Technical Requirements for the Connection of a MW-scale PV Array with Battery Storage to an 11kV Feeder in Queensland

Vince Garrone 1, Mark Hibbert 2, Jason Mayer 2, Craig Froome 1, Shane Goodwin 3, Paul Meredith 1

1Global Change Institute, The University of Queensland, St Lucia Campus, Queensland 4072 Australia
2Aurecon Australasia, 32 Turbot St, Brisbane, Queensland 4001 Australia
3School of ITEE, The University of Queensland, St Lucia Campus, Queensland 4072 Australia

v.garrone@uq.edu.au

Abstract

The University of Queensland (UQ) is in the process of adding a 3.275 MW photovoltaic research plant to 124 kW of existing PV at its Gatton campus, 80 km west of Brisbane. The plant is funded under the Federal Government’s Education Investment Fund (EIF) program in conjunction with the utility-scale AGL Solar PV Project at Nyngan and Broken Hill in NSW. Comprised of fixed, single axis and dual axis arrays, the plant is scheduled for completion in early 2015.

As part of the PV plant approvals process, UQ had to negotiate a Customer Connection Contract with Energex, the local Distribution Network Service Provider (DNSP). Although adopting Energex’s standard commercial terms and conditions, the agreement required specific technical conditions to be met to reassure the utility that power quality would not be compromised. Given the considerable powers available to utilities when it comes to imposing connection conditions, it was essential during negotiations to focus on the technical facts of any contentious issues and seek mutually beneficial solutions. As it transpired, these negotiations required comprehensive technical analysis, careful attention to detail and persistence over an extended period before a mutually acceptable agreement was reached.

The result is a workable solution that will satisfy the DNSP’s obligations to its other customers and allow UQ to realise its research and generation objectives. This paper provides a discussion on some of the key issues that arose and may provide a guide for future connection agreements for large PV installations on distribution networks.

1. Introduction

The Gatton campus is rural and is supplied by a radial 11 kV feeder from the Gatton 33/11 kV Energex zone substation. Site voltage is controlled by a pair of 200 A 11 kV series voltage regulators arranged in an open delta configuration about 4.5 km from the substation. The Point of Common Coupling (PCC) is 1 km downstream of these regulators and the campus substation is a further 2 km away. Other low voltage (LV) customers are supplied by the remainder of 11 kV feeder.

With many rural customers supplied from the same feeder, it was critical that the feeder voltage be managed within acceptable limits. The relatively significant 3.4 MW of total proposed PV generation (Table 1) compared to the modest PCC fault level of only 41 MV.A underscored utility concerns. Similarly, obligations to manage power factor, harmonics and voltage fluctuations had to be unambiguously quantified to set design objectives and allow compliance to be verified.
The actual technical conditions were negotiated over a period of approximately 7 months. Although there were over 20 initial contentious clauses, many of these were quickly resolved. Some challenges included addressing regulations which were framed with rotating machines in mind, rather than inverter energy systems. Other difficulties revolved around the nuances associated with collocating load with similarly sized generation on a single point of supply. Some of the key performance requirements described in detail below were more difficult to resolve however, and these consumed most of the negotiating period, which was shared relatively equally by both parties.

### Table 1. Photovoltaic Arrays at the UQ Gatton Campus

<table>
<thead>
<tr>
<th>PV ARRAYS</th>
<th>PV PANEL DC RATING</th>
<th>INVERTER AC RATING</th>
</tr>
</thead>
<tbody>
<tr>
<td>Three fixed axis arrays each with 7,200 First Solar 95 W Series 3 CdTe PV panels and one SMA SC720CP inverter</td>
<td>2,052 kW (3 x 684 kW)</td>
<td>2,160 kW (3 x 720 kW)</td>
</tr>
<tr>
<td>A single axis array with 7,200 First Solar 95 W Series 3 CdTe PV panels and one SMA SC720CP inverter</td>
<td>684 kW</td>
<td>720 kW</td>
</tr>
<tr>
<td>A dual axis array with 7,200 First Solar 95 W Series 3 CdTe PV panels, 160 5000HD DEGERtrakrs and one SMA SC720CP inverter</td>
<td>684 kW</td>
<td>720 kW</td>
</tr>
<tr>
<td>A fixed axis array with 1,320 First Solar 95 W Series 3 CdTe PV panels and six SMA Tripower 20000TLEE inverters</td>
<td>125.4 kW</td>
<td>120 kW (6 x 20 kW)</td>
</tr>
<tr>
<td>An existing fixed axis array on the library with 448 Trina TSM 240PC05 240 W PV panels and eight Aurora Trio PVI-12.5-OUTD-AU inverters</td>
<td>107 kW</td>
<td>100 kW (8 x 12.5 kW)</td>
</tr>
<tr>
<td>An existing fixed axis array on Sub0 with 144 Conergy P170M 170 W mono crystalline PV panels and three SMA 8000TL inverters</td>
<td>24.5 kW</td>
<td>24 kW (3 x 8 kW)</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>3,677 kWdc</td>
<td>3,844 kWac</td>
</tr>
<tr>
<td></td>
<td>3.4 MWac nom</td>
<td></td>
</tr>
</tbody>
</table>

### 2. Key Performance Requirements

#### 2.1. Steady State Voltage

##### 2.1.1. Voltage Regulations

S5.2.5.13 of the National Electricity Rules (Rules) [1] places constraints on generating systems to ensure that network voltage is managed appropriately. The Queensland Electricity Regulation [2] imposes constraints by requiring utilities to maintain the 11 kV network within ±5% of the nominal voltage and the LV network within 415 V ± 6%. As no mechanisms are deployed to specifically control the LV, in practice utilities must manage the 11kV to a much tighter band than the 10% range that the Regulations [2] suggest.

##### 2.1.2. Voltage Analysis

Analysis of the network was done internally and by UQ’s consulting engineers, Aurecon. Whilst Aurecon undertook extensive early studies on the network using PSCAD and Paladin...
load flow packages, the radial nature of the network meant that iterative modelling was not required. The university therefore constructed a simple spreadsheet model in Excel around the schematic shown in Figure 1, to provide a sanity check on the more complex calculations and provide additional supporting data.

Figure 1. Radial Distribution Feeder Schematic and Model

Using Excel macros, multiple load/generation combinations were assessed to explore typical, extreme and non-viable operating conditions. Seven loads from 500 kW to 3,000 kW, eight generator outputs from 0 to 3,500 kW and 11 power factors from 0.90 lag to 0.90 lead for each of the load and generating components allowed 6,776 combinations to be evaluated. The results when arranged in a similar manner to Table 2, quickly demonstrated that voltage rise could be controlled to levels only marginally above light load non-generation conditions with allowable leading power factor above 0.90. The key to performance would be in sinking sufficient reactive power to offset any voltage rise associated with generated real power.

Table 2. Feeder Voltage Calculations at the Point of Common Coupling and on Campus, for a sample of the 6,776 Load and Generation Permutations Modelled

<table>
<thead>
<tr>
<th>Load Power (kW)</th>
<th>Load PF</th>
<th>PV Power (kW)</th>
<th>PV PF</th>
<th>Net Power (kW)</th>
<th>Net PF</th>
<th>Net Reactive Direction</th>
<th>ΔV for PCC (%)</th>
<th>ΔV for Campus (%)</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1000</td>
<td>0.90 lag</td>
<td>0</td>
<td>1.00 lag</td>
<td>1000</td>
<td>0.90 source</td>
<td>0.10%</td>
<td>-0.10%</td>
<td>-0.25%</td>
<td>low load leading, no generation, highest permissible voltage w/o gen.</td>
</tr>
<tr>
<td>1000</td>
<td>0.92 lag</td>
<td>0</td>
<td>1.00 lag</td>
<td>1000</td>
<td>0.92 source</td>
<td>0.05%</td>
<td>-0.11%</td>
<td>-0.29%</td>
<td>low load unity PF, high generation - no go zone</td>
</tr>
<tr>
<td>1000</td>
<td>1.00 lag</td>
<td>-3500</td>
<td>0.90 lag</td>
<td>-2500</td>
<td>0.83 sink</td>
<td>0.07%</td>
<td>-0.25%</td>
<td>0.12%</td>
<td>low load lagging, high generation is only marginally higher than maximum delta V for allowable non generation case</td>
</tr>
<tr>
<td>1000</td>
<td>0.92 lag</td>
<td>-3500</td>
<td>0.92 lag</td>
<td>-2500</td>
<td>0.79 sink</td>
<td>0.01%</td>
<td>-0.29%</td>
<td>0.12%</td>
<td>low load lagging, high generation</td>
</tr>
<tr>
<td>1000</td>
<td>0.90 lag</td>
<td>-3500</td>
<td>0.90 lag</td>
<td>-2500</td>
<td>0.76 sink</td>
<td>0.03%</td>
<td>-0.32%</td>
<td>0.15%</td>
<td>high load lagging, high generation</td>
</tr>
<tr>
<td>1500</td>
<td>0.92 lag</td>
<td>-3500</td>
<td>0.92 lag</td>
<td>-2000</td>
<td>0.68 sink</td>
<td>0.07%</td>
<td>-0.36%</td>
<td>0.11%</td>
<td>medium load lagging, high generation</td>
</tr>
<tr>
<td>3000</td>
<td>0.92 lag</td>
<td>-3500</td>
<td>0.92 lag</td>
<td>-500</td>
<td>0.18 sink</td>
<td>0.06%</td>
<td>-1.63%</td>
<td>0.12%</td>
<td>high load lagging, high generation</td>
</tr>
<tr>
<td>3000</td>
<td>0.90 lag</td>
<td>-3500</td>
<td>0.92 lag</td>
<td>-500</td>
<td>0.17 sink</td>
<td>-0.73%</td>
<td>-1.75%</td>
<td>0.17%</td>
<td>high load lagging, high generation</td>
</tr>
<tr>
<td>3000</td>
<td>0.92 lag</td>
<td>-3500</td>
<td>0.90 lag</td>
<td>-500</td>
<td>0.17 sink</td>
<td>0.07%</td>
<td>-1.77%</td>
<td>0.17%</td>
<td>high load lagging, high generation</td>
</tr>
<tr>
<td>3000</td>
<td>0.90 lag</td>
<td>-3500</td>
<td>0.90 lag</td>
<td>-500</td>
<td>0.16 sink</td>
<td>-0.79%</td>
<td>-1.89%</td>
<td>0.19%</td>
<td>high load lagging, high generation</td>
</tr>
<tr>
<td>1500</td>
<td>0.90 lag</td>
<td>-3500</td>
<td>0.90 lag</td>
<td>-2000</td>
<td>0.62 sink</td>
<td>0.07%</td>
<td>-0.56%</td>
<td>0.15%</td>
<td>high load lagging, high generation</td>
</tr>
<tr>
<td>3500</td>
<td>1.00 lag</td>
<td>0</td>
<td>1.00 lag</td>
<td>3500</td>
<td>-1.00 sink</td>
<td>0.17%</td>
<td>0.07%</td>
<td>-1.74%</td>
<td>high load unity PF, no generation</td>
</tr>
<tr>
<td>3500</td>
<td>0.92 lag</td>
<td>0</td>
<td>1.00 lag</td>
<td>3500</td>
<td>-0.92 sink</td>
<td>0.17%</td>
<td>0.08%</td>
<td>-2.02%</td>
<td>high load unity PF, no generation</td>
</tr>
<tr>
<td>3500</td>
<td>0.90 lag</td>
<td>0</td>
<td>1.00 lag</td>
<td>3500</td>
<td>-0.90 sink</td>
<td>0.17%</td>
<td>0.13%</td>
<td>-3.13%</td>
<td>high load lagging, no generation, lowest permissible voltage w/o gen.</td>
</tr>
</tbody>
</table>

2.1.3. Voltage Performance Negotiations

Figure 2 maps how the utility’s requirements evolved during negotiations. Initially, the university was offered generation access only below 0.98 pu (gold curve) but without any
guarantees where the utility would maintain the PCC voltage below the 1.05 pu statutory limit (red curve). In early July, the draft agreement raised the upper limit to 1.00 pu but precluded generation below 0.95 pu (green curve) which would have barred the university’s generators from supporting low voltage conditions. Although this restriction was quickly lifted at the university’s suggestion, the utility still resisted including its own operational voltage targets in the agreement and for the rest of July, the margin between UQ’s maximum proposed operating voltage and the utility’s uncommitted maximum voltage were too slim to be achievable given the accuracies of instrumentation and typical phase unbalance. A final commitment in early August to include the utility’s limits in the document broke the impasse. The utility’s agreement to list its own voltage management requirements in the agreement alongside the restrictions placed on the university was an important outcome in assuring a degree of equality in the agreement. As Figure 2 shows, the final agreement limits the maximum voltage at the PCC to 1.01 pu, or 1% above 11 kV. However, the utility’s stated control range of 0.9875 pu ± 0.0125pu means that it has a responsibility to manage the voltage to no higher than 1.00 pu (11.00kV). The establishment of both sets of criteria should ensure that any breaches of the desired voltage can be attributed to the appropriate party, particularly given that generation will not be continuous. The 1% margin should provide ample leeway for the university’s reactive compensation control algorithm.

![Figure 2. UQ Gatton Campus Network Connection Agreement Point of Common Coupling Voltage Limit Negotiation History](image)

### 2.2. **Power Factor**

#### 2.2.1. **Power Factor Regulations**

The Electricity Regulation 36(d)(ii) requires customers to maintain power factor as measured over a 30 minute period to within the limits stated in S5.3.5 of the Rules [1]. The Rules state that on an 11 kV network, power factor shall be maintained between 0.90 lagging to 0.90
leading. Some flexibility is granted at low loads less than 30% of the maximum demand, where the utility has the discretion to allow power factors below 0.90.

2.2.2. Power Factor Analysis

Likely power factor outcomes at the Gatton campus were calculated by combining the university’s extensive load data records for 2013 with the predicted PV output. The latter was forecast on an hourly basis over a full year using the National Renewable Energy Laboratory’s PV Watts Calculator [8]. Unsurprisingly for a site with generating capacity closely matched with its peak demand, the resultant site power factor was predicted to be below 0.90 for about 40% of the year as indicated by Figure 3. For net loads below 1.2 MW, in excess of 90% of the time was forecast to exhibit a combined power factor below 0.90. An innovative solution was required.

![Gatton Sub0 PF Distribution (With 5 x 684 kW Arrays)](image)

**Figure 3.** UQ Gatton Campus Power Factor Distribution during 2013 if 3.4MW PV Array was Operating at 0.90 PF Sinking

2.2.3. Power Factor Negotiations

Initially, utility representatives did not fully accept that a generator and a matching load could each operate with power factors of better than 0.90 and combine to produce a power factor well below this figure. Relying on the utility’s discretion under the Rules was therefore a risky option. The university pointed out that if it had two points of supply; one for generation and one for load, it could easily meet standard power factor requirements but that additional supply points were to no-one’s benefit. Finally, after much discussion, the discretion allowable under the Rules was manifested in the utility’s acceptance that the university would manage the load and generation power factors independently, each within the 0.90 lag to lead limits required by the Rules.

The novel solution allows a strict control regime to be implemented and non-compliances to be readily identified without having to rely on arbitrary discretion. Further, with the addition of batteries, it will lend itself to the dynamic assignment of the battery connection to either the
load or generation power factor calculation, depending on whether the battery is charging or discharging.

2.3. Harmonics

2.3.1. Harmonics Regulations

S5.3.8 and S5.1.6(a) of the Rules requires the utility, under the automatic access standard, to “allocate emission limits no more onerous than the lesser of the acceptance levels determined in accordance with either of the stage 1 or the stage 2 evaluation procedures defined in AS/NZS 61000.3.6:2001” [3]. Although this standard on emission limits for distorting load has been superseded since 2012 by a Technical Report of the same name, it is still referenced by the Rules and accordingly used by the utilities to set harmonic limits.

2.3.2. Harmonics Analysis

Using the harmonic test report data for the 720 kVA SMA inverters and network source impedances, Aurecon and the university calculated the maximum harmonic voltages impressed upon the PCC due to the PV installation. These revealed that the inverter contribution to the voltage Total Harmonic Distortion (THDv) could be as high as 0.7% to 0.8% at the PCC. The largest individual contributors were the 5th and 25th harmonic respectively, with the latter understood to be just above the inverter low pass filter cutoff frequency.

Contrasted against these calculations, harmonics measurements on site in early 2013 revealed existing levels of THDv at about 0.7%. This was expected to be slightly improved when the campus was switched to an alternate spur off the same feeder following some conductor augmentation. When this work was completed though, levels of THDv remained substantially unchanged, with levels of 0.8% to 0.9% measured during tests. To determine the source of the emissions, the university conducted further measurements with the whole campus de-energised. These THDv measurements of between 0.7% and 0.8% established that existing network issues were the main contributor to any harmonics on the system and demonstrated that contract limits needed to be fairly set to avoid future contention.

2.3.3. Harmonics Negotiations

AS/NZS 61000.3.6:2001 allows 3 stages (or options) for allocating emission limits for voltage distortion. Stage 1 is a simple evaluation, stage 2 evaluates limits relative to actual network characteristics and stage 3 accepts higher emission levels. Apportionment of emission levels to customers under the stage 2 approach adopted by the utility is assessed according to several methods of varying complexity and rigour. Of these, the utility elected to use the first approximation described in Appendix D2.2 of the standard [3] in conjunction with the recommended planning levels of HB264-2003 [5].

The utility initially provided emission limits for each harmonic and a proposed limit for THDv. Where the assessment produced individual harmonic emissions less than 0.1%, these were set to 0.1% to provide a more realistic ceiling as per the standard. The 0.55% proposed for the THDv however, was much less than the 1.13% that corresponded to the sum of the individual limits proposed. The THDv had been set to 130% of the 5th harmonic limit as per a minor note in the standard which does not appear in TR IEC 61000.3.6:2012 [6].

The harmonic analysis of the inverters had earlier indicated that some proposed individual harmonic limits could be breached and the low THDv of 0.55% would certainly be breached if each individual limit was approached. Although verbal discussions with the utility had previously suggested some flexibility towards harmonics excesses, the proposed low emission
limits, comparably high existing harmonic measurements at site and the flexibility of the standard to utilise less conservative approaches encouraged the university to pursue more appropriate limits. Fortunately this yielded a positive response from the utility and the individual harmonic limits and THDv were raised after revising the conservative assumptions originally used in the assessment. The calculated THDv corresponding to the individual limits were increased to 2.2% and the allowable THDv was raised to an acceptable 1.33%.

2.4. Voltage Fluctuations

2.4.1. Voltage Fluctuation Regulations
S5.3.7 and S5.1.5(a) of the Rules requires the utility, under the automatic access standard, to “allocate emission limits no more onerous than the lesser of the acceptance levels determined in accordance with either of the stage 1 or the stage 2 evaluation procedures defined in AS/NZS 61000.3.7:2001” [4]. As per the harmonics situation, this standard was also superseded in 2012 by a Technical Report.

2.4.2. Voltage Fluctuation Analysis
Aurecon undertook a number of studies at the early stages of the project and identified that the power up ramp rate in the SMA Sunny Central inverters is configurable. With an allowable active power change gradient from 1%/s to 100%/s, concern about inverter induced voltage fluctuations due to cloud bursts was substantially reduced. A lower ramp rate could easily resolve this, particularly if reactive compensation largely offset any generation voltage rise attributed to increased active power.

Sudden power reductions cannot be ramped down by the inverters without storage, however the physical size of the site automatically alleviates this issue. With approximate east-west and north-south dimensions of about 700 m and 300 m respectively, all but the fastest clouds will take from at least 10 to 20s to transit the site. The inverters’ contributions to voltage fluctuations are therefore expected to be quite low.

2.4.3. Voltage Fluctuation Negotiations
The utility set basic flicker emission limits on the university from AS/NZS 61000.3.7:2001 as follows:

- Short-term limit $E_{Psti} = 0.35$ and
- Long-term limit $E_{Pphi} = 0.25$

Similarly, the utility prescribed limits on voltage changes per hour as per Table 7 of AS/NZS 61000.3.7:2001. Both sets of requirements were readily accepted by the university as reasonable and achievable.

3. Other Technical Issues

3.1. Queensland 5MW derogation
Some of the requirements proposed in the first draft of the technical agreement were based on S5.2 clauses in the Rules. There is a derogation in clause 9.37.2(e) however that provides Small Generators with an exemption to the conditions of connection set out in S5.2. Given that the Rules define a generating system of less than 5 MW nameplate rating as a Small Generator, the university maintained that requirements covered by S5.2 should only be proposed provided they were justifiable on a technical basis specific to the proposed PV
installation. This logic was accepted and a number of clauses were deleted or amended. Some are described below.

3.1.1. **Reactive Power Capability**
S5.2.5.1 of the Rules requires generators to supply and absorb up to 39.5% of the nameplate rated active power regardless of the actual active power being produced. Whilst this may be feasible with rotating plant, such reactive compensation is not necessarily available over all operating inverter conditions and more importantly, not necessary when the inverter is not producing energy. The utility’s proposed clause was subsequently deleted and when similar requirements were added elsewhere, these were revised to only require reactive capability equal to 39.5% of **actual** active power when at or exceeding 30% of rated output.

3.1.2. **Protection to Trip Plant for Unstable Operation**
S5.2.5.10 of the Rules requires generators to include a protection system to disconnect when system parameters become unstable as per AEMO guidelines. The university questioned why this was applicable to a sub 5 MW generator and pointed out the utility’s responsibility to carry out detailed planning with respect to stability impacts to provide a basis for any necessary protection of this type. The clause was subsequently deleted.

3.1.3. **Frequency Control**
S5.2.5.3 of the Rules requires generators to remain on line during abnormal system frequency for prescribed periods of between 2 and 10 minutes depending on the excursion. For generators collocated with load however, such time restraints could potentially inhibit anti-islanding features of the inverters which are designed to trip under voltage or frequency excursions. The utility subsequently amended the clause to set clear frequency limits outside of which, disconnection would occur within the 2s typical of inverter grid connect standards.

A related draft clause referred to S5.2.5.11 of the Rules requiring generators to reduce active power if system frequency exceeds normal operating levels. The required output reduction (10% of maximum operating level) was insignificant compared to total network generation and as a derogated clause, the university suggested that the requirement be deleted. The utility subsequently agreed.

3.1.4. **Remote Monitoring**
Another draft clause proposed remote monitoring in accordance with S5.3.11.1 of the Rules which in turn referred to other clauses subject to civil penalty provisions. The university argued that the derogation applied, the references related to scheduled and semi-scheduled generators and whilst remote monitoring was reasonable, the obligations under the Rules was not. The utility subsequently amended the clause to delete the cross reference and penalty provisions.

3.2. **Incorrect Standards Referenced**
Demonstrating that processes to deal with inverter energy system connections are still being developed by utilities, requirements based on a number of inapplicable standards were initially proposed. A stipulation to comply with relevant parts of AS4777.2-2005 [7] was refuted by the university on the basis that the SMA inverters being used, exceeded the 30 kV.A rating scope of AS4777.2, generated at a non-standard 324 V and interfaced to the grid via special external isolating transformers. A separate reference to IEC 60364.7.712 which is a European standard applying to ‘Electrical Installations of Buildings’ was similarly contested. References to both standards were subsequently removed by the utility.
4. Conclusion
The completion of the 3.4 MW PV plant at The University of Queensland’s Gatton campus will afford an opportunity to identify first hand, the benefits and challenges associated with 11 kV grid connection at relatively low fault levels. The technical agreement negotiated with Energex offers a solid framework for assessing performance and provides incentive for researching more effective control techniques to manage network quality of supply. Although utilities have enormous powers, embedded generation proponents can successfully negotiate with them provided they research the facts and present objective arguments that are logical, pragmatic and mindful of all stakeholders including other network customers. Such technical agreements will continue to be refined, particularly if they are made publically available.

Acknowledgements
The authors would like to thank Energex staff for engaging in professional debate and being open to alternative views.

References
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2. 2013, ‘Electricity Regulation 2006’
3. AS/NZS 61000.3.6:2001 ‘Electromagnetic compatibility (EMC) Part 3.6: Limits - Assessment of emission limits for distorting loads in MV and HV power systems’
4. AS/NZS 61000.3.7:2001 ‘Electromagnetic compatibility (EMC) Part 3.7: Limits - Assessment of emission limits for fluctuating loads in MV and HV power systems’
5. HB264-2003 ‘Power quality - Recommendations for the application of AS/NZS 61000.3.6 and AS/NZS 61000.3.7’
6. TR IEC 61000.3.6:2012 ‘Electromagnetic compatibility (EMC) Part 3.6: Limits - Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems’
7. AS 4777.2-2005 ‘Grid connection of energy systems via inverters Part 2: Inverter requirements’