From: David Sweeting [mailto:david@sweeting.com.au]
Sent: Fri 11/24/2006 2:17 AM
To: anthony.england@aemc.gov.au
Cc: a.england@aemc.gov.au; Kate Summers; David.LeLievre@alcoa.com.au
Subject: Technical Standards for wind generators and other generation

Anthony,

I understand you are conducting a consultation on technical standards.

I have searched the AEMC website and found no reference to it.

I have guessed two possible email addresses for you and have included Kate on the distribution in case I have failed to guess your email address.

Pleased find attached a paper that I presented to the EESA Annual Conference in Melbourne this year on Regulatory Issues relating to wind farms. This may have been forwarded to you earlier this year by Charlie Macauley.

I am in London at present but am interested in how I could contribute to improving the NER.

One of the significant issues is the use of internationally un-defined terms. High Voltage equipment can only be purchased on the basis of IEC and American specifications. The Australian standards are based on IEC.

Using un-defined terms such as normal voltage or weakly defined terms such as nominal voltage leaves the rules based on weak foundations.

I have attached a list of IEC voltage definitions. These should be used in the NER. Notice that the nominal voltage is weakly defined and normal not at all.

As an example Figure S5.1a.1 should be based on the "Highest System Voltage", which is less than or equal to the "Highest Voltage for Equipment". With Highest System Voltage as the base the long time horizontal line should be at 0% and not 10%. This is what equipment can withstand.

As it is presently written, the normal voltage can be 10% above the nominal voltage and the maximum voltage another 10% higher then Figure S5.1a.1 allows this to rise another 10% for 600 seconds. Equipment is not designed for this.

It is acceptable for the normal voltage to be up to the Highest voltage for equipment but no higher. If you operate with a high normal voltage you have cut into allowable voltage increases.

The allowable voltage rises need to be based on what equipment can tolerate.

David

SWEETING CONSULTING PTY. LTD.
Electrical Power, High Voltage and Control Engineers

A.B.N.: 48 003 795 257
A1 Pindari Ave St.Ives, 2075
Ph: +61 2 9488 7094
Fax: +61 2 9144 4461
Mobile: +61 4 1488 7094
Email: david@sweeting.com.au

To:	Attention:	Email/Fax No:
From: Dr.D.K.Sweeting	Date:	Pages (including this page)

SUBJECT: IEC VOLTAGE DEFINITIONS

601-01-21
nominal voltage of a system

A suitable approximate value of voltage used to designate or identify a system

604-03-01

highest voltage for equipment

The highest r.m.s. value of phase-to-phase voltage for which the equipment is designed in respect of its insulation as well as other characteristics which relate to this voltage in the relevant equipment standards.

601-01-23 601-01-24

highest [lowest] voltage of a system

The highest [lowest] value of operating voltage which occurs under normal operating conditions at any time and any point in the system.
Note. - Transient overvoltages due e.g. to switching operations and abnormal temporary variations of voltage, are not taken into account

446-12-07

nominal value of an energizing quantity

A suitable approximate value of an energizing quantity used to designate or identify a relay.

446-12-08

rated value of an energizing quantity

That value of an energizing quantity, which is assigned either by the standard or the manufacturer, for a specified condition.

National Electricity Rule's Performance Standards And Imbedded Wind Generation

Dr. David Sweeting
Sweeting Consulting Pty Ltd

SUMMARY: This paper discusses the Power Quality issues involved in re-negotiating an existing use of system or connection agreement when wind generation is embedded within an existing large load connected to the transmission system.

Many of the power quality issues are transmitted through the existing Large Load's connection agreement and the Network Service Provider's requirements must be transferred across voltage levels and equitably between the legal entities.

These problems are exacerbated by changes in Code requirements, changes in Standards and the fact that the National Electricity Rules are still evolving and themselves require changes.

This paper proposes substitution of the current over-simplified power factor requirements in the code with separate VAR balance and voltage stability requirements, which meet the technical needs.

1. INTRODUCTION

Wind generators can be imbedded in large system loads in order to take advantage of an existing high voltage substation and to avoid Transmission Use of System (TUOS) charges.

This however requires re-negotiation of the Use of System Agreement between the Owner of the Large Load (With the embedded generator) and the Transmission Network Service Provider (TNSP). The National Electricity Rule's Performance Standards negotiated with Nemmco also require changes.

The Wind Farm is invariably owned by a different legal entity to the Owner of the Large Load requiring two contracts between three legal entities

A "Use of System Agreement" is required between the TNSP and the "Large Load Owner".

A "Connection Agreement" is required between the "Large Load Owner" and the "Wind Farm Owner".

These agreements need to be written so that they can span over 30 years and accommodate all the changes that are likely to occur in such time frames.

These agreements also have to handle the power quality issues in Schedule 5 of the National Electricity Rules (NER). These include:

Normal voltage range,
Fault levels,
Reactive Power Demand,
Voltage stability and control
Unbalance
Flicker and Voltage Fluctuations
Harmonics.

This paper discusses some of the technical issues involved in distributing the power quality restraints and emissions between legal entities and across different voltage levels.

It also discusses the problems that arise because the Large Load's existing contract is based on old and often incompatible standards. The Large Load will need to grand father some of the technical details of the existing contract due to existing equipment limitations.

2. NATIONAL ELECTRICITY RULES

The large Load will have been constructed to the code and contract conditions prevailing when it was built.

The addition of wind generation embedded within the Large Load allows the Network Service Provider to renegotiate the contract between the NSP and the Large Load on the basis of the current National Electricity Rules (NER).

It is imperative that the new contract does not include conditions from new standards that the Large Load has not been designed to meet. This could cause significant expenditure for the Large Load.

The National Electricity Rules have recently replaced the National Electricity Code with little change in content.

Schedule 5 of chapter 5, Network Connection, contains the items of interest in this paper. Broadly speaking the main components are:

Schedule5.1 What the network provider can do to the customer.
Schedule 5.2 What a generator can do to the network.
Schedule 5.3 What a load can do to the network.

Historically the Network Service Provider has provided few guarantees on what he will do to the customer. The introduction of the System Code required the network provider to meet some of the standards of the time of introduction but this was rarely transferred into the customer's connection agreement.

Re-negotiation of Schedule 5.1 conditions therefore tends to start with no previous contract conditions, earlier system code conditions plus the conditions in the current National Electricity Rules.

The wind generator will be new and have to meet current conditions. Schedule 5.2 negotiations will be based on the conditions in the current National Electricity Rules.

The Large Load will have many Schedule 5.3 conditions in the existing connection agreement. These need to be considered along with the conditions in the current System Rule's Schedule 5.3.

3. PRIMARY PLANT REQUIREMENTS

As well as agreeing on basic issues such as the connection point, the point of common coupling, basic insulation levels and surge arrestor ratings, it is necessary to agree on the normal voltage range.

Simply because a customer has sat for many years within a particular voltage range does not guarantee this will continue.

Running out of voltage taps when the Network Service Provider wishes to transfer more energy to another customer is a major issue and must be addressed during any renegotiation of the connection contract.

4. NORMAL VOLTAGE RANGE

Whilst at first glance the normal voltage range appears to be a simple concept, when you need to include it in a contract you realise that it can be very loosely defined.

It is not difficult to get agreement that you are talking about the phase-to-phase RMS value of the voltage.

It becomes much more difficult to establish what is included and what is excluded from the concept of normal and what time aggregation should be used.

The first problem is that normal-operating conditions is not an IEC or AS defined term.

The National electricity Rules are not a lot of help. Schedule 5.1a.4 on power frequency voltage talks about a variation of ± 10% around a normal voltage except for a contingency event.

It goes on to define "normal Voltage" as nominal voltage or such other voltage ± 10% of the nominal as approved by NEMMCO.

As written, the Rules allow up to +20% (10% on 10%) on nominal voltage as a voltage normally seen by equipment.

The Rules go on to allow another +10% in Figure 5.1a.1 for up to 600 seconds during a contingency event.
High Voltage equipment is rated and designed on the basis of highest voltage for equipment. The nominal voltage is often 10% lower but this is not mandatory nor has it been consistent historically.

There is therefore a problem in that the rules at high voltage have been drafted on the wrong base i.e. on a nominal value rather than the highest voltage for equipment or the highest system voltage, which can be less than the highest voltage for equipment.

The large load customer need to ensure the interpretation of clause 5.1a.1 in the connection agreement keeps the maximum normal voltage below his system's highest voltage for equipment.

The limits to the normal voltage range can be aggravated by changes in the standard voltages in IEC 60038 or AS 60038. The highest system voltage of 525kV has become 550kV so older 500kV nominal equipment has limitations on the maximum voltage for equipment.

This problem can also occur in old 10.5kV areas where the equipment is not designed for a 12kV highest voltage for equipment.

In order to resolve issues relating to the normal voltage range at the connection point it is necessary to agree an how the voltage will be measured.

The network service provider will prefer that voltage measurement be defined in terms of whatever the presently installed equipment can provide. This is a function of where and what instrument measures the voltage. Service providers do not want to spend money on measuring meaningful voltage and therefore are likely to try to avoid a clear definition.

On the other hand the customer needs to know not only what his equipment needs to be capable of but also that it not being over stressed.

The measured Normal Operating Voltage range at the connection point needs to be defined as the r.m.s. Phase-to-phase voltage range after removal of any excursions allowed for in other parts of the agreement or standards.

That is after accounting for the deviations in Figure 5.1a.1 of the NER.

There is a similar need to define the Normal Voltage Range in IEC and AS documents in terms of the r.m.s. Phase-to-phase voltage range after removal of any excursions allowed for in the Insulation Co-ordination and Power Quality Standards.

This allows power quality excursions to be defined as excursions around the normal voltage range. The sum of the two then becomes the total measured voltage profile.

IEC61000.4.30, testing and measurement techniques for power quality measurements, provides for a range of time aggregations.

You can choose from a single cycle refreshed every half cycle (Urms (1/2)), ten cycle aggregation, 3 second aggregation, 10 minute aggregation, and 2 hour aggregation.

The standard does not however include a synchronised 15-minute aggregation of Voltage, VA Watts and VARS, which could be provided by energy meters.

Time aggregation has historically been proposed to minimise the influence of short time voltage excursions.

When it relates to switchgear ratings, the customer needs limits on single cycles of voltage. One attempted operation outside switchgear capability can lead to a significant failure.

Much longer 10 or 15 minute aggregation is however meaningful in terms of the thermal behaviour of transformers and the saturation of iron cores.

As well as the range of normal voltages defined in AS 60038 (standard voltages), the capability of existing equipment needs to be considered. Switchgear may not have test certificates for the present AS 60038 voltage range. Transformers may suffer loss of rating at high voltage due to saturation or have insufficient taps for the full AS 60038 voltage range.

During negotiations the Large Customer will be trying to ensure the existing equipment remains adequate whilst the Network Service Provider will be looking to gain flexibility by achieving access to as wide a voltage range as is allowed in current standards. The original connection agreement may however be based on the original configuration and the Large Customer will want to grandfather any restrictions into the new contract.

After reaching agreement on the voltage range at the connection point between the Network Service Provider and the Large Load, the Large Load then needs to do the same with the wind farm at generally a lower voltage level.

Before tackling how to keep the voltage at a particular node in the network within an agreed normal voltage range and excursions outside the normal voltage range, you need agreement on the fault levels.

5. FAULT LEVELS

With a Large Load and a large wind farm, fault levels are required at a number of voltage levels. Two of these voltage levels involve connection points and contracts.

Whilst the present fault level is required to analyse current behaviour it will vary over time and should not be included in the contracts. It should instead be subject to notification between the parties.

It is far more important to include the ultimate system fault levels both three-phase and single-phase together with the assumed pre-fault voltage. These values define equipment ratings.

At transmission voltages, transformers have star connections on the HV windings and therefore the customer's transformers affect the single-phase fault currents. The wind generators, motors and any local generation also add to the three-phase fault levels.

It is necessary to ensure the contract is clear on whether the ultimate fault levels in the contract are from everyone or just from the Network Service Provider and that all parties have correctly specified equipment.

It is also necessary to agree on the minimum three-phase and single-phase fault levels to be used in power quality studies. These can be the normal minimum fault levels.

The minimum single-contingency three-phase and single-phase fault levels are also required because these are required to determine whether the plant can recover from a system black with adequate protection.

6. REACTIVE POWER BALANCE AND VOLTAGE STABILITY

Voltage regulation has been made more complicated by the introduction of the national electricity market and the break-up of the system into independent generators, transmitters, distributors and loads.

The complication comes from the rules requiring reactive compensation be installed by the entity, which generated the requirement rather than in terms of where it is best for the network.

There are two energy components within a power system:

Active power (Watts) and
Reactive power (VARs).

The generation and consumption of both of these components need to be continually balanced.

Active power is created by generators and consumed by loads and losses.

Reactive power is created by inductive loads and the inductance of the power system. It is compensated by the capacitance of the power system, capacitors banks, static VAR compensators and generators.

To achieve a reactive energy balance at periods of maximum reactive demand there must be sufficient compensating capacitive or leading VARs installed in the network.

This gives rise to the need for each load and Network Service Provider to install sufficient reactive-power compensation to cover his peak demand condition.

Since the total reactive compensation is only required for a few days per year maintenance can be performed outside the critical periods and there is no need for standby plant.

Similarly since reactive compensation plant has a high availability, outages can be covered by setting the required ratings in the Rules to allow for statistical outages after allowing for the fact that the system maximum demand is smaller than the sum of the load maximum demands.

There is therefore no need to require reactive compensation plant to cover outage contingencies.

In terms of reactive power balance, there is only a need to require a load to have installed sufficient compensation for the load's maximum demand.

Outside of the few peak demand periods each year there is significant excess reactive power compensation available on the network and this needs to be controlled on the basis of voltage stability not VAR balance.

In other words, at part load, the main issues are voltage stability and the voltage distribution throughout the network.

This is particularly evident with embedded generation. As an embedded generator increases its generation, the load on the system decreases and the voltage at the connection node increases. The reactive balance at the node needs to be controlled to stabilise the voltage at the node. This is not achieved with constant power factor.

The historically simplistic concept for controlling system voltage has been to achieve a VAR balance first and then use tap-changers as a fine-tuning.

This is not always appropriate but it has been historically enshrined in the system Rules and in connection contracts as the only approach.

For loads, the NER seeks to regulate reactive power in Schedule 5.3.5, Power Factor Requirements, and Table 5.3.1a, which sets permissible ranges based on nominal supply voltage.

Because this table attempts to fulfil two functions (VAR balance and a part of voltage control) in a single simple table it produces rules that do not match the engineering requirements.

The NER Table S5.3.1a should only deal with VAR balance. That is it should set the required reactive power capability at the maximum demand of the load. This can be stated in terms of power factor at the maximum demand.

That is Table S5.3.1a should state that at 50kV the power factor at maximum demand should be less lagging than 0.9 and at greater than 400kV less lagging than 0.98.

What it does say however is the power factor over any critical demand period must fall within a particular range. This varies from 0.9lagging to 0.9 leading at 50kV to 0.98 lagging to unity above 400kV.

In other words it attempts to combine VAR balance and voltage control in the one table. It then goes on to allow exemptions when this causes voltage control problems.

When looking at the influence of VAR flows on the voltage profile it matters where they are generated and where they are consumed.

In a sense, Active power is created at the energy source and reactive power at the opposite end of the network at the energy sink.

In the transmission system and the upper levels of the distribution system inductive reactance has more influence than resistance.

As a result the in-phase voltage drop caused by reactive currents flowing through system inductances has more influence on the voltage drop than active current flowing through the system resistances.

In the traditional model of a load separated from a generator by a system, as the active power drawn by the load increases, you need the reactive power to drop proportionally by lowering the power factor so that the voltage drop across the system remains similar.

With a generator that is embedded in the load, as it increases its generation the load current decreases and the voltage at that node increases. If you increase reactive generation at the same time by keeping the power factor constant you reduce the reactive power from the rest of the system and have two mechanisms in tandem both increasing the node voltage. This leads to voltage instability.

Wind generators not only have fluctuating active power output they are often embedded in a load region of the network. Specification of constant power factor is a major cause of wind generators being blamed for voltage fluctuations.

The second restriction of the Table S5.3.1a range on the leading power factor of the load is not important at maximum demand. The leading restriction needs to be applied at part load.

That is the lagging and leading restrictions need to apply differently to maximum and part loads and they need to apply at different times (peak and non-peak). This cannot be properly handled in a single power factor table.

Take the case of a 500kV load, consisting of large inductive rectifiers with compensating capacitor banks, trying to remain within 0.98 to unity power factor.

The real need of the tight range is voltage stability. In order to achieve the power factor limitations however, the 220kV busbar voltage has to be controlled to match the capacitive VARS with the rectifier VARS. In other words 220kV voltage fluctuations have to be artificially created in order to achieve a rule requirement, which is part of minimising voltage fluctuations.

The cause of this is the wrong rule. But for a while the TNSP wanted to apply the 0.98 to unity for every half hour period. When this was implemented the TNSP could not maintain the node voltage within the customer's equipment ratings and provide sufficient power to other customers.

Thankfully such problems can be negotiated out of the connection agreement but Customer's need to be aware that they need to address such problems whenever re-negotiating their connection agreement.

The addition of an embedded wind generator decreases the active power consumed by the Large Load. It also reduces the current in the main transformers of the Large Load thereby reducing the reactive demand on the system. These need to be controlled on the basis of stability at all voltage levels. This does not involve constant power factor.

It also does not involve installation of more capacitor banks that cannot be turned on because they will generate excess voltage.

The NER Schedule 5.2.5.1 requires generators be able to supply reactive VARs and absorb a certain level of capacitive VARs depending on whether they are synchronous or asynchronous. This requirement is also based on the traditional separation of generator and load by the system.

Wind generators are often asynchronous and therefore capacitive VARs require the cost of installing reactive compensation. This needs to follow voltage regulation requirements and not simplistic power factor rules.

7. VOLTAGE/CURRENT UNBALANCE

Historical use of system agreements tend to be silent on voltage unbalance.

The NER Table 5.1a.7 sets out the present (and only) requirements on the Network service Provider in terms of unbalance voltage.

These are expressed as "Maximum negative sequence voltage as a percentage of nominal voltage" for four cases. Above 100kV these are:

0.5% for	No contingency 30-minute average
0.7% for	Credible Contingency 30-minute av.
1.0% for	General 10-minute average
2.0% for	Once per hour 1-minute average

On the other hand NER Schedule S5.3.6 requires for load connections above 30kV that the average current in any phase is between 98% and 102% of the average current in all phases.

Notice that in moving from what the load has to tolerate to what it can produce, the definition of negative sequence changes and averaging periods are omitted.

The most important requirement for any load negotiating a use of system agreement is to uncouple the two issues by requiring only load unbalance currents generated within the load contribute to the ±2% of allowable unbalance currents.

Whilst this leaves a measurement issue on how to subtract the unbalance currents generated by the network unbalance voltage, it means the load is allowed a genuine 2%.

In my example, the Large Load had to accept a drop from being allowed to previously create 4% negative sequence currents, although this was not an issue.

I have run a model comparing the percentage current unbalance method with the equivalent negative sequence value. The current unbalance method produces a smaller number for most phase angle variations and the same values for certain cases. The change in methodology therefore favours the customer.

For the wind farm connection agreement, the use-of-system agreement conditions have to be translated down a voltage level to establish what the negative sequence voltage the wind farm must tolerate.

If the large load has any unbalance issues, you need to remember that the on-site generation lowers the system load current and therefore the allowable negative sequence currents flowing into the system.

8. FLICKER

Historically use of system agreements did not include the concept of a flicker planning level nor any statement requiring the supply authority to limit the flicker it can impose on a customer.

The National Electric Code introduced the concept of the supply authority having to set limits and keep the supply within those limits.

These limits were all set using the limit of perceptibility and the limit of irritability as defined in AS2279.4. These are graphs of the percentage voltage change verses the rate of occurrence.

The historical use of system agreements did however include restrictions on the customer using a graph like T14/155/18, which is similar to the graphs in AS2279.4.

The current National Electricity Rules however are based on AS/NZS 61000.3.7, which superseded AS2279.4 and introduced new concepts as well as dropping out some of the older concepts.

The first problem therefore is to establish equivalence between the old and new Australian Standards.

Flicker in the 61000 series of standards is based on the output of a "Flickermeter", which records short term flicker as a Pst number and long term flicker as a Plt number. This has the advantage that no matter what the waveform you finish up a single number for short-term flicker and a single number for long-term flicker.

These results are based on a table of the percentage amplitude of rectangular voltage changes verses the frequency of occurrence for the value of Pst =1. This is a curve similar to the ones in AS2279.4.

Comparison between AS2279.4 and AS/NZS61000.3.7 shows that:

The irritability curve is approximately Pst=1
The Perceptibility curve is approximately Pst = 0.3
The T14/155/18A curve is approximately Pst =0.11.

As a result the old concepts can be carried forward into the new standard using these Pst numbers for short-term flicker. Long-term flicker is however a completely new concept.

Whilst the old curves applied to all voltage levels, AS/NZS 61000.3.7 defines compatibility levels at only 230/400 Volts. This is logical in that lighting, which is the main issue with flicker, is only supplied at 230/400 Volts. The compatibility levels are:

	Compatibility levels in LV system (230/400V)
Pst	1.0
Plt	0.8

For all other voltage levels in the system, planning levels less than or equal to the compatibility levels need to be established.

Table 2 of AS/NZS 61000.3.7 provides indicative values of what the planning levels might be for MV and HV-EHV systems.

The actual values that the planning levels need to be, depends on the transfer coefficients between the voltage levels. There is little experience available in setting these transfer coefficients so there is a tendency to start with the indicative numbers from the standard. The Standards Australia handbook HB 264-2003 on Power Quality provides some assistance in this regard but it does not include transmission voltage levels.

We finished up with maximum values of Pst from Table 1 and Planning levels from table 2 of AS/NZS 61000.3.7. i.e.

	Maximum anticipated level at 500kV
Pst max	1.0
Plt max	0.8
	Planning level at 500kV
Lpst	0.8
Llst	0.6

This means our equipment must tolerate the Pstmax levels and this minimises the risk for the network provider but the network provider will plan to keep the values below the Lpst and Lplt levels.

These levels are higher than I derive from the 1998 version of the National Electric Code. That would have required a Pst of 0.24 when all network plant is in service.

Similarly were we allowed the basic emission levels from Table 6 in AS/NZS 61000.3.7 of:

	Basic emission levels At 500kV
Epsti	0.35
Eplti	0.25

This is also higher than an Epst equivalent to 0.11 for emissions in the existing contracts.

The large load then needs to convert the levels in the use of system agreement with the Network Service Provider to another voltage level using transfer coefficients and to the wind farms alone using summation laws. This is needed for the connection agreement with the wind farms.

Transfer coefficients are not symmetrical. There is a different value going down in voltage to going up in voltage. The values do not come out of AS/NZS 61000.3.7.

The summation laws however do come from AS/NZS 61000.3.7.

The details of deriving these values would make this paper unacceptably long.

9. LESS FREQUENT VOLTAGE CHANGES

AS/NZS 611000.3.7 covers the AS 2279.4 frequency range of voltage changes with flicker or the Pst method plus a separate Table 7 for less frequent repetitive voltage changes. This covers single sided voltage changes that occur when something is switched on or off.

Table 7 of AS/NZS 61000.3.7	
Emission limits for voltage changes in function of the number of changes per hour	
≤1	3
>1 or ≤10	2.5
>10 or ≤100	1.5
>100 or ≤1000	1

These are simpler to handle because AS/NZS 61000.3.7 states that there are no summation laws. These events occur infrequently enough for the probability of addition of the effect from different loads to be small.

This means that the planning levels and emission levels for each HV customer can be the same.

Network Service Providers may however wish to apply their own summation laws.

10. HARMONICS

Harmonics is like flicker in the sense that existing contracts included no concept like a planning level or a maximum level the Network Service Provider could inflict upon the customer.

The National Electric Code introduced the concept of the Network Service Provider having a responsibility to set and keep within limits.

The 1998 version of the National Electric Code required the Network Service Provider keep the harmonic levels at all voltage levels within the values listed in Table 1 of AS2279.2 except for intermittent or short duration periods where it could go to twice those levels.

The use of system agreements between large Loads and Network Service Providers do however contain restrictions on the harmonic voltages that each load can generate. Normally these are a set proportion of the AS 2279.2 Table 1 values.

The National Electricity Rules however are based on AS/NZS 61000.3.6, which superseded AS2279.2 and changed the allowable voltage levels for nearly every harmonic. The 2^{nd}, 3^{rd}, 4^{th}, 5^{th}, 7^{th}, 11^{th}, 13^{th} and THD all increased and the rest are either lower or the same.

AS/NZS 61000.3.6 sets compatibility levels in Table 1 for 230/400V, 11kV and 22kV systems only. Planning levels are required at all the higher voltages.

Whilst Table 2 of AS/NZS 61000.3.6 provides indicative planning levels for MV and HV-EHV voltage levels, these are only indicative and do not really apply to transmission level voltages, like 500kV.

Network Service Providers may however set planning levels using the Table 2 indicative levels in any contract negotiation.

Negotiations on the allowable emissions level of an existing load are complicated by the fact that previously allowed levels at some frequencies are lower than the new planning levels. At each frequency the voltage level can be viewed in terms of percentage values and absolute voltage values and each vary in a different manner from the old to the new standard.

After agreeing to new planning and emission levels with the Network Service Provider, the Large Load must then transform these values to a different voltage level and distribute equitably the allowable emissions.

The procedures in AS/NZS 61000.3.6 are so vague that Standards Australia has produced HB 264 to assist in calculating planning levels in distribution systems. This does not however apply at transmission levels.

The details of how to make these calculations need to be left to a paper on this topic alone.

After agreeing on planning and emission voltage levels, the problem that occurs when these levels are exceeded is to actually measure who is generating the harmonic voltages. That issue is also for another day.

11. CONCLUSIONS

Embedding a wind generator inside a large load has a number of commercial advantages but it unfortunately allows the Network Service Provider to renegotiate and update the use of system agreement between the large load and the network service provider.

This means a number of power quality issues undergo re-negotiation and are transferred to the wind farm via the Large Load.

These power quality issues need to be transferred to different voltage levels and equitably shared between the different legal entities sharing the connection point.

This is made more difficult by ever-changing power quality standards and National Electricity Rules on the one hand and the typically expected thirty-year length of the contracts on the other hand.

The National Electricity Rules are still evolving and one area where changes are required is treating VAR Balance and Voltage Control as two separate topics and eliminating use of the concept of power factor, which attempts and fails to properly address both the issues at once.

12. REFERENCES

National Electricity Rules published by The Australian Energy Regulator

National Electricity Code previously published by The National Electricity Code Administrator, NECA

IEC 61000.4.30 and AS/NZS 61000.4.30, Testing and Measuring Techniques for Power Quality Measurements, available from Standards Australia

IEC 60038 and AS 60038, Standard Voltages, available from Standards Australia

AS2279.4, Disturbances in Mains Supply Networks, Limitations of Voltage Fluctuations Caused by Industrial Equipment, available from Standards Australia

AS2279.2, Disturbances in Mains Supply Networks, Limitations of Harmonics Caused by Industrial Equipment, available from Standards Australia

IEC 61000.3.7 and AS/NZS 61000.3.7, Electromagnetic Compatibility, Limits- Assessment of Emission Loads in MV and HV Power Systems, available from Standards Australia

IEC 61000.3.6 and AS/NZS 61000.3.6, Electromagnetic Compatibility, Limits- Assessment of Emission Limits for Distorting Loads in MV and HV Power Systems, available from Standards Australia

Hand Book HB 264, Power Quality, available from Standards Australia