Part of Energy Queensland

Request for Proposal Gulf Network Voltage Management

18 October 2023

Version 2.0

Consultation Period Start: 01/08/2023

Consultation Period Finish: 08/12/2023

EXECUTIVE SUMMARY

This Request for Proposal (RFP) document is an invitation to proponents to submit either a network option to replace / refurbish the end-of-life static var compensators (SVCs) at Georgetown and Normanton substations or a non-network, Volt-var Control Network Support Service (VCNSS) solution to replace the functionality of the end-of-life static var compensators (SVCs) at Georgetown and Normanton substations. This RFP provides:

- Background information on the network limitation.
- An invitation to submit credible network and non-network options
- The network and non-network solution technical requirements; and
- Information on what to include in your submission.

Network Need:

Ergon Energy Corporation Limited (Ergon Energy) is part of Energy Queensland and is responsible (under its Distribution Authority) for electricity supply to the Gulf network area in far north Queensland.

There are two ageing Static Var Compensators (SVCs) at Georgetown (GEOR) 132/66/22/6.6kV substation and Normanton (NORM) 66/22/6.6kV substation.

At GEOR, the ageing SVC is connected to the network via the 6.6kV tertiary windings of the 132/66/6.6kV transformers and is set up to control the 6.6kV bus voltage which effectively controls the 66kV bus voltage due to the fixed transformer winding ratio. The SVC has a reactive power range of 6MVAR inductive to 9.75MVAR capacitive.

At NORM, the ageing SVC is connected to the network via the 6.6kV tertiary windings of the 66/22/6.6kV transformers and is set up to control the 6.6kV bus voltage which effectively controls the 22kV bus voltage due to the fixed transformer winding ratio. The SVC has a reactive power range of 3.7MVAR inductive to 8.4MVAR capacitive.

Both SVCs also provide Negative Phase Sequence (NPS) correction to address voltage balance issues associated with the large Single Wire Earth Return (SWER) networks in the area.

The identified need for this RFP is that both the GEOR SVC and NORM SVC are approaching end of life and spare parts are no longer able to be sourced for some of the components. The GEOR SVC is recommended for replacement by June 2027 whereas the NORM SVC is recommended for replacement by June 2030, assuming spares recovered from the GEOR SVC can be used to defer the replacement timeframe for the NORM SVC.

Requirements:

The requirements of a proposed solution to address the identified need at GEOR and NORM zone substations are outlined in the technical requirements section of this document.

Submissions:

Ergon Energy is seeking submissions from proponents on potential credible options, both network or non-network solutions, to address the identified need at GEOR and NORM zone substations. Only submissions received by 08/12/2023 will be accepted. Submissions will need to address the issues described in the RFP and are to be submitted to demandmanagement@ergon.com.au.

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1. Background

Ergon Energy Corporation Limited (Ergon Energy) is part of Energy Queensland and is responsible (under its Distribution Authority) for electricity supply to the Gulf network area in far north Queensland.

The Gulf sub-transmission radial network supplied from Ross (ROSS) 275/132kV substation in Townsville is approximately 677km in length, consists of 387km of single circuit concrete pole 132kV feeders and 290km of single circuit concrete pole 66kV feeders. The gulf network supplies approximately 1805 customers from the Kidston (KIDS) 132/6.6kV substation, Georgetown (GEOR) 132/66/22/6.6kV substation, Croydon (CROY) 66/22kV substation and Normanton (NORM) 66/22/6.6kV substation.

There are two large solar farms connected to the gulf network, a 50MW solar farm connected to the 132kV bus at KIDS substation and a 5MW solar farm connected to the 22kV bus at NORM substation.

To manage the voltages on the gulf network due to the long lightly loaded transmission lines, GEOR has an SVC and a 5MVAR shunt reactor connected to the 6.6kV tertiary windings of the 132/66/6.6kV transformers and NORM has an SVC connected to the 6.6kV tertiary windings of the 66/22/6.6kV transformers.

Both SVCs also provide Negative Phase Sequence (NPS) correction to address voltage balance issues associated with the large Single Wire Earth Return (SWER) networks in the area.

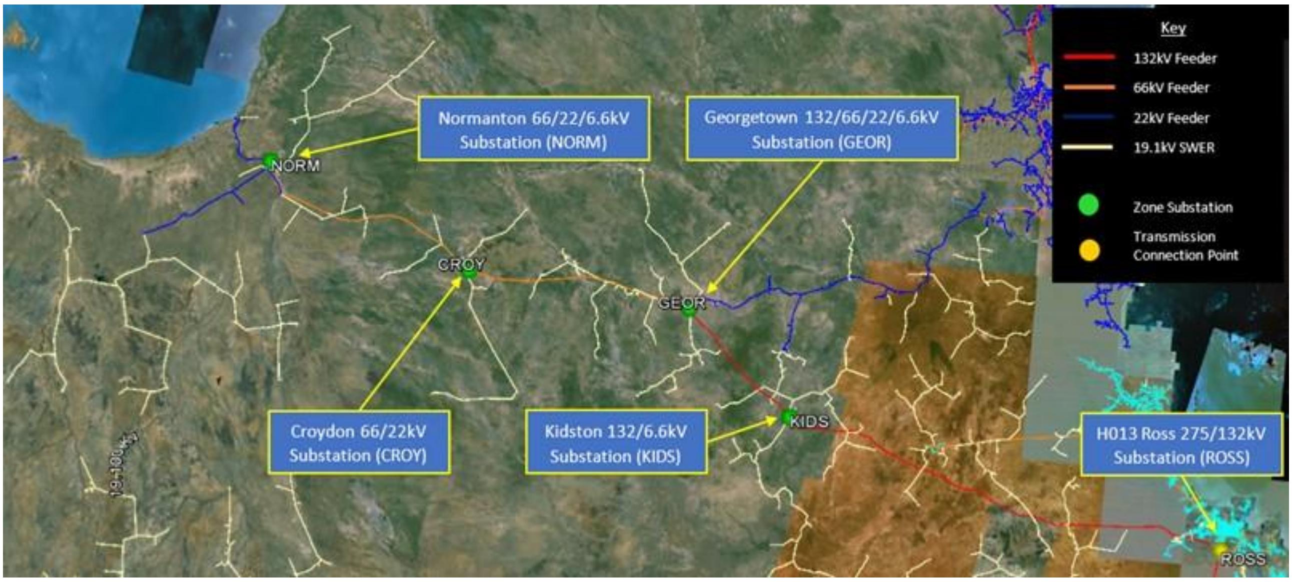

Figure 1: Geographic Diagram of the Gulf Network

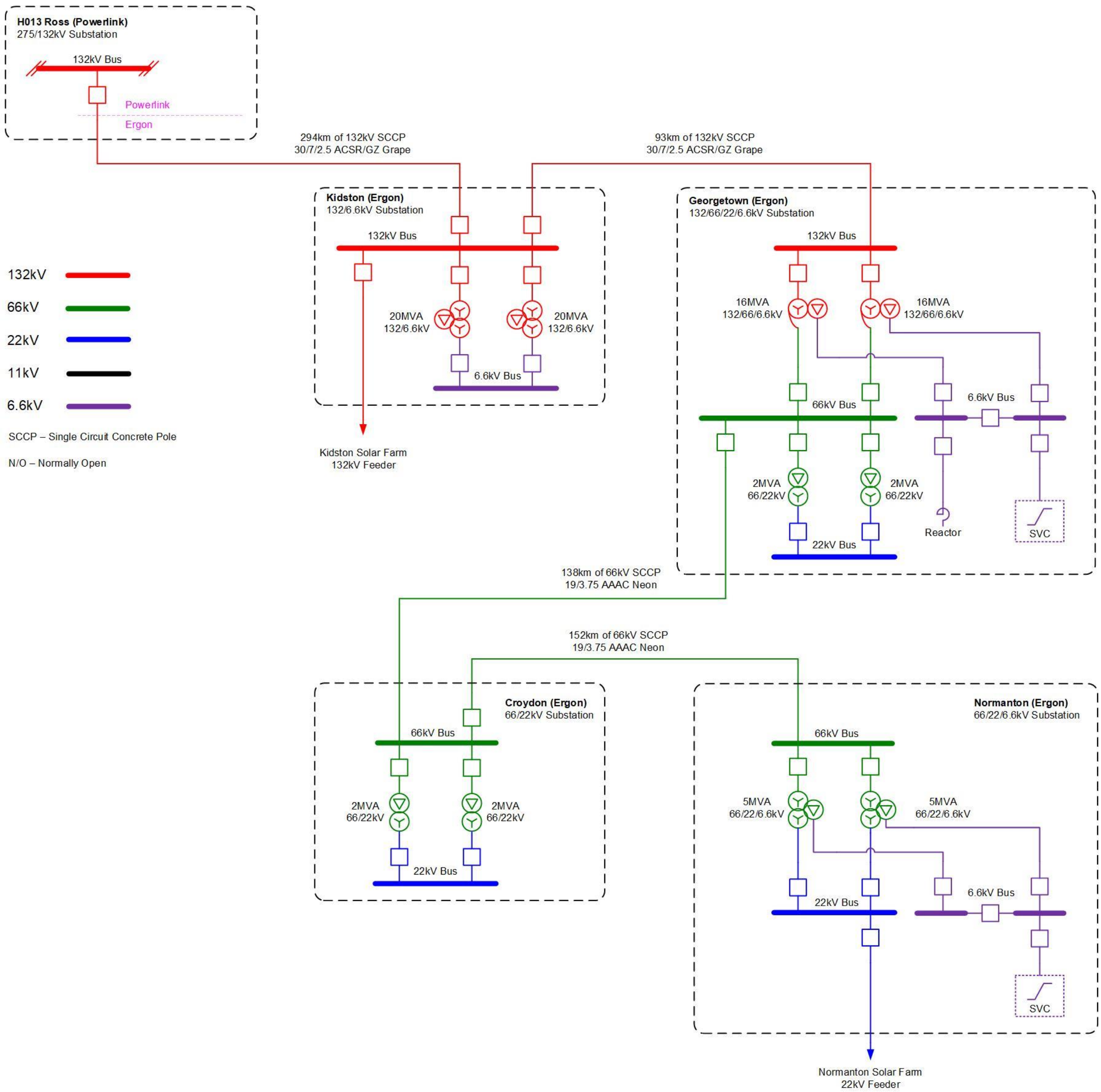

Figure 2: Schematic Diagram of the Gulf Network

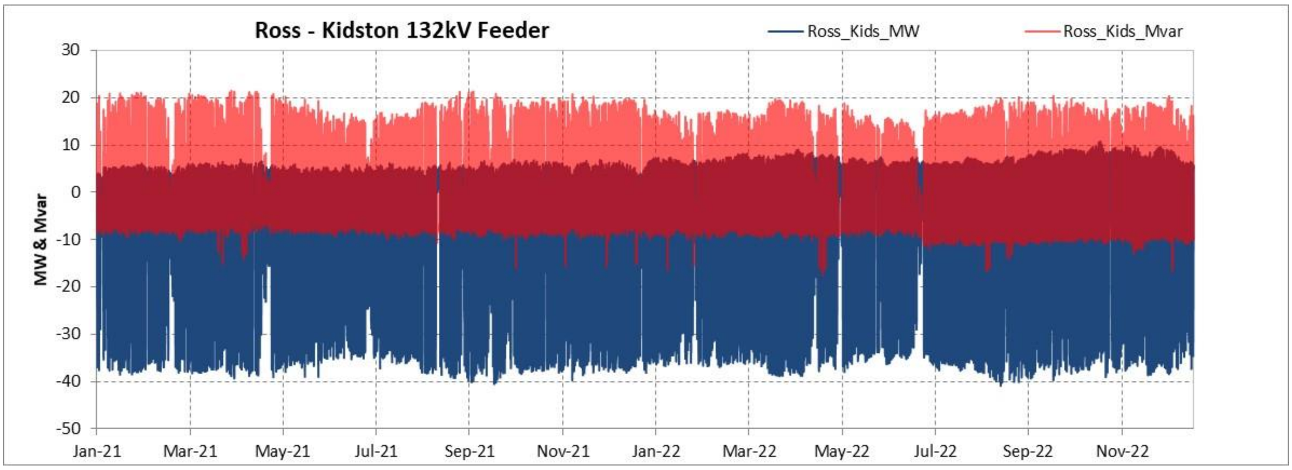

Figure 3: Ross – Kidston 132kV Feeder half hourly average profile for the period Jan 2021-Jan 2023

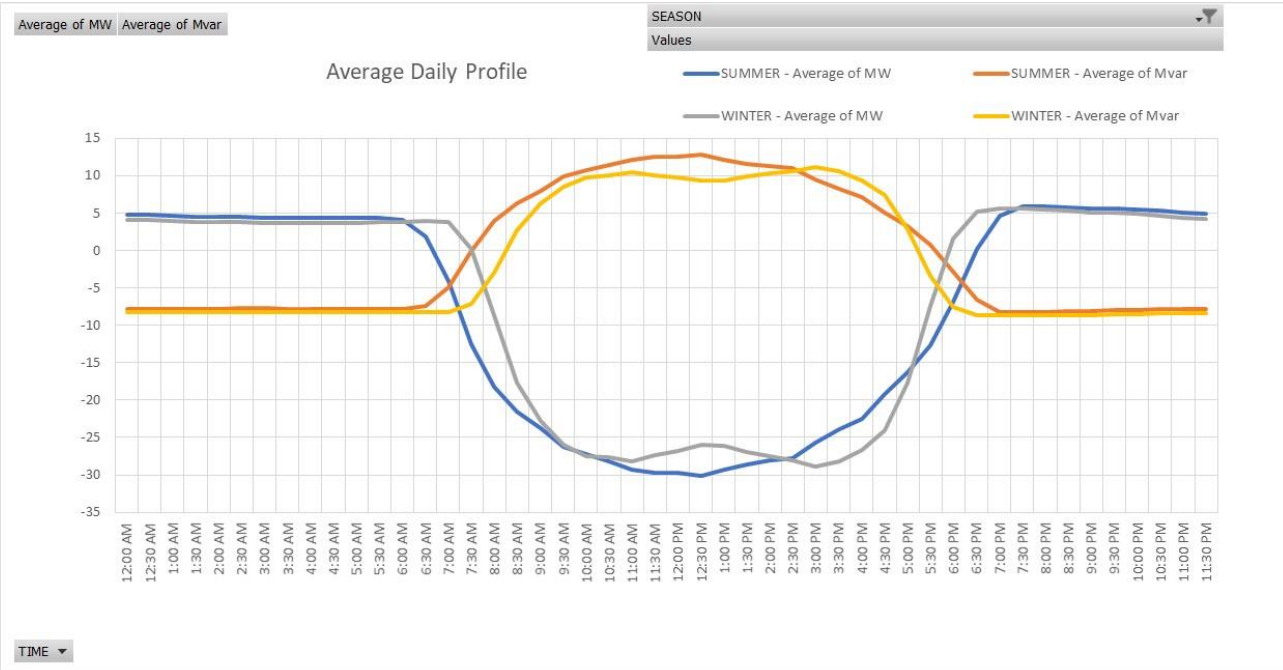

Figure 4: Ross – Kidston 132kV Feeder average daily profile for the period Jan 2021-Jan 2023

The plots above show the half hourly average 132kV load profile and the average daily 132kV load profile for the Ross – Kidston 132kV feeder for the period January 2021 to January 2023. The daily profiles are heavily influenced by the export from the Normanton and Kidston Solar Farms which are generally exporting MWs and absorbing MVARs when they are operational during the day.

Due to the line charging MVARs generated by the 387km 132kV feeder, the 132 kV section of the network has been designed for a maximum allowable continuous operating voltage of 1.15puV. This includes a 15% buck tap range on the KIDS 132/6.6kV transformers and the GEOR 132/66/6.6kV transformers.

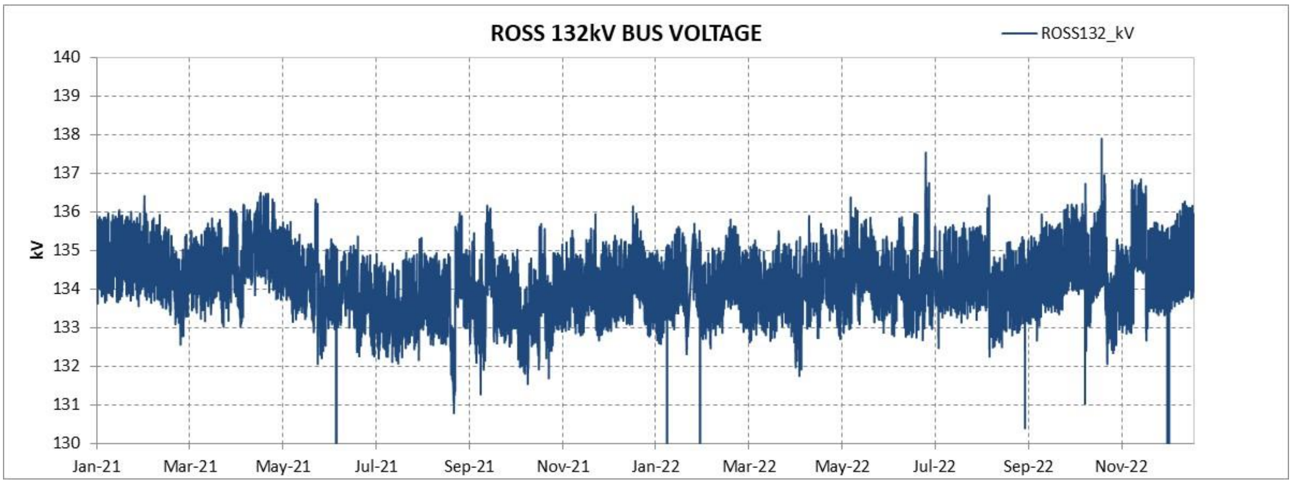

Figure 5: Ross 132kV bus voltage half hourly average profile for the period Jan 2021-Jan 2023

The plot above shows the half hourly average ROSS substation 132kV bus voltage profile for the period January 2021 to January 2023.

The gulf network is susceptible to harmonic resonance conditions and voltage transients during reclose events and system restoration due to the inrush currents of the reactive plant connected. To minimise the impacts of these conditions, after a system outage the network is normally restored in a sequence.

Feeder	Conductor	Length	Summer Day (9am – 6pm) (A)	Summer Evening (6pm-10pm) (A)	Summer Night Morning (10pm-9am) (A)
ROSS – KIDS 132kV Feeder	Grape 30/7/2.50 ACSR	294km	360	391	351
KIDS – GEOR 132kV Feeder	Grape 30/7/2.50 ACSR	93km	298	344	342
GEOR – CROY 66kV Feeder	Neon 19/3.75 AAAC 1120	138km	457	487	472
CROY – NORM 66kV Feeder	Neon 19/3.75 AAAC 1120	152km	457	487	472

Table 1: Sub-transmission Feeder Ratings

The table above shows the thermal ratings for the 132kV and 66kV feeders supplying the Gulf network. The power flows on this network tend to be limited more by voltage and stability constraints.

1.1 Georgetown Substation

GEOR is supplied via a single 93km 132kV transmission feeder from KIDS. GEOR consists of 2 x 132/66/6.6kV transformers, 2 x 66/22kV transformers, 1 x 5MVAR shunt reactor, an SVC, 2 x 22kV feeders that supply 549 customers on the 22kV distribution network and 19.1kV single wire earth return (SWER) network and an outgoing 66kV feeder that supplies CROY and NORM substations.

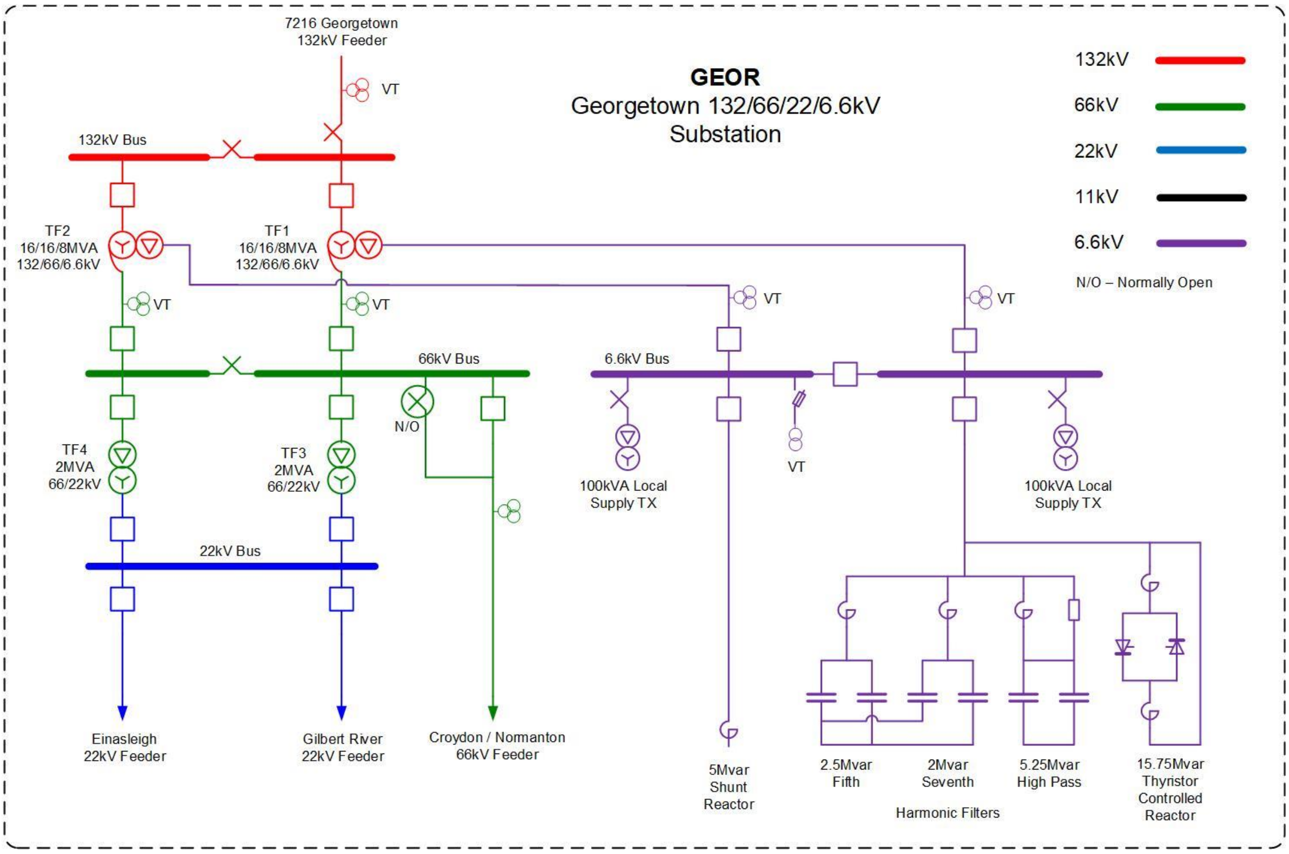

Figure 6: Schematic Diagram of Georgetown Substation

Figure 7: Aerial View of Georgetown Substation

The capacity at GEOR is limited by the rating of the 132/66/6.6kV transformers and the 66/22kV transformers. The Normal Cyclic Capacity (NCC) and an Emergency Cyclic Capacity (ECC) of the transformers is shown in the table below:

Element	Nameplate Rating (MVA)	Cooling	Winding	Nominal NC Summer (MVA)	Nominal NC Winter (MVA)	Nominal LTEC Summer (MVA)	Nominal LTEC Winter (MVA)	Operational NC Summer (MVA)	Operational NC Winter (MVA)	Operational LTEC Summer (MVA)	Operational LTEC Winter (MVA)
TF1 132/66/6.6 kV	16/16/8	ONAN	132kV	18.26	22.96	21.01	23.92	18.26	22.96	21.01	23.92
			66kV	14.11*	19.17*	17.09*	20.18*	14.11*	19.17*	17.09*	20.18*
			6.6kV	8.00*	8.00*	8.00*	8.00*	8.00*	8.00*	8.00*	8.00*
TF2 132/66/6.6 kV	16/16/8	ONAN	132kV	18.26	22.96	21.01	23.92	18.26	22.96	21.01	23.92
			66kV	14.11*	19.17*	17.09*	20.18*	14.11*	19.17*	17.09*	20.18*
			6.6kV	8.00*	8.00*	8.00*	8.00*	8.00*	8.00*	8.00*	8.00*
TF3 66/22 kV	2	ONAN	22kV	2.74	2.99	2.99	2.99	2.74	2.99	2.99	2.99
TF4 66/22 kV	2	ONAN	22kV	2.74	2.99	2.99	2.99	2.74	2.99	2.99	2.99

Table 2: GEOR Transformer Ratings

**__Indicative Only__. The combined loading on the 66kV and 6.6kV windings for TF1 & TF2 will be limited by the rating of the 132kV windings. The apparent power in the 132kV winding would be equivalent to the vectorial sum of the apparent power on the 66kV and*

6.6kV windings plus the associated transformer losses, etc. The loadings on the 66kV and 6.6kV windings would also be limited by the individual ratings for those windings and any additional flows in the tertiary winding due to unbalanced loads. The values for the 66kV and 6.6kV windings in this table have been estimated based on 8MVAR of inductive vars on the 6.6kV winding and a 0.95 lagging power factor for the 66kV winding load.

The table above shows that the amount of reactive power that the SVC + Shunt Reactor can absorb or supply at GEOR would be limited by the 8MVA 6.6kV tertiary windings. Under a system normal arrangement with both transformers in service the capacity would be adequate for the full SVC + Shunt Reactor reactive power range. The steady state capacitive and inductive limits in the SVC control system currently limits the reactive power to less than 8MVAR.

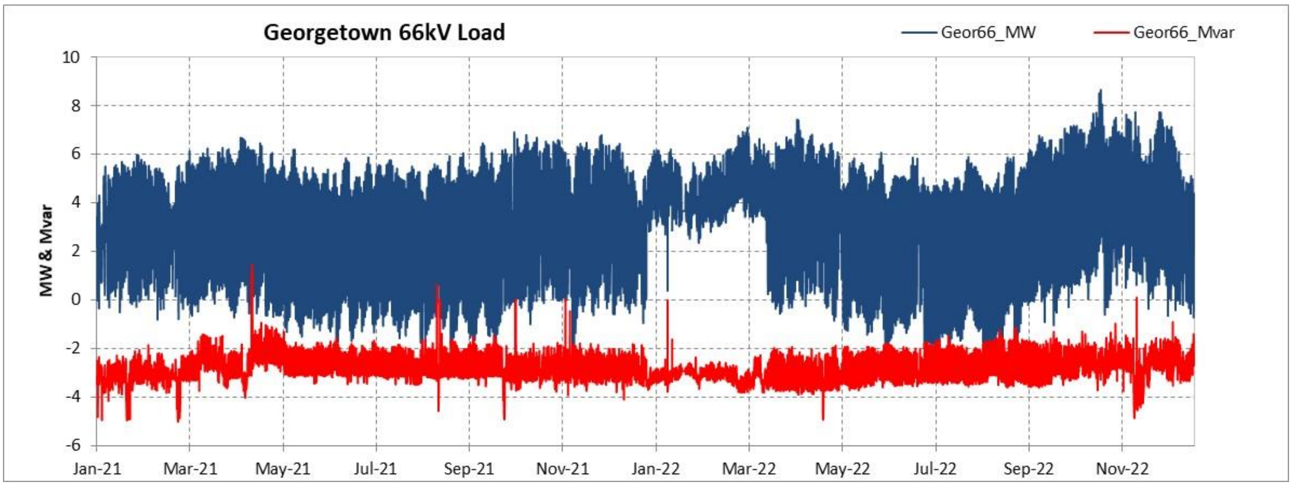

Figure 8: GEOR 66kV load half hourly average profile for the period Jan 2021-Jan 2023

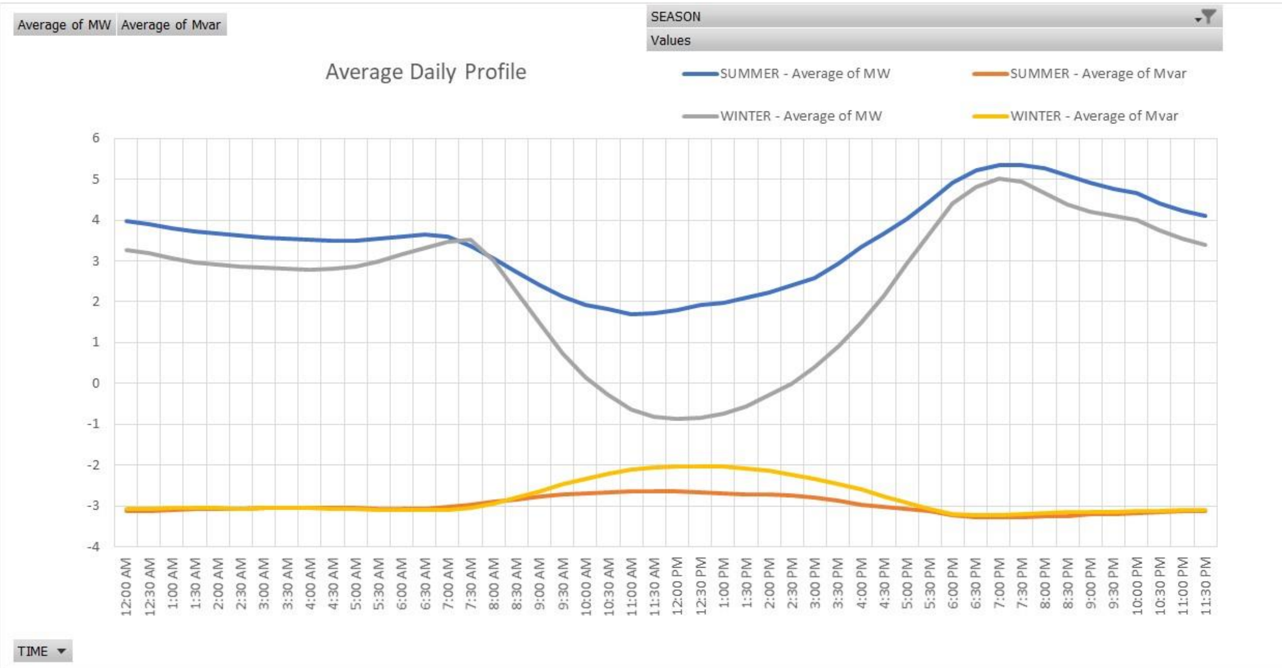

Figure 9: GEOR 66kV load average daily profile for the period Jan 2021-Jan2023

The plots above show the half hourly average 66kV load profile and the average daily 66kV load profile at GEOR for the period January 2021 to January 2023. The GEOR 66kV loading includes the GEOR 66/22kV transformers and the 66kV feeder which supplies CROY and NORM substations.

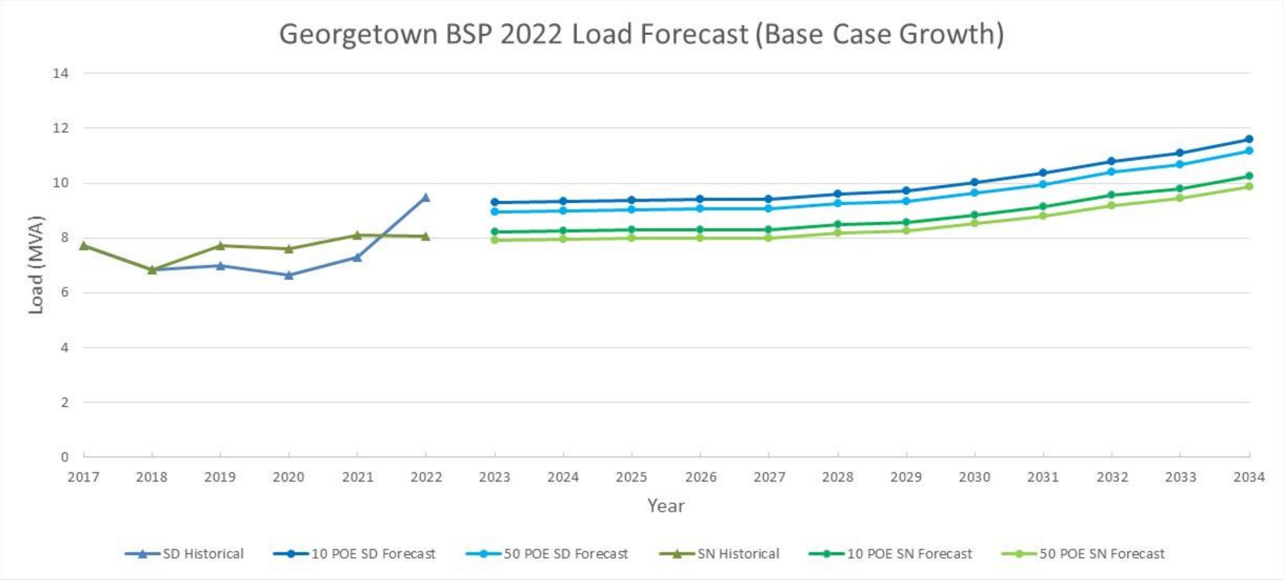

Figure 10: GEOR 66kV base case growth 2022 load forecast

The plot above shows the 10PoE and 50PoE (10% and 50% probability of exceedance) forecasts for the GEOR 66kV load. The load is not forecast to exceed the transformer N-1 capacity during this period.

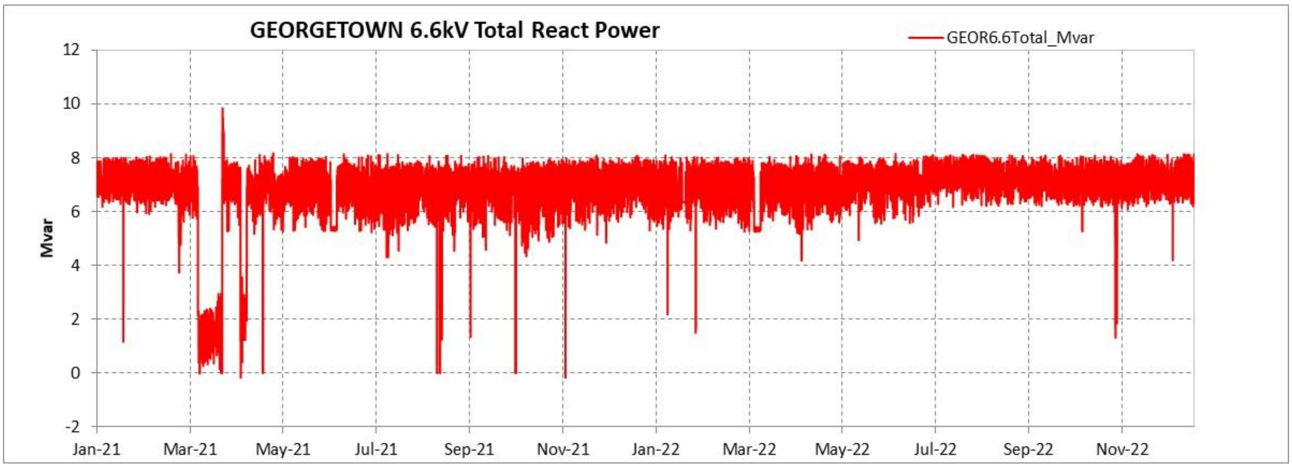

Figure 11: GEOR 6.6kV (SVC+Shunt Reactor) half hourly average profile for the period Jan 2021-Jan 2023

The plot above shows the half hourly average 6.6kV reactive power profile at GEOR for the period January 2021 to January 2023. The plot shows that the amount of reactive power normally absorbed by the combination of the 5MVAR shunt reactor and SVC does not normally exceed the transformer N-1 capacity.

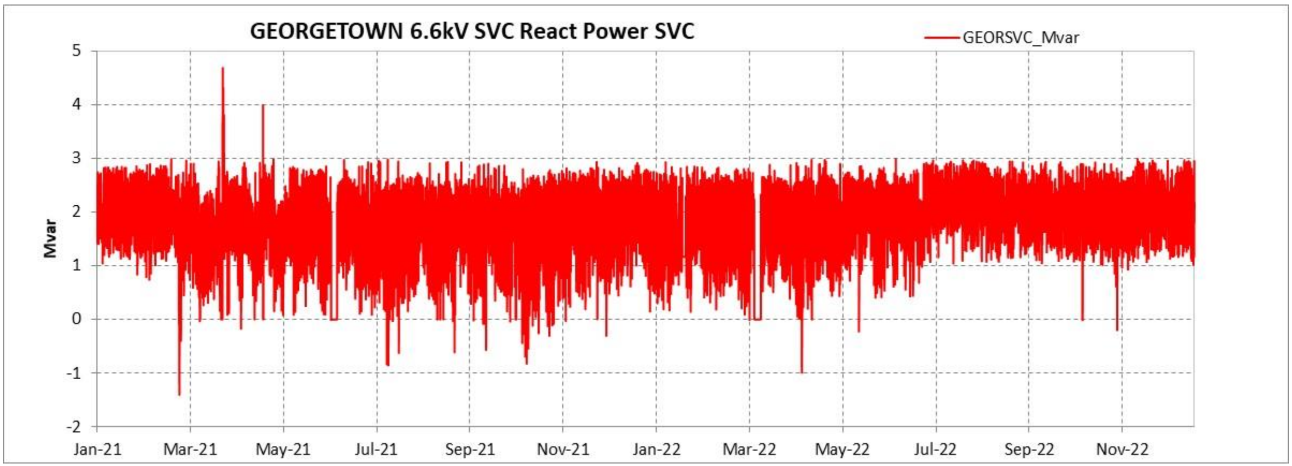

Figure 12: Georgetown SVC reactive power half hourly average profile for the period Jan 2021-Jan2023 (+ve is absorbing reactive power)

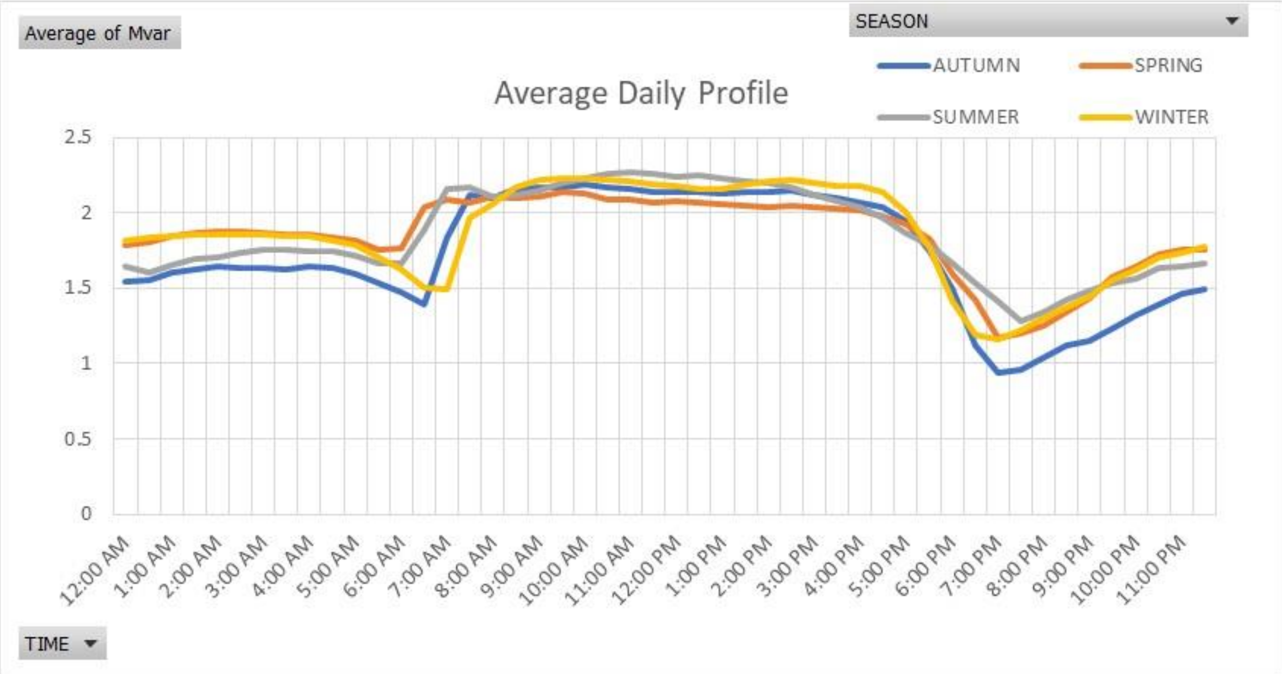

Figure 13: Georgetown SVC reactive power average daily profile for the period Jan 2021-Jan2023 (+ve is absorbing reactive power)

The plots above show the half hourly average reactive power profile and the average daily reactive power profile for the GEOR SVC for the period January 2021 to January 2023. The plots show that the SVC predominantly operates in the inductive range and absorbs more reactive power during the day when the solar farms are operating.

The SVC at GEOR is connected to the network via the 6.6kV tertiary windings of the GEOR 132/66/6.6kV transformers. The SVC consists of a 15.75MVAR Thyristor Controlled Reactor (TCR), 2.5MVAR 5th Harmonic Filter, 2MVAR 7th Harmonic Filter and a 5.25MVAR High Pass Filter providing a reactive power range of 6MVAR inductive to 9.75MVAR capacitive. The SVC is set up to control the 6.6kV bus voltage which effectively controls the 66kV bus voltage due to the fixed

66/6.6kV winding ratios on the transformers. When the SVC if offline, the GEOR 132/66/6.6kV transformer tap changers are used to control the 66kV voltage.

GEOR 132/66/22/6.6kV substation was commissioned in 1992 and most of the primary plant at this site is of this vintage. The 5MVAR shunt reactor has had failures on all three cores over the years and now has Nokian reactors on all three phase (YOM 2002, 2017 & 2017). The SVC outer loop control system was replaced with SCD5200 RTUs in 2011. Due to plant failures over the years some components on the SVC have required repairs or replacement including PCBs on the inner loop control system, capacitor cans on the filters, cooling water pumps, thyristors, etc.

Figure 14: GEOR TCR and Harmonic Filters

Figure 15: GEOR TCR Thyristor Stacks

Figure 16: GEOR TCR Inner Loop Control Panel (Left) and Cooling Water Pumps (Right)

Figure 17: GEOR 6.6kV Switchboard

The GEOR GEC ALSTOM 6.6kV switchboard consists of 5 x SBV2 1250A circuit breakers (2 x transformer, 1 x shunt reactor, 1 x SVC and 1 x bus tie).

Figure 18: GEOR SVC Protection panel (Left) and SCADA panel (Right)

The GEOR SVC protection panel contains 2 x MCGG22 filter unbalance relays, 1 x MCGG62 TCR overcurrent relay, 3 x MVTU12 overvoltage relays and a disturbance recorder. The functionality of the disturbance recorder has been shifted to Elspec G4420 analysers.

Note that the TCR inner loop control system has asymmetry, overvoltage, undervoltage and overload protection functions.

1.2 Normanton Substation

NORM is supplied via a single 152km 66kV transmission feeder from CROY. NORM consists of 2 x 5/5/5MVA 132/66/6.6kV transformers, an SVC and 3 x 22kV feeders that supply 1082 customers on the 22kV distribution network and 19.1kV single wire earth return (SWER) network. A dedicated 22kV feeder provides a connection to the Normanton 5MW Solar Farm.

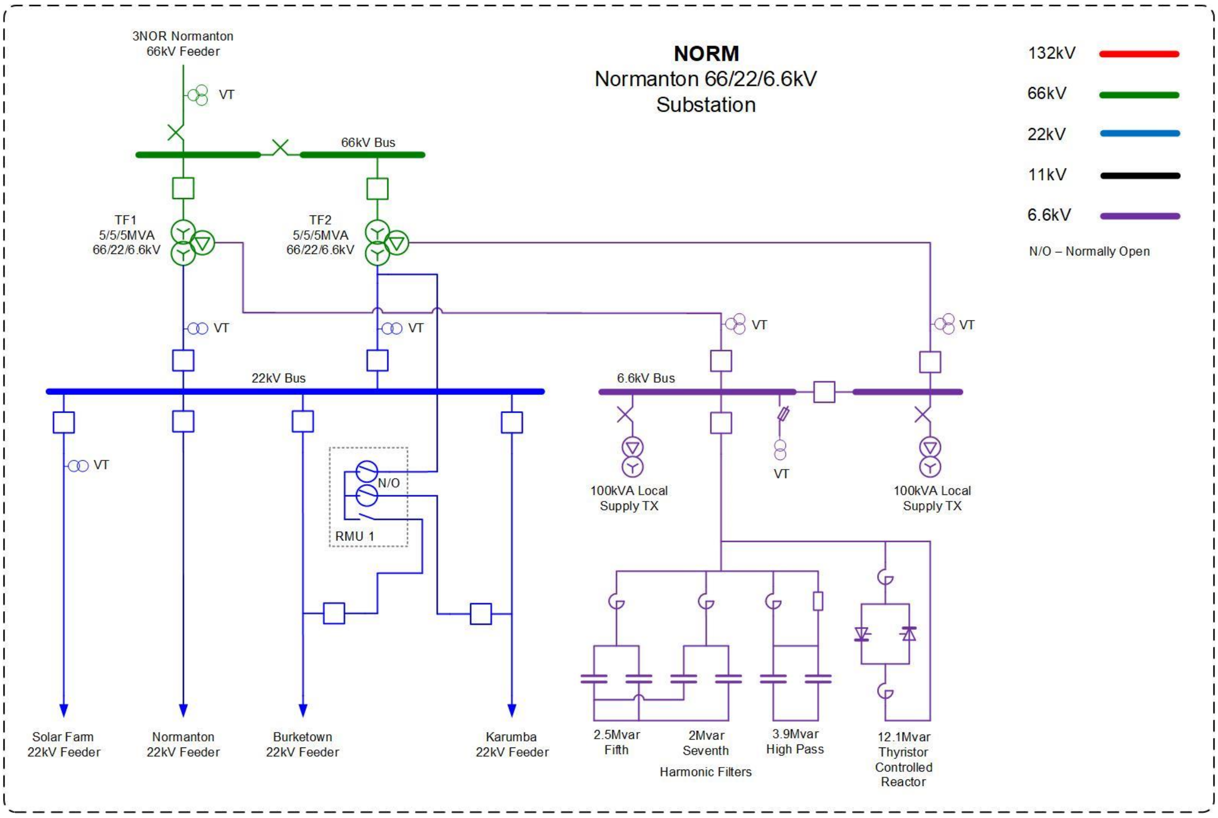

Figure 19: Schematic Diagram of Normanton Substation

Figure 20: Aerial View of Normanton Substation

The capacity at NORM is limited by the rating of the 66/22/6.6kV transformers. The Normal Cyclic Capacity (NCC) and an Emergency Cyclic Capacity (ECC) of the transformers is shown in the table below:

Element	Nameplate Rating (MVA)	Cooling	Winding	Nominal NC		Nominal LTEC		Operational NC		Operational LTEC	
				Summer (MVA)	Winter (MVA)	Summer (MVA)	Winter (MVA)	Summer (MVA)	Winter (MVA)	Summer (MVA)	Winter (MVA)
TF1 66/22/6.6 kV	5/5/5	ONAN	66kV	6.21	7.48	7.08	7.48	6.21	7.48	7.08	7.48
			22kV	4.70*	6.04*	5.62*	6.04*	4.70*	6.04*	5.62*	6.04*
			6.6kV	2.50*	2.50*	2.50*	2.50*	2.50*	2.50*	2.50*	2.50*
TF2 66/22/6.6 kV	5/5/5	ONAN	66kV	6.23	7.48	7.06	7.48	6.23	7.48	7.06	7.48
			22kV	4.72*	6.04*	5.60*	6.04*	4.72*	6.04*	5.60*	6.04*
			6.6kV	2.50*	2.50*	2.50*	2.50*	2.50*	2.50*	2.50*	2.50*

Table 3: NORM Transformer Ratings

**__Indicative Only__. The combined loading on the 22kV and 6.6kV windings for TF1 & TF2 will be limited by the rating of the 66kV windings. The apparent power in the 66kV winding would be equivalent to the vectorial sum of the apparent power on the 22kV and 6.6kV windings plus the associated transformer losses, etc. The loadings on the 22kV and 6.6kV windings would also be limited by the individual ratings for those windings and any additional flows in the tertiary winding due to unbalanced loads. The values for the 22kV* *and 6.6kV windings in this table have been estimated based on 2.5MVAR of inductive vars on the 6.6kV winding and a 0.9 lagging power factor for the 22kV winding load.*

The table above shows that the amount of reactive power that the SVC can absorb or supply at NORM would be limited by the 5MVA 6.6kV tertiary windings. Under a system normal arrangement with both transformers in service, depending on the 22kV load, the capacity should be adequate for the steady state 6.4MVAR capacitive and 2.4MVAR inductive limits in the SVC control system.

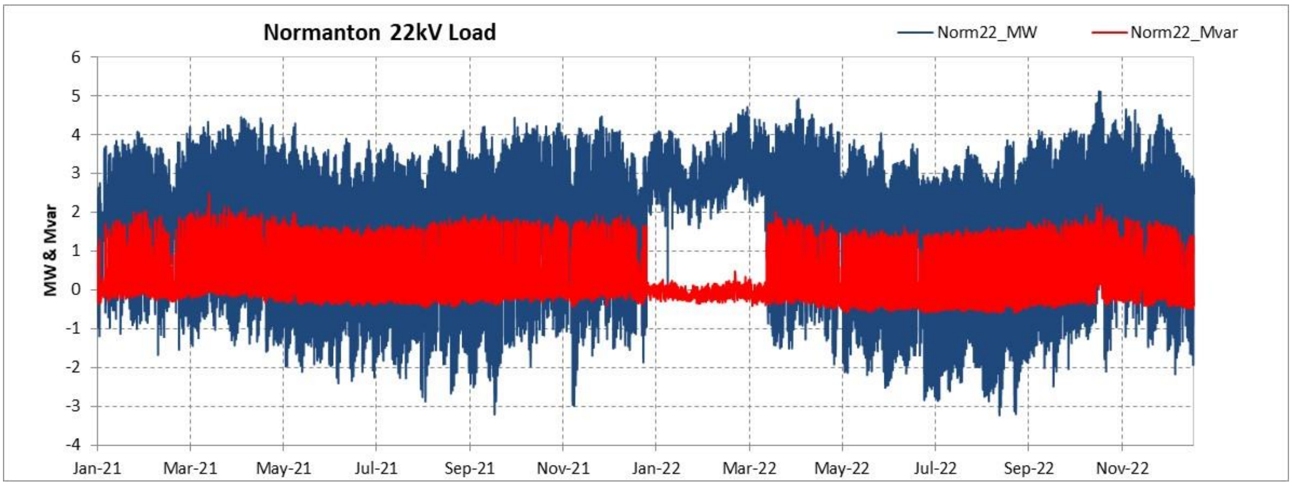

Figure 21: NORM 22kV load half hourly average profile for the period Jan 2021-Jan 2023

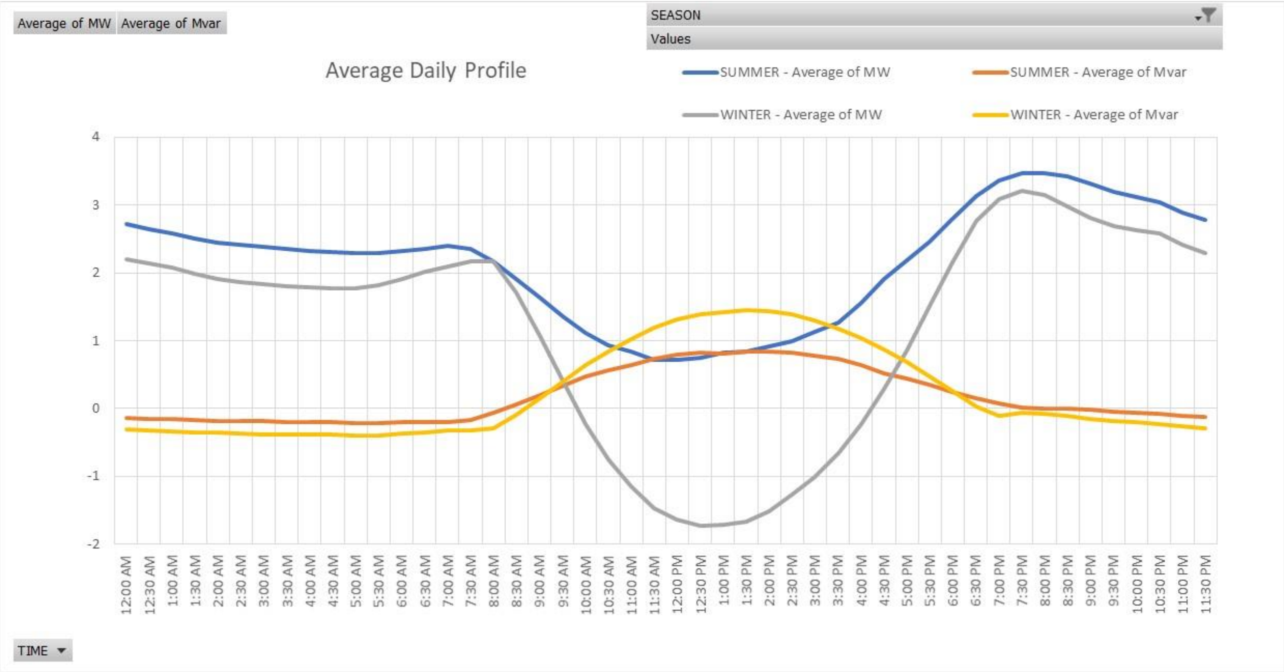

Figure 22: NORM 22kV load average daily profile for the period Jan 2021-Jan2023

The plots above show the half hourly average 22kV load profile and the average daily 22kV load profile at NORM for the period January 2021 to January 2023. The daily profile is heavily influenced by the export from the Normanton Solar Farm which is generally exporting MWs and absorbing MVARs when operational during the day.

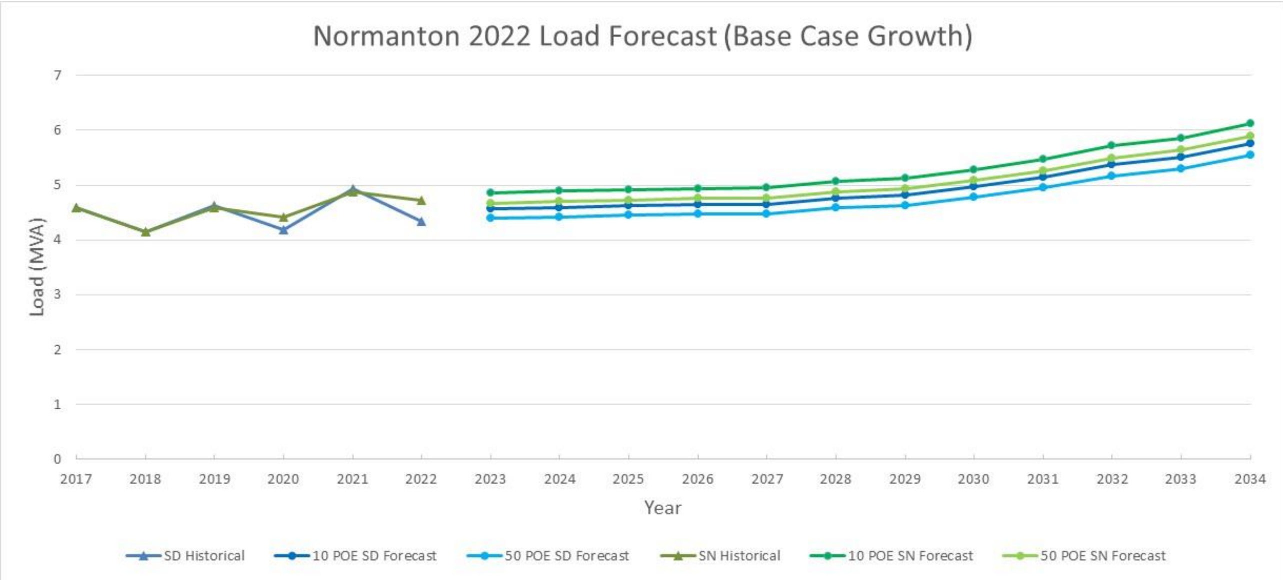

Figure 23: NORM 22kV base case growth 2022 load forecast

The plot above shows the 10PoE and 50PoE (10% and 50% probability of exceedance) forecasts for the NORM 22kV load. The load is not forecast to exceed the transformer N-1 primary winding capacity during this period but depending on the SVC output would be approaching the transformer N-1 secondary winding capacity towards the end of the forecast period.

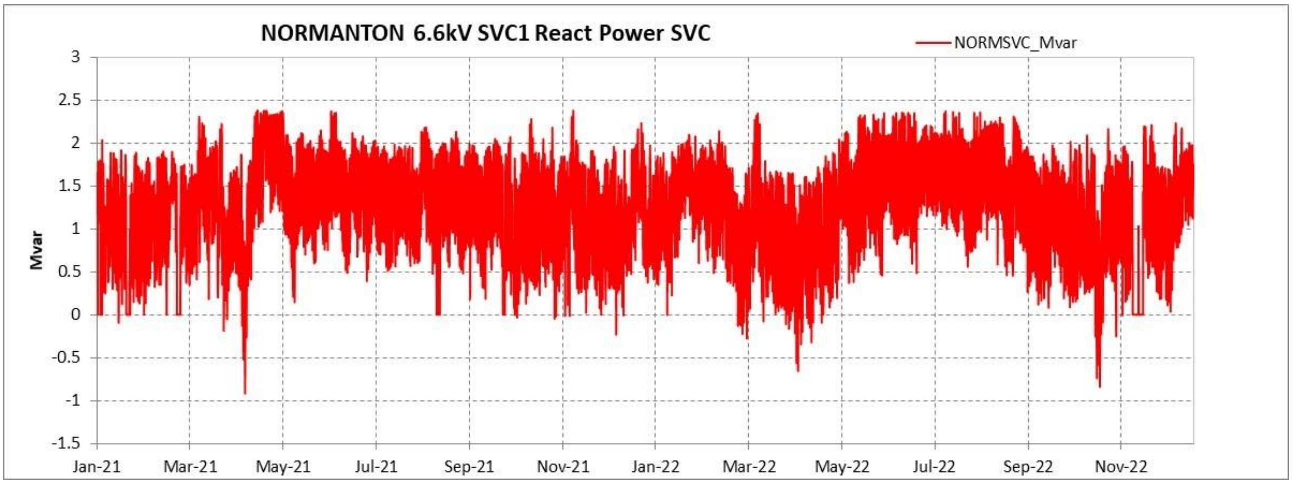

Figure 24: NORM SVC reactive power half hourly average profile for the period Jan 2021-Jan 2023 (+ve is absorbing reactive power)

The plot above shows the half hourly average 6.6kV reactive power profile at NORM for the period January 2021 to January 2023. The plot shows that the amount of reactive power normally absorbed by the SVC does not normally exceed the transformer N-1 capacity.

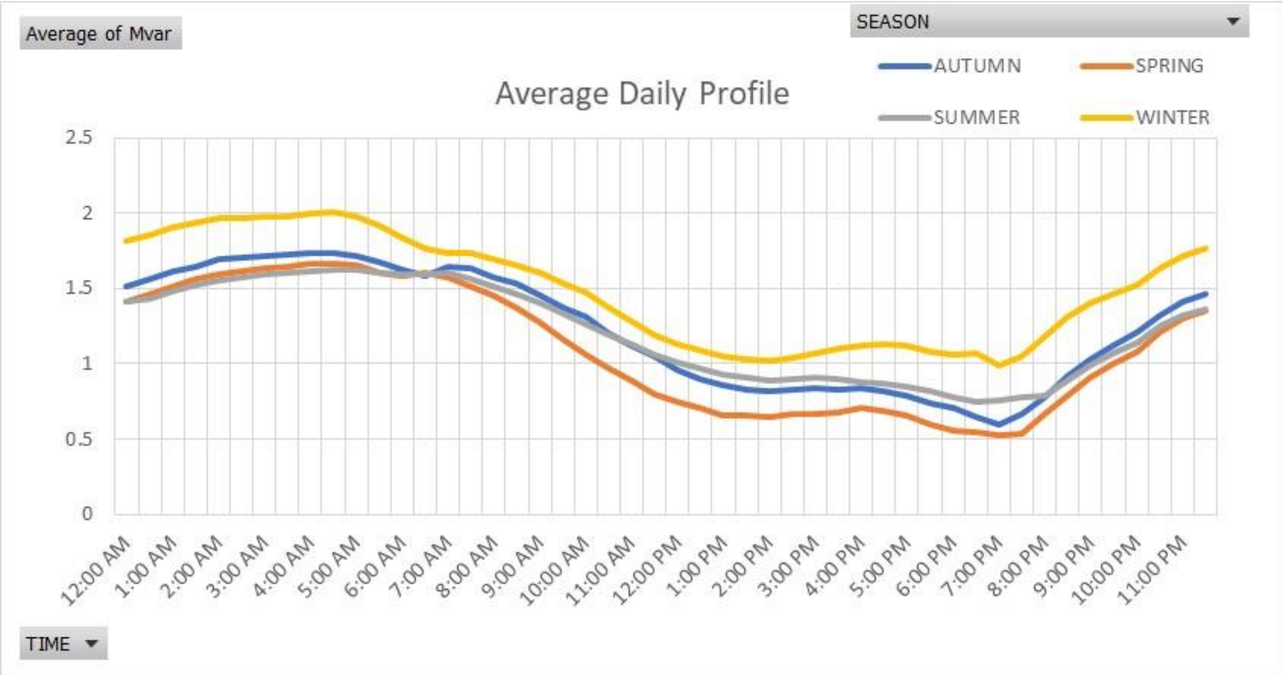

Figure 25: NORM SVC reactive power average daily profile for the period Jan 2021-Jan2023 (+ve is absorbing reactive power)

The plot above shows the average daily reactive power profile for the NORM SVC for the period January 2021 to January 2023. The plots show that the SVC predominantly operates in the inductive range.

The SVC at NORM is connected to the network via the 6.6kV tertiary windings of the NORM transformers. The SVC consists of a 12.1MVAR TCR, 2.5MVAR 5th Harmonic Filter, 2MVAR 7th Harmonic Filter and a 3.9MVAR High Pass Filter providing a reactive power range of 3.7MVAR inductive to 8.4MVAR capacitive. The SVC is set up to control the 6.6kV bus voltage which effectively controls the 22kV bus voltage due to the fixed 22/6.6kV winding ratios on the transformers. When the SVC is offline, the NORM transformer tap changers are used to control the 22kV voltage.

NORM 66/22/6.6kV substation was commissioned in 1992 and most of the primary plant at this site is of this vintage. The SVC outer loop control system was replaced with SCD5200 RTUs in 2010. Due to plant failures over the years some components on the SVC have required repairs or replacement including PCBs on the inner loop control system, capacitor cans on the filters, cooling water pumps, thyristors, etc.

Figure 26: NORM TCR and Harmonic Filters

Figure 27: NORM TCR Thyristor Stacks

Figure 28: NORM TCR Inner Loop Control Panel (Left) and Cooling Water Pumps (Right)

Figure 29: NORM 6.6kV Switchboard

The NORM GEC ALSTOM 6.6kV switchboard consists of 4 x SBV2 1250A circuit breakers (2 x transformer, 1 x SVC and 1 x bus tie).

Figure 30: NORM SVC Protection panel (Left) and SCADA panel (Right)

The NORM SVC protection panel contains 2 x MCGG22 filter unbalance relays, 1 x MCGG62 TCR overcurrent relay, 3 x MVTU12 overvoltage relays and a disturbance recorder. The functionality of the disturbance recorder has been shifted to Elspec G4420 analysers.

Note that the TCR inner loop control system has asymmetry, overvoltage, undervoltage and overload protection functions.

2. SVC Operation

At GEOR the SVC controls the 6.6kV bus voltage (V_{TARG} +/- 0.001pu) which effectively controls the 66kV bus voltage and the tap changers on the 132/66/6.6kV transformers are used to control the 132kV bus voltage (V_{REF}) to minimise line losses. The tap changers are also used to restrict the SVC output to maintain a margin of controlled swing range for system contingencies. The control system can also switch the GEOR 5MVAR shunt reactor in if the SVC is operating at >=**4MVAR** of inductive VARS or switch the shunt reactor out if the SVC is operating at >=**6MVAR** of capacitive VARS. If the SVC is offline the tap changers on the 132/66/6.6kV transformers are used to control the 66kV voltage. The Georgetown SVC inductive limit is **6MVAR** and the capacitive limit is **9.75MVAR**.

At NORM the SVC controls the 6.6kV bus voltage (V_{TARG} +/- 0.001pu) which effectively controls the 22kV bus voltage and the tap changers on the 66/22/6.6kV transformers are used to control the 66kV bus voltage (V_{REF}) to minimise line losses. The tap changers are also used to restrict the SVC output to maintain a margin of controlled swing range for system contingencies. If the SVC is offline the tap changers on the 66/22/6.6kV transformers are used to control the 22kV voltage. The Normanton SVC inductive limit is **3.7MVAR** and the capacitive limit is **8.4MVAR**.

The control systems for the GEOR and NORM SVCs consist of an inner loop TCR control system and an outer loop control system performed within the C5200 RTU's.

The SVC inner loop control system controls of the firing angle of the TCR thyristors to maintain the 6.6kV target voltage (V_{TARG}) based on a slope characteristic and phase balancing. The control system also has asymmetry, overvoltage, undervoltage and overload protection functions.

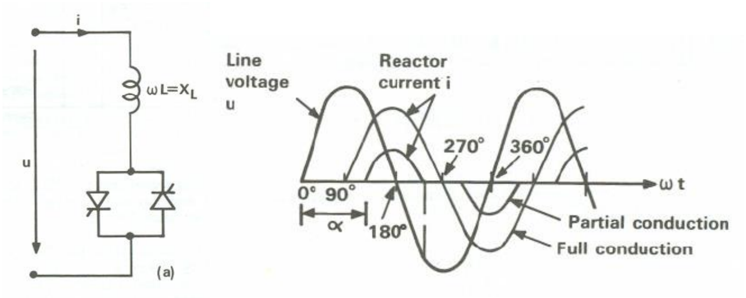

Figure 31: Basic TCR model and TCR firing angle / conduction diagram

The thyristors conduct on alternating half cycles of the supply frequency, based on the firing angle (α), as shown above. During conduction the thyristors are essentially short-circuited, the current through the reactor is lagging the voltage by 90 degrees. Partial conduction occurs when the firing angle is between 90 and 180 degrees. Full conduction is obtained with a firing angle of 90°, which is equivalent to the reactor fully energised on the network. Firing angles between 0 and 90 degrees are not permitted as they produce asymmetrical currents with dc offset, which are unacceptable. The delay in conduction of the TCR generates harmonics currents when the firing angle is between 90 and 180 degrees. When the thyristor firing is symmetrical, only odd harmonics are created. For this reason, SVC installations generally consist of tuned capacitor banks to filter out odd harmonic components.

The SVC's go into a force fire mode (full conduction) when the system voltage goes below 0.3pu, this functionality discharges the filter capacitors during an outage and helps to manage system over voltages during re-energisation of the network. The force fire mode is also used as part of the normal SVC shut down sequence to discharge the filter capacitors.

The SVC outer loop control system performs higher level functions such as start-up and shut-down sequences for the SVC's, provides voltage control setpoints V_{TARG} and SVC slope for the inner loop control system and controls the transformer On Load Tap Changers (OLTC).

The SVC outer loop control system has 3 modes of operation for OLTC control on the transformers depending on the MVAR output of the SVC and the reference voltage (V_{REF}):

- **Mode 1** - the SVC outer loop controller controls the 132kV (GEOR) or 66kV (NORM) voltage via the OLTCs to V_{REF} +/- 0.01pu while the SVC MVAR output is within its Inductive and Capacitive steady state limit set points (SS Ind Lim and SS Cap Lim).
- **Mode 2** - the SVC outer loop controller allows the 132kV (GEOR) or 66kV (NORM) voltage to stay within outer voltage limits (0.9-1.15pu for GEOR, 0.9-1.1pu for NORM) so that the SVC MVAR output can remain within its deadband limit set points (SS Ind Lim + Ind DB and SS Cap Lim + Cap DB). The SVC will perform tap changes to maintain the SVC MVAR output within its deadband limit set points.
- **Mode 3** - the 132kV (GEOR) or 66kV (NORM) voltage is outside the outer voltage limits. The SVC outer loop controller will perform tap changes to bring the voltage back within the outer voltage limits. The SVC MVAR output will continue to its physical limits to maintain the 6.6kV voltage to the V_{TARG} set point.

Parameter	Georgetown	Normanton	Description
Slope (%)	0	-7.14	TCR slope setting
Vtarg(pu)	1.02	1.027	TCR target voltage on the 6.6kV busbar (+/- 0.001pu)
Vref(pu)	0.987	1.037	SVC reference voltage on the 132kV (G) or 66kV (N) busbar (+/- 0.01pu)
SS Cap Lim (kvar)	6000	6000	SVC steady state capacitive var limit
Cap DB (kvar)	2000	400	SVC steady state capacitive limit hysteresis amount
SS Ind Lim (kvar)	1000	2000	SVC steady state inductive var limit
Ind DB (kvar)	2000	400	SVC steady state inductive limit hysteresis amount
Line Loss Min Divider	200	111	Line loss minimisation divider constant
SVC Capacitive Limit (kvar)	9750	8400	SVC capacitive limit (Filter Capacitance)
SVC Inductive Limit (kvar)	6000	3700	SVC inductive limit (=TCR limit - Filter Capacitance)
TCR delta (kvar)	15750	12100	TCR inductive range
Cap Reserve Margin (kvar)	1750	2000	=SVC capacitive limit - (SS Cap Lim + Cap DB)
Ind Reserve Margin (kvar)	3000	1300	=SVC inductive limit - (SS Ind Lim + Ind DB)

Table 4: SVC Control Parameters

The table above shows the existing parameters for the GEOR and NORM SVC's. The steady state limits are used to provide a reserve margin for contingencies and limit voltage swings associated with an SVC trip.

The voltage target set point (V_{TARG}) is adjusted based on the SVC slope setting. The NORM SVC has a negative slope to offset the effects of the impedance between the 6.6kV and 22kV windings on the 66/22/6.6kV transformers. The GEOR SVC has its slope set at zero to manage interactions with the Kidston Solar Farm voltage control system.

The voltage refence set point (V_{REF}) is adjusted based on the line loss minimisation formula:

$$V_{REF(mod)} = V_{REF} - \text{Power Flow through both transformers / Line Loss Min Divider}$$

When operating in auto mode the GEOR 5MVAR shunt reactor is controlled by the SVC outer loop control system. The reactor is switched in during the SVC shutdown process (if not already closed) or if the SVC is operating at >=**4MVAR** of inductive VARS for 5 secs and switched out if the Georgetown SVC is operating at >=**6MVAR** of capacitive VARS for 5 secs. The reactor is switched back in at <=**4MVAR** of capacitive VARS.

3. SVC Reactive Power Capability

The reactive power range of the GEOR SVC is 6MVAR inductive to 9.75MVAR capacitive and the reactive power range of the NORM SVC is 3.7MVAR inductive to 8.4MVAR capacitive.

Preliminary steady state load flow studies were undertaken to determine if there is likely to be a requirement for additional reactive power capability at GEOR and NORM over the coming years based on load forecasts for the Gulf network.

3.1 Modelling and Network Assumptions

The model used for the steady state load flow studies was set up with the following parameters and assumptions:

- The network has been modelled with a voltage source to represent the 132kV transmission supply point at ROSS 132kV bus (Powerlink-owned). Voltage levels were varied between 1.0pu and 1.05pu.
- GEOR 6.6kV SVC controlling the GEOR 6.6kV bus at 1.02pu with 0% droop and the GEOR transformers T1 and T2 controlling the GEOR 132kV bus. SVC operating control modes set up as outlined in section 2. If the SVC is out of service, transformers T1 and T2 control the GEOR 66kV bus at 1.05pu.
- GEOR reactor is modelled in service and switched off when GEOR SVC output is >6MVAR capacitive to simulate the GEOR reactor auto control mode.
- NORM 6.6kV SVC controlling the NORM 6.6kV bus voltage at 1.027pu with -7.14% droop on a 12MVA base and the NORM transformers T1 and T2 controlling the NORM 66kV bus. SVC operating control modes set up as outlined in section 2. If the SVC is out of service, transformers T1 and T2 control the NORM 22kV bus to 1.027pu.
- Normanton Solar Farm connected to the NORM 22kV bus modelled with a peak 4.5MW at 0.94 leading power factor set point (absorbing vars from the network). The solar inverters not providing any reactive power control outside of daylight hours.
- Kidston Solar Farm connected to the KIDS 132kV bus modelled with a peak output of 48MW, controlling the KIDS 132kV bus at 1.005pu with 4% voltage droop on a 50MVA base. Inclusive of a 2.2MVAR net inductive harmonic filter and 2 x 3MVAR shunt reactors (approx. 8.2MVAR inductive). The solar inverters not providing any reactive power control outside of daylight hours.
- Loads at KIDS, GEOR, CROY and NORM based on forecast maximum loads and historical minimum loads.
- It has been assumed that the existing SVC reactive power reserve margins would be adequate for the dynamic/transient response required for the forecast loads and network configuration. This would need to be verified by dynamic/transient studies.

3.2 Network Scenarios

The following network scenarios were modelled for the steady state load flow studies:

- System Normal – where all network assets are in service.
- System N-1 – where a single network asset has been taken out of service such as GEOR SVC, GEOR Reactor, NORM SVC, GEOR 132/66/6.6kV T1 and NORM 66/22/6.6kV T1.
- The solar farms at NORM and KIDS as well as the KIDS solar farm reactor modelled both online and offline.
- The 132kV voltage source at ROSS modelled at 1.0pu, 1.03pu and 1.05pu
- Two different load scenarios were assessed:
  - Ergon peak load forecast projected out to around 2050 based on existing growth rates beyond 2034, taking into consideration the available N-1 transformer capacity at GEOR, CROY and NORM. Including expected customer loads of 6MVA load on the 132kV ROSS to KIDS line and 2MVA load at KIDS substation (System Normal and System N-1).
  - Historical light load with 0MVA from the expected customer loads (System Normal and System N-1).

3.3 Load Flow Study Results

The maximum levels of steady state reactive support recorded from the studies are outlined in the following table:

	System Normal	GEOR React OOS	GEOR SVC OOS	NORM SVC OOS	GEOR TF1 OOS	NORM TF1 OOS
GEOR SVC Max Capacitive support required (MVAR)	6.20#	1.65	-	6.33#	6.44#	6.14#
GEOR SVC Max Inductive support required (MVAR)	2.31	2.25	-	2.47	1.78	2.37
NORM SVC Max Capacitive support required (MVAR)	6.32	2.64	6.38	-	6.23	6.20
NORM SVC Max Inductive support required (MVAR)	2.20	2.05	2.40	-	2.37	2.10

Table 5: Maximum SVC outputs from steady state studies

#***Values with GEOR 5MVAR shunt reactor in service***. *When operating in auto mode the reactor would switch out when the GEOR SVC output is > 6MVAR capacitive.*

The table shows that the steady state reactive power required from the SVCs is expected to remain within the existing steady state bands of 8MVAR capacitive to 3MVAR inductive for the GEOR SVC and 6.4MVAR capacitive to 2.4MVAR inductive for the NORM SVC for the study period based on the forecast loading.

Further assessment would be required to determine the frequency at which the GEOR shunt reactor is expected to switch in and out for the future peak load scenario's when the SVC output is reaching 6MVAR capacitive. Excessive switching of the shunt reactor could be detrimental to the lifetime of the switchgear, so a review of the control algorithm and SVC settings may be required to minimise the switching frequency.

Based on the studies and the existing dynamic reactive power margins for the SVCs, the results suggest that the existing SVC capacitive and inductive ranges at GEOR and NORM are expected to be adequate for the study period. This assumes that the GEOR 5MVAR shunt reactor is also available, therefore the overall GEOR inductive range required would be 11MVAR (6MVAR SVC + 5MVAR shunt reactor). The existing SVC limits are summarised in the following table:

GEOR SVC capacitive limit	GEOR SVC inductive limit	NORM SVC capacitive limit	NORM SVC inductive limit
9.75MVAR	6MVAR	8.4MVAR	3.7MVAR

Table 6: Existing GEOR and NORM SVC reactive power limits

4. Description of the Identified Need

The GEOR and NORM SVCs are imperative for the management of steady state voltages, system transients and voltage unbalance levels on the gulf network. Without reactive compensation at Georgetown and Normanton, supply to the gulf network suffers from poor voltage regulation.

The GEOR and NORM SVCs were commissioned in 1991/92 and the asset lives of the components such as the TCR's, harmonic filters, inner control systems, protection relays, thyristor stacks and cooling systems are at or approaching the end of their useful life. The Trench TCR's are a unique size for each site and there are no readily available spares to replace a failed TCR. The original Trench 5MVAR shunt reactor has had failures on all three cores over the years and now has Nokian reactors on all three phase (YOM 2002, 2017 & 2017).

The SVC outer loop control systems were replaced in 2010/11 and other SVC components have required repairs or replacement over the years due to failures including PCBs on the inner loop control system, capacitor cans on the filters, cooling water pumps, thyristors, etc. Spare parts are no longer able to be sourced for some of the SVC components such as the PCB inner loop control cards and there is a distinct possibility that if one of the control cards can no longer be repaired or replaced the SVC would be rendered inoperable.

The risk of extended outages to both SVCs' aged inner loop control systems is anticipated to increase over the coming years due to the depletion of spares. At present a prolonged outage of either the GEOR or NORM SVC can normally be managed through the extended operating voltage range of the 132 kV plant (+/-15% OLTC range), GEOR 5 MVAr shunt reactor and remaining SVC.

The deterioration of the SVCs significantly increases the likelihood of SVC outages that may lead to network instability, customer power supply quality issues, voltage compliance issues, operational constraints and network outages initiated by over-voltage and under-voltage protection.

5. Network Risks and Emerging Issues

5.1 Harmonic Resonance Conditions

The gulf network is susceptible to harmonic resonance conditions and voltage transients during reclose events and system restoration due to the inrush currents of the reactive plant connected.

One of the scenarios where there are known resonance conditions is during the energisation of the GEOR 132/66/6.6kV transformers when the SVCs and Kidston Solar Farm are offline, which can result in over-voltage tripping of the KIDS-GEOR 132kV feeder (trip setting >1.18pu volts, 2 secs).

To minimise the impacts of these conditions, after a system outage the network is normally restored in a sequence. A typical re-energisation procedure for the entire gulf system is as follows:

Check the Network Status:

- Check that the ROSS 132kV Ross-Kidston Fdr CB is OPENED
- Check that the KIDS 132kV Ross-Kidston Fdr CB is OPENED
- Check that the KSF 132kV PoW single pole CB is OPENED

Restoration Steps:

- Open the KIDS 132kV Solar Farm Fdr CB
- Open the KIDS 132kV Georgetown Fdr CB
- Open the KIDS 6.6kV Feeder CBs
- Open the GEOR 66kV Transformer 3 and 4 CB's
- Initiate Stop Via SCADA of the GEOR SVC
- Open the GEOR 66kV Croydon Fdr CB
- Open the CROY 66kV Normanton Fdr CB
- Initiate Stop Via SCADA of the NORM SVC

- Close the ROSS 132kV Ross-Kidston Fdr CB
- Close the KIDS 132kV Ross-Kidston Fdr CB
- Close the KIDS 132kV Solar Farm Fdr CB
- Contact Genex to Energise Kidston Solar farm via the 132kV KSF PoW single pole CB as per Note 1 to Note 3 below.
- Genex to Close KSF 22kV Filter and Reactor No.1
- Genex to Close KSF 22kV 3MVAr Reactor No.2
- Genex to Close KSF 22kV 3MVAr Reactor No.3
- Genex to Contact Ergon when KSF 22kV Feeder F1, F2, F3 are Closed
- Close the KIDS 6.6kV Feeder CBs
- Close the KIDS 132kV Georgetown Fdr CB (energising Georgetown 132kV bus, 132/66kV transformers and 6.6kV shunt reactor in the process)
- Close the GEOR 66kV Transformer 3 and 4 CB's (energising 66/22kV transformers and load in the process)
- Initiate Start Via SCADA of the GEOR SVC
- Close the GEOR 66kV Croydon Fdr CB
- Close the CROY 66kV Normanton Fdr CB
- Initiate Start Via SCADA of the NORM SVC

Note 1: Ergon Energy's 132kV KSF feeder CB has an interlock to stop it closing while KSF132kV PoW CB is closed.

Note 2: After a sustained outage, where Kidston Solar Farm is:

- Restored AFTER the Gulf system with KIDS 6.6kV Feeders Energised: Kidston Solar Farm is to energise their Inverter transformers one at a time, 6 minutes apart with a max of 10 per hour.
- Restored BEFORE the Gulf system with the Kidston Substation 6.6kV Feeders de-energised: Kidston solar farm can energise up to 8 inverter transformers at a time (i.e. one KSF 22kV feeder at a time), 2 minutes apart.

Note 3: The Kidston Solar Farm 56MVA Transformer is only to be energised via the 132kV single pole PoW CB.

5.2 SVC Reactive Power Capability

The GEOR SVC has a total capacitive range of 9.75MVAR and a total inductive range of 6MVAR. Under steady state operation the SVC reactive power range is limited to 8MVAR capacitive to 3MVAR inductive reserving the remaining capacity for dynamic/transient response. This is supplemented by the GEOR 5Mvar shunt reactor so the overall inductive range would be 11MVAR.

The NORM SVC has a total capacitive range of 8.4MVAR and a total inductive range of 3.7MVAR. Under steady state operation the SVC reactive power range is limited to 6.4MVAR capacitive to 2.4MVAR inductive reserving the remaining capacity for dynamic/transient response.

Based on steady state load flow studies and forecast loads for the area, the existing SVC steady state capacitive and inductive limits are expected to be adequate for the next 20 years. However, any significant changes to the network or significant increases to network loading could drive the need to increase the amount of reactive support required on the gulf network.

5.3 Growth of Distributed Energy Resources

There is significant amount of Distributed Energy Resources (e.g. rooftop solar PV) installations within the Gulf network and this is expected to continue to grow. Large customers in the area are also exploring opportunities to reduce their load with onsite generation. The lowest loads are now seen during the middle of the day, during months with more mild weather conditions (see *Figure* ***32*** and *Figure* ***33*** below). In short, it is expected that low load periods will continue to decline putting additional pressure on inductive compensation.

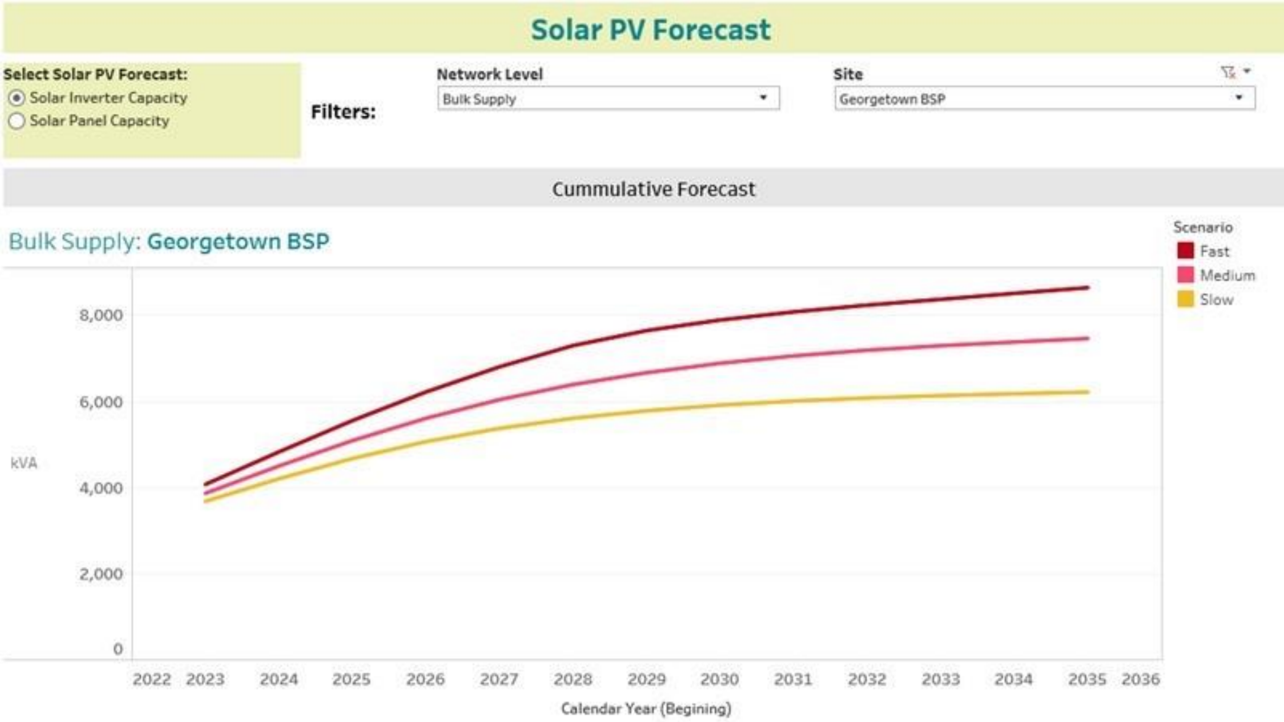

Figure 32: Georgetown BSP Solar PV Forecast

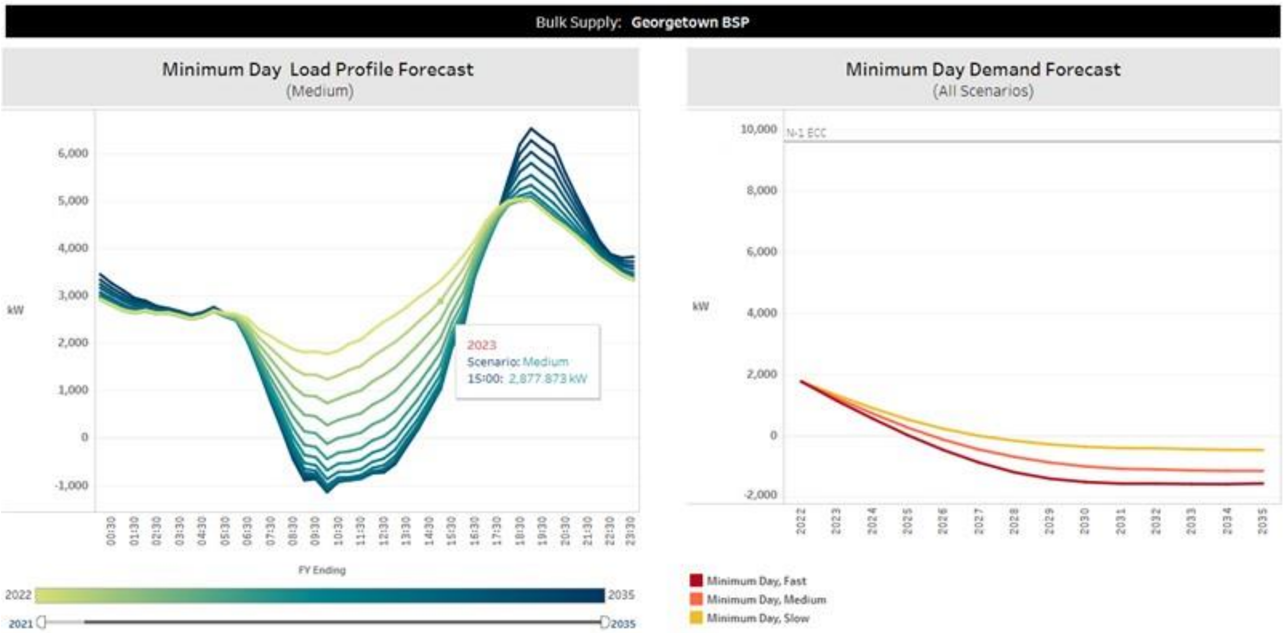

Figure 33: Georgetown BSP 66kV load profile growth and Min. Demand Forecast

6. Purpose and Scope of Request for Proposal

Ergon Energy calls for Request for Proposal (RFP) for the provision of either a network option to replace / refurbish the end-of-life static var compensators (SVCs) at Georgetown and Normanton substations or a non-network, Volt-var Control Network Support Service (VCNSS) solution to replace the functionality of the end-of-life static var compensators (SVCs) at Georgetown and Normanton substations.

The main purpose of this document, RFP pre-qualification technical specification, is to assist Ergon Energy in the selection of either a network or non-network option to address the identified need resulting from the end-of-life static var compensators (SVCs) at Georgetown and Normanton substations.

The RFP process consists of key stages listed in *Table 7* below:

Stages	Description of RFP Process	Preliminary Timeline
1	Issue request for RFP	01/08/2023
2	RFP submissions close	08/12/2023 (18 weeks)
3	Evaluate RFP submissions of solution providers produce a shortlist of qualified proponents	08/12/2023 to 01/01/2024 (3 weeks)
4	Issue Invitation for final submissions to Short-listed Pre-qualified Proponents	01/01/2024 to 01/03/2024 (8 weeks)
5	Evaluate proposals	01/03/2024 to 01/05/2024 (8 weeks)
6	Notify preferred proponent of next steps. If network option is selected, commence RIT-D process if the estimated project cost is above the RIT-D threshold.	01/05/2024

Table 7: The RFP process

7. Site Specific Conditions

7.1 Environmental Conditions

All materials supplied under this proposal that are installed outdoors are required to withstand the environmental conditions listed in Ergon Energy standard "STNW3007 - Standard for Climate and Natural Hazard Resilience" and as detailed in the table below:

Item	Particular	Details
7.1.1	Altitude	1000 metres above sea level
7.1.2	Ambient air temperature	50°C summer daytime (maximum) -5°C winter night-time (minimum) AS 2067 2.4.3.4 "very hot climates"
7.1.3	Humidity	100% (maximum) 25% (minimum)
7.1.4	Isokeraunic level	Ergon Energy standards and AS1768 must be applied for lightning protection design.
7.1.5	Pollution	Site pollution severity class d (Heavy) in accordance with SA TS60815.1
7.1.6	Rainfall intensity	Five-minute duration 350 mm/h (refer STNW3007)
7.1.7	Solar radiation	1100 W/m^2 AS 2067 normal
7.1.8	Wind velocity	Wind load in accordance with (AS/NZS 1170.2, 2021) as follows: • Annual probability 1:2000 • Terrain Category 2 • Shielding Multiplier 1.0 • Topographical Multiplier to suit site • **Georgetown** - Region A with V2500 Wind gust speed 172 km/h (48 m/s) • **Normanton** – Region C with V2500 • Wind gust speed 241 km/h (67 m/s)

Table 8: Rated Climatic Requirements

7.2 Power System Existing Conditions

Item	Description	Rating
7.2.1	Highest voltage, under normal system conditions, for equipment with nominal voltage from 1kV up to 35kV	Per Table 3 of AS IEC 60038-2022
7.2.2	Highest voltage, under normal system conditions, for equipment with nominal voltage from 35kV up to 230kV	Per Table 3 of AS IEC 60038-2022 for the 66kV network. The 132kV network has been designed to operate continuously at 1.15pu volts.

Table 9: System Conditions

System Configuration	Fault Location	Fault Type	Network Fault Current Contribution at Fault Location (kA)
Existing *distribution system* – system normal	GEOR 6.6kV Bus	3ϕ - Maximum	8.27
		1ϕ-g - Maximum	0.00
		3ϕ - Minimum	4.94
		1ϕ-g - Minimum	0.00
	GEOR 22kV Bus	3ϕ - Maximum	1.23
		1ϕ-g - Maximum	1.46
		3ϕ - Minimum	0.86
		1ϕ-g - Minimum	1.03
	GEOR 66kV Bus	3ϕ - Maximum	1.05
		1ϕ-g - Maximum	1.47
		3ϕ - Minimum	0.59
		1ϕ-g - Minimum	0.83
	GEOR 132kV Bus	3ϕ - Maximum	0.67
		1ϕ-g - Maximum	0.88
		3ϕ - Minimum	0.36
		1ϕ-g - Minimum	0.47
Existing *distribution system* – N-1 condition (GEOR T1 Out of Service)	GEOR 6.6kV Bus	3ϕ - Minimum	3.73
		1ϕ-g - Minimum	0.00
	GEOR 66kV Bus	3ϕ - Minimum	0.50
		1ϕ-g - Minimum	0.67
Existing *distribution system* – N-1 condition (GEOR T3 Out of Service)	GEOR 22kV Bus	3ϕ - Minimum	0.57
		1ϕ-g - Minimum	0.63

Table 10: Georgetown 132/66/22/6.6kV Substation Fault Levels

System Configuration	Fault Location	Fault Type	Network Fault Current Contribution at Fault Location (kA)
Existing *distribution system* – system normal	NORM 6.6kV Bus	3ϕ - Maximum	3.65
		1ϕ-g - Maximum	0.00
		3ϕ - Minimum	1.54
		1ϕ-g - Minimum	0.00
	NORM 22kV Bus	3ϕ - Maximum	1.25
		1ϕ-g - Maximum	1.80
		3ϕ - Minimum	0.50
		1ϕ-g - Minimum	0.73
	NORM 66kV Bus	3ϕ - Maximum	0.44
		1ϕ-g - Maximum	0.62

		3ϕ - Minimum	0.19
		1ϕ-g - Minimum	0.27
Existing *distribution system* – N-1 condition (NORM T1 Out of Service)	NORM 6.6kV Bus	3ϕ - Minimum	1.28
		1ϕ-g - Minimum	0.00
	NORM 22kV Bus	3ϕ - Minimum	0.44
		1ϕ-g - Minimum	0.62

Table 11: Normanton 66/22/6.6kV Substation Fault Levels

- *Maximum and minimum fault levels are sourced from the published 2023 Ergon Energy Fault Level Summary Report. The information obtained from the report is intended as general in nature, may be based on assumptions that change with time and may not necessarily be complete. Information contained in, or obtained from, the report should not be relied upon, and use of the information contained in the report is at your own risk.*

- *Fault summaries were performed in Powerfactory with fault level calculation method IEC 60909.*

- *For minimum faults:*

  - *The network model used included the full PSSE snapshot (minimum fault level case uses a minimum dispatch scenario with all asynchronous generation offline as provided by Powerlink Queensland) of the NEM, with the addition of all of the relevant Ergon Energy network.*

- *For maximum faults:*

  - *Maximum fault levels are produced based on all network elements being 'intact'; where normally open switches, circuit breakers, and isolators are closed within the boundary of a substation to produce the maximum fault levels results for that substation, except where indicated in the report. This assumption can result in short circuit current appearing to be higher at some locations compared to its system normal fault level configuration.*

- *The synchronous generation is represented by its sub-transient impedance values.*

8. Technical Requirements

Key functional requirements of the proposed solution:

a. Regulate and control both the positive and negative phase sequence voltages at the 66kV bus at GEOR and the 22kV bus at NORM, to the required setpoints, under normal steady state and contingency conditions.
b. Provide dynamic, fast reactive power response following system contingencies (e.g. network short circuits, line and generator disconnections).
c. Enhance system voltage stability during frequency and / or voltage disturbance events.

8.1 Fundamental Requirements

The proponent must ensure that their services and equipment satisfy fundamental requirements below. Any departures, exceptions and alternative solutions must be clearly stated in their offer documents. The proposed solution shall:

a. Be available at any time of day or night and have the capability to vary reactive power output continuously to control voltages at the 66kV bus at Georgetown 132/66/22/6.6kV substation and the 22kV bus at Normanton 66/22/6.6kV substation within the Specific Performance Levels.
b. Provide all equipment and services required to connect to the connection point e.g. substation switchgear, cables, protection upgrades and construction costs.
c. Provide suitable levels of redundancy within its design to meet the Specific Performance Levels.
d. Have control systems that provide the following control modes simultaneously:
    i. Voltage
        - With or without droop
        - With or without independent phase control
    ii. Constant var
        - With or without independent phase control
    iii. Power factor
        - With or without independent phase control
    iv. Negative phase sequence unbalance (minimum 10% total current)
    v. A configurable/programmable gain option
    vi. Power oscillation dampening
    vii. Capacitor & reactor switching
    viii. Manual mode – independent of controller for testing purposes
e. The design and operation of the control systems shall be coordinated with the existing Network and other Network Users control systems in order to avoid or manage interactions that would adversely impact on the Network and other Network Users.
f. Have communications equipment required to interface with the Ergon Energy communication network for the monitoring, collection and storage of operational data as per Ergon Energy

Operational Technology Standard for Data Collection STNW3374 and Ergon Energy Standard for Intelligent Electronic Devices (IED) STNW3383. This information includes, but is not limited to alarms, events, monitoring, measurement, control, protection signals and setpoints of reactive power and voltages.

g. Regulate (i.e. generate or absorb) reactive power continuously at the points of connection to:

   i. Improve voltage stability during and post network contingency events,
   ii. Mitigate low and high voltage issues on the network,
   iii. Control positive and negative phase sequence voltages according to Ergon Energy's operational setpoints.

h. Comply with the relevant Australian Standards, industry codes, statutory requirements and any applicable Ergon Energy standards.

i. Comply with the Ergon Energy Major Customer Connection process which aligns with Chapter 5.3A of the National Electricity Rules (NER).

j. Comply with any relevant performance requirements and financial obligations, fees and charges of an ultimate connection agreement with Ergon Energy and relevant requirements under the NER.

k. Have high availability and reliability and must be robust in its operation during system disturbances as required under the Specific Performance Levels.

l. Have the short-term overload capability to meet the Specific Performance Levels.

m. Be individually single phase controlled in such a manner to reduce the NPS voltages at the connection points within relevant dead band parameters set by Ergon Energy. Balance Negative Phase Sequence (NPS) up to the Specific Performance Levels in Table 12 (which aligns with NER S5.1a.7 requirements):

Nominal supply voltage (kV)	**Maximum negative sequence voltage (% of nominal voltage)**			
Column 1	**Column 2**	**Column 3**	**Column 4**	**Column 5**
	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

Table 12: Voltage unbalance system standards (NER table S5.1a.1)

These limits apply for normal and credible single contingency conditions on the Ergon Energy system. Large voltage unbalances higher than the values in the table, may occur for short intervals up to one minute due to faults, switching operations or transformer energisation.

n. Comply with allocated harmonic emission limits as per AS/NZS 61000.3.6:2001 and allocated voltage fluctuation emission limits as per AS/NZS 61000.3.7:2001 (allocations to be provided by Ergon Energy). The requirement for harmonic mitigation should not reduce the capability of the solution to meet the reactive power output or negative phase requirements.
o. Have a predictable response at the connection point for any internal plant or communication failures such that appropriate actions such as the shutdown or control system response blocked for an appropriate period
p. Have well-designed emergency shutdown procedures such that, whenever possible, the system shall shutdown in a controlled manner to reduce impacts on the power system. When and where it is safe to do so, the system shall follow the normal automatic shutdown sequence. However, the system must also act promptly to protect itself from damages due to faulty equipment and/or dangerous system conditions if deemed necessary.
q. 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, except when the unit has tripped by protection systems.
r. The Start-up control sequence shall:
    i. Be fully automatic following the start-up signal which may be locally or remotely applied,
    ii. Indicate ready to start or if not ready, list all reasons why a start is inhibited,
    iii. Set the voltage regulator to the level existing immediately prior to sending a circuit-breaker close allowed signal,
    iv. Indicate locally and at the remote operator’s location when the unit is fully regulating and ready to receive voltage set point instructions from the operator.

s. The Shut-down control sequence shall:
    i. Be fully automatic following the shut-down signal which may be locally or remotely applied,
    ii. Gradually adjust the output to zero Mvar at an adjustable rate in order to mitigate voltage fluctuations,
    iii. Indicate locally and at the remote operator’s location that the unit is fully shutdown and offline.
t. Comprehensive recording and monitoring systems, e.g. Power Quality Meter (PQM), High Speed Monitoring Meter (HSM), and PMU (Synchrophasor Measurement Unit), to monitor the performance at the connection point for ongoing compliance.
u. Have an environmental and cultural heritage management plan and comply fully with the local rules and regulations

8.2 Ride-through Capability

The proposed solution shall remain in service, fully function up to the Specific Performance Levels, to support the network under all, but not limited to, scenarios below:

a. Energisation of local and remote network elements, e.g. lines, cables, transformers, reactors / inductors, and capacitors. For example, after a circuit breaker reclose event, Volt-var support must be promptly provided, up to the specified levels, to maintain stable voltages on the gulf network.
b. Frequency disturbances in the network due to tripping of lines and / or generators (synchronous and asynchronous), control actions of generating plant and any interactions of power electronic controllers with the power system.
c. Expected to balance NPS up to the Specific Performance Levels if the NPS at the connection points is higher than the Specific Performance Levels.
d. Voltage dips, sags, swell, notching, harmonic distortion, lighting and switching transients in the network. Expected to perform up to the Specific Performance Levels to minimise the impacts of these events to the network.
e. Voltage fluctuation, harmonic voltage distortion and voltage unbalance conditions at GEOR and NORM within the levels specified in clauses S5.1a.5, S5.1a.6 and S5.1a.7 of the NER.

8.3 Availability, Reliability and Robustness

The proposed solution shall:

a. Have an average annual availability (including planned and unplanned outages) of not less than the Specific Performance Levels and a high reliability, where the mean time between Unscheduled Services must be better than the Specific Performance Levels.
b. Shall operate in a robust manner and must remain in stable operation throughout system events where system voltage and frequency excursions may temporarily exceed expected normal operating conditions. Be capable of providing uninterrupted operation during and following power system voltage, frequency, and voltage / current waveform disturbances some of which may occur simultaneously as defined under the Specific Performance Levels.

8.4 Specific Performance Levels

Table 13 lists the Specific Performance Levels required for the proposed solution. Note that additional performance levels and technical requirements might also apply, depending on the type/size of plant used in the solution and the specific connection arrangement. E.g. a HV connected renewable generation solution would be expected to meet the requirements specified in the National Electricity Rules (NER), Ergon Energy Standard STNW1175 (Standard for Connection of Embedded Generating Systems to a Distributor's HV Network) as well as the Specific Performance Levels.

Item	Description	Rating
8.4.1	Minimum reactive power capability range at connection point – 0.9 - 1.1 pu voltage, frequency 49.75 to 50.25 Hz	

	a. Inductive, Continuous	GEOR 11MVAR (6MVAR SVC + 5MVAR Shunt Reactor) NORM 3.7MVAR
	b. Capacitive, Continuous	GEOR 9.75MVAR NORM 8.4MVAR
8.4.2	Capability for system to be easily expanded in the future if required	Provide details of expansion capability of the proposed solution (static and dynamic)
8.4.3	Redundancy of system design	System must have sufficient reactive power capacity in the event of a single failure of any system element (N – 1) to maintain system voltages and stability.
8.4.4	Be capable, on receipt of appropriate input signals, of changing its output from fully inductive to fully capacitive	≤ 40 milliseconds
8.4.5	Capability of continuous uninterrupted operation during and following a system voltage disturbance e.g. a load reduction event	Capable of continuous operation for voltage changes of up to 30% from its pre-disturbance level
8.4.6	Black-start capability	System must be able to provide reactive power support during re-energisation of the gulf network
8.4.7	Availability (*) $\% \text{ Availability} = \frac{\text{Total Time system is able to Perform Specific Performance Levels}}{\text{Total Time Period}}$	>99.5%
8.4.8	Maximum percentage Downtime (**) $\% \text{Downtime} = \frac{\text{Total Downtime}}{\text{Total Time Period}} \times 100$ also, $\% \text{Downtime} = 100 - \% \text{Availability}$	<0.5%
8.4.9	Maximum time taken to become fully available to provide the service following a circuit breaker reclose event	0 hours (must remain operational following a reclose event and ride through other dips or transients)
8.4.10	System voltage at point of connection	
	a. Nominal system voltage	132kV / 66kV / 22kV / 6.6kV
	b. Voltage range for continuous operation	0.9 to 1.1 pu of nominal (0.9 to 1.15pu of nominal on 132kV network)

8.4.11	Measurement accuracy for voltage transformers	Class 0.5M
8.4.12	Allowable Droop Settings	
	a. Boost	0% to 10%, 0.1% increment
	b. Buck	0% to 10% 0.1 % increment
	c. Voltage Dead band	0 to ±0.1 pu 0.001 pu increment
8.4.13	Required to ride through and operate to the expected performance levels during and following power system voltage, frequency and voltage/current waveform disturbances some of which may occur simultaneously as follows:	
	a. Maximum temporary voltage (30 sec)	1.30 pu V
	b. Minimum temporary voltage (30 sec)	0.70 pu V
	c. Long term over voltage (1800s)	1.15 pu V
	d. Short term over voltage (0.2s)	1.50 pu V
	e. A drop in one or more phases of the voltage at the point of connection	0.5 pu V for 0.6 sec
	f. Voltage oscillating (at a frequency of ± 0.25 to ± 2.5Hz)	0.7 to 1.3 pu V
	g. Worst asymmetrical faults to be expected at 132 kV bus	0.25 pu V
	h. Worst asymmetrical faults to be expected at 66 kV bus	0.25 pu V
	i. Worst asymmetrical faults to be expected at 22 kV bus	0.33 pu V
	j. Worst asymmetrical faults to be expected at 6.6 kV bus	0.33 pu V
	k. A switching surge of 2.2 pu at the connection point	Up to 20 msec
	l. A fall in system frequency to 46.5 Hz, with recovery to 46.5 – 52.5 Hz	Within 4 minutes
	m. High speed auto reclose	
	i. Dead time	5 – 15 sec
	ii. Reclaim time	20 sec
8.4.14	Maximum allowable reactive power step	0.03 pu
8.4.15	System frequency at point of connection	
	a. Nominal frequency	50 Hz
	b. Normal control range	49.75 - 50.25 Hz
	c. Transient excursions (less than 10 minutes)	49.0 - 51.0 Hz
	d. Transient excursions (less than 2 minutes)	46.5 - 52.5 Hz
8.4.16	Maximum equipment design fault currents	
	a. 132kV	40kA rms for 1 sec
	b. 66kV	25kA rms for 3 sec
	c. 22kV	25kA rms for 3 sec

	d. 6.6kV	25kA rms for 3 sec
8.4.17	Negative Phase Sequence Control	
	a. Minimum reactive power required, per phase, for individual phase control.	10% of the full operational output rating
8.4.18	Power System Monitoring	
	a. Power Quality Measurement System	Relevant IEC Standards Up to 100th Harmonics
	b. High Speed Fault Recorder System (multi-channels)	Up to 24kHz per channel
	c. Synchrophasor Measurement Units (PMU)	Per Standard IEC / IEEE 60255-118-1:2018
8.4.19	Maximum allowable sound pressure levels at one metre outside perimeter fence	55 dBA
8.4.20	Maximum Radio Interference Voltage outside of the perimeter fence.	Per Standard AS2344
8.4.21	Maximum Allowable Electric Field	
	a. Occupational for the whole working day	10 kV/m
8.4.22	Maximum Allowable Magnetic Field	
	a. Occupational for the whole working day	10,000 milliGauss

Table 13: Proposed Solution – Specific Performance Levels

Explanatory Notes

(*) The system is considered to be available for service only if it is able to perform the whole of the specified duty. Operation with limited control functions or within a limited range of outputs not meeting the specified levels due to a component, software or subsystem failure is to be treated as unscheduled servicing downtime.

(**) Total Downtime within a Total Time Period is defined as the sum of the scheduled service downtime and unscheduled service downtime.

9. Testing Requirements

The proponent must have a proven standard Inspection and Test Plan (ITP) and records of previous test results to demonstrate their capability to meet the specific Testing Requirements. The ITP shall include the following fields that are relevant for each test items listed in the Testing Schedules under Section 11 of this document.

- Test parameters.
- Method of testing – The manner in which the test was carried out (including a copy of the test procedure).
- Response times including simulated outputs with trip signals disabled, if applicable.
- Test schedules – Initial and Subsequent tests.

The previous test results shall at least include relevant reports of Type Tests, Factory Acceptance Tests (FAT) and Site Acceptance Tests (SAT).

10. Information to be Provided by Respondents

The information to be provided by Respondents to a Request for Proposal include, without limitation:

a. Completed Technical Schedule under section 11 of this document

b. Registration status of the Respondent, or proposal to register, under Chapter 2 of the NER;

c. Relevant experience of the Respondent in relation to the provision of the proposed solution, e.g. a Memorandum of Understanding (MoU) of a connection agreement between the Respondent and the relevant Network Service Provider allowing for the delivery of the proposed solution;

d. A description of the equipment to be used to provide the proposed solution and its capabilities;

e. Configuration, concept footprint layout and electrical single line diagram with sufficient rating information of the proposed solution;

f. Complete PSCAD and PSSE models, ratings and parameters of the proposed solution and its control systems for Energy Queensland to facilitate assessment of the network and network participant impacts. These models (irrespective of registration status) must conform to the AEMO Power System Model Guidelines. Model accuracy staging will at minimum require an initial model and a final validated (post commissioning model). This is sometimes referred to as an R1 and R2 validated model;

g. Relevant documentation as agreed with Ergon Energy to demonstrate that the proposed solution is able to provide both Volt-var control and NPS balance as set out under the Technical Requirement section. This includes applicable Volt-var and NPS regulator block diagrams for evaluation purposes.

h. Relevant documentation as agreed with Ergon Energy that demonstrate the technical capability, performance and response (i.e. QV) of the proposed solution before, during and after a network fault event;

i. Relevant previous test records demonstrating the capability of the system and equipment to provide the proposed solution;

j. Relevant maintenance records and planned maintenance for the proposed system and equipment;

k. Information on overload capability and control modes e.g. voltage or reactive power control modes;

l. Relevant technical information of equipment, subsystems and systems used in the proposed solution:

    a. Primary plant;

b. Secondary systems – monitoring, control, protection and SCADA equipment and systems;
c. Auxiliary equipment and systems.

m. Information of proposed solution's overvoltage and undervoltage schemes (both control and protection) and associated settings;

n. Relevant information on cyber security safeguard practices and applicable cyber security frameworks for the proposed solution;

o. Information of the proposed solution's harmonic and interharmonic emissions up to the 100th order over the full operating range, including single phase control limits;

p. A list of technical departures and alternative proposals for the specified requirements that the proposed solution cannot meet. A full explanation must also be supplied together with any alternative proposals;

q. Relevant information of the Power System Monitoring Equipment as per the specific performance levels;

r. Information of the start-up, controlled shut-down and emergency shut-down sequences;

s. Details of the proposed solution's self-diagnosis capability as per the fundamental requirements;

t. Reliability, Availability and Maintainability (RAM) calculation of the proposed solution;

u. The loss assessment of the proposed solution for evaluation purposes;

v. Control and protection Systems reports, including typical operational settings of the open loop and close loop control system strategies to efficiently control Volt-vars at the connection points.

w. A table of all protection trips (whether triggered internally or externally to the proposed solution) and shall indicate which trips are to be controlled in a step-less manner, and which are to be instantaneous.

x. Designed system service life, warranty details and technical support.

11. Technical Schedules for RFP Evaluation

11.1 Technical Schedule A - Specific Performance Levels

Item	Description	Compliance / Departures / Alternative Offers
11.1.1	Capability of reactive power range at connection point – 0.9 - 1.1 pu voltage, frequency 49.75 to 50.25 Hz	
	Inductive, Continuous	

	Capacitive, Continuous	
11.1.2	Capability for system to be easily expanded in the future if required	
11.1.3	Redundancy of system design	
11.1.4	Be capable, on receipt of appropriate input signals, of changing its output from fully inductive to fully capacitive	
11.1.5	Capability of continuous uninterrupted operation during and following a system voltage disturbance e.g. a load reduction event	
11.1.6	Black-start capability	
11.1.7	Availability (*) $\% \text{ Availability} = \frac{\text{Total Time system is able to Perform Specific Performance Levels}}{\text{Total Time Period}}$	
11.1.8	Maximum percentage Downtime (**) $\% \text{Downtime} = \frac{\text{Total Downtime}}{\text{Total Time Period}} \times 100$ also, $\% \text{Downtime} = 100 - \% \text{ Availability}$	
11.1.9	Maximum time taken to become fully available to provide the service following a circuit breaker reclose event	
11.1.10	System voltage at point of connection	
	a. Nominal system voltage	
	b. Voltage range for continuous operation	
11.1.11	Measurement accuracy for voltage transformers	
11.1.12	Allowable Droop Settings	
	a. Boost	
	b. Buck	
	c. Voltage Dead band	
11.1.13	Required to ride through and operate to the expected performance levels during and following power system voltage, frequency and voltage/current waveform disturbances some of which may occur simultaneously as follows:	
	a. Maximum temporary voltage (30 sec)	
	b. Minimum temporary voltage (30 sec)	
	c. Long term over voltage (1800s)	
	d. Short term over voltage (0.2s)	
	e. A drop in one or more phases of the voltage at the point of connection	
	f. Voltage oscillating (at a frequency of ± 0.25 to ± 2.5Hz)	

	g. Worst asymmetrical faults to be expected at 132 kV bus	
	h. Worst asymmetrical faults to be expected at 66 kV bus	
	i. Worst asymmetrical faults to be expected at 22 kV bus	
	j. Worst asymmetrical faults to be expected at 11 kV bus	
	k. A switching surge of 2.2 pu at the connection point	
	l. A fall in system frequency to 46.5 Hz, with recovery to 46.5 – 52.5 Hz	
	m. High speed auto reclose	
	iii. Dead time	
	iv. Reclaim time	
11.1.14	Maximum allowable reactive power step	
11.1.15	System frequency at point of connection	
	a. Nominal frequency	
	b. Normal control range	
	c. Transient excursions (less than 1 minute)	
	d. Transient excursions (less than 2 minutes)	
11.1.16	Maximum equipment design fault currents	
	a. 132kV	
	b. 66kV	
	c. 22kV	
	d. 6.6kV	
11.1.17	Negative Phase Sequence Control	
	a. Minimum reactive power required, per phase, for individual phase control.	
11.1.18	Power System Monitoring	
	a. Power Quality Measurement System	
	b. High Speed Fault Recorder System (multi-channels)	
	c. Synchrophasor Measurement Units (PMU)	
11.1.19	Maximum allowable sound pressure levels at one metre outside of the perimeter fence	
11.1.20	Maximum Radio Interference Voltage outside of the safety fence.	
11.1.21	Maximum Allowable Electric Field	
	a. Occupational for the whole working day	
11.1.22	Maximum Allowable Magnetic Field	
	a. Occupational for the whole working day	

Table 14: TECHNICAL SCHEDULES A – Specific Performance Levels

11.2 Technical Schedule B - Specific Testing Requirements

Test Items	Test Parameters	Test Methods and assumptions	Recommended Initial and Subsequent Tests
11.2.1	Generation of reactive power		
11.2.2	Absorption of reactive power		
11.2.3	Response times including simulated outputs with trip signals disabled where applicable		
11.2.4	Automatic gain adjustment when voltage instability is detected		
11.2.5	Automatic (PPS) Voltage Regulation		
11.2.6	Automatic Reactive Power Regulation		
11.2.7	Automatic NPS balance		
11.2.8	Ride-through capability as per specified conditions		
11.2.9	Equipment and Transducer calibration tests		
11.2.10	Measurement accuracy tests		
11.2.11	Control system tests		
11.2.12	Protection system tests		
11.2.13	Data and communication network tests		
11.2.14	Voltage step tests		
11.2.15	Voltage Stability tests		
11.2.16	Sustained abnormal voltage tests – high and low voltages		
11.2.17	Sustained reactive power tests – generate and absorb reactive power at specified limits.		
11.2.18	Harmonic Compliance Tests		
11.2.19	NPS balance Tests		
11.2.20	EMC tests		

Table 15: TECHNICAL SCHEDULES B – Specific Testing Requirements

12. Connection Assets

For a non-network option, the provider will need to arrange with Ergon Energy's Customer Connection team for the establishment of suitable connection assets for connection of the VCNSS equipment. These connection costs depend on the system voltage, nominal current, location from existing infrastructure and other aspects defined in the NER such as system strength remediation. Proponents **are asked to exclude these costs in the initial RFP**.

Shortlisted proponents will be required prior to submission of their final offer to give an indication of likely connection costs for their proposal.

13. Submissions from Solution Providers

Ergon Energy invites written submissions to address the identified need in this report from registered participants and interested parties. Ergon Energy will not be legally bound in any way or otherwise obligated to any person who may receive this RFP or to any person who may submit a proposal. At no time will Ergon Energy be liable for any costs incurred by a proponent in the assessment of this RFP, any site visits, obtainment of further information from Ergon Energy or the preparation by a proponent of a proposal to address the identified need specified in this RFP. The RFP is aimed at identifying a technically feasible network or non-network solution that addresses the identified need that has the greatest net economic benefits. However, the selection of the solution provider to implement the preferred option will be done after the conclusion of the RFP and in accordance with Ergon Energy standards for procurement. Submissions in writing are due by 08/11/2023 and should be lodged to demandmanagement@ergon.com.au

14. Next Steps

At the conclusion of the consultation process, Ergon Energy intends to take steps to progress the recommended solution(s) to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvement(s), as necessary. Please note that at the conclusion of the RFP, for Ergon Energy to act on a submission from a non-network proponent, Ergon Energy need to enter into a legally binding contract with that non-network proponent for delivery of the non-network solution within a timeframe satisfactory to Ergon Energy to ensure timely completion of the project.

15. Risks

In the event that during the RFP process there is a catastrophic failure of the SVC at Georgetown or Normanton Ergon Energy may revert to a Network solution or need to consider compressed time frames for this RFP.

16. References

1. STNW3007 - Standard for Climate and Natural Hazard Resilience, Ergon Energy
2. STNW3042 - Standard for Electric and Magnetic Field Design, Ergon Energy
3. STNW3048 - Guide for Reactive Plant in Substations, Ergon Energy
4. STNW3374 - Operational Technology Standard for Data Collection, Ergon Energy
5. STNW3383 - Standard for Intelligent Electronic Devices (IED), Ergon Energy
6. National Electricity Rules, AEMC
7. Modelling requirements, AEMO.
8. Power System Model Guidelines, AEMO.
9. Major Customer Connection Manual, Ergon Energy.
10. Australian Standard AS 60038 – 2012, Standard Voltages, Standards Australia 2012.