Wire Earth Return (SWER) network areas;
- Other fringe of grid areas; and
- Brisbane CBD.

It will also not be required for warranty replacements. A search tool will be available on the Ergon Energy Network and Energex websites that will allow a National Metering Identifier (NMI) based search to be undertaken to confirm AFLC availability and determine if the emergency backstop requirements apply. Further, it is expected that Ergon Energy Network and Energex customer portals will include a functionality that advises a connection applicant if a GSD needs to be installed, at the time a connection application is submitted.

An annual review of the emergency backstop mechanism will be undertaken to determine the ongoing need for the operation of the mechanism in light of emerging technology and options for customer participation.

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Introduction of backstop requirement into Standards

Energex and Ergon Energy's embedded generating connection standards will be updated to include a requirement to install a GSD. The impacted standards include:

- Standard for Small IES Connections (STWN 1170) [4];
- Standard for Low Voltage EG Connections (STWN 1174) [5]; and
- Dynamic Standard for Small IES Connections (STNW 3510) [6].
- Dynamic Standard for LV EG Connections (STNW 3511) [7].
- These standards form part of the safety and technical requirements that a customer must comply with under the terms of their connection contract.

Installation of the generation signalling device

It is expected that a GSD will be capable of satisfying the following requirements:

- the GSD must be installed before the IES is connected;
- where required under Standards, a GSD will be required for each impacted inverter;
- an AC power supply to be available for the GSD;
- the GSD to be installed adjacent to the inverter; and
- the GSD is IP64 rated.

The GSD manufacturer(s) will also provide generic instructions on installation of the device. Inverter manufacturers may also provide model specific instructions.

It is expected that the GSD will be able to be purchased through a Queensland based supplier TMAC (Thew & McCann Group) or other electrical wholesalers and will cost around $70. Other manufacturers of devices may also enter the market, and subject to those devices meeting appropriate technical specifications (using AFLC as the Network signalling format), further GSD supply options may become available.

Installers will be responsible for ensuring that the GSD is fitted correctly and that the inverter has been appropriately configured so that customers will be able to comply with the relevant connection standard and the applicable network connection agreement. A random inspection process will be undertaken to ensure compliance with the requirement to install the device. As the requirement to install the GSD will be a condition of the network connection agreement/contract, enforcement provisions applicable to customers of those contracts will also apply.

When the emergency backstop mechanism is triggered, the inverter will enter into DRM0, which will cause the inverter to operate the disconnection device which will cease all electricity generation – this includes preventing any generation for self-consumption on-site. When the emergency event that triggers the emergency backstop mechanism has passed, a second signal will be sent to the GSD which will allow the inverter to return normal operation. The GSD has an in-built 'fail safe' mechanism that returns the inverter to normal operation if the device does not receive or respond to the second signal after four hours.

When DRM0 is activated, the customer may consume electricity from the grid, which will be charged at their agreed retail tariff rate. Similarly, where applicable, the solar PV system will not earn any feed-in tariff whilst in DRM0.

The bill impact for a customer will vary based on a range of factors, including the size of the system, time of day and the site's electricity consumption during the event. However, a simple cost calculation for a typical 10kW system, with a consumption tariff of $0.25kWh, where the premise has to purchase additional electricity from the grid (in lieu of utilising electricity generated on-site), during a four-hour outage event would be:

10kW X 4 hours X $0.25/kWh = $10

Operation of, and duration of emergency backstop events

As this measure is being implemented to address wider system issues, triggering of an emergency backstop signal to impacted IES will be undertaken at the direction of AEMO. This will occur in response to specific network emergency conditions such as the separation of Queensland from the rest of the NEM coincident with periods of high levels of distributed generation being exported to the grid. Queensland has separated from the NEM five times in the last 10 years, with connectivity typically restored after a few hours.

In September 2021, AEMO introduced a new market notification for managing 'minimum system load (MSL)' – similar to the existing Lack of Reserve (LOR) notification arrangements [8]. This framework would govern the use of the emergency backstop mechanism.

The duration required for an emergency backstop event would be based on the required time for the relevant authorities to restore system stability after a minimum system load scenario, or for the level of load to naturally increase in accordance with its daily profile. It is expected that this could take in the range of two to four hours, during daylight hours.

Benefits of the emergency backstop mechanism

Implementing an emergency backstop mechanism provides a range of benefits to customers and networks, including:

- increasing the capacity for Queensland's distribution network to connect more DER, such as solar PV;
- reducing the risk of state-wide network outages, where excess generation coincides with planned or unplanned network contingencies;
- using reliable and proven technology to support the use of emergency backstop operation as a last resort to ensure whole of system stability in Queensland; and
- mitigating against the potential for community-wide economic costs associated with widespread interruptions to electricity supply.

It is important to consider that the costs of 'doing nothing' could be significant to the Queensland economy. The major blackouts that occurred in South Australia in September 2016 were estimated to cost commercial consumers around $367 million (based on customer surveys) [9]. Based on the size of the Queensland economy compared to South Australia's, the impact in terms of dollars could exceed $500 million for just one similar outage.

Interaction with dynamic customer standards

As outlined in our initial consultation document in early 2021 [10], and the stage 2 consultation paper issued in November 2021 [11], dynamic customer connections are a new type of connection offer for customers. Dynamic customer connections utilise SEP2 for interoperability with embedded generation systems. The new connection type aims to increase a customer's capability to access market benefits by optimising hosting capacities, such as export limits, in a dynamic (near real time) arrangement. For example, when the local network can support increased export to the grid, the limit applied will increase and at times where the network has a reduced capability to host export to the grid, the limit will be decreased.

Dynamic limits will be applied independent of the emergency backstop mechanism. However, the functionality of GSDs will have a higher priority than any dynamic limits applied to a customer’s connection. That is, while dynamic limits will be applied in frequent five-minute intervals, a signal that an inverter receives for emergency backstop will be required to take precedence over an operational signal from any other source.

The GSDs will have priority as they are designed to manage whole of system constraints rather than local network constraints. Whole of system constraints during times of minimum system load, are relatively infrequent, whereas local constraints affecting peak inverter operation may be more frequent. Further, operation of the GSD for system constraints will not present a risk to local networks. For more information on dynamic customer connections, see https://www.talkingenergy.com.au/dynamicconnections.

Utilising the interoperability capability of SEP2 to support an emergency backstop mechanism is not an available technology solution at this time but is being explored further as a future option.

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CONSULTATION QUESTIONS

Responses to these questions can be submitted by:

- email: emergencybackstop@energyq.com.au OR
- Using the website form at www.talkingenergy.com.au/emergencybackstop

Q1. Do you understand the reasoning behind the proposal to implement an emergency backstop mechanism in Queensland to manage the risks of minimum system load? If not, please suggest where you'd like more information?

Q2. Do you see any potential technical challenges to installing the Generation Signalling Device? Please provide specific examples.

Q3. Do you see any potential technical challenges in relation to multi string inverters, multi-inverter systems, micro-inverter systems, or inverter battery energy storage systems? Please provide specific examples.

Q4. What additional information or support will installers and consumers need in order to understand the proposed changes and their obligations, including communicating the new requirements to end customers? Please provide specific examples.

Q5. Please provide any other feedback you think will assist us the implementation of the emergency backstop mechanism.

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APPENDIX 1: EMERGENCY BACKSTOP – SCOPE OF REQUIREMENTS

Connection Categories	Aggregate IES System Capacity (kVA)	Types of IES Connections	Required to install GSD[1-5]	Requirement for inverters to be GSD capable and have GSD installed
LV	< 10	Initial Connect	No	-
		Increase inverter capacity	No	-
		Replace inverter (no increase of supply) – not warranty replacement	No	-
	≥ 10	Initial Connect	Yes	All IES
		Increase inverter capacity	Yes	All new IES only
		Replace inverter (no increase of supply) – not warranty replacement	Yes	All new IES only
	Any	Replace inverter (no increase of supply) – warranty replacement	No	-
HV	Any	Any	No	

Note 1 – Generation Signalling Device for emergency backstop not required where there is no Network standard switching capability available. A search tool will be available on the Ergon Energy Network and Energex websites that will allow a National Metering Identifier (NMI) based search to be undertaken to confirm AFLC availability and determine if the emergency backstop requirements apply.

Note 2 – Anticipated commencement November 2022.

Note 3 – There is no requirement for installation of GSD for customers who had a valid IES embedded generating system (EG) connection agreement for the Energex or Ergon Energy distribution network in place before the commencement date of the Backstop mechanism (expected in November 2022) and where the installation of the IES occurs within the terms of the connection agreement, including the timeframes.

Note 4 – All inverters shall meet the requirements of the relevant EG connection standard and the Queensland Electricity Connection Manual (QECM).

Note 5 – An inverter can be replaced under warranty only where the following requirements are met:

- The replacement inverter is the same make and model (like-for-like).
- The replacement is for warranty purposes.
- The inverter is set up to comply with the existing connection agreement.

Where the above requirements are not met the inverter will need to comply with the latest connection standards and customers shall apply for a connection agreement as relevant:

- Replace inverter (no increase of supply) – not warranty replacement; or
- Increase inverter capacity