Part of Energy Queensland

## Substation Standard

# Guide for Reactive Plant in Substations



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Abstract: This standard provides guidance on the selection type and application of Reactive Plant in substations.

Keywords: Reactive, Plant, Capacitors, Reactors, Inductors, SVC, STATCOM, Synchronous Condenser, HV Filters.

## CONTENTS

## FIGURES

## TABLES



## EQUATIONS

# 1 Overview

## 1.1 Purpose

This guide is designed to provide advice for the selection and use of Reactive Plant used in DNSP (Ergon Energy and Energex) substations and those connected to the DNSP's network.

It details and describes different types of plant and how they can be implemented to resolve network issues and to comply with Queensland Acts and Regulations, the Network Electricity Rules, and Australian Standards. This has become of high importance due the high number of synchronous and asynchronous generator connections and the way they effect the distribution network.

This guide does not include Medium or Low Voltage plant used on distribution feeders to maintain system values within statutory compliance requirements.

# 2 References

## 2.1 Legislation, Regulations, Rules, and Codes

| Document | Type |
|---|---|
| *Electricity Act 1994* (Qld) | Legislation |
| Electricity Regulation 2006 (Qld) | Regulation |
| *Electrical Safety Act* 2002 (Qld) | Legislation |
| Electrical Safety Regulation 2013 (Qld) | Regulation |
| National Electricity Rules | Regulation |
| *Queensland WH&S Regulation 2011* | Legislation |

## 2.2 Controlled Documents

| Document | Alternative Doc ID |
|---|---|
| Standard for Substation Protection - 2948492 | STNW1002 |
| Standard for Intelligent Electronic Devices (IEDS) - 21097268 | |
| Standard for Sub-Transmission and Distribution Planning - 11539388 | |
| Standard for Plant Energisation - 3059318 | STNW1179 |
| Standard for Voltage and Reactive Power Management - 3060854 | STNW3417 |

## 2.3 Other sources

Substations and high voltage installations exceeding 1 kV a.c., AS 2067, 2016, Standards Australia

Standard voltages, AS 60038 – 2012, Standards Australia

Electromagnetic compatibility (EMC) Limits - Assessment of emission limits for fluctuating loads in MV and HV power systems, TR IEC 61000.3.7:2012, Standards Australia

Electromagnetic compatibility (EMC) Limits - Steady state voltage limits in public electricity systems, AS 61000.3.100-2011, Standards Australia

Static Var Compensators, TB 25, 1986 CIGRE, Technical Brochure

Reactive Power Compensation Analysis and Planning Procedure, TB 30, 1989 CIGRE, Technical Brochure

Analysis and optimization Of SVC use in transmission systems, TB 77, 1993 CIGRE, Technical Brochure

Static Synchronous Compensator (STATCOM), TB 144, 2000 CIGRE, Technical Brochure

Transformer Energization in Power Systems: A Study Guide, TB 568, 2014 CIGRE, Technical Brochure

Influence of shunt capacitor Banks on circuit breaker Fault interruption duties, TB 624, 2015 CIGRE, Technical Brochure

Guidelines for the procurement and testing of STATCOMS, TB 663, 2016 CIGRE, Technical Brochure

Power quality aspects of solar power, TB 672, 2016 CIGRE, Technical Brochure

Protocol for reporting operational Performance of FACTS, TB 717, 2018 CIGRE, Technical Brochure

# 3 Definitions and Abbreviations

## 3.1 Definitions

For the purposes of this standard, the following definitions apply.

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|---|---|
| Anti-islanding | Refers to the functionality of a protection system to detect islanded conditions and disconnect the EG system from the Distribution System. |
| CBD | A feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution system containing significant interconnection and redundancy when compared to urban areas. |
| Connection Agreement | Agreement between a Network Service Provider and a registered participant (or other person) to connect to the distribution network and receive distribution services. For Energex and Ergon Energy is typically comprises an establishment contract and an ongoing contract. |
| Connection Assets | Those components of the Distribution System which are used to provide connection services (that is, to a particular Connection Point). |
| Connection Point | The agreed point of supply established between the Network Service Provider and the registered participant |
| Distribution Network | A Network in Queensland which is not a transmission network (as defined in rule 9.32.1(b) of the NER). |
| Distribution System | A Distribution Network, together with the Connection Assets associated with the Distribution Network, which is connected to another transmission or distribution system. |

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| Distributor | Either Energex (who owns and operates the Distribution System in South East Queensland) or Ergon Energy (who owns and operates the Distribution System in the remainder of Queensland). |
| EG system(s) | Two or more electricity generating units and auxiliary equipment that are interconnected with a Distribution System. |
| Embedded Generating unit or EG unit | A generating unit connected within a Distribution System and not having direct access to the transmission network. |
| Energy Laws | Relevant laws relating to the subject matter of this Standard, including, without limitation and where applicable, the *Electricity Act 1994* (Qld), the *Electricity Regulation 2006* (Qld), the *Electrical Safety Act 2002* (Qld), the *Electrical Safety Regulation 2013* (Qld), the Electricity Distribution Network Code, the National Electricity (Queensland) Law, the National Electricity Rules, the National Energy Retail Law (Queensland) and the National Energy Retail Rules. |
| Export | Net power that is fed into the Distribution System through the Connection Point. |
| Generator | A person who engages in the activity of owning, controlling, or operating a generating system that is connected to, or who otherwise supplies electricity to, a distribution system and who is registered by AEMO as a Generator. |
| High Voltage (HV) | A voltage exceeding 1,000 V AC and 1,500 V DC. |
| Inverter Energy System (IES) | A system comprising one or more inverters together with one or more energy sources (which may include batteries for energy storage), controls and one or more grid protection devices. |
| Isolation Device | A device designed to safely prevent the flow of current such as a circuit breaker or contactor. |
| Isolated Distribution System | Refers to the small remote electricity Distribution Systems operated by Ergon Energy that are not connected to the National Grid. These are typically supplied with electricity via a dedicated power station. |
| Lagging Power Factor (Absorbing) | For a generating unit, the unit absorbs reactive power from the Distribution System; that is, when the generating unit acts as an inductive load from the perspective of the Distribution System.<br><br>For a load, this is when the load acts as an inductive load. |
| Leading Power Factor (Sourcing) | For a generating unit; the unit acts as a source of reactive power into the Distribution System; that is, when the generating unit acts as a capacitive load from the perspective of the Distribution System.<br><br>For a load, this is when the load acts as a capacitive load. |
| Long Rural | A feeder which is not a CBD or urban feeder and has a total route length greater than 200 km. |
| Low Voltage (LV) | A voltage not exceeding 1000 V AC or 1500 V DC. |

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| Meshed sub-transmission networks | Sub-transmission networks operated in a closed ring configuration (e.g. such as the Rockhampton 66kV mesh) |
| NER | The National Electricity Rules under the National Electricity Law as in force in Queensland. |
| Network | The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any Connection Assets. In relation to a Distributor, a Network owned, operated or controlled by that Distributor. |
| Proponent | The entity with which the connection agreement resides. Relevant owner, operator, or controller of the system (or their agent). |
| PSCAD™/EMTDC™ | Refers to a software package developed by the Manitoba-HVDC Research Centre that comprises a power systems computer-aided design package which includes an electromagnetic transients (including DC) simulation engine, and which is used to carry out electromagnetic transient type studies. |
| Registered Participant | A person who is a *Registered Participant* under the NER (broadly speaking, someone who is registered by AEMO). |
| Short Circuit Ratio | For the purposes of this Standard, is the synchronous three phase fault level in MVA of the Distribution System at the Connection Point divided by the rated output of the generating unit or system.<br>Several other methods exist to calculate Short Circuit Ratio (SCR) and need to be used based depending on the conditions and configuration of the EG system. |
| Short Rural | A feeder which is not a CBD or urban feeder and has a total route length less than 200km. |
| Sub-transmission | Network for the purpose of carrying electricity from bulk supply substations to zone substations. Normally includes 132kV, 110kV, 66kV feeders and in some topologies may also include 33kV. |
| Substation Categorisation | In Energex, substations are categorised as follows:<br>• Flat – minimal voltage drop expected<br>• Category 3.5 – up to 3.5% voltage drop expected<br>• Category 7.5 – up to 7.5% voltage drop expected<br>• Category 10 – up to 10% voltage drop expected<br>This categorisation is not present in the Ergon Energy network. |
| Technical Study | Modelling to evaluate the effects the proposed connection (Reactive Plant) shall have on the Distribution System under various conditions or in the event contingencies. |
| Urban | A feeder which is not a CBD feeder, with a maximum demand per total feeder route length greater than 0.3 MVA/km. |

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| Zone Substation | The zone substation is the location where nominal sub-transmission voltages are transformed to nominal distribution voltages. This generally includes substations with transformations of 132/11kV, 132/22kV, 110/11kV, 66/22kV, 66/11kV, 33/11kV, and in some cases 132/33kV, 110/33kV, 33/22kV (other combinations also exist in the Ergon Energy and Energex networks and voltage management for those locations may be bespoke). |

### 3.2 Abbreviations

This list does not include well-known unambiguous abbreviations, or abbreviations defined at their first occurrence within the text.

| | |
|---|---|
| AC | Alternating Current |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AVR | Automatic Voltage Regulation |
| CB | Circuit Breaker |
| CBF | Circuit Breaker Fail |
| CBD | Central Business District |
| DC | Direct Current |
| DER | Distributed Energy Resources |
| DNSP | Distribution Network Service Provider. In the context of this standard, Ergon Energy and Energex |
| EG | Embedded generator/ generating unit |
| FCAS | Frequency Control Ancillary Service |
| GPR | Grid Protection Relay |
| GPS | Generator Performance Standard |
| HV | High voltage |
| IES | Inverter Energy Systems |
| LDC | Line drop compensation |
| LV | Low voltage |
| LVR | Low voltage regulator |
| MEGU | Micro-embedded generating unit |
| NCP | Network Coupling Point |
| NER | National Electricity Rules |
| NRPS | Non-Registered Performance Standard |
| OH | Overhead conductor, “lines” |
| OLTC | Online Tap Changer |
| 10PoE | Forecasting; 10% Probability of Exceedance |
| p.u. | Per unit |

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|---|---|
| ROCOF | Rate of change of frequency |
| RPEQ | Registered Professional Engineer of Queensland |
| SACS | Substation Automated Control System |
| SVC | Static Var Compensator |
| SCADA | Supervisory Control and Data Acquisition |
| SCR | Short Circuit Ratio |
| UG | Underground conductor, “cables” |
| VVR | Volt Var Regulation |
| ZS | Zone Substation |

# 4 General Requirements and User Information

This guide is intended to be used by planners, customer connection specialists, designers, commissioning teams and operations engineers to simplify and support the development and connectivity of reactive plant to the DNSP network.

This guide includes:

- a summary of the types of reactive plant and the techniques available to implement them
- details of system issues coupled with the plant and techniques used to address them
- plant calculation and details to assist with design
- case studies to be used as examples of best practice and identify problems to avoid
- key plant details to assist with design and procurement

# 5 Reactive Device Overview

A reactive compensation device is a system composed of equipment used for the alternating current (AC) transmission of electrical energy. It is meant to enhance control and increase power transfer capability of the network. This equipment can include mechanically switched capacitors and reactors, Static Var Compensators (SVCs) or Static Synchronous Compensators (STATCOMs).

## 5.1 Capacitor Banks

Capacitor banks are generally used for power factor correction, or voltage boost during high load periods.

Capacitor banks comprise of several individual capacitor cans in series and parallel combinations to achieve the desired capacitance. Each can have several internally fused series and parallel combinations with insulating wraps and fluid. They may also have inrush reactors and tuning reactors installed in series. The reactance values are typically small in comparison to the capacitor. Medium voltage capacitor banks can be installed inside container solutions with all required support equipment. High voltage capacitor banks are installed in insulated racks inside substation yards.

In the transmission network, series capacitance can be used to improve the power transfer capability; however, this is not a typical use in the distribution network.

The energisation of capacitor banks must be managed, as described in Annex A.1, to avoid excessive inrush currents.

In the transmission network, series capacitance can be used to improve the power transfer capability. This is not a typical use in the distribution network.

### 5.1.1 Capacitor Bank Advantages

Capacitors have a lower establishment cost than dynamic devices.

They have lower maintenance and lifecycle costs.

They are relatively simple to control using telemetering and SCADA.

They can be installed in stages and on each bus section with their own feeder bay.

### 5.1.2 Capacitor Bank Disadvantages

Capacitor bank switching is discrete, they can only be switched in certain increments (usually from 0 MVAr to the full capacitor bank capacity).

If a capacitor bank has an internal failure the entire device is unavailable.

Capacitor banks cannot respond in a dynamic manner unless controlled by high-speed switching.

Shunt connected capacitors require their own feeder bay with special instrument transformers and protection.

They require circuit breakers capable of switching capacitive reactive current; (Vacuum or SF6 insulating medium – not Oil).

## 5.2 Harmonic Filters

Harmonic filters are largely composed of capacitors to filter a specific or wide band of harmonics. In terms of power quality, at 50Hz these filters act as a voltage boost in the same manner as a capacitor bank.

They are typically installed in sites where equipment is likely to create harmonics such as industrial plants using VSDs, Solar and Wind Farm inverters, and in SVCs.

Harmonic filter design is crucial to having a filter installation fit for purpose. They have low establishment, maintenance, and lifecycle costs. Harmonic filters can be either passive filters, which have a fixed performance, or active filters which produce compensating harmonic current in response to actual loads.

When installed on the same bus as power transformers, a side effect is to drain remnant flux during transformer demagnetisation, which improves switching inrush on re-energisation of the transformer.

## 5.3 Reactors

Reactors (inductors) are generally used on feeders to reduce voltages during some network conditions but may also be used for other reasons such as in the design of harmonic filters or in the limiting of fault currents or inrush currents.

Shunt reactors are tee connected to the lineside feeder bay of long transmission lines, or on SWER lines, to compensate for voltage rise during low-load periods.

They can also be connected via their own feeder bays with special instrument transformers and protection. As penetration of DER (distributed energy resources) increases, it may be required to install reactors to reduce voltages as transformer taps become constrained.

Reactors comprise of coils of copper or aluminium windings. They can have either:

- A transformer tank type design with a magnetic core and oil insulation or
- An air core design with insulating formwork and paint.

The air-cored design is more cost effective and hence more prevalent, although they do require extra clearance around the reactor due to magnetic field generated. They are mounted on insulated steel frames installed inside substation yards and buildings.

### 5.3.1 Reactor Advantages

Reactors have a lower establishment cost than dynamic devices.

They have lower maintenance and lifecycle costs.

They are relatively simple to control using telemetering and SCADA.

They can be installed on each bus section with their own feeder bay.

Alternatively, they can be tee-connected to an existing feeder bay.

### 5.3.2 Reactor Disadvantages

Reactor switching is discrete, they can only be switched in certain increments (usually from 0 MVAr to the full capacity).

If a Reactor has an internal failure the entire device is unavailable.

Shunt connected reactors require their own feeder bay with special instrument transformers and protection.

Tee connected reactors are always in service with the feeder they are connected to.

They require circuit breakers capable of switching inductive reactive current (SF6 insulating medium – Not Oil or Vacuum breakers).

## 5.4 Static Vac Compensator (SVC)

A Static Var Compensator (SVC) is a device that contains high voltage capacitor and reactor branches that are switched by fast operating control systems and power electronics that use Thyristors. A step-up power transformer connects the SVC to the power network at the appropriate system voltage.

SVCs can detect system changes and operate to compensate in less than 3 cycles, to alter the system to maintain the voltage at a constant, by absorbing or injecting vars.

SVCs improve voltage and power stability on transmission systems operating near limits with varying loads. The term ‘static’ is used to indicate that SVCs, unlike synchronous condensers, have no moving or rotating main components.

SVCs can be used for voltage control, reactive power control, increase the active power transfer capability of networks, increase transient stability margins, improve fault recovery through dynamic injection of reactive power, dampening of oscillations, phase balancing and response to overvoltages.

SVCs are typically used where high output fast acting dynamic reactive power compensation is required, and for phase balancing, such as in electric rail networks or for electric mining machines.

An SVC can have several combinations of fixed and switchable reactive plant typically connected through a power transformer including:

- Mechanically Switched Capacitors and Reactors (MSC and MSR)
- Saturable reactors
- Thyristor Controlled reactors (TCR)
- Thyristor Switched Reactors (TSR)
- Thyristor Switched Capacitors (TSC)
- Capacitor harmonic filter banks

The design will depend on the intended use and the network characteristics of the network. They have outdoor equipment in a specially earthed and fenced area (typically 4 x 8 metres). They have their own control room to house high current power electronics, control panels and special auxiliary systems including water cooling (typically 4 x 8 metres). A full SVC installation could require 20 x 20 metre, similar to a small substation.

### 5.4.1 SVC Advantages

SVCs are fast operating dynamic devices, capable of 3 cycle detection and operation to maintain system stability.

They consist of many integrated components and typically include internal redundancy for some plant, control and auxiliary system failures.

SVC operation can provide a continuously variable output, depending on plant and control design, from 0 MVAr to the full capacity both positive and negative.

They can be installed in stages and on each bus section with their own feeder bays.

By providing fixed reactive compensation and harmonic filters an SVC can be designed to have different capacitive and inductive outputs.

They have a short-term Overload capability, linked to the thermal properties of the power electronics.

Typically, less expensive than STATCOMs above 80 MVAr, hence suited to long transmission networks.

### 5.4.2 SVC Disadvantages

SVCs have a higher establishment cost than Capacitor banks and Reactors.

They have high maintenance and lifecycle costs.

They comprise many specialist components bespoke to each design.

They have complex proprietary control systems that may not easily link to SCADA.

They typically have outdoor equipment in a specially earthed and fenced area.

They typically have a control room to house high current power electronics, control panels and special auxiliary systems including water cooling.

They have a larger civil design footprint than a similar MVAr rated STATCOM.

They require their own feeder bay or bays in a substation to connect to the network.

They require circuit breakers capable of switching inductive reactive current (SF6 insulating medium – Not Oil or Vacuum breakers).

When the voltage is low, the SVCs behaves as fixed device whose output current varies with the square of the voltage.

### 5.5 Static Synchronous Compensator (STATCOMs)

A Static Synchronous Compensator (STATCOM) is an active power electronic device which generates or absorbs reactive power without the need for switched high voltage capacitors or reactors. The basic components of the STATCOM are a Voltage Source Converter (VSC) and a DC-capacitor connected on the DC-side of the VSC. Typically, a step-up power transformer connects the STATCOM to the power network at the appropriate system voltage. The VSC maintains a particular V/Q characteristic by providing reactive power.

The reactive power at the terminals of the STATCOM depends on the amplitude of the voltage source. For example, if the terminal voltage of the VSC is higher than the AC voltage at the point of connection, the STATCOM injects reactive current; conversely, when the amplitude of the voltage source is lower than the AC voltage, it absorbs reactive power.

STATCOMs can detect system changes and operate to compensate in less than 2 cycles to alter the system in such a way to maintain the voltage at a constant by absorbing or producing vars.

STATCOMs provide reactive power at a connection point to maintain a particular V/Q characteristic. The term ‘static’ is used to indicate that STATCOMs, unlike synchronous condensers, have no moving or rotating main components.

STATCOMs can be used for voltage control, dynamic reactive power support, increasing the active power transfer capability of networks, increase transient stability margins, improve fault recovery through dynamic injection of reactive power, dampening of oscillations, phase balancing, active filtering, and response to overvoltages.

STATCOMs are typically used where fast acting dynamic reactive power compensation is required, and for phase balancing, such as renewable connection points or remote substations at ends of sub-transmission networks.

STATCOMs can be utilised at HV or LV, depending on local network requirements. LV STATCOM are not considered as part of this standard.

STATCOM modules are typically designed to a specific rating (e.g. 5Mvar) and consist of a bank of LV VSCs, DC Capacitors and associated auxiliary equipment housed in a small outdoor enclosure (typically 4 x 4 metres). These modules are connected through step-up transformers to the power network. A STATCOM has a control and communications panels that can be installed within an existing substation building. STATCOM controls can be connected into a SCADA system or remote engineering control facility. Depending on the power network requirements multiple STATCOM modules may be connected in parallel and integrated with capacitor banks and reactors to develop the most cost-effective solution. The STATCOM control system can be used to control the operation of all the integrated plant.

#### 5.5.1 STATCOM Advantages

STATCOMs are fast operating dynamic devices, capable of 2 cycle detection and operation to maintain system stability. Faster response than an SVC as it has almost no time delay associated with power electronic thyristor firing.

They consist of integrated components and typically include internal redundancy for some plant, control and auxiliary system failures.

STATCOMs operation can provide a continuously variable output, depending on plant and control design, from 0 MVAr to the full capacity both positive and negative.

They can be installed in stages and on each bus section with their own feeder bays.

They have a short-term Overload capability, linked to the thermal properties of the power electronics.

They can produce rated reactive current when voltage is low.

The overall footprint is smaller in STATCOM systems, taking 30-40% of the area of a similarly rated SVC, because STATCOMs do not require HV power capacitors, reactors or filters.

STATCOM Control systems can operate and integrate with substation Capacitor Banks and Reactors.

STATCOM Control systems and Communications panels can be housed in an onsite substation control room and do not require their own building.

They can be installed using standard substation earthing and fencing principles and do not require water cooling.

Typically, less expensive than SVCs below 80 MVAr, hence suited to renewable customer connections and long sub-transmission networks.

### 5.5.2 STATCOM Disadvantages

STATCOMs may have a higher establishment cost than Capacitor banks and Reactors.

They have high maintenance and lifecycle costs.

They comprise specialist components bespoke to each design.

They have complex proprietary control systems that may not easily link to SCADA.

A STATCOM module includes a step-up transformer and an outdoor enclosure that houses the LV VSCs, DC Capacitors and associated auxiliary equipment.

They require space in a substation control building to house control and communications panels.

They require their own feeder bay or bays in a substation to connect to the network.

They require circuit breakers capable of switching inductive reactive current (SF6 insulating medium – Not Oil or Vacuum breakers).

Capacitive / Inductive output of a STATCOM is symmetrical unless combined with another compensation device

Lack of overload capability compared to an SVC

## 5.6 Synchronous Condensers (SYNCONs)

Synchronous condensers are rotating machines not attached to any driving equipment. They provide improved voltage regulation and stability by continuously generating or absorbing reactive power, improved short-circuit strength and frequency stability by providing synchronous inertia. Typically, a step-up power transformer connects the SYNCONs to the power network at the appropriate system voltage.

SYNCONs can detect system changes and operate to compensate in similar timeframes as SVCs and STATCOMs, to alter the system in such a way to maintain the voltage at a constant by absorbing or producing vars.

SYNCONs can be used for voltage control, dynamic reactive power support, increase transient stability margins, or improve fault recovery and ride through, by the inherent feature of rotating machines, synchronous inertia.

SYNCONs are typically used where fast acting dynamic reactive power compensation is required for weak grids, such as power networks with a high penetration of renewable generation or in remote transmission networks at a high risk of 'islanding' from the main network.

Traditionally, the majority of power network supply was delivered by rotating machine generators that provided inertia inherently. Now asynchronous renewable generators, like solar and wind (using VSCs), are much more prevalent; but do not have inherent inertia. SYNCONs have now been installed in power networks to provide inertia, increase system strength and reduce the risk of unstable operation and outages.

A SYNCON typically consists of a rotating machine with associated control systems and special auxiliary systems, including water cooling housed in its own building (typically 4 x 8 metres). Step-up transformers are utilised to connect to the power network. A SYNCON has control and communications panels installed in the same building. SYNCON controls can be connected into a SCADA system or remote engineering control facility. Depending on the power network requirements SYNCONs from 20 to 200 MVAr are presently available from manufacturers.

As rotating machines, SYNCONs have several integral components including:

- Stator and rotor with solid integral pole tips
- Cooling system
- Excitation system
- Lubrication oil system
- Auxiliary supply requirements

It is envisaged that SYNCONs will be utilised by the transmission service provider and generation proponents, rather than the DNSP.

#### 5.6.1 SYNCON Advantages

By using modern excitation and control systems, SYNCONs are fast operating dynamic devices, capable of 3 cycle detection and operation to maintain system stability, like SVCs and STATCOMs.

Depending on requirements, they may include internal redundancy for some plant, control and auxiliary system failures.

SYNCON operation can provide a continuously variable output, depending on plant and control design, from 0MVAr to the full capacity both positive and negative.

Typical overall footprint is smaller than SVCs but larger than STATCOM systems.

Provide system inertia; as it is a rotating machine, which improves the overall behaviour on the system.

Increase short-term overload capability; depending on design, a SYNCON can provide more than two times its rating up to a few seconds, enhancing system support during emergency situations or contingencies.

Provide Low-voltage ride through; even under extreme low voltage contingencies, it remains connected and provides smooth, reliable operation.

Provide additional short-circuit strength; SYNCONs provides real short short-circuit strength to the grid, which improves system stability with weak interconnections and enhances system protection.

Produce minimal harmonics; SYNCONs are three phase machines rotating and not a source of harmonics and can even absorb harmonic currents.

They can be installed using standard substation earthing and fencing principles.

Can produce fault current.

Strong MVAr production ability.

Ability to continuous adjustment of the reactive power amount.

### 5.6.2 SYNCON Disadvantages

SYNCONs are rotating machines like generators or motors and have similar design, installation, commissioning, and lifecycle requirements.

SYNCONs have very high establishment and operating costs.

They have very high maintenance and lifecycle costs.

They comprise specialist components bespoke to each design.

They have complex proprietary control systems that may not easily link to SCADA.

A SYNCON typically includes a step-up transformer and their own control building to house the rotating machines, control panels and special auxiliary systems including water cooling.

They have a large civil design footprint.

They require their own feeder bay or bays in a substation to connect to the network.

They require circuit breakers capable of switching inductive reactive current ($SF^6$ insulating medium – Not Oil or Vacuum breakers).

Synchronous condensers are typically more expensive than SVCs or STATCOMS.

Require extensive maintenance.

## 5.7 Inverter-Based Technology

Inverter-based technology, such as the inverters associated with solar generation or battery systems, can also provide reactive output if required. It is also possible to configure solar inverters to provide reactive compensation without active power, known as “Q at Night”. Q at night solar inverters have additional componentry for them to be able to operate like a STATCOM.

As a network service provider, Ergon Energy or Energex are not currently permitted to own generating devices, as stipulated in the National Electricity Rules (NER) set by the Australian Energy Market Commission. As such, utilisation of such plant would occur as part of a network support agreement where identified through a RIT-D. The generating system would need to connect to the network, following the requirements of the NER and the normal connections process, a time frame of 18 months – two years.

Contract negotiation is a key component of utilising this technology, and shall consider aspects of performance, non-conformance, availability. Solution development should consider requirements for contingency scenarios and ensure an appropriate operating protocol is developed.

### 5.7.1 Inverter-Based Technology Advantages

Cost-effective; utilising a third-party solution to address a network voltage need can be a cost-effective solution.

Offers an opportunity to defer works and DNSP assets, especially where it is not necessary in the future.

### 5.7.2 Inverter-Based Technology Disadvantages

Relies on third-party and commercial arrangements

Requires means of accurately measuring service provided and means of penalising contracted service provider and changing service provider if non-compliant to agreed terms, for the duration of the contract.

These contracts, tenders, RIT-Ds, and legal terms are time consuming to action and a typical project could require a further 2 years of advanced management and actions to meet project completion timeframes suggested by planner and asset managers.

## 6 Reactive Selection Guide

Table 1 below is intended to provide information about network issues and solutions. In some cases, the best solution could be an SVC or a combination of SVC, STATCOM and capacitors.

**Table 1 - Reactive Plant Selection Guide**

| Network or Customer Need | Potential Solutions | Modelling Required |
|---|---|---|
| Power factor correction | Capacitor banks | PowerFactory / steady state |
| Voltage Boost | Capacitor banks<br>STATCOM<br>SVC<br>Inverter Based Technology | PowerFactory / steady state and quasi-dynamic |
| Voltage Buck | Reactor<br>STATCOM<br>SVC<br>Inverter Based Technology | PowerFactory / steady state and quasi-dynamic |
| Voltage Control | STATCOM<br>SVC<br>Inverter Based Technology<br>SYNCON | PowerFactory / steady state and quasi-dynamic |
| Dynamic voltage control, Xms | Inverter based technology<br>SVC | PSS/E and/or PSCAD/ Dynamic |
| Increase fault level | SYNCON | PSS/E and/or PSCAD/ Dynamic |
| Improve voltage response on load rejection | STATCOM<br>SVC | PowerFactory / steady state and PSS/E dynamic |

# 7 Modelling Tools and Requirements

Various computer power network models for use in load flow analysis, dynamic stability and transient simulations should be developed. These models shall be benchmarked throughout the various phases of the project, with a final validation being done against the actual installed system during the system integration tests. For a suitable benchmark of any model, accurate power system data and contingency scenarios are needed.

## 7.1 Steady State Analysis

Steady state network assessment shall be completed using PowerFactory to identify voltage or reactive power concerns that could potentially be solved by a reactive device. PowerFactory shall also be used for harmonic analysis. For devices such as SVCs, STATCOMs etc, the Supplier shall provide PowerFactory models for harmonic analysis.

### 7.1.1 Reactive Power Flows

As part of the steady state study, reactive power flows shall be examined to determine the maximum current flows.

### 7.1.2 Harmonic Analysis

To conduct harmonic analysis, a Norton equivalent model shall be provided, or details of the connecting transformer size, voltage, impedance, vector groups, components of L, R and C as relevant for the device.

Any connected devices / solutions shall be configured to avoid resonance with any existing power system components. The generation of harmonic voltages and currents on the Queensland system is strictly controlled. The maximum permissible harmonic voltages, as a combined result of all harmonic sources, are limited to the planning levels given in Table 2 of IEC Electromagnetic compatibility (EMC) Part 3.6: Limits - Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems (IEC 61000-3.6).

To preserve the limits throughout the system, harmonic voltages arising from harmonic currents generated by connected devices shall be limited to an allocation that is assigned at the planning stage. The limits are the target levels for continuous harmonic generation. It shall be considered that all characteristic connected device generated harmonics (i.e. the odd series) are continuously produced. Limits must be achieved for a system frequency range of 49.85 to 50.15 Hz.

The harmonic distortion shall be studied and verified through tests provided to the DNSP. During commissioning the harmonic currents injected into the point of connection by the device, over the full operational range of the unit, shall be measured to verify the harmonic performance.

A harmonic performance, resonance and harmonic amplification studies and report shall include:

- The general methodology, modelling approach and software employed
- The predicted highest harmonic currents up to the fiftieth (50th) injected into the point of connection by the device
- A summary of the highest system harmonic voltages up to the fiftieth (50th) appearing on the system
- A general description and outline of the design calculations including the voltage and current rating of the filter components

- Studies to check ability of filter components to withstand overvoltage and frequency variation conditions

The Supplier shall propose a standardised or industry-accepted test method to verify harmonic performance including the performance of the audio frequency blocking filter. This study shall include the effects of the device / solution on the electrical network and all existing plant. A detailed report of these studies shall be submitted to the DNSP.

The SVCs, STATCOMs and Inverter Based Technology solutions should be capable of assisting in the reduction of system harmonics. (e.g., active harmonic filtering, PWM switching algorithms, etc.) The requirement for harmonic mitigation should not reduce the capability of the solution to meet the reactive power output or negative phase requirements.

### 7.2 Dynamic Analysis

The Supplier shall provide an electromagnetic transient-type simulation model of the dynamic reactive device compatible with PSCAD version 4.6.3 or later and with an Intel Fortran compiler version 15 or later to assess the impact and effect of connecting the device to the network. This is required to facilitate stability analysis and the interaction of the device with other active electronic devices.

All PSCAD models shall be black boxed real code models including all control and protection functions and phase locked loop performance. Model veracity must be demonstrated through; measurement results (from an equivalent facility and plant performance from other installations, lab tests, hardware in loop etc.) confirming the validity of the PSCAD vs PSS®E models using a set of benchmarking tests of faults and contingency scenarios. All PSCAD models shall be programmable with any control modes available including adjustment settings such as gains, set-points, limits, etc.

The Supplier shall also supply a PSS®E model with dynamic and steady-state modelling application (including automatic and manual start-up and shutdown control modules) i.e., SMIB in .DLL or .obj/.lib in V34.5 format. A releasable user guide for the PSS®E model, which should incorporate details on how to use the PSS®E model (including details of load flow setup, the control scheme, model control modes and dynamic setup with details of the model’s ICONs, CONs, STATEs, and VARs) shall also be provided.

All models are required to be made available to any connecting party through a methodology that is mutually agreeable to EQL and the Supplier. Preference is that all models be included freely with the transmittance of the system model. The provision of EQL system models is either under an NDA or commercial in confidence as per relevant law, regulations, laws, and guidelines.

## 8 Performance Requirements

### 8.1 Power System Voltages

Queensland network voltages in the DNSPs include 11, 22, 33, 66, 110, 132 and 220 kV. The voltage profile of the system is normally maintained between 0.95 and 1.05 per unit (p.u). All power system equipment must be capable of continuous operation at voltages between 0.9 p.u and 1.1 p.u.

### 8.1.2 Dynamic Device Operating Voltages

Dynamic devices shall provide the rated three phase reactive power output range (leading and lagging currents), at the point of connection, without any degradation of performance, for power system over-voltages and periods:

0.70 p.u to 0.8 p.u for 3 seconds

0.80 p.u to 0.9 p.u for 15 seconds

0.90 p.u to 1.1 p.u continuously

1.15 p.u for 1800 seconds

1.20 p.u for 30 seconds

1.30 p.u for 2.0 seconds

1.40 p.u for 0.2 seconds

Up to surge arrester operation for at least the first cycle

## 8.2 Reactive Power Output

The rated reactive power output shall be provided over the full operating voltage range, frequency range and operating conditions at the point of connection to the DNSP network. The required rating shall apply under the environmental conditions, for the design life and availability and reliability specified.

Redundancy design provisions of the reactive plant, equipment and critical spares shall be detailed to confirm the basis of the continuous capability. If further redundancy or duplication of the components may improve the availability of the reactive plant system, the Supplier may include this as an option in the offer.

### 8.2.1 Dynamic Devices Reactive Power Output

For dynamic devices the minimum operational three phase reactive power output range at the point of connection, at normal operating frequency range 49.85 to 50.15 Hz and voltage operating range of 0.9 to 1.1 p.u.

They are typically capable of a level of overload capacity for a short duration of time. This may aid in low or high voltage disturbances due to system fault transients, flicker, and load rejection situations. Suppliers shall detail any overload capacity and duration available including recovery time in their tender offer.

They may be capable of mitigating negative sequence current of a minimum of 10% of the full operational output rating. The requirement for negative phase sequence must not reduce the devices capability to meet the reactive power output or harmonic mitigation requirements.

Suppliers shall provide a Reactive Capability Performance Report that includes a Reactive Capability Performance Characteristic, which shows voltage control versus MVAr output over the specified full operational reactive output range of the device and guarantees this performance.

### 8.2.3 Dynamic Device Transient Response

Dynamic devices shall be capable of responding to changes of measured system values within 10ms. The change of measured system voltage to small disturbance (typically <3%) should reach 90% of the desired total change within 60ms. The capability will be tested though the simulation of a 5% step change of voltage reference.

The maximum overshoot shall not exceed 10% of the final value, and the settling time should not exceed 100ms, after which the voltage shall be within ±5% of the final value defined as the settling band.

The response of the system voltage using the actual controller shall be validated on a real-time simulator.

## 8.3 Power System Frequency

Reactive devices shall provide the rated three phase reactive power output range (leading and lagging currents as relevant), at the point of connection, without any degradation of performance, for power system frequencies from 46.5 Hz to 52.5 Hz for a period of at least 4 minutes.

These requirements override those of section 6.3.2.2 of Standards Australia Electronic equipment for use in power stations (AS 62103-2006).

**Table 2 - Frequency Limits**

| Condition | Containment | Stabilisation | Recovery |
|---|---|---|---|
| Accumulated time error | 5 seconds | | |
| No contingency event or load event | 49.75 to 50.25 Hz, 49.85 to 50.15 Hz 99% of the time | 49.85 to 50.15 Hz within 5 minutes | |
| Generation event or load event | 49.5 to 50.5 Hz | 49.85 to 50.15 Hz within 5 minutes | |
| Network event | 49 to 51 Hz | 49.5 to 50.5 Hz within 1 minute | 49.85 to 50.15 Hz within 5 minutes |
| Separation event | 49 to 51 Hz | 49.5 to 50.5 Hz within 2 minutes | 49.85 to 50.15 Hz within 10 minutes |
| Multiple contingency event | 47 to 52 Hz | 49.5 to 50.5 Hz within 2 minutes | 49.85 to 50.15 Hz within 10 minutes |

### 8.3.1 Dynamic Device Frequency Response

Conformance shall be demonstrated using a variable frequency source that is capable of sourcing and sinking the full reactive power output of the dynamic device while supplying the real power required to operate.

The maximum Rate of Change of Frequency (RoCoF) requirement shall comply with Clause S5.2.5.3 Generating system response to frequency disturbances of the NER, Automatic access standard.

> (*b*) *The automatic access standard is a generating system and each of its generating units must be capable of continuous uninterrupted operation for frequencies in the following ranges:*

*… unless the rate of change of frequency is outside the range of –4 Hz to 4 Hz per second for more than 0.25 seconds, -3 Hz to 3 Hz per second for more than one second, or such other range as determined by the Reliability Panel from time to time.*

### 8.4 Power System Fault Levels

All primary plant, secondary equipment or components in the reactive system shall be capable of sustaining, without damage, any fault limited by the maximum design short-circuit level and duration of the system and the coupling equipment impedances. These fault levels shall align with substation standard plant ratings.

The minimum and maximum fault levels at the point of connection to the network shall be detailed in Project Scope Specification document, or for customer connections, the Negotiated Ongoing Connection Contract.

### 8.5 Audio Frequency Load Control Blocking

The DNSP uses Audio Frequency Load Control (AFLC) as a demand management tool for specific loads at certain times of the day, such as hot water systems and air conditioning. A ripple control frequency is modulated onto the 50 Hz waveform which varies depending on the region. The frequencies currently used by the DNSP are 167, 217, 225, 317, 425 and 1042 Hz. Reactive devices must not act as a sink to the AFLC signal otherwise demand management system will be compromised. The supplier shall detail how this is achieved in the design and prove during commissioning. The DNSP shall include the AFLC frequency that is to be blocked in the Project Scope Specification document, or for customer connections, the Negotiated Ongoing Connection Contract.

### 8.6 Voltage Unbalance

Voltage unbalance on the DNSP network, expressed as the ratio of the Negative Phase Sequence Voltage to the Positive Phase Sequence Voltage, should not, under normal system conditions (i.e. no contingency) exceed:

**Table 3 - Voltage Unbalance System Standards (NER Table S5.1a.1)**

| Nominal supply voltage (kV) | Maximum negative sequence voltage (% of nominal voltage) | | | |
|---|---|---|---|---|
| | no contingency event | credible contingency event or protected event | general | Once per hour |
| | 30 minute average | 30 minute average | 10 minute average | 1 minute average |
| More than 100 | 0.5 | 0.7 | 1.0 | 2.0 |
| More than 10 but not more than 100 | 1.3 | 1.3 | 2.0 | 2.5 |
| 10 or less | 2.0 | 2.0 | 2.5 | 3.0 |

These limits apply for normal and credible single contingency conditions as per the National Electricity Rules for Distribution Network Service Providers (DNPSs).

Although the National Electricity Rules state that the 1-minute voltage unbalance limit of 2% can be exceeded once per hour, they do not prescribe by how much. Large voltage unbalances, over 2%, may occur for short intervals of up to one minute due to faults, switching operations or transformer energisation. EQL sub-transmission and transmission lines are generally fully transposed.

It is likely within DNSP systems that dynamic reactive devices will be required to mitigate negative sequence unbalance therefore it is expected that they should be able to withstand unbalance equal to twice the system standard.

### 8.7 Auto-Reclose and Protection Details

Dead-times of up to 10 seconds are typical with up to four shots to lockout if unsuccessful. EQL shall include the auto-reclose details at the point of connection in the Project Scope Specification document. EQL shall include the protection details and operating times at the point of connection in the Project Scope Specification document.

## 9 Design and Construction Requirements

Site specific ratings, parameters and requirements for each project shall be included the Project Scope Specification document. In particular, the HV interconnections and plant supplied by EQL shall be clearly stated and agreed.

If design and construction of any primary equipment is to be performed by the Supplier, it shall comply with the Purchasers relevant internal standards and specifications. Site specific parameters and requirements for each project shall be included the Project Scope Specification document.

Power transformers shall be designed with a low loss level (resistance) and have a core saturation range suitable for the full range of dynamic device operation.

### 9.1 Engineering Studies

These studies shall demonstrate that the design solution shall meet all specified performance criteria. The events simulated shall use worst case situations and values including graphical results where appropriate. Engineering studies shall outline general methodology, modelling approach and software employed and should include, but not be limited to the following:

- Insulation coordination
- Electro-magnetic Field
- Audible noise
- Harmonic performance, resonance, and harmonic amplification
- Audio frequency load control (AFLC) signal absorption
- Availability and Reliability
- Control and Protection assessment reports
- Power Loss evaluation report

For STATCOMs, dynamic performance studies in accordance with Cigre Guidelines for the Procurement and Testing of STATCOMs (TB 663, 2016)

### 9.2 Design Reports and Drawings

Design reports and drawings detailing the equipment and associated plant, components, physical layouts, electrical connections, protection, controls, and communications shall be provided by the Supplier. Design reports shall contain full details of key considerations, assumptions made, calculations performed, and reference materials used in the design. The design of the major aspects, systems, components, plant items and settings shall be addressed and detailed in the reports.

Drawings shall include Single Line Diagrams, General Arrangements, schematics, connection diagrams, foundations & footings, and civil & building layouts.

### 9.3 Dynamic Device Stability and Fault Ride Through

A dynamic device must remain stable and in operation throughout system events and disturbances where system voltage and frequency excursions may temporarily exceed expected normal operating conditions. The device shall be capable of uninterrupted operation during and following power system voltage, frequency, and voltage/current waveform disturbances some of which may occur simultaneously. Severity and likelihood of these events should be considered when undertaking power system studies.

The response to disturbances shall comply with NER Clause S5.2.5.5 Generating system response to disturbances following contingency events; Automatic access standard;

*(1A) a generating system and each of its generating units must remain in continuous uninterrupted operation for a series of up to 15 disturbances within any five minute period caused by any combination of the events described in subparagraph (b)(1) where:*

> *(i) up to six of the disturbances cause the voltage at the connection point to drop below 50% of normal voltage;*
>
> *(ii) in parts of the network where three-phase automatic reclosure is permitted, up to two of the disturbances are three phase faults, and otherwise, up to one three phase fault where voltage at the connection point drops below 50% of normal voltage;*
>
> *…provided that none of the events would result in:*
>
> *…*
>
> *(viii) the cumulative time that voltage at the connection point is lower than 90% of normal voltage exceeding 1,800 milliseconds within any five minute period; or*
>
> *(ix) the time integral, within any five minute period of the difference between 90% of normal voltage and the voltage at the connection point when the voltage at the connection point is lower than 90% of normal voltage exceeding 1 p.u second;*

The dynamic device shall be capable of returning to regulation within 10ms of voltage recovery following a fault. The output cannot cause a breach of a shared allocation of overvoltage allowance under Section 8.1.

Multiple control modes for fault ride through include:

- Full capacitive
- Full inductive
- Settable partial reactive levels
- Online with no switching

As a result of a credible contingency event it is expected that the voltage at the dynamic device connection point could fall to zero. For such faults the dynamic device shall ride through, including any reclose sequences.

Suppliers shall guarantee that dynamic devices can meet specified availability and reliability and be stable in operation. If a dynamic device would not remain in uninterrupted operation for any of the specified system conditions, suppliers must state the limiting conditions.

### 9.4 Dynamic Device Monitoring, Control, and Indication

Two (2) dynamic device system controllers shall be provided that monitor each other's health via watchdog systems and transfer operational control of the System to the healthy controller if one experiences a failure. This is necessary to maximise the operational availability and reliability as these systems will be installed in remote sites taking first responders up to three hours to attend to diagnose faults.

#### 9.4.1 Communications Equipment and Access

The EQL Operational Technology Standard for Data Collection STNW3374 and the Standard for Intelligent Electronic Devices STNW3383 detail the requirements for the monitoring, collection and storage of operational data for the purposes of SCADA, metering or the Alternative Data Acquisition Service (ADAS) onto the Purchasers Operational Technology Environment (OTE).

Dynamic device control systems shall include all communication equipment required to interface with the EQL communication network. Engineering access and SCADA over Ethernet and be equipped for IP-based communications. All operational events and alarms shall be time stamped.

EQL operational control centres (OCC), located remotely from the substations, shall be able to control, monitor and modify, start-up, adjust and shut down the dynamic device system. In addition, the dynamic device system shall provide performance data and alarms to the SCADA system.

Provision shall be made to allow internal control system signals to be monitored externally as analogue outputs. All channel outputs should be refreshed at least 6 times per 50 Hz cycle.

Digital outputs are also required for external event recording and monitoring from logic signals within the dynamic device control system. A minimum of twelve digital outputs will be required.

The system shall be capable of logging all events (disturbances) and alarms that the dynamic device system produces and store the information to be accessed later via the OTE.

Digital recordings of disturbances within the dynamic device and the power system shall provide both high speed and slower phasor quantity recordings.

#### 9.4.2 Cyber Security and Access Restrictions

These standards include the Purchaser’s basic Cyber Security requirements. No external connectivity with Purchaser’s communications networks should be permitted. The Purchaser minimises all connections to the Operational Communications Network (OCN). This network facilitates engineering access for the management of devices from desktop applications to support remotely located equipment. Any connections that have exploitable hardware or software shall not be permitted to connect to the OCN. Typically, if the Purchaser does not control the hardware or software used then a device is considered as non-trusted. If connectivity is necessary as part of the installation the Supplier shall detail the requirements and negotiate a secure outcome with agreement from the Purchaser.

#### 9.4.3 Control Modes – Dynamic Devices

Suppliers shall include a Dynamic Control and Regulation Performance Characteristic, which shows voltage control versus output over the specified full operational reactive output range.

The dynamic device system shall provide the following control modes simultaneously:

- Voltage
    - With or without droop

- With or without independent phase control
- Constant var
  - With or without independent phase control
- Power factor
  - With or without independent phase control
- Negative phase sequence unbalance (minimum 10% total current)
- A configurable/programmable gain option
- Power oscillation dampening
- Capacitor & reactor switching
- Manual mode – independent of controller for testing purposes

Suppliers shall provide a detailed description of start-up and shut-down sequences including flow diagrams and an indication of times required in each stage. The start-up and shut-down sequences shall minimise the reactive step during switch on and switch off of the dynamic device, except when the unit has tripped by protection systems.

An Emergency Shut-Down shall be undertaken when the dynamic device must act to protect itself from damage due to faulty equipment and/or dangerous system conditions and if necessary, shall be tripped as fast as possible. The control system shall self-diagnose and initiate immediate and appropriate actions such as shut-down or control system response blocked for an appropriate period. Suppliers shall provide details of their proposed self-diagnosis capability.

Suppliers shall provide a table of all protection trips triggered internally or externally and shall indicate which trips are to be controlled in a stepped manner and which are to be instantaneous.

#### 9.4.4 Indications, Alarms and Trips

A central control unit shall monitor its own operation and the operations of the various dynamic device components. Three levels of status / alert shall be provided. The first-level (Indication) provides device status information. The second-level (Alarm) indicates a problem exists but that the equipment or its proper operation is not in immediate danger. The Third-level (trip) initiates the immediate isolation or a controlled shutdown of the dynamic device due to equipment problems that might cause damage if left uncorrected. The central control unit should also have a built-in protective system for self-monitoring (watchdog).

Suppliers shall provide a table of all alarms and protection trips triggered internally or externally to the dynamic device and shall indicate which trips are to be controlled in a stepped manner, and which are to be instantaneous.

#### 9.4.5 Operator Interface

The dynamic device should provide a local control facility (LCF) and/or indication panel for local control and monitoring.

Hard-wired switches shall be included to enable auto-run, stop, system shutdown and local or remote/SCADA control where only one control point can be active at any one time. Indication LEDs shall also be used to indicate running status, selected control point and active alarms as a minimum.

The control modes shall be selectable and configurable either locally via the LCF or remotely by the OCC. The STATCOM system status and alarms shall be viewed and/or reset via the LCF or remotely by the OCC.

If a hybrid solution is implemented, capacitor banks and/or reactors shall be available to be switched independently if the dynamic device system is out of service.

### 9.5 Protection

All protection schemes shall comply with the EQL Substation Protection standard Standard for Substation Protection - 2948492 (STNW1002), be designed to ensure a high degree of reliability and be graded and coordinated to prevent maloperation. Fail-safe principles should be applied throughout.

The protection relays shall receive their inputs from appropriately rated instrument transformers that are either supplied as part of the STATCOM system or by the Purchaser. Redundant protective functions should be included and demonstrated in the design. The use of common instrument transformers is acceptable.

### 9.6 Auxiliary and Control Equipment

The Supplier shall ensure that basic insulation and basic protection shall form part of the secondary wiring system as detailed in The Wiring Rules (AS/NZS 3000) to provide a minimum level of protection against electric shocks. Supplementary insulation shall be used where applicable to provide an increased level of protection including the use of Residual Current Devices (RCD) where required. Where the nominal voltage of any circuit exceeds 50 V AC or 120 V ripple-free DC, the wiring shall be segregated from other wiring and all related terminals shall be shrouded. Hinged panels carrying live terminals shall be fitted with a transparent rear safety cover, of suitable material, which completely surrounds all live parts, preventing access to live terminals without first removing the whole cover.

### 9.7 Power Loss Evaluation

The Supplier shall specify the total system losses in idle mode, including transformer losses, in kW and in percentage of the device rating. In addition, the detailed losses should include all auxiliary loads including cooling fans and pumps, battery chargers, UPS systems, controls and other auxiliary loads and losses. The total losses of the system shall not exceed 1% of the system rating.

Suppliers shall include a Loss Performance Characteristic, which shows total dynamic device System losses versus output over the specified full operational reactive output range. Suppliers shall guarantee that losses determined and documented in a Loss Assessment Report shall not be exceeded. The report will detail all values and calculations undertaken to compile the assessment.

The Purchaser will assess offers with an economic evaluation of the capital cost of Suppliers by adding the cost of losses for a 20-year period to the cost of capital investment.

The Supplier is able to propose hybrid solutions for the purpose of loss minimisation, ensuring the dynamic performance is not limited.

Guaranteed Losses over entire operating range to a tolerance of +10% with the following conditions:

- Bus voltage of at 1.0 per unit
- Ambient temperature of 40 °C

Transformers and reactors, losses based on 75 °C operating temperature

Depending on the System main control objective, it will typically operate in various operating ranges depending on time. One hundred percent time is the maximum operating time per year. IEEE Guide for the Functional Specification of Transmission Static Var Compensators (IEEE Std 1031, 2011) shows examples used for stability purposes (SVC A) and system voltage control (SVC B).

### 9.8 Spares, Special Test Equipment, Tools, Options and Accessories

Suppliers shall submit separate details of any special test equipment, tools, gauges, and jigs necessary for the installation, operation, and maintenance of the plant.

Spare parts required and location of storage shall be provided including onsite, regional depots (typically four to eight hours away from substations) and others held by the Supplier in an Australian capital city (typically one or two days via express transport from regional depots).

Suppliers shall submit a spare parts strategy detailing costs of recommended spare parts and their storage. The spares strategy may form part of a service and maintenance agreement offered by the Supplier.

Where additional equipment such as a cooling system is required, the Supplier shall provide a general description of the cooling system, including the cooling media, and detail the measures to protect against overheating and cold temperatures. Cooling capacity at the highest ambient temperature shall be detailed.

## 10 Performance and Testing

The testing of all dynamic device primary and secondary equipment, hardware and software, consists of Type Tests, Routine Tests, Factory Acceptance Tests (FAT), Pre-Delivery Inspections, Site Acceptance Tests (SAT), Commissioning Tests and System Integration Tests (SIT).

All dynamic device primary and secondary equipment, hardware and software shall be subjected to and pass all specified tests in accordance with relevant Australian and International standards and Purchaser specifications. All test reports shall be provided as part of the quality assurance procedure of the Supplier.

Prior to commencing testing and commissioning the Supplier shall produce quality system documentation including a comprehensive list of required tests that shall be negotiated and agreed with the Purchaser. The Purchaser shall be allowed to witness any or all type, routine and factory acceptance tests performed.

Some SAT or commissioning tests may not be able to be performed due to power system constraints or limitations imposed by the operational control centre during the commissioning period. If this occurs the testing and commissioning plan shall be reviewed to verify the dynamic device is proven to be fully capable of performing its designed functionality without any detrimental effects to the power system network.

A final in service commissioning period of 90 days shall follow the successful completion of the System Integration Testing to confirm the full system performance is stable and compliant with specifications and designs; the system shall be deemed suitable for permanent system connection and the warranty period shall begin.

## 10.1 Type Tests and Routine Tests

All plant and equipment shall be subjected to and pass all specified type tests in accordance with relevant Australian and International standards and Purchaser specifications. All type test reports shall be provided as part of the quality assurance procedure of the Supplier.

## 10.2 Factory Acceptance Tests (FAT)

All primary and secondary equipment, control and protection, hardware and software shall be subjected to and pass all specified FAT tests in accordance with relevant Australian and International standards and Purchaser specifications. All FAT test reports shall be provided as part of the quality assurance procedure of the Supplier.

FAT shall be performed by the Supplier of the system, as close as practicable, fully factory assembled; consisting of plant, equipment, control and protection, hardware, and software to verify the full functional and dynamic performance. The system shall be FAT tested before being delivered to site.

Verification of actual primary and secondary equipment, control & protection, hardware, and software shall be performed by running the real control systems together with a real-time simulator. The real-time simulator shall accurately represent the steady-state and dynamic behaviour of the power electronic devices (including any power electronic device or inverter protection algorithms). A network equivalent together with the dynamic device must be modelled on the real-time simulator. Functional performance tests may be done using a reduced network model. This shall be benchmarked against the PSCAD and PSS®E models.

Real-time simulator FAT tests detailed in the IEEE Guide for the Functional Specification of Transmission Static Var Compensators (IEEE Std 1031, 2011) shall be complied with for SVC and large Statcom installations installed in zone substations.

## 10.3 Site Acceptance Tests (SAT)

All primary and secondary equipment, control and protection, hardware and software shall be subjected to and pass all specified SAT tests in accordance with relevant Australian and International standards and Purchaser specifications. All SAT test reports shall be provided as part of the quality assurance procedure of the Supplier.

Site Acceptance Testing (SAT) shall be performed by the Supplier of the system, fully assembled onsite, consisting of plant, equipment, control and protection, hardware, and software to verify the erection and installation conforms with agreed designs, interfaces with Purchaser's control systems and all equipment is ready for full operational service performance. The system shall be SAT tested to the Purchaser specified requirements before permitting the Supplier to proceed to Commissioning or System Integration Tests.

### 10.5 Commissioning Tests

All primary and secondary equipment, control and protection, hardware and software shall be subjected to and pass all specified Commissioning tests in accordance with relevant Australian and International standards and Purchaser specifications. All Commissioning test reports shall be provided as part of the quality assurance procedure of the Supplier.

Commissioning Testing shall be performed by the Purchaser and Supplier of the system, fully assembled onsite, consisting of plant, equipment, control and protection, hardware, and software to verify the erection and installation conforms with agreed designs, interfaces with Purchaser's control systems and all equipment is ready for full operational service performance.

The system shall have all Commissioning tests performed to the Purchaser specified requirements before permitting the Supplier to proceed to System Integration Tests.

Commissioning tests are completed onsite following SAT testing with the system fully assembled and ready for service. Commissioning hold points for each sub-system shall be presented to the Purchaser to verify the specified requirements at each stage of installation and testing prior to System Integration Tests.

### 10.6 System Integration Tests (SIT) and AEMO R2 Tests (Generator Sites)

All primary and secondary equipment, control and protection, hardware and software shall be subjected to and pass all specified SIT and AEMO R2 tests in accordance with relevant Australian and International standards and Purchaser specifications. All SIT and AEMO R2 test reports shall be provided as part of the quality assurance procedure of the Supplier.

System Integration Testing (SIT) and AEMO R2 tests shall be performed by the Purchaser and Supplier of the system, fully assembled onsite, consisting of plant, equipment, control and protection, hardware, and software to verify that the full STATCOM system operational service performance is to the agreed designs and the impact on the power system network at the point of connection conforms to the Purchaser specifications.

SIT and AEMO R2 tests shall include a combination of energisation tests and simulations of specified and designed power system network events to verify the STATCOM system performance simultaneously by the Purchaser and Supplier together.

During SIT and AEMO R2 testing the developed PSCAD, and PSS®E models of the dynamic device performance with the power system network shall be observed by the Purchaser and the Supplier on site.

#### 10.6.1 AEMO R2 Model Validation Tests and Report (Generator Sites)

The National Electricity Rules (NER) (Version 105), Chapter 5 Network Connection, Planning and Expansion, Clause 5.2 details the obligations of Network Service Providers, Customers and Generators. Clause 5.7 Inspection and Testing details the testing requirements for these participants, as per the AEMO, "R2 Testing Guideline" Prepared By: Network Models – Systems Capability", (28 June 2013),

The National Electricity Rules (the Rules) in clause S5.2.4(b) require that generators provide network service providers and AEMO with a range of data relating to their generating units, control systems and protection systems.

The Rules require AEMO to maintain a Generating System Design Data Sheet, a Generating System Setting Data Sheet (Data Sheets) and Generating System Model Guidelines (Model Guidelines).

These documents provide detail about the information and data parameters required for each type of generation technology.

The data required is categorised by the installation development stage, denoted as standard planning data **(S)**, detailed planning data **(D)**, and registered data **(R1** and **R2)**. The data is used for modelling generation systems (including generating plant, control, and protection systems) in network analysis software that is used to assess and plan the security and performance of the electricity system.

Clause S5.5.2 defines R1 and R2 data as follows:

Registered data consists of data validated and agreed between the Network Service Provider and the Registered Participant, such data being:

(a) prior to actual connection and provision of access, data derived from manufacturers' data, detailed design calculations, works or site tests etc. (R1); and

(b) after connection, data derived from on-system testing (R2)

Each model shall be developed and tested to the extent reasonably necessary to establish that it will meet the accuracy requirements described for the relevant model type. To achieve this:

During the generating system design and development stages, it is expected that the model will be rigorously derived from design information.

Parameters and models that are designated as R2 in the Data Sheets shall be derived from on-site tests.

Where parameters are not designated as R2 in the Data Sheets, the value of these parameters (in aggregate) shall be validated through the overall performance validation of the system, device, unit or controller to which they pertain.

In general, R2 testing entails deriving and validating generation system modelling data onsite, during and following commissioning. It includes a range of tests, measurements and simulations to demonstrate that the performance and behaviour of the installed generating system matches the modelled system.

R2 testing requires testing of plant and systems across a range of levels – from individual plant items up to integrated, farm-level systems. To demonstrate the validity of a model across the range of potential study conditions, it is expected that the behaviour of the actual generating system and its model will be assessed for both steady state and dynamic conditions.

The model package submitted by a Connection Applicant shall be revised periodically throughout a connection project, reflecting the stage of the process. The final (registered) data packages as defined under clause S5.5.2 of the Rules are:

- R1 model package – must be submitted at least three months before commissioning as specified under Clause S5.2.4 of the Rules,
- R2 model package – is the validated data, and must be submitted, along with an R2 model verification report, within three months of the final commissioning tests being completed.

Further support is found using, AEMO, “GPS Compliance Assessment And R2 Model Validation Test Plan Template For Power Electronic Interfaced Non-Synchronous Generation Technologies”, (September 2016), Full system SIT and AEMO R2 test results shall be provided to the Purchaser for review and acceptance. The system shall not remain permanently energised and final in service commissioning shall not proceed unless the Purchaser has accepted the full SIT and AEMO R2 test details.

### 10.7 Final in Service Commissioning

A final in service commissioning period of 90 days shall only begin after all testing has been successfully performed, completed and accepted by the Purchaser and Supplier of the dynamic device system, fully assembled onsite, consisting of plant, equipment, control and protection, hardware and software to verify that the full system operational service performance is to the agreed designs and the impact on the power system network at the point of connection conforms to the Purchaser specifications.

For the full duration of the final in service commissioning period, the system shall perform to the full Purchaser specified requirements, design and operational service performance without trips or loss of rating; as long as it is operated in accordance with the range, protocols and procedures detailed by the Supplier. If it does not the system shall be deemed faulty and the Supplier shall render full service and support to ascertain and rectify the situation at their cost until such time the system is available for full operational service performance.

## 11 Maintenance and Lifecycle Requirements

In addition to the inclusions of the offer the Supplier shall provide comprehensive details of service agreement options, maintenance plans or spares strategies that can be negotiated upon award of the contract. It is expected that the term of a maintenance and service agreement would align with the 20-year design life of the secondary equipment.

As a minimum the Supplier shall provide details of the following:

- The standard five (5) year warranty period and options for an extended warranty period
- Full preventative maintenance plan for the 40-year life of the system including minor and major service times and guidelines, and major component replacement options. This should incorporate combined interaction of both the Supplier and Purchaser personnel to develop a long-term effective business relationship
- Corrective and preventative maintenance options should also be considered and include outlining how redundancy and availability may be impacted
- Failure troubleshooting and replacement procedures, plans and guides that detail the level of skill and training required at each stage such as operator, local first responder, maintenance technician, testing engineer or Supplier support necessary
- Remote service capabilities including 24/7 telephone support and interrogation by Supplier remote monitoring systems
- Spare parts required and location of storage; onsite, regional depots (typically four to eight hours away from substations) and others held by Supplier in an Australian capital city (typically one or two days via express transport from regional depots)
- Control system settings, software and firmware updates, upgrades and cyber security.
- Methods to minimise outages and maximise availability
- Cost breakdown of recommended maintenance activities for the operational life of the solution, including estimated labour hours and replacement parts

### 11.1 Design Life and Warranty

The primary plant shall have a design life of 40 years and the secondary equipment shall have a design life of 20 years.

Warranty for the systems shall be a minimum of five (5) years. This is due to the complexity of this type equipment and expected level of support required from the Supplier and Manufacturer.

A final in-service commissioning period of 90 days shall begin after all testing has been successfully performed, completed, and accepted by the Purchaser and Supplier. If the full system is compliant and stable for the entire period the system shall be deemed suitable for permanent system connection, and the warranty period shall begin.

### 11.2 Reliability, Availability and Maintainability (RAM)

The Supplier shall provide all details of the calculations of their Reliability, Availability and Maintainability (RAM) values and specify the spare parts included in their tender. The supplier shall provide a recommended maintenance plan to be followed by the Purchaser so that the calculated and expected RAM values can be achieved over the operational life of the system.

A performance guarantee shall be provided by the supplier that the RAM values shall be maintained for the warranty period after the agreed commercial in-service date. The Purchaser shall monitor the RAM of the plant and if it does not meet the guaranteed RAM values, the Supplier will be liable for liquidated damages.

#### 11.2.1 Availability

EQL requires a high level of availability equal to 98.5% or greater in one year, including planned and unplanned outages. The system is considered to be available for service only if it is able to perform the whole of the specified duty. The system shall operate under the service conditions with the design and construction performance requirements detailed. Operation with limited control functions or within a limited range of outputs due to a sub-system failure is to be treated as unscheduled outage.

#### 11.2.2 Reliability

EQL requires a high level of reliability equal to 4380 hours or greater mean time between unplanned outages. Suppliers shall provide evidence in support of the reliability and performance claimed including information relating to Mean Time Between Failures (MTBF), Mean Time To Restore System (MTTRS) and Failure Mode and Effect Analysis (FMEA). The mean time to restore system for failures which cannot be rectified using a spare item shall include the time taken to either repair on site, or transport and repair at a central workshop or obtain a replacement item and reinstall test and re-commission the system.

### 11.3 Training

A comprehensive training program shall be provided by the Supplier and is required for all levels of personnel in the Purchaser’s organization. This is to provide a solid basis for operation and maintenance over the operational life of the system. The training program shall cover all equipment as supplied by the Purchaser, including inverter modules, cooling system, control and protection, transformers, auxiliary systems, switchyard equipment, measurement, interlocking and safety.

The formal program should provide appropriate training to all levels of the Purchaser’s staff, including Management and non-technical staff, Design and asset management engineers, Network operators, Maintenance technicians, Test and Commissioning technicians and engineers.

# Annex A

**Informative**

# Plant Calculations and Details

## A.1 Capacitor Banks

When a capacitor bank is energised, inrush current and overvoltages can result. The total inrush current combines the steady state load current of the capacitor bank, with the inrush from the system, as well as any sympathetic inrush from adjacent banks.

The inrush current can be represented by:

$$I_{peak} = \frac{V_{peak}}{Z_C}$$

$$Z_C = \sqrt{\frac{L}{C}}$$

$$f = \frac{1}{2 \cdot \pi\sqrt{LC}}$$

**Equation 1: Inrush Current**

Where:

$I_{peak}$ = peak inrush current;

$V_{peak}$ = peak voltage;

f = transient frequency.
In addition, the inrush from the system, and the sympathetic inrush from adjacent banks must be included.

This large inrush current can result in a significant voltage dip. One method of mitigation of this inrush current is with the installation of an inrush reactor.

Immediately following the voltage dip, the system voltage will attempt to recover, but will over-shoot the normal system voltage by an amount that is nearly equal to the voltage dip. Theoretically, two per-unit over-voltages can occur due to capacitor switching.

## A.2 SVC Operating Points

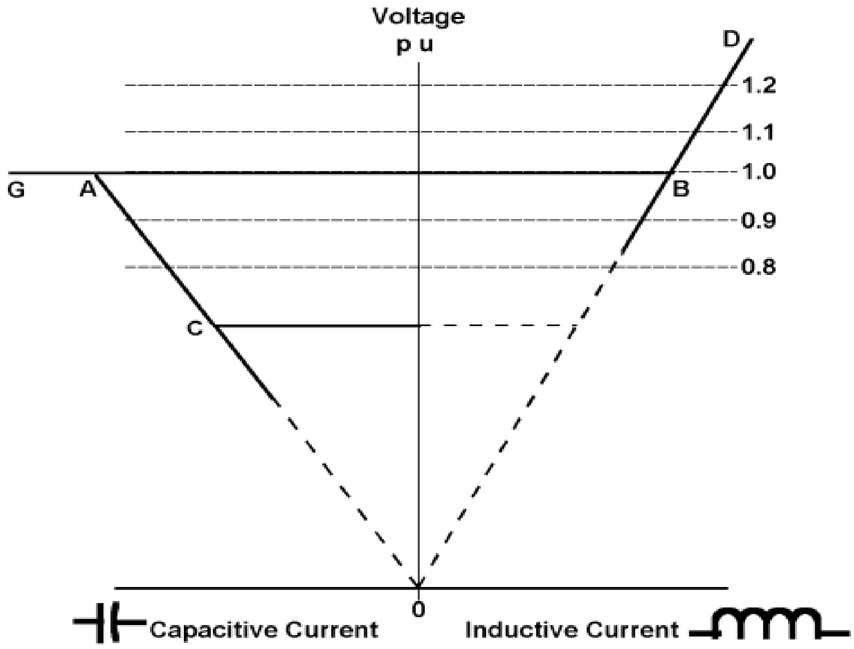


**Figure 1 – V/I Characteristic of the SVC to define Operating Points**

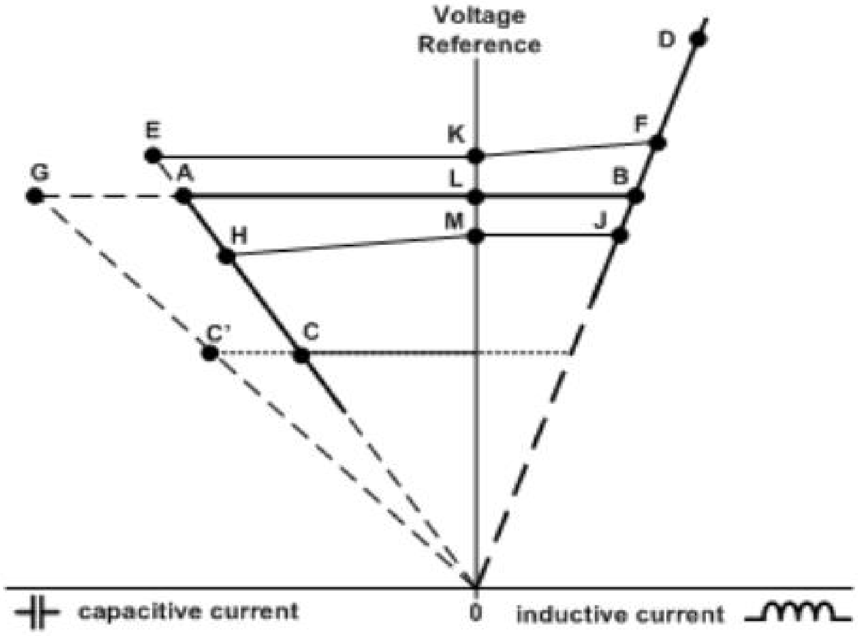


**Figure 2 – Details of SVC Operating Points**

A is defined by the capacitive design point for continuous operation.

B is defined by the inductive design point for continuous operation.

C, C' is defined by lines 6 and 7 of Table 7 below.

Below point C, C' the SVC should normally block TSC branches, if included, and await a recovery of voltage before resuming normal action.

D is defined by lines 4 and 5 Table 7 below. It is an extension of line 0B.

E is an extension of line 0A at maximum reference voltage (K) and minimum slope.

F is an extension of line 0B at maximum reference voltage (K) and maximum slope.

G is defined by the capacitive design point for short time operation.

H is an extension of line 0A at minimum reference voltage (M) and maximum slope.

J is an extension of line 0B at minimum reference voltage (M) and minimum slope.

K is the maximum reference voltage.

L is the nominal reference voltage.

M is the minimum reference voltage.

# Annex B

**Informative**

# Case Studies

## A.3 Large Load Distant from the Source

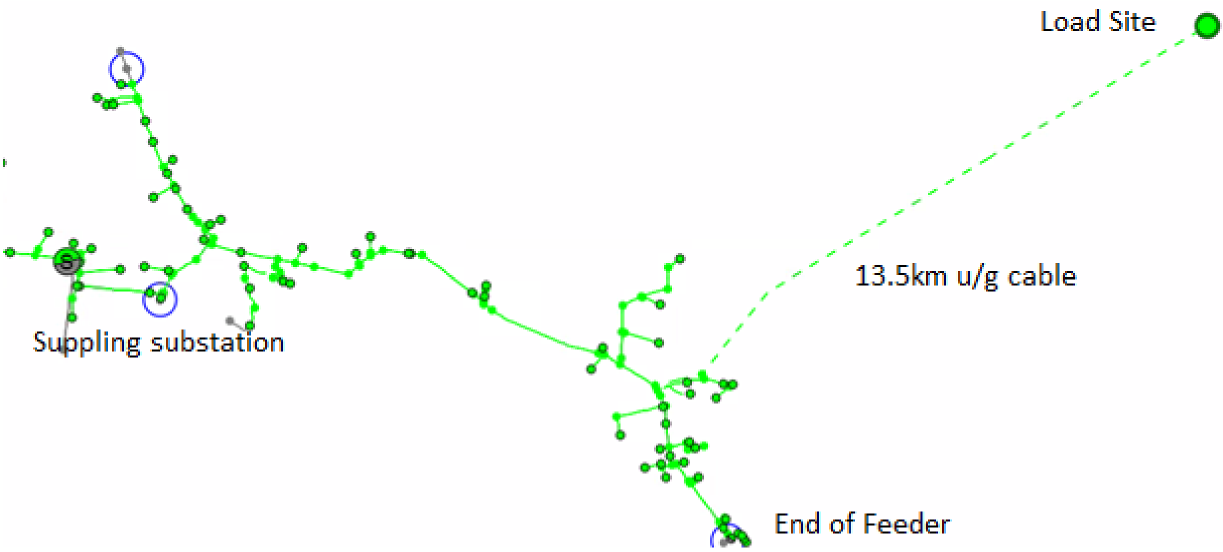


**Figure 3 - Representation of System**

The nature of the load will have an impact on both the steady-state voltage, and the voltage following a load rejection event. In order to meet the required system standards, load flow analysis is undertaken to determine the reactive requirements.

**Table 4 - Steady State Load Flow Analysis**

| Case | Voltage at Substation | Voltage at Feeder End | Voltage at Site |
|---|---|---|---|
| Base Case – No Load | 1.00 | 1.005 | 1.01 |
| Scenario A, 4 MW load, 0.9 pf lagging | 0.99 | 0.945 | 0.92 |
| Scenario B, 4 MW load, unity pf | 1.00 | 0.967 | 0.95 |
| Scenario C, 4 MW load, 0.9 pf leading | 1.01 | 0.995 | 0.99 |
| | | | |

From Table 4, it can be seen that Standard for Voltage and Reactive Power Management - 3060854 (STNW3417) is breached for Scenario A. Additionally, any load growth in Scenario B would likely also cause excursion outside acceptable limits.

The customer may not be able to tune their load to meet the leading power factor. Therefore, some external reactive compensation is required.

**Table 5 - Scenario A with Compensation**

| Case | Voltage at Substation | Voltage at Feeder End | Voltage at Site |
|---|---|---|---|
| Scenario A, 4 MW load, 0.9 pf lagging, with additional 3 MVAr capacitor bank at site | 1.00 | 0.98 | 0.97 |

However, we must also consider whether any dynamic compensation is required. To do this, as a preliminary stage, load rejection studies can be undertaken.

**Table 6 - Voltage Rejection Studies**

| Case | Change in Voltage at Substation | Change in Voltage at Feeder End | Change in Voltage at Site |
|---|---|---|---|
| Loss of load at site | 3% | 7.1% | 9% |
| Loss of cable | 0% | 1.6% | N/A (site goes black) |
| Loss of capacitor bank | 2% | 5% | 5% |

The voltage change in a number of circumstances is in excess of the 5% limit. Therefore, this indicates that dynamic compensation is required. Further investigation can then determine:

- Capacitive/inductive requirements
- Response time

Indicative steady-state studies can be completed using the static generator model in PowerFactory. However dynamic simulation shall be used to determine final dynamic requirements.

## A.4 Energisation Compensation

Upon energisation of transformers, long cables runs, long lines, or reactive plant, an energisation inrush occurs. Standard for Plant Energisation - 3059318 (STNW1179) defines the acceptable energisation limits in terms of voltage fluctuation. In cases where energisation (or, unplanned de-energisation) results in poor outcomes, dynamic compensation can be used to minimise disturbance to other customers.

Table 6 demonstrates that the voltage change under a rejection event results in unacceptable voltage excursion. Therefore, this indicates that dynamic reactive compensation is required.

# Annex C

**Informative**

# Key Plant Specification Requirements

## A.5 Key Plant Specification Requirements

An example of some of the power system information required for a STATCOM system is shown in the table below. Site specific parameters and requirements for each project shall be included in the Project Scope Specification document. Some of the parameters below are outlined in greater detail in this Technical Specification.

**Table 7 - Example of Necessary Power System Characteristics (IEEE Std 1031-2011, Clause 7)**

| No. | Type of Information | Value | Units |
|---|---|---|---|
| 1 | Nominal AC system voltage, line to line | | kV |
| 2 | Maximum continuous AC system voltage, line to line | | kV |
| 3 | Minimum continuous AC system voltage, line to line | | kV |
| 4 | Maximum short-term AC system voltage, line to line[1] | | kV |
| 5 | Duration of item (4) | | s |
| 6 | Minimum short-term AC system voltage, line to line | | kV |
| 7 | Duration of item (6) | | s |
| 8 | Continuous negative-sequence voltage component (used for performance calculation) | | % |
| 9 | Continuous negative-sequence voltage component (used for performance calculation) | | % |
| 10 | Continuous zero-sequence voltage component | | % |
| 11 | Nominal AC system frequency | 50 | Hz |
| 12 | Maximum continuous AC system frequency[2] | | Hz |
| 13 | Minimum continuous AC system frequency | | Hz |
| 14 | Maximum short-term AC system frequency | | Hz |
| 15 | Duration of item (14) | | s |
| 16 | Maximum rate of change of frequency (df/dt) | | Hz/s |

[1] Maximum voltage excursion are defined by NER clause S5.1a.4 and plant connecting the Ergon or Energex network shall be capable of withstanding this

[2] Frequency in the NEM is governed by the Frequency Operating Standard. Cross Reference with Section 8.3

| No. | Type of Information | Value | Units |
|---|---|---|---|
| 17 | Minimum short-term AC system frequency | | Hz |
| 18 | Duration of item (17) | | s |
| 19 | Basic insulation level | | kV peak |
| 20 | Switching Impulse Level | | kV peak |
| 21 | Power frequency withstand voltage | | kV |
| 22 | Maximum three-phase fault current<br>- for performance requirements<br>- for ratings[3] | | kA<br>kA for _s |
| 23 | Existing three-phase fault current | | kA |
| 24 | Minimum three-phase fault current<br>- for performance requirements<br>- for safe operation | | kA<br>kA<br>kA |
| 25 | Maximum single-phase fault current | | kA |
| 26 | Existing single-phase fault current | | kA |
| 27 | Minimum single-phase fault current | | kA |
| 28 | Harmonic impedance sectors for each harmonic number or system impedance data as R-X values with frequency steps not larger than 1 Hz (for performance and/or component rating) | (A table or figure shall be attached) | |
| 29 | Background harmonic voltage (or current) spectrum (for components rating) | (A table or figure shall be attached) | |

[3] Cross reference with Section 8.4

## A.6 Cost and Ownership

The Table below is intended to provide information about network costs and ownership. Generalised quotes are not available for STATCOM / SVC systems, as the system design tends to be specific of the use case. Budget estimates have been obtained for small systems.

**Table 8 - Costs and Ownership**

| Technology | Indicative Plant Cost ($/kVAr)<br>Installation not included | Maintenance Cost (Annualised), excluding travel | Typical Ownership and Connection |
|---|---|---|---|
| Capacitor Bank | $50k / MVAr for 12 & 24 kV<br>(Includes cost of containers, cap cans, filters, heaters, etc. Not feeder bay.)<br><br>$20k / MVAr for 36 & 72.5 kV<br>(Only cost of capacitor cans. Not feeder bay, insulated structures, cabling, etc.) | $1.5k / year is typical for maintenance by EQL | DNSP within Substation<br>Shunt connected<br>Distribution |
| Harmonic filters | A 10 MVAr, 33 kV C-type filter cost approx. $250k.<br><br>A 31 MVAr 66 kV damped harmonic filter cost approx. $450k.<br><br>A 50 MVAr, 132 kV C-type harmonic filter cost approx. $750k. | $1.5k / year is typical for maintenance by EQL | External party to meet harmonic allocation. Typically Solar / wind farms with Inverters. |
| Reactor | 12kV Aitkenvale capacitor bank 2<br>Inrush reactor. Three-phase stacked air core reactor.<br>$35k for 3 off 176 kVAr, 13.2mH / 206 A.<br>6.6kV Georgetown SVC shunt reactor. Single-phase air core reactor.<br>$50k for 1 off 2.03 MVAr 27.69 mH, 483A | $1.5k / year is typical for maintenance by EQL | DNSP within Substation<br>distribution sub-transmission lines |

| Technology | Indicative Plant Cost ($/kVAr)<br>Installation not included | Maintenance Cost (Annualised), excluding travel | Typical Ownership and Connection |
|---|---|---|---|
| SVC | $350k / MVAr<br>Including transformers, capacitors, reactors, Thyristors, cooling system and control system. | $30k / year is typical for maintenance by manufacturer. Not including Power transformers or feeder bay switchgear.<br>Add $10k / year is typical for EQL maintenance support. | DNSP within Substation |
| STATCOM | $175 /± MVAr<br>Including step-up transformers, inverters and control system. | $40k / year is typical for maintenance contracts with suppliers. Not including Power transformers or feeder bay switchgear.<br>Add $10k / year is typical for maintenance by EQL support. | DNSP within Substation |
| SYNCON | Costs below include design, machines, coupling transformers, interconnecting MV cabling & switchgear, auxiliaries cooling & control system.<br><br>10 MVA – $8M<br>30 MVA - $9.5M<br>60 MVA - $12M<br>60 MVA with flywheel - $14M<br>Install & Commission add $1M , $1.4M, $2M & $2.2M. | $32k / year is typical for maintenance by Manufacturer. Plus 1x large half-life maintenance $100k and 2x mid-lifecycle maintenances $60k; based on 20 year cycle. Not including Power transformers or feeder bay switchgear.<br>Add $10k / year is typical for maintenance by EQL support. | Typically owned by a connecting party or transmission network service provider |
| Inverter based technology | As negotiated | As negotiated | External party with network support agreement |

# Annex D

# Revision History

| Revision date | Release number | Author | Description of change/revision |
|---|---|---|---|
| May 2026 | 4 | John Lansley | Update references and STATCOM price Appendix C, format fixes |