IMP/001/017 – Standard for the Application of System Monitoring

1. Purpose

The purpose of this document is to define the standard power system parameters that are to be monitored by Northern Powergrid in order to aid the efficient design, planning and control of the electricity distribution system. It also defines the environmental and other asset related measurements that are used to inform the assessment of power system capacity and capability.

Detail is provided on the parameters that are to be measured, the source of measurement and how those measurements flow through to the Network Management System (NMS) and the relevant data historian. Information on where parameters are used to derive additional measurements is also provided.

This document supersedes the following documents, all copies of which should be destroyed.

Document Reference	Document Title	Version	Published Date
IMP/001/017	Standard for the Application of System Monitoring	2.0	April 2019

2. Scope

The scope of this document covers the standard power system, environmental and asset related parameters to be measured as a minimum at the following locations, the equipment that those measurements are to be taken from and where those parameters are used to derive monitored values:

- Grid supply point substations
- Supply point substations
- Primary substations
- Customer substations
- Ground mounted distribution substations (including switching stations)
- Voltage regulators
- Pole mounted equipment

A use case for each measurement quantity is provided.

Conventions for measured and derived parameters are defined.

Measurements required for local monitoring (without remote indication), protection and control purposes i.e. those that are not required remotely are out with the scope of this document.

This standard shall be applied to all new build sites and on a retrospective basis as part of our smart grid enabling programme. Details of the timescales associated with implementation of this standard can be found in section 3.4.2 for NMS power flow convention and section 3.7.3 for parameter measurement requirements.

2.1. Table of Contents

3. Code of Practice

3.1. Assessment of Relevant Drivers

The key internal business drivers relating to system monitoring are:

Employee commitment	achieved by providing our employees with the information and tools necessary to develop a distribution system that is fit for purpose;
Financial strength	achieved by developing a distribution system that has an efficient overall lifetime cost;
Customer service	achieved by providing accurate information on distribution system power flows to third parties who are interested in a connection to the Northern Powergrid distribution systems;
Regulatory integrity	achieved by designing a robust distribution system that meets mandatory and recommended standards;
Environmental respect	achieved through giving due consideration to the environmental impact of new developments including the impact on distribution system losses and carbon footprint; and
Operational excellence	achieved through improving the quality, availability and reliability of supply through improved monitoring of electrical system parameters.

The external business drivers relating to the application of system monitoring are detailed in the following sections.

3.1.1. Requirements of the Electricity Act 1989 (as amended)[1]

Section 9 (1) of the Electricity Act 1989 (as amended) places an obligation on Distribution Network Operators (DNOs) to develop and maintain an efficient, co-ordinated and economical system of electricity distribution and to facilitate competition in the supply and generation of electricity.

Discharge of this obligation is supported by this document in providing guidance on the application of system monitoring to be used in the planning, design and operation of the distribution system.

3.1.2. The Health and Safety at Work Act 1974

Section 2(1) of The Health and Safety at work Act 1974, states that ‘It shall be the duty of every employer to ensure, so far as is reasonably practicable, the health, safety and welfare at work of all his employees.’ Section 3(1) also states that ‘It shall be the duty of every employer to conduct his undertaking in such a way as to ensure, so far as is reasonably practicable, that persons not in his employment who may be affected thereby are not thereby exposed to risks to their health or safety.’

This is addressed in this Code of Practice by providing guidance on the application of system monitoring thereby contributing towards ensuring assets are operated in a safe manner within their capabilities.

3.1.3. Requirements of The Electricity Safety, Quality and Continuity (ESQC) Regulations

The ESQC Regulations 2002 (No.2665, 31st January 2003) and its amendments impose a number of obligations on the business, mainly relating to safety and quality of supply, the key ones relevant to this Code of Practice being shown below:

[1] The Utilities Act 2000 and The Energy Act 2004 and The Energy Act 2004 (Amendment) Regulations 2012 (No. 2723, 2012)

Reg. No	*Text*	*Application to this Code of Practice*
3(1)(a)	…distributors…shall ensure that their equipment is sufficient for the purposes for and the circumstances in which it is used.	This Code of Practice will contribute to compliance with the ESQC Regulations by detailing the requirements for system monitoring that will inform when equipment is approaching the limits of its capability.
4	Generators, distributors, suppliers and meter operators shall disclose such information to each other as might reasonably be required in order to ensure compliance with these Regulations.	Guidance is given on the application of system monitoring such that information on power flows can be shared in order to ensure the adequacy of third party plant.
17(1)	17.—(1) Subject to paragraph (3), the height above ground of any overhead line, at the maximum likely temperature of that line, shall not be less than that specified by paragraph (2).	Guidance is given on the application of system monitoring such that information on power flows can be used to ensure that clearance infringements are not realised.

3.1.4. Requirements of the Electricity at Work Regulations 1989

Regulation 5 of The Electricity at Work Regulations 1989 states: 'No electrical equipment shall be put into use where its strength and capability may be exceeded in such a way as may give rise to danger' and places obligations on the business relating to the safety of plant and equipment used on the distribution system. It requires that plant and equipment is designed and operated within the limits of its capability.

This is addressed in this Code of Practice by providing guidance on the application of system monitoring, which, in turn can be used to ensure that equipment continues to be operated within its capability.

3.1.5. Requirements of Northern Powergrid's distribution licences

Additional external business drivers relating to the application of system monitoring are the distribution licences applicable to Northern Powergrid Northeast and Northern Powergrid Yorkshire.

The distribution licences also facilitate an incentive scheme for overall network performance known as the Interruption Incentive Scheme (IIS). This scheme is a driver to reduce Customer Minutes Lost (CML) and Customer Interruptions (CI), which may incentivise investment beyond that needed to meet the requirements of Engineering Recommendation P2/6. This requirement is supported by this Code of Practice by providing guidance on the application of system monitoring that will provide key information to ensure that the distribution system is not operated beyond its capability under both system intact and outage conditions.

3.1.6. Requirements of the Distribution Code

As a distribution licence holder, Northern Powergrid is required to have in force, implement and comply with the Distribution Code of Licensed Distribution Network Operators of Great Britain. The Distribution Code covers all material technical aspects relating to connections to and the operation and use of the distribution systems of the Distribution Network Operators.

The Distribution Planning and Connection Code (DPC) specifies the technical and design criteria and the procedures which shall be complied with in the planning and development of the distribution systems. It also applies to users of the distribution systems in the planning and development of their own systems in so far as they affect Northern Powergrid systems.

It also sets out principles relating to the design of equipment and its operating regime. Equipment on the Northern Powergrid systems and on User's systems[2] connected to them shall comply with relevant statutory obligations, international and national specifications and Energy Networks Association technical specifications and standards.

3.2. Key Policy Requirements

The general objective in operating and developing the distribution system is to obtain a simple and robust system having minimum overall cost, taking into account the initial capital investment, system losses and the maintainability and operability over the life of the asset to achieve the required standards of reliability and availability.

This Code of Practice is written to help ensure that key information regarding the electrical parameters that the distribution system is operated and developed in such a way as to:

- discharge the obligation under section 9 of the Electricity Act, and specifically to have due regard to future requirements and network performance;
- ensure that major substations have the capacity to supply our customers under normal and outage conditions; and
- satisfy all other relevant obligations.

3.3. General System Monitoring Requirements

There has been a great deal of work undertaken as part of innovation projects, including Northern Powergrid's Customer Led Network Revolution Project, to determine what system monitoring requirements are required to understand the impact of low carbon technologies (LCT) and permit the operation of a more flexible distribution system. This code of practice supports the findings of this work by setting out Northern Powergrid's standard requirements for system monitoring and the provision of a greater level of network visibility. The equipment necessary to facilitate additional measurements is not to be installed at every network location in the short term; much of the secondary substation and low-voltage monitoring suggestions below shall be installed on a prioritised basis when it is evident that additional monitoring would be economically advantageous e.g. where it suspected that there are power quality issues, areas of high LCT uptake or substations with high utilisation etc.

Informed by findings from the CLNR network monitoring project[3] and other DNO projects the following measurements are required for HV and LV design purposes:

Measurement of:

- Half-hourly or better averages of bi-directional / 4 quadrant real and reactive power for each phase of each transformer at primary substations (note that 10 minute or shorter time averages are required for control purposes).
- Half-hourly or better averages of bi-directional / 4 quadrant real and reactive power for each phase of all feeders at primary substations (note that 10 minute or shorter time averages are required for control purposes).
- Half hourly average voltage of lower voltage busbar at primary substations (note that 10 minute or shorter time averages are required for control purposes).
- Half hourly average or better bi-directional / 4 quadrant real power of each phase of distribution transformers at secondary substations.

[2] DPC 4.4 refers specifically to the requirements of Users Systems.

[3] Customer-Led Network Revolution, Enhanced Network Monitoring Report, CLNR-L232, page 61

- Half hourly average or better voltage of LV busbar at secondary substations.
- 10 minute average bi-directional / 4 quadrant real and reactive power of each phase of feeders of interest at secondary substations. Consideration of direct measurement of neutral currents.
- 10 minute averages of voltage, real and reactive power at key points of each phase of feeders of interest.
- Total Harmonic Distortion (THD) to indicate the presence or otherwise of actual or potential power quality issues.

Where power quality issues are known or suspected to be an issue (e.g. customer reporting flicker, significant proportion of feeder power supplied by inverter connected generation) then obtaining additional measurements will be considered:

- Current Harmonic Distortion: Maximum, Minimum & Average over each 10 minute period for all harmonics up to 50th order + value for Total Harmonic Distortion.
- Voltage Harmonic Distortion: Maximum, Minimum & Average over each 10 minute period for all harmonics up to 50th order + value for Total Harmonic Distortion.

In addition for larger (half hourly metered generator connections) the following measurements are required:

- Half-hourly or better averages of bi-directional / 4 quadrant real and reactive power for each phase at the point of connection (note that 10 minute or shorter time averages are required for Control purposes).

3.4. System Monitoring Convention

It is becoming increasingly important to understand the direction of power flow on the distribution system with the connection of more embedded generation and low carbon technologies leading to uncertainty on the direction of power flow. A company-wide standard for power flow convention is therefore critical in order to ensure that any new monitoring equipment is installed and configured in a consistent manner. The application of a standard power flow convention will improve the understanding of power flows and provide the information necessary to facilitate the move to operating a smarter more flexible electricity system.

3.4.1. Direction of Power Flow[4]

AC current, voltage and apparent power are, by themselves, non-directional quantities and are therefore generally unsigned. The direction of real and reactive power flow depends on the relationship (angle) between the voltage waveform and the current waveform. This relationship can be shown in two ways, as a diagram of voltage and current by angular displacement (as shown in Figure 1) or as a vector diagram (as shown in Figure 2).

[4] Based on Engineering Recommendation G100, Technical Guidance for Customer Export Limiting Schemes, Appendix F.

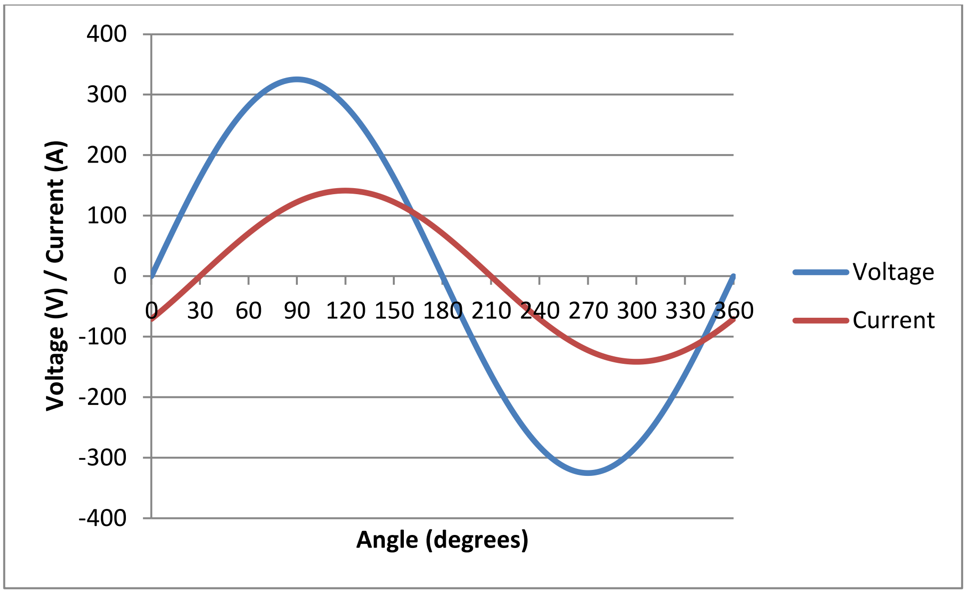


Figure 1 Current & Voltage Waveforms - Current Lagging Voltage by 30°

NB: A complete cycle (i.e. 360°) has a duration of 20ms where the frequency is 50Hz.

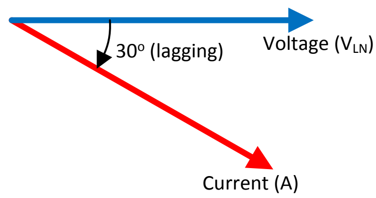


Figure 2 Vector Diagram – Current Lagging Voltage by 30°

Real Power

If the current lags or leads the voltage by 90° or less the real power is positive. If the current lags or leads the voltage by more than 90° the flow of real power is negative.

Reactive Power

If the current lags the voltage more than 0° and by less than 180° the reactive power is positive. If the current leads the voltage by more than 0° and less than 180° the flow of reactive power is negative.

Figure 3 shows the relationship between apparent power, real power and reactive power. In this case both real power and reactive power are positive since the current is lagging the voltage by less than 90°.

Figures 4 and 5 show how the direction of power flow changes as the angle between the current and voltage varies. Four examples are provided:

- I_1 lags the voltage by approximately 20° and, in this case, the Real Power and Reactive Power are both positive (lagging power factor).
- I_2 leads the voltage by approximately 20° and in this case the Real Power is positive and the Reactive Power is negative (leading power factor).
- I_3 lags the voltage by approximately 160° and in this case the Real Power is negative and the Reactive Power is positive (leading power factor).

- I_4 leads the voltage by approximately 160° and so in this case, the Real Power and the Reactive Power are both negative (lagging power factor).

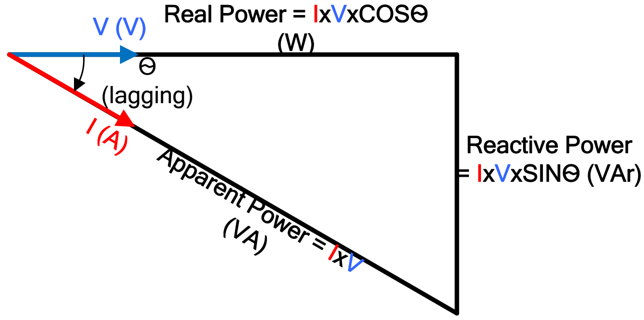


Figure 3 Apparent Power, Real Power and Reactive Power

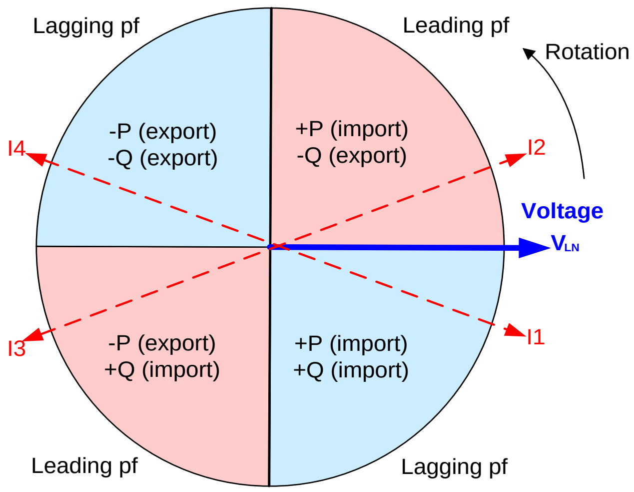


Figure 4 Four Quadrant Diagram – Direction of Power Flow

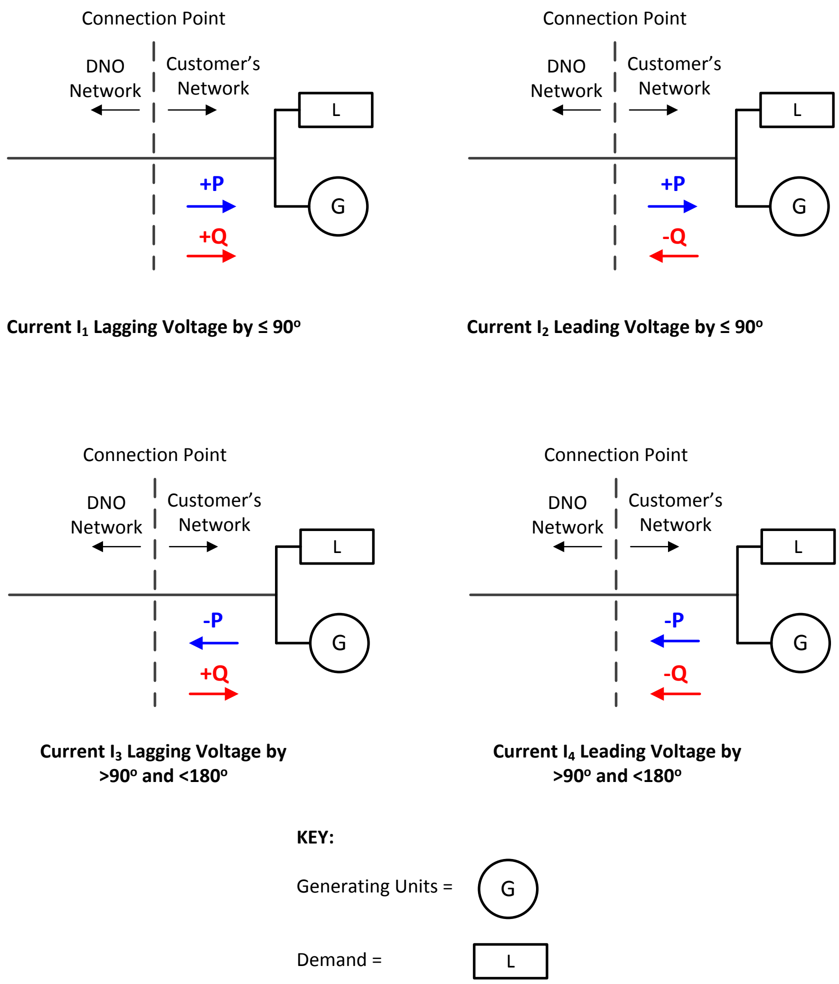


Figure 5 – Power Flow Direction in Relation to Changes in the Angle between Voltage and Current

3.4.2. Standard Power Flow Convention

The standard power flow convention adopted across Northern Powergrid is shown in figure 6 below. Power flowing "down" through the system at a substation site i.e. transformers and outgoing lower voltage feeders, is signed positive and power flowing back "up" through the system is signed negative. On ring systems with multiple circuits in/out, the convention is negative in to the busbar, positive out from the busbar as per the illustration in figure 6 below. Note that the arrows in figure 6 relate to the arrows in NMS, which are static and DO NOT change direction and dictate the positive direction of power flow i.e. where a current or power measurement is signed negative, power is flowing in the opposite direction to the arrow:

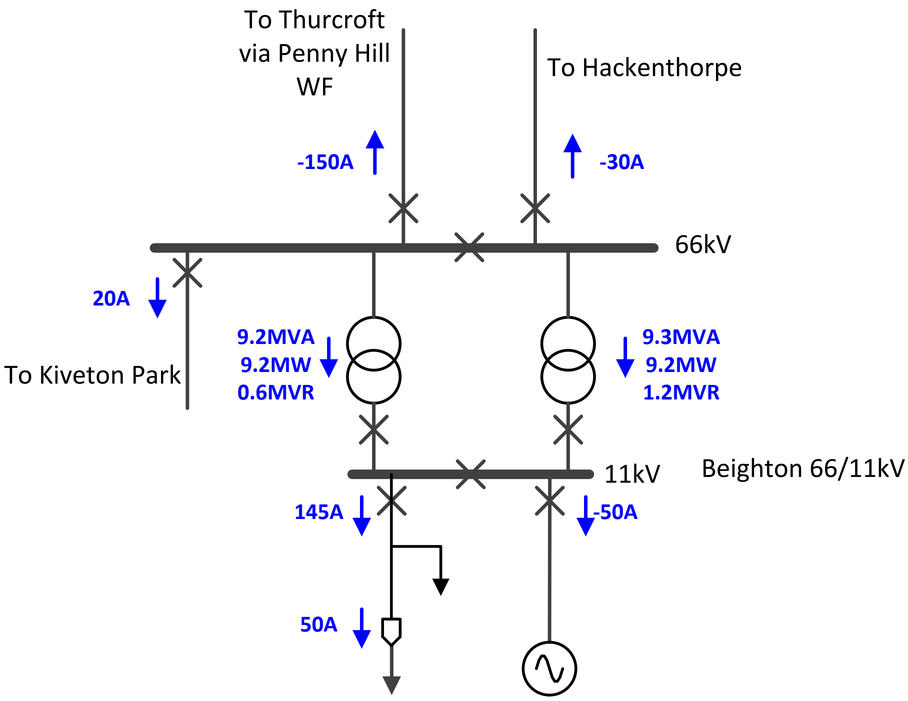


Figure 6 – Power Flow Convention at a Substation Site and 66kV ring[5]

Network re-configuration on a permanent basis that includes alteration of circuits (movement of open points) containing pole mounted auto reclosers with directional power flow indication will need to be re-dressed accordingly in NMS to ensure that power flow direction will be represented appropriately.

At a customer interface the measurements will be represented as per figure 7 below. In this case the customer's site has a mix of generation and load and is capable of either drawing power from or exporting power to Northern Powergrid's system. In the example in figure 7, the customer is exporting power and the illustration reflects that that will be seen in NMS and the signing convention that will be reflected in the data historian which is presently the Plant Information (PI) system.

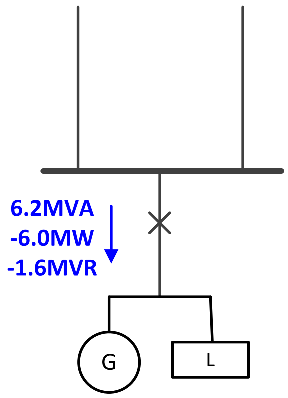


Figure 7 - Power Flow Convention at a Customer Site

[5] Feeder loadings are for illustrative purposes only; the remaining demand on the substation would be shared among the remaining feeders, which are not shown.

The move to a standardised power flow convention in NMS in both the Northeast and Yorkshire will take time and the existing conventions in NMS shall be moved over to the standardised convention gradually with a target completion date prior to end 2018.

Assigning an indication of direction of current flow on outgoing primary substation feeders in NMS cannot be done unless there is an appropriate voltage reference (to be taken from the voltage selection scheme) used on site and as such this facility will only be available following site-works e.g. post AVC and RTU upgrade as part of the smart grid enabling works. For supply point feeders at 132kV this will require a directional relay instead of the traditional inverse definite minimum time (IDMT) backup scheme that may exist. For radial EHV feeders a directional relay may be required instead of any traditional overcurrent and earth fault or unit protection backup scheme. Rollout will require a strategy for implementation that targets generation dominant sites initially.

Assigning an indication of direction of current flow on 66kV ring systems and similar cannot be done unless there is an appropriate voltage reference used on site and as such this facility will only be available following other site-works that can facilitate this e.g. protection changes, site rebuild etc.

No indication of positive direction of power / current flow in NMS will be available if power / current flow direction is not available at that site i.e. no arrow = magnitude only.

3.5. Granularity of Data

Information from the closedown reports of multiple other DNO innovation projects and CLNR's network monitoring report suggests that 10 minute averages are more than adequate for most design related monitoring requirements. Specifically the CLNR report notes the following:

- For evaluating network performance, 10 minute sampling intervals should be adopted to avoid underestimating voltage impacts.
- There is no significant benefit in adopting shorter sampling intervals, unless input to operational control systems is required.

In addition to the findings in the CLNR network monitoring report, a 10 minute average also aligns with the test method of determining network voltage contained in BS EN 50160:2010, voltage characteristics of electricity supplied by public electricity networks. Furthermore, a move from 30 minute to 10 minute average data provides a significant improvement in the accuracy of losses calculations[6].

Rather than migrate all substation sites from the existing half hourly average sampling intervals to 10 minute averages, these will be migrated on an ad-hoc basis for instance where more detailed design analysis or network control is required e.g. for real-time thermal ratings deployment. This may change in future as our knowledge and experience dictates.

It is worth noting that all primary substations (and above) with a new RTU installed (an RTU that complies with the technical specification for remote terminal units (RTUs) for use at primary substations, NPS/005/002, v1.1) will have the capability to calculate and issue 5 minute averages configurable up to a 60 minute average in one minute steps.

3.6. Measurement Accuracy

Care needs to be taken at primary substations and above, especially on pre circa year 2000 installations with measurement accuracy. Using such measurements for planning / design and control purposes will need to consider that these legacy installations will generally use protection class CT's and VT's with no guarantee of measurement accuracy.

[6] Reference CIRED 24th International Conference on Electricity Distribution, paper 0654, Analysing the Ability of Smart Meter Data to Provide Accurate Information to the UK DNOs.

In general, post circa year 2000, there was a move towards protection class CTs and VTs with a measurement accuracy of class 1.0. Whilst the CLNR monitoring report suggests a move to class 0.5s accuracy class for voltage and current measurements at 10 minute intervals, this shall only be considered for future installations where it is economically justifiable. All new installations shall have CTs and VTs with a measurement accuracy class of at least 1.0.

For HV feeders and LV monitoring equipment the accuracy of measurements may only be guaranteed at lower levels e.g. NULEC PMAR real power measurement guaranteed at class 5.0 and whilst the preference is for class 1.0, it is recognised that manufacturer's standard offerings may have to be adopted.

In addition to the above accuracy requirements, it is worth highlighting the specific importance of phase angle accuracy in relation to its impact on calculating power analogue values. Phase angle accuracy shall generally be better than $\pm 1^{o}$, although it is recognised that manufacturer's standard offerings may have to be adopted.

It is also worth being aware that the relays themselves used to create analogue measurements will also introduce a small error into the final recorded analogue.

3.7. Measurement Flows from Site

This section provides a brief overview of the measurements that are retrieved from most existing substation and customer sites followed by the future requirements for monitoring at these sites. The future monitoring requirements are set out in a series of measurement flow diagrams that can be found in appendix 1, which detail the source of each measurements and how each one flows through to both NMS and the data historian (PI).

3.7.1. Existing Parameter Monitoring at Primary Substations and Above

The following half hourly average measurements are typically already available in the Company data historians:

At a substation level:

- Substation apparent power (kVA)
- Substation power factor (pf)

At a transformer level:

- Active power (kW, limited directional capability)
- Reactive power (kVAr, limited directional capability)
- Apparent power (kVA)
- Power factor (pf)
- Red-blue voltage (Volts)
- Individual phase currents (amps, one phase only in the Northeast)
- Phase angle (degrees, Yorkshire only)

At an outgoing feeder level:

- Yellow or red phase current (amps, magnitude only)

In the Northeast there are some additional environmental related measurements such as:

- Ambient temperature (^{o}C)
- Wind speed (m/s)

NMS generally displays the above information on a half hourly average basis with the capability to provide a spot value on poll. Additional measurement values are also available in NMS such as transformer temperatures that are not currently stored in the current data historians.

3.7.2. Existing Parameter Monitoring at Customer Sites

In Northern Powergrid Yorkshire the majority of information held on customer site measurements is held in the Durabill system where data is held on energy consumption and / or export for:

- Active energy (kWh)
- Reactive energy (kVArh)

Limited customer data can be found in the legacy Northern Powergrid Yorkshire PI system from any installed substation RTUs at those sites, with more data available for the Northern Powergrid Northeast in the legacy LIPP system. Metering data associated with customers that are half hourly metered via Durabill or Settlements will be available in the new PI system for all generators at all voltage levels and for all demand customers at all voltage levels apart from those LV system customers not supplied via a dedicated feeder.

3.7.3. Parameter Measurement Requirements

The future monitoring requirements are set out in a series of measurement flow diagrams that can be found in appendix 1, which detail the source of each parameter measurement and its flow through to both NMS and the relevant data historian (PI or iHost) as per table 1 below:

Measurement Requirements	Appendix	Implementation
New grid supply point substations (GSPs) and GSPs where the distribution system switchboard is to be replaced that also have a modern RTU	1A	Now
New primary and supply point substations	1B	Now
Existing primary substations retrofitted with new automatic voltage control (AVC) relays and new remote terminal units (RTUs)	1C	Now
New EHV / 132kV customer connections	1D	Now
Secondary HV system voltage regulators, new build and retrofit	1E	Sites to be identified by Smart Grid Implementation Unit
Secondary HV system pole mounted auto reclosers, new build and retrofit NULEC's	1F	Sites to be identified by Smart Grid Implementation Unit
Secondary LV system ground mounted distribution substations, new build and retrofit	1G	Sites to be identified by Smart Grid Implementation Unit
New HV or LV generator connections	1H	To be determined by Smart Grid Implementation Unit
New primary substation (and above) environmental monitoring requirements	1J	To be determined by Smart Grid Implementation Unit

Table 1 - Parameter Measurement Flow Diagrams

For the future monitoring requirements laid out in appendices 1E and 1F, the detailed design standard is to be developed and then initially rolled out as part of our smart grid enabling investment, there is some further work to do to determine the implementation strategy. The development of selection criteria for the on-going deployment of 1G is in progress as part of the smart grid enabling investment programme. While a specification for environmental monitoring equipment required by appendix 1I requires development, it is important to state what those future monitoring requirements are now in order to develop the solution that will facilitate the eventual transmission, storage and use of the environmental monitoring data.

3.7.3.1. Primary (and above) System Monitoring

Measurement flow diagrams 1A, B, C and D relate to the primary system and above with a colour co-ordinated key designating calculated, unchanged and "pass through" measurements. The additional notes field provides useful additional detail, but are not exhaustive. The requirements for measurements in appendix 1C relate to retrofitted sites, where the term retrofit means part of the existing AVC and RTU replacement programme through the Revenue = Incentives + Innovation + Outputs, Electricity Distribution 1 (RIIO ED1) period.

The measurement requirements detailed in these measurement flow diagrams are generally available from more modern electronic relays and modern RTUs; however there are some particular and additional cases that warrant specific mention:

Power Quality Monitoring

Ideally total harmonic distortion (THD) information would be measured on all primary substation sites and above and provided for use in PI for interrogation; however this is not yet practical due to capability limitations associated with the power quality monitor Northern Powergrid currently uses, inaccuracies associated with existing VT's used and the data sample rates upon event detection. It is Northern Powergrid's intention to pursue the capability to feed the THD data held on-site in power quality monitoring equipment in to a data historian (currently either PI or iHost). The additional requirements for harvesting THD information should be considered when designing telecommunications infrastructure for such sites.

Fault Disturbance

Ideally, fault disturbance information would be measured on all primary substation sites and above and provided for use in a data historian for interrogation; however this is not yet practical due to capability limitations associated disturbance recorder Northern Powergrid currently uses and the data sample rates upon event detection. It is Northern Powergrid's intention to pursue the capability to interrogate data held on-site in disturbance recorders remotely in reaction to a triggering event such as a fault or customer enquiry. The requirements for remote interrogation of such equipment should be considered when designing telecommunications infrastructure for such sites. The opportune installation of VT's with specific harmonic windings shall be considered as part of other works that may result in an efficient installation.

Tap Position and Tap Count

Ideally tap position would be reported upon change and an incremental tap count total submitted. Such capability shall be investigated with the manufacturers of the modern AVC relays. Until such capability is available, an interim solution such as a whole number rounded half hourly average for tap position passed through NMS to PI and cumulative tap count storage and reset capability within NMS will be investigated, which could then be used to inform tapchanger maintenance requirements.

Environmental Factors

The environmental measurement requirements stated in appendix 1I shall only be applied to new and existing substations where there is a need to utilise the short-term ratings of assets, use real-time thermal ratings or for detailed design assessment purposes. The environmental measurements detailed in appendix 1I shall be taken initially as a half hour average from a weather station, whilst recognising that more granular data may be required for assets with shorter thermal inertia time constants.

- Wind speed (m/s)
- Wind direction
- Humidity (switchroom and external)
- Solar gain

- Daylight
- Ambient temperature (switchroom and external, ^oC)
- Rainfall (mm)
- Substation electrical demand (heating, lighting, pumps, motors etc, kWh)
- Soil temperature (^oC)

Fault-level Monitoring

Fault-level monitors should be deployed in accordance with the Code of Practice for the Management of Short Circuit Currents in Distribution Switchgear, IMP/001/104.

3.7.3.2. Secondary HV and LV System Monitoring

Measurement flow diagrams 1E, F and G relate to secondary HV and LV system monitoring requirements. These will be dependent upon equipment capability to provide and cost to acquire both initially and on an on-going basis. This is a relatively new and developing area of system monitoring. Deviations from this standard may be permitted as it is recognised that the standard may not be achievable due to equipment and / or cost limitations. Additional detail supporting the measurement requirements of appendix 1G for secondary distribution substation monitoring can be found in NPS/007/021, Technical Specification for Secondary Distribution Substation Monitoring Systems.

The data historian for LV system data is at present the Nortech iHost solution, while HV system will use the PI system.

3.7.3.3. Generator Connection Monitoring Requirements

In addition to the general power flow related monitoring requirements contained in appendix 1D and 1H, there are some additional requirements relating to power quality and disturbance recording for all generators >200kVA installed capacity. IMP/001/014, Code of Practice for the Protection of Distribution Networks requires the installation of power quality logging equipment at sites where the generator installed capacity exceeds 200kVA. It is Northern Powergrid’s preference to supply and install the equipment that provides both power quality monitoring and fault disturbance information as part of the generation connection project; however there may be instances in which the customer wishes to supply and install the equipment and present Northern Powergrid with the necessary signals. In these latter circumstances Northern Powergrid shall provide the customer with the functional specification for such monitoring equipment, the data items to be provided and the means of transferring the data to Northern Powergrid e.g. measurement values, accuracy, sensitivity, sampling rates, communications protocols, error handling etc. Power quality and fault disturbance information, whether sourced from Northern Powergrid or customer’s equipment, shall be stored in iHost for use in the investigation of system disturbances.

It is anticipated that, in future, there will be a case for monitoring technology specific generator parameters e.g. wind speed and direction at a wind farm, % charge of battery storage, solar gain at a solar farm etc. The additional requirements for transmitting these generator specific parameters, power quality and fault disturbance and information to the iHost system should be considered when designing telecommunications infrastructure for generation sites.

3.7.3.4. Independent Distribution Network Owner (IDNO) Monitoring Requirements

For all major new connections to IDNO’s, i.e. via EHV points of connection or new primary substations, Northern Powergrid requires the same power flow related monitoring that is specified in appendix 1B. For example, where the point of connection is at EHV on the outgoing feeders of a supply point substation, the power flow measurements should be taken from the outgoing feeder protection relay and these shall have directional capability. If the connection is provided via a new primary substation and the point of connection is on the outgoing HV feeders the requirements for system monitoring are the same as those in appendix 1B. For other connections further down the distribution system, the appropriate power flow monitoring requirements shall be taken from appendix 1G. It is recognised that not all IDNO connections will conform to the standard connections described above. It is also recognised that it may not be reasonably and economically practicable to source the power flow measurements stated in the appendices; however, the general ethos of power measurement requirements in the appendices shall be used to determine the parameters that are reasonably and economically viable to source from IDNO connections. It is not necessary to source any additional non-power flow related parameters from IDNO connections.

3.8. Analogue Use Cases

Use cases for all future measurements can be found in the following appendices:

Use case	Appendix
Primary system measurement (and above)	2A
Secondary HV system measurement	2B
Secondary LV system measurement	2C

Table 2 - Analogue Use Cases

The main purpose of the use cases is to inform the future requirements for telecommunications and IT networks, such as infrastructure capacity, determining which telecommunications path each parameter should use e.g. primary, secondary, tertiary or on-site only and the data storage requirements.

Each use case provides a high-level description of the measurement use from the different system locations alongside an indication of the non-functional communications requirements[7] in terms of:

- Criticality – a characteristic associated with the level of success of data transfer between systems
- Reliability – an indication of the communications systems immunity from errors that prevent data delivery
- Ideal resolution - the level of granularity that is required to perform the required tasks adequately.

Each of the non-functional communications requirements are split into multiple classes in line with the following tables:

Criticality

Data Delivery Criticality	Class
High Criticality – Requires end-to-end confirmation of successful delivery.	A
Medium Criticality - No end-to-end confirmation is required, but the receiver can detect the loss of data.	B
Non-Critical - Loss of data due to a failed transfer is acceptable with no further action required.	C

Table 3 – Criticality Classification

[7] Based on Analysis Mason report for Western Power Distribution, “Global appraisal of Smart Grid telecoms solutions”, final draft, project NEXUS, 5 May 2017, Ref 2006986-162.

Reliability

Reliability	Level	Class
Extremely low probability of data transfer errors	>99.9%	A
Low probability of data transfer errors	< 99.9 but > 98%	B
Probability of errors occurring exist but only temporary	< 98%	C

Table 4 – Reliability Classification

Latency and bandwidth can also be considered in terms of non-functional communications requirements; however the latency requirements for measurements can be much more relaxed than those of control and alarm functions. As a general rule, any control action that should result in an associated measurement change requires such a change to occur within 10 seconds e.g. opening a feeder circuit breaker via NMS should result in the measurement associated with that feeder changing to zero in NMS within 10 seconds of the action being implemented. Similarly, if a refresh of a particular measurement is requested in NMS, that refresh should take no longer than 10 seconds and for ALL measurements that may be combined in one refresh request This 10 second rule shall be implemented where practical to do so considering the criticality of the control, alarm and indication.

Where a class A criticality or reliability has been assigned to any measurement value it is proposed that these measurements should use primary SCADA telecommunications infrastructure to reach NMS. All other measurements may be transmitted over either secondary or tertiary telecommunications channels.

3.9. Assumptions

Bandwidth requirements need to be considered in conjunction with the telecommunications requirements of other services, protocols to be used, packet sizes etc. and the collective impact understood.

The communication and storage of system monitoring information shall be done in accordance with the Information Classification policy and considered to be internal data until it is shared with external parties, in-line with our Distribution Code responsibilities.

4. References

4.1. External Documentation

Reference	Title
CLNR-L232	Enhanced Network Monitoring Report

4.2. Internal Documentation

Reference	Title
IMP/001/014	Code of Practice for the Protection of Distribution Networks
IMP/001/104	Code of Practice for the Management of Short Circuit Currents in Distribution Switchgear
NPS/005/002	Technical Specification for Remote Terminal Units (RTUs) for use at Primary Substations
NPS/007/021	Technical Specification for Secondary Distribution Substation Monitoring Systems

4.3. Amendments from Previous Version

Reference	Amendments
Whole Document	Format updated to current CDS Template
Whole Document	Changed classification from Internal to Public

5. Definitions

Term	Definition
ASC	Arc suppression coil
AVC	Automatic voltage control
CAPE	Control and protection enclosure
CLNR	Customer-led network revolution
CML	Customer minutes lost
CT	Current transformer
DETC	De-energised tap changer
DG	Distributed generator
DSO	Distribution System Operator
EHV	EHV refers to voltages greater than or equal to 33kV and less than 132kV. For the purposes of this document 25kV traction supplies are also considered to be EHV.
FFI	Fault flow indicator
Grid supply point	Any substation that transforms transmission voltage (i.e. 275 or 400kV) to any distribution system voltage, usually 132kV or EHV.
HV	HV refers to voltages greater than 1000V and less than 33kV. For the purposes of this document 25kV traction supplies are considered to be EHV.
iHost	iHost (Nortech's data storage platform)
LCT	Low carbon technology
LIPP	Load Information for Planning Purposes
LV	LV refers to voltages up to and including 1000V
NMS	Network Management System
OHL	Overhead line
OLTC	On-load tap changer
PI	Plant Interface
Primary substations	Any substation that transforms EHV/HV, EHV/EHV, 132kV/EHV or 132kV/HV.
Secondary substations	Any substation that transforms HV/LV.
THD	Total harmonic distortion
VT	Voltage transformer

6. Authority for Issue

6.1. CDS Assurance

I sign to confirm that I have completed and checked this document and I am satisfied with its content and submit it for approval and authorisation.

		Date
Liz Beat	Governance Administrator	17/11/2021

6.2. Author

I sign to confirm that I have completed and checked this document and I am satisfied with its content and submit it for approval and authorisation.

Review Period - This document should be reviewed within the following time period.

Standard CDS review of 3 years?	Non Standard Review Period & Reason	
Yes	Period: n/a	Reason: n/a
Should this document be displayed on the Northern Powergrid external website?		Yes

		Date
Ian Fletcher	Programme Manager	17/11/2021

6.3. Technical Assurance

I sign to confirm that I am satisfied with all aspects of the content and preparation of this document and submit it for approval and authorisation.

		Date
Mark Callum	Smart Grid Development Engineer	17/11/2021

6.4. Authorisation

Authorisation is granted for publication of this document.

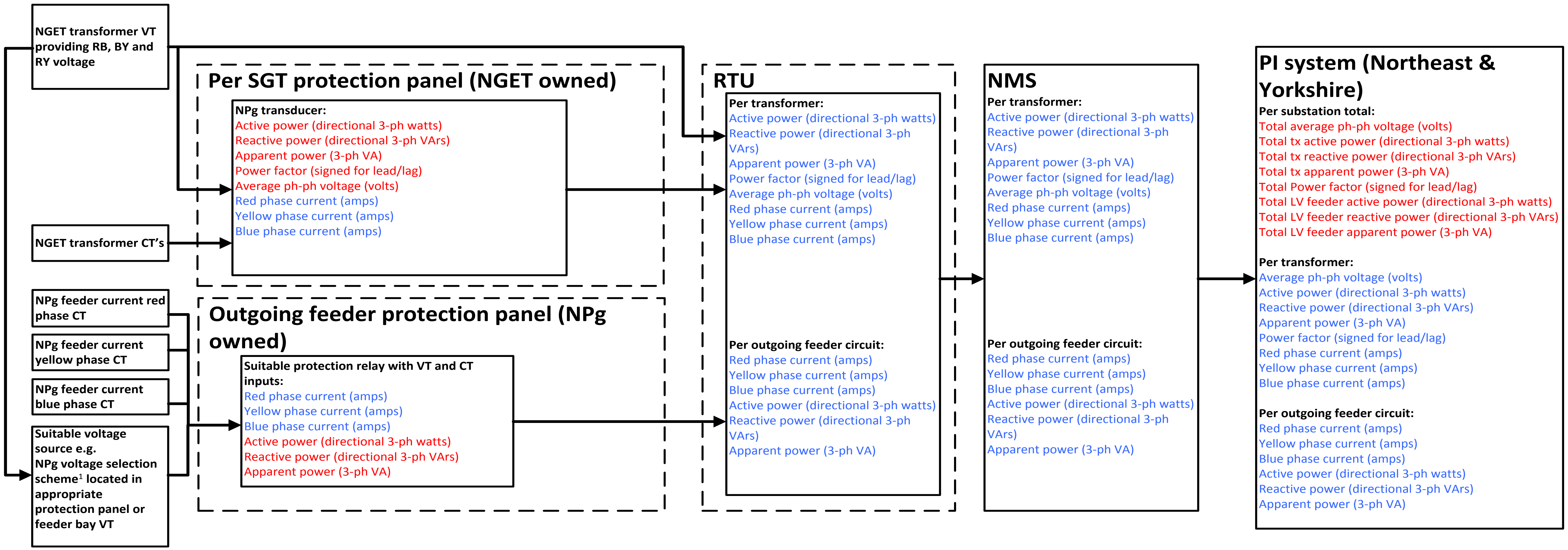
		Date
Mark Nicholson	Head of Smart Grid Implementation	17/11/2021

Appendix 1A – Grid Supply Point Substation Measurement Flow Diagram

Applicable to all new grid supply points (GSPs) and GSPs where switchboard replacement is to be undertaken and a modern RTU is installed.
All flows are one way from site to NMS/PI in this chart and relate to electrical analogue requirements only.

Notes:

Red text denotes a calculated value including change of sign for direction or is an internal setting value
Blue text denotes a value that is "unchanged" as received (including inferred from mA or voltage signal)
Green text denotes that a value is NOT shown in NMS, but passed through.



Key:

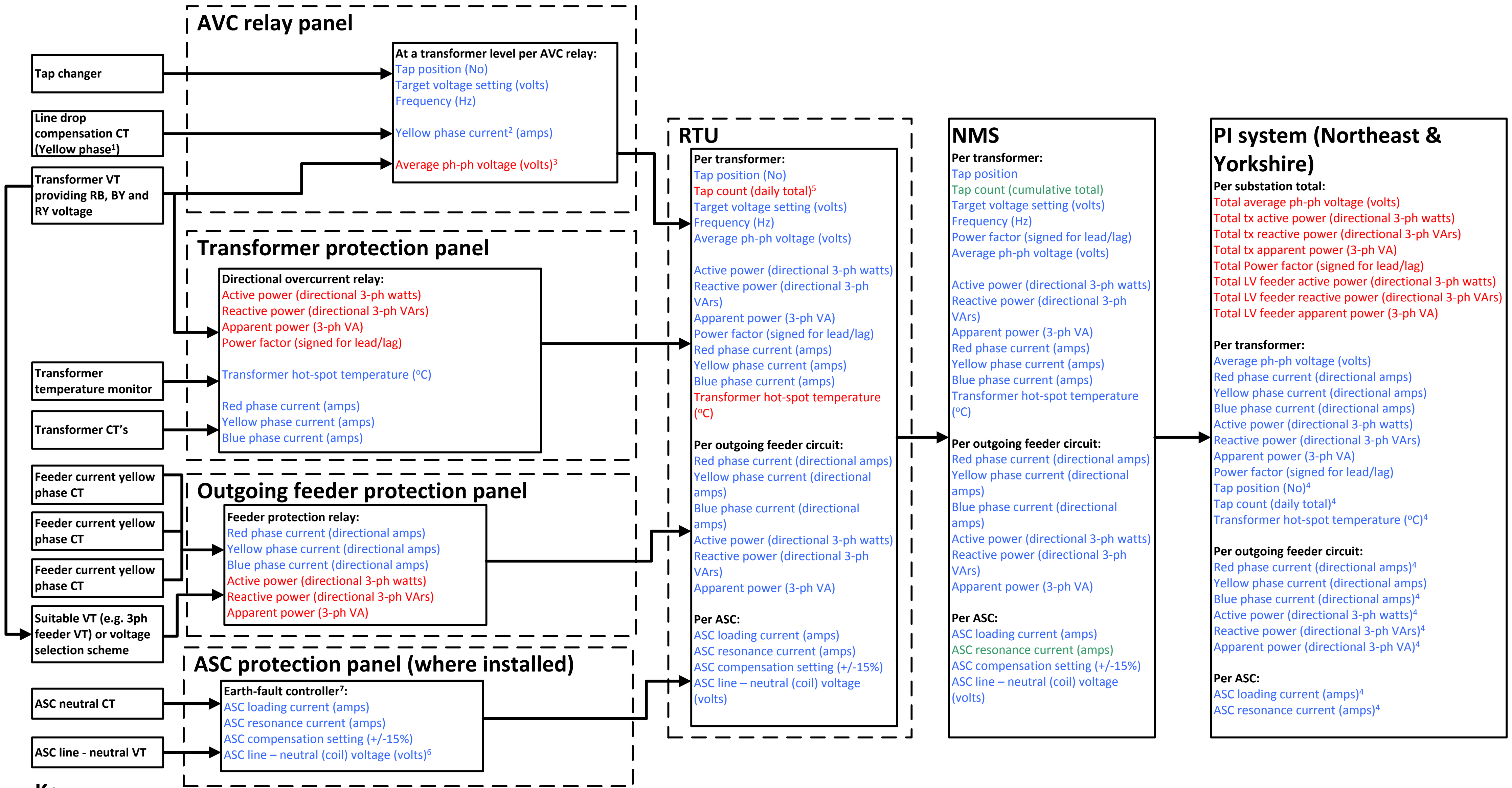
1. There will be an element of bespoke design required based on the busbar configuration at the grid supply point and the number of SGT's. The voltage selection scheme itself should be located in the most appropriate protection panel and voltage signals distributed to outgoing feeder panels as appropriate. If a feeder bay has its own VT for example for distance protection, then it is acceptable to use this as the source of the voltage signal for use in the calculation of power analogues.

Appendix 1B – New Build Substation Measurement Flow Diagram

Applicable to all new substation sites with a modern AVC relay and RTU.
All flows are one way from site to NMS/PI in this chart and relate to electrical measurement requirements only.

Notes:

Red text denotes a calculated value including change of sign for direction or is an internal setting value
Blue text denotes a value that is "unchanged" as received (including inferred from mA or voltage signal)
Green text denotes that a value is NOT shown in NMS, but passed through.

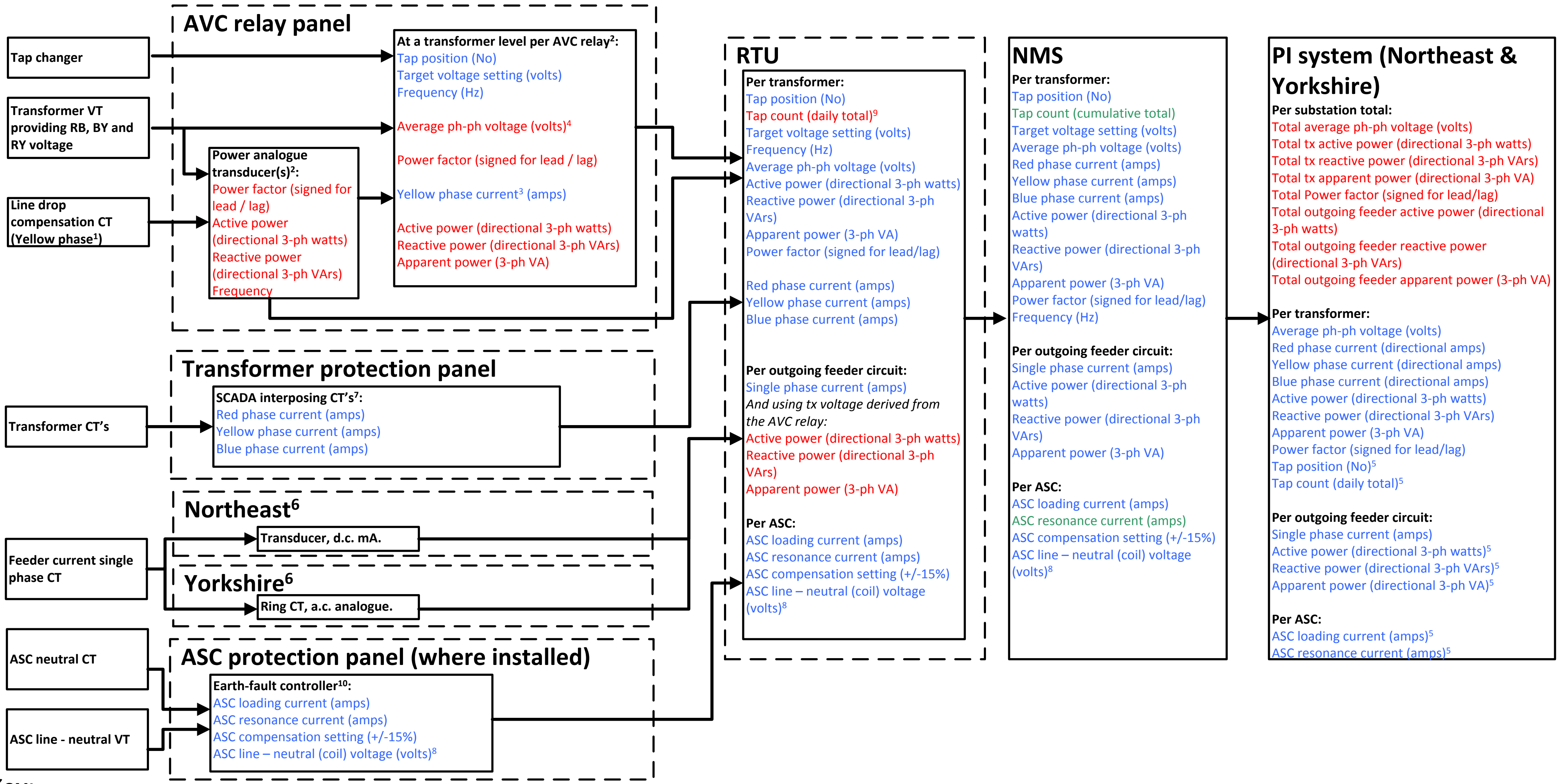


Key:

1. LDC CT generally on yellow phase but may be on red or blue phases.
2. AVC relay does not report analogue amps (3-ph currents are provided from the tx protection panel). LDC CT input to AVC is for AVC function, NOT SCADA.
3. The voltage reported by the Supertapp SG relay is set-up to provide the average of the voltage inputs to the relay and as such is not "R-B volts". Both the Tapcon and Microtapp relays report all three average line voltages individually.
4. Not currently part of the standard PI template for a substation.
5. Not currently available from any AVC relays used in NPg. Derived by the RTU from each change of tap position.
6. The rise in coil voltage will be seen by the RTU, but most likely not polled by NMS (Northeast) in time to see a fault as the time from fault inception to bypass circuit closure is about 5 seconds. There is therefore no value in passing a half hourly average through to PI.
7. Where functionality exists these analogue values should be harvested where practical to do so.

Appendix 1C – Existing Substation Retrofitted with AVC and RTU Measurement Flow Diagram

Applicable to all existing sites that have been retrofitted with a modern AVC relay and RTU.
All flows are one way from site to NMS/PI in this chart and relate to electrical measurement requirements only.
Notes:
Red text denotes a calculated value including change of sign for direction or is an internal setting value
Blue text denotes a value that is “unchanged” as received (including inferred from mA or voltage signal)
Green text denotes that a value is NOT shown in NMS, but passed through.



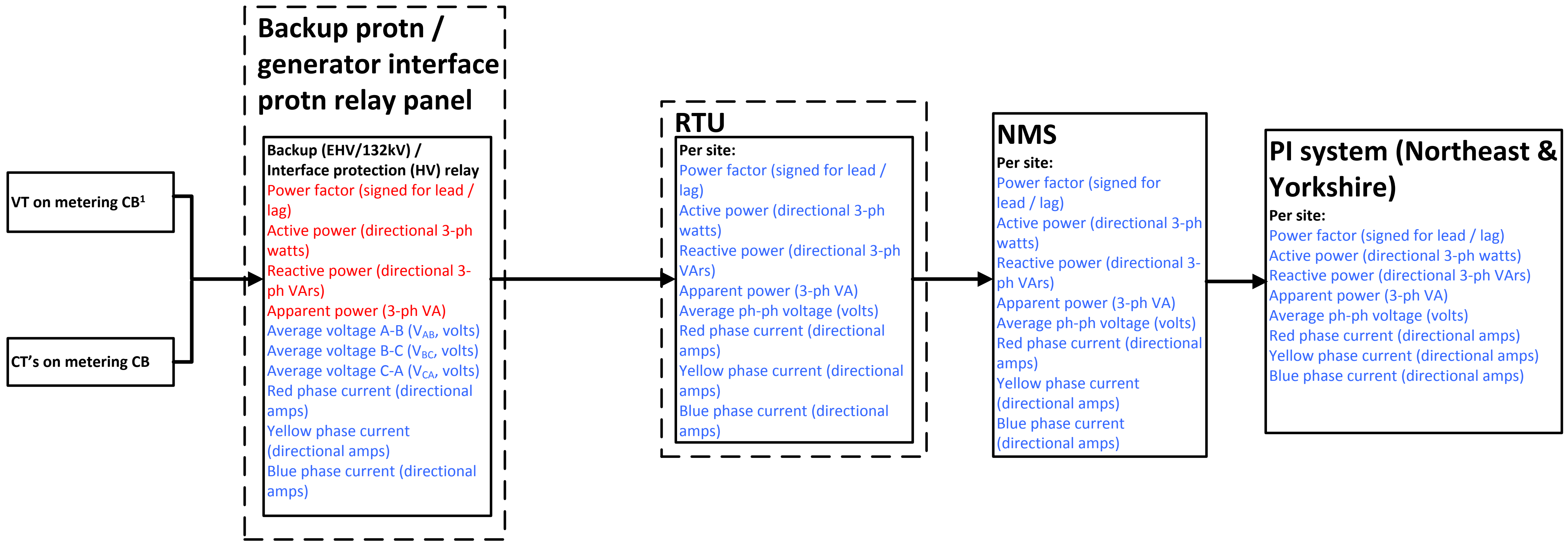
Key:

1. LDC CT generally on yellow phase but may be on red or blue phases.
2. Pf, MW, MVAr and frequency are only available from transducers for Microtapp installations where mA/V signals are passed to the RTU and interpreted as analogue values. For Supertapp SG and Tapcon relays ALL of these values are all available and shall be taken from the relay itself.
3. AVC relay does not report analogue amps (3-ph currents are provided from the tx relay panel). LDC CT input to AVC is for AVC function, NOT SCADA.
4. The voltage reported by the Supertapp SG relay is set-up to provide the average of the line voltage inputs to the relay and as such is not “R-B volts”. Both the Tapcon and Microtapp relays report all three average line voltages individually.
5. Not currently part of the standard PI template for a substation.
6. Reflects sites with electromechanical relays. On some substation sites with modern relays it may be possible to use the feeder protection relay to calculate all three phase current and power analogues on a per outgoing feeder basis by using the transformer VT analogues available via the voltage selection scheme as per appendix 1A. This method should be used if available and shall also be deployed where it is economically justifiable to do so as part of other works.
7. In the Northeast area only red phase current is typically available to flow through to NMS and PI.
8. The rise in coil voltage will be seen by the RTU, but most likely not polled by NMS (Northeast) in time to see a fault as the time from fault inception to bypass circuit closure is about 5 seconds. There is therefore no value in passing a half hourly average through to PI.
9. Not currently available from any AVC relays used in NPg. Derived by the RTU from each change of tap position.
10. Where functionality exists these analogue values should be harvested where practical to do so; a limited dataset may only be available at some sites.

Appendix 1D – New EHV and 132kV Customer Connections Measurement Flow Diagram

Applicable to all new EHV and 132kV customer connections i.e. any demand and/or generation connection.
All flows are one way from site to NMS/PI in this chart and relate to electrical measurement requirements only.

Notes:
Red text denotes a calculated value including change of sign for direction or is an internal setting value
Blue text denotes a value that is "unchanged" as received (including inferred from mA or voltage signal)



Key:
1: Metering code of practice 3 (connections where rated circuit capacity ≤10MVA) allows the use of the metering VT winding for purposes other than metering provided the additional burden is within limits specified therein. For metering code of practice 2 (connections where rated circuit capacity >10MVA and ≤100MVA), the metering VT requires a dedicated winding for metering purposes and an additional winding is required for protection / instrumentation purposes. Metering code of practice 1 (connections where rated circuit capacity >100MVA) requires a dedicated metering VT winding for "main" and a separate winding for "check", but the "check" winding can be shared with protection and/or instrumentation functions, provided the burden and accuracy limits are not compromised. A suitable VT winding is required in all cases.

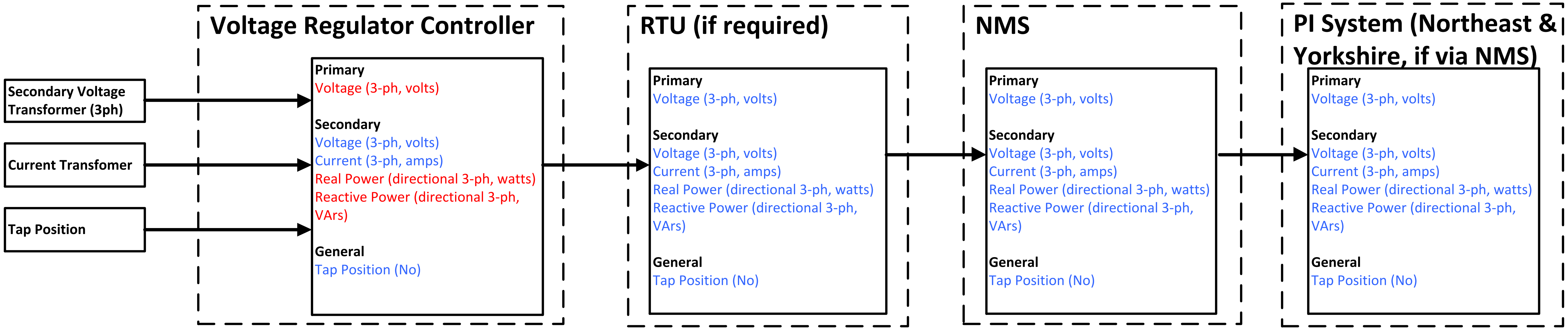
Appendix 1E – Proposed Voltage Regulator Monitoring Flow Diagram

Proposed voltage regulator monitoring at all new installations and retrofit installations where functionality has been enabled

Notes:

Red text denotes a calculated value including change of sign for direction or is an internal setting value

Blue text denotes a value that is "unchanged" as received (including inferred from mA or voltage signal)



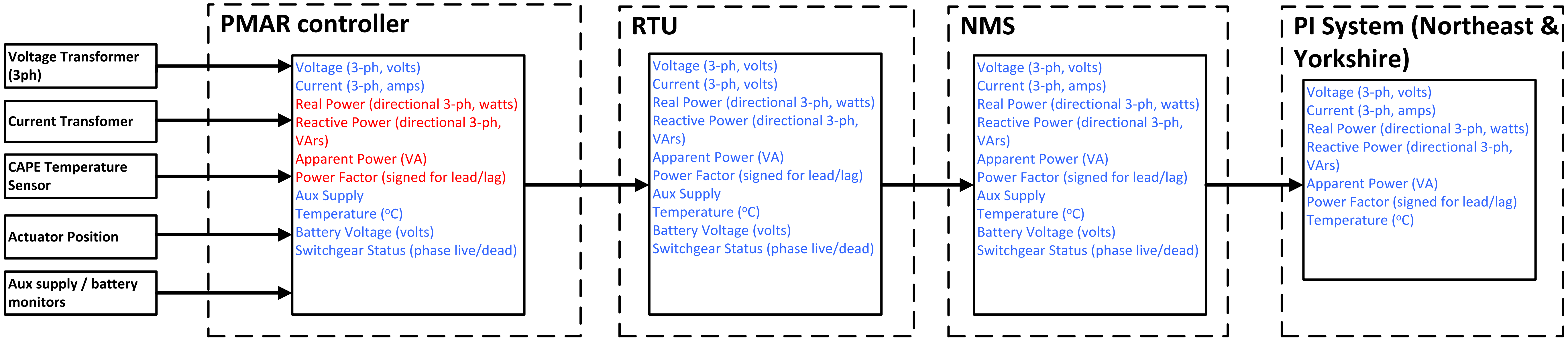
Appendix 1F – Proposed Pole Mounted Auto Recloser Monitoring Flow Diagram

Proposed pole mounted auto recloser monitoring for all new installations and retrofit NULECs

Notes:

Red text denotes a calculated value including change of sign for direction or is an internal setting value

Blue text denotes a value that is "unchanged" as received (including inferred from mA or voltage signal)



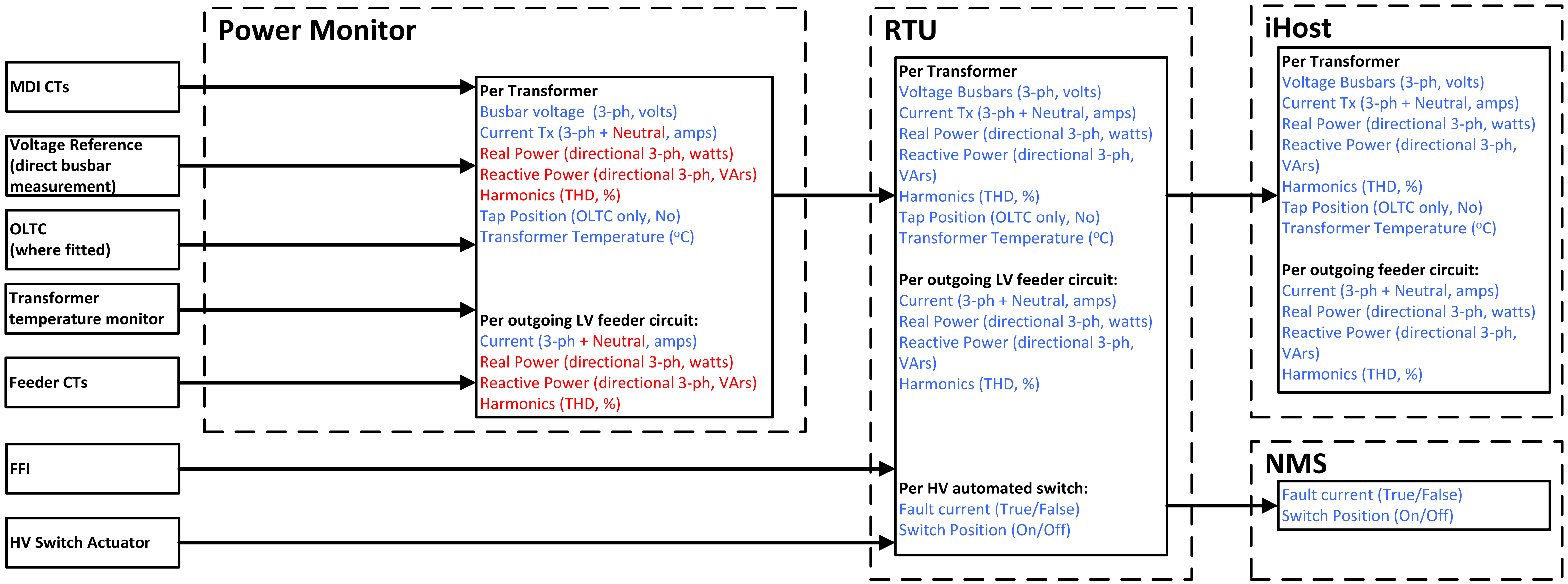
Appendix 1G – Proposed Ground Mounted Distribution Substation Monitoring Flow Diagram

Proposed new ground mounted distribution substation monitoring and substations retrofitted with monitoring equipment

Notes:

Red text denotes a calculated value including change of sign for direction or is an internal setting value

Blue text denotes a value that is “unchanged” as received (including inferred from mA or voltage signal)

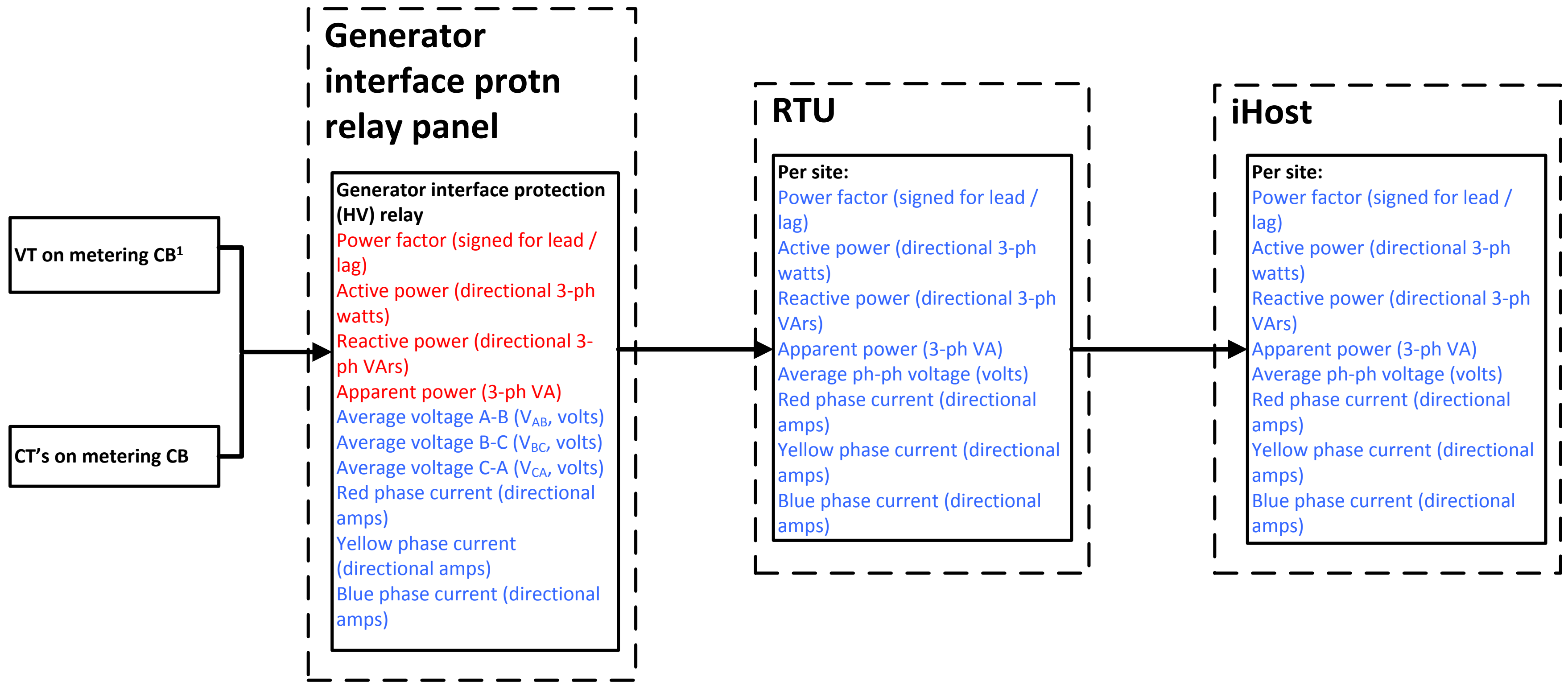


Appendix 1H – Proposed New HV/LV Generator Connections Monitoring Flow Diagram

Applicable to new HV and large LV customer generator connections that are half hourly metered.
All flows are one way from site to iHost in this chart and relate to electrical measurement requirements only.

Notes:

Red text denotes a calculated value including change of sign for direction or is an internal setting value
Blue text denotes a value that is “unchanged” as received (including inferred from mA or voltage signal)



Key:

1: Metering code of practice 3 (connections where rated circuit capacity ≤10MVA) allows the use of the metering VT winding for purposes other than metering provided the additional burden is within limits specified therein. For metering code of practice 2 (connections where rated circuit capacity >10MVA and ≤100MVA), the metering VT requires a dedicated winding for metering purposes and an additional winding is required for protection / instrumentation purposes.

Appendix 1I – Proposed Environmental Measurements for New Primary Substations (and above) Monitoring Flow Diagram

Applicable to all new primary substation sites and above. Also applicable to existing sites where a subset of this environmental data exists to be retrieved once the substation RTU has been replaced.

Notes:

Blue text denotes a value that is "unchanged" as received (including inferred from mA or voltage signal)

Environmental data:
Wind speed (m/s)
Wind direction
Humidity (switchroom and external)
Solar gain
Daylight
Temperature (switchroom and external, °C)
Rainfall (mm)
Substation electrical demand (heating, lighting, pumps, motors etc, kWh)
Soil temperature (°C)

→

RTU
Wind speed (m/s)
Wind direction
Humidity (switchroom and external)
Solar gain
Daylight
Temperature (switchroom and external, °C)
Rainfall (mm)
Substation electrical demand (heating, lighting, pumps, motors etc, kWh)
Soil temperature (°C)

→

iHost
Wind speed (m/s)
Wind direction
Humidity (switchroom and external)
Solar gain
Daylight
Temperature (switchroom and external, °C)
Rainfall (mm)
Substation electrical demand (heating, lighting, pumps, motors etc, kWh)
Soil temperature (°C)

Appendix 2A – Primary Distribution System Analogue Use Case

	Primary Network				
	Primary	**Supply Point**	**Criticality**	**Reliability**	**Resolution**
Tap Position/count					
- Planning/design	Input to power system model	Input to power system model	B	C	Report change of state on poll.
- Planning/design	Maintence Planning	Maintence Planning	B	C	Report change of state on poll.
- Control	Voltage Alarm investigation	Voltage Alarm investigation	A	B	Report change of state on poll.
- Control	Planning pickup	Planning pickup	A	B	Report change of state on poll.
- Future (Control)	Tap stagger	Tap stagger	A	B	Report change of state on poll.
- Future (Control)	Set Target voltage	Set Target voltage	A	B	Report change of state on poll.
- Future (Control)	Power flow balancing by tap pos'n adj	Power flow balancing by tap pos'n adjustme	A	B	Report change of state on poll.
Voltage					
- Planning/design	Input to power system model	Input to power system model	B	C	10minute average.
- Control	Voltage validation	Voltage validation	A	B	10minute average and on poll.
- Control	Voltage Alarm investigation	Voltage Alarm investigation	A	B	10minute average and on poll.
- Control	Planning pickup	Planning pickup	A	B	10minute average and on poll.
- Future	Tap stagger	Tap stagger	A	B	10minute average and on poll.
- Future	Set Target voltage	Set Target voltage	A	B	10minute average and on poll.
- Future	Power flow balancing by tap pos'n adj	Power flow balancing by tap pos'n adjustme	A	B	10minute average and on poll.
Real and reactive power					
- Planning/design	Input into power system model	Input into power system model	B	C	10minute average.
- Planning/design	Understand Power Flow direction	Understand Power Flow direction	B	C	10minute average.
- Control	Understand Power Flow direction	Understand Power Flow direction	A	B	10minute average and on poll.
- Future	Future losses control	Future losses control	B	B	30minute average.
- Future	Future DSO Var Control	Future DSO Var Control	A	B	10minute average and on poll.
Apparent Power					
- Planning/design	Input into power system model	Input into power system model	B	C	10minute average.
- Control	Planning pickups	Planning pickups	A	A	10minute average and on poll.
- Control	Thermal Alarm investigation	Thermal Alarm investigation	A	A	10minute average and on poll.
Current					
- Planning/design	Input into power system model	Input into power system model	B	C	10minute average.
- Control	Thermal Alarm investigation	Thermal Alarm investigation	A	A	10minute average and on poll.
Phase Angle/power factor					
- Planning/design	Verification of operating condition	Verification of operating condition	B	C	10minute average.
- Planning/design	Setting DG PF	Setting DG PF	B	C	10minute average.
- Control	Verification of operating condition	Verification of operating condition	A	B	10minute average and on poll.
- Future	Dynamic DG PF setting	Dynamic DG PF setting	A	B	10minute average and on poll.
Harmonic (THD)					
- Planning/design	Identification of high harmonic sites	Identification of high harmonic sites	C	C	30minute average.
Environmental*					
- Control	Alarm investigation	Alarm investigation	C	C	10minute average.
- Planning/design	Transformer bespoke rating	Transformer bespoke rating	C	C	10minute average.
- Planning/design	OHL bespoke rating	OHL bespoke rating	C	C	10minute average.
Transformer temperature					
Planning/ design	Transformer bespoke rating	Transformer bespoke rating	B	C	10minute average.
Control	Thermal alarm investigation	Thermal alarm investigation	B	B	10minute average.
ASC**					
- Planning/design	ASC utilisation		C	C	30minute average.
- Control	ASC utilisation		C	C	30minute average.
- Planning/design	Fault type identification		C	C	On event. 1 second average.

*Ambient Temp, Wind Speed, Solar Radiation

** Loading current, resonance current, compensation setting, coil voltage

Appendix 2B – Secondary HV Distribution System Analogue Use Case

	Secondary HV network				
	Voltage Regulator	**PMAR**	**Criticality**	**Reliability**	**Resolution**
Tap Position/count					
- Planning/design	Input to power system model	N/A	C	C	Report on change of state.
- Planning/design	Maintence Planning	N/A	C	C	Report on change of state.
- Control	Voltage Alarm investigation	N/A	C	C	Report on change of state.
- Control	Planning pickup	N/A	C	C	Report on change of state.
- Future (Control)	Voltage services	N/A	C	C	Report on change of state.
Voltage					
- Planning/design	Input to power system model	Input to power system model	C	C	10minute average.
- Control	Voltage indication	Voltage indication	B	B	10minute average and on poll.
- Control	Planning pickup	Planning pickup	B	B	10minute average and on poll.
Real and reactive power					
- Planning/design	Input into power system model	Input into power system model	C	C	10minute average.
- Planning/design	Understand Power Flow direction	Understand Power Flow direction	C	C	10minute average.
- Control	Understand Power Flow direction	Understand Power Flow direction	C	C	10minute average and on poll.
Apparent Power					
- Planning/design	Input into power system model	Input into power system model	C	C	10minute average.
- Control	Planning pickups	Planning pickups	C	C	10minute average and on poll.
Current					
- Planning/design	Input into power system model	Input into power system model	C	C	10minute average.
- Control	Current indication	Current indication	B	B	10minute average.
Phase Angle/power factor					
- Planning/design	Verification of operating condition	Verification of operating condition	C	C	10minute average.
- Planning/design	Setting DG PF	Setting DG PF	C	C	30minute average.
- Control	Verification of operating condition	Verification of operating condition	C	C	10minute average.
- Future	Dynamic DG PF setting	Dynamic DG PF setting	C	C	10minute average.
Harmonic (THD)					
- Planning/design	Identification of high harmonic site	Identification of high harmonic sites	C	C	30minute average.
Environmental*					
- Planning/design		OHL bespoke rating	C	C	10minute average.

*Ambient Temp, Wind Speed, Solar Radiation

Appendix 2C – Secondary LV Distribution System Analogue Use Case

	Secondary LV network				
	GM S/S OLTC	**GM S/S DETC**	**Criticality**	**Reliability**	**Resolution**
Tap Position/count					
- Planning/design	Input to power system model	N/A	C	C	Report on change of state.
- Planning/design	Maintence Planning	N/A	C	C	Report on change of state.
- Future (Control)	Voltage services	N/A	C	C	Report on change of state.
Voltage					
- Planning/design	Input to power system model	Input to power system model	C	C	10minute average.
- Control	Network configuration checks	Network configuration checks	C	C	10minute average and on poll.
Real and reactive power					
- Planning/design	Input into power system model	Input into power system model	C	C	10minute average.
- Planning/design	Understand Power Flow direction	Understand Power Flow direction	C	C	10minute average.
Apparent Power					
- Planning/design	Input into power system model	Input into power system model	C	C	10minute average.
Current					
- Planning/design	Input into power system model	Input into power system model	C	C	10minute average.
- Planning/design	Identify unbalance (neutral I)	Identify unbalance (neutral I)	C	C	10minute average.
- Control	Network configuration checks (tx only)	Network configuration checks (tx only)	C	C	10minute average.
Phase Angle/power factor					
- Planning/design	Verification of operating condition	Verification of operating condition	C	C	10minute average.
- Planning/design	Setting DG PF	Setting DG PF	C	C	30minute average.
Harmonic (THD)					
- Planning/design	Identification of high harmonic sites	Identification of high harmonic sites	C	C	30minute average.
Environmental*					
- Planning/design	Transformer bespoke rating	Transformer bespoke rating	C	C	10minute average.
Transformer temperature					
Planning/ design	Transformer bespoke rating	Transformer bespoke rating	C	C	10minute average.

*Ambient Temp, Wind Speed, Solar Radiation