Asia-Pacific
Economic Cooperation

Addressing Grid-interconnection Issues in Order to Maximize the Utilization of New and Renewable Energy Sources

APEC Energy Working Group

October 2010

APEC Project EWG 02/2009

Produced by

IT Power (Australia) Pty Ltd
ABN 42 107 351 673
PO Box 6127, O'Connor, ACT 2602, AUSTRALIA
telephone: +61 (0)2 6257 3511
facsimile: +61 (0)2 6257 3611
email: itpau@itpau.com.au
web: www.itpau.com.au

Ref Number: *ITP/Ref: A0032*

For

Asia Pacific Economic Cooperation Secretariat

35 Heng Mui Keng Terrace

Singapore 119616

Tel: (65) 68919 600

Fax: (65) 68919 690

Email: info@apec.org

Website: www.apec.org

APEC#210-RE-01.16

Client RfT No.: EWG 02/2009
IT Power reference: A0032 APEC

Addressing Grid-Interconnection Issues in Order to Maximize the Utilization of New and Renewable Energy Sources

October 2010

This report was funded by the Asia-Pacific Economic Cooperation Energy Working Group

IT Power (Australia) Pty Ltd
PO Box 6127,
O'Connor, ACT 2602, Australia

tel: +61 (0)2 6257 3511,
fax: +61 (0)2 6257 3611,
email: itpau@itpau.com.au
web: www.itpau.com.au

Document control	
Authors	Rob Passey, Ted Spooner, Muriel Watt, Julia McDonald, Philippe McCracken, Joseph Gordon and Katerina Syngellakis
Project Manager	Rob Passey
Date	October 2010

About IT Power

The IT Power Group, formed in 1983, is a specialist renewable energy, energy efficiency and carbon markets consulting company. The group has offices and projects throughout the world. IT Power (Australia) was established in 2003, and has undertaken a wide diversity of projects, including providing advice for government policy, feasibility studies for large hybrid systems, developing micro-finance models for small-scale community-owned systems in developing countries and modelling large-scale systems for industrial use.

The staff at IT Power (Australia) have backgrounds in renewable energy and energy efficiency research, development and implementation, managing and reviewing government incentive programs, high level policy analysis and research, including carbon markets, engineering (system) design and project management.

About this report

The APEC Energy Working Group (EWG) called for tenders for a study ‘Addressing Grid-interconnection Issues in Order to Maximize the Utilization of New and Renewable Energy Sources’. This report characterises the main issues with integration of stochastic and only partially predictable renewable energy technologies into distribution networks (i.e. distributed generation). It summarises the approaches currently being used to address them, including research and development activities. It then identifies best practices in addressing these issues, including non-technical approaches. It then outlines future research and development activities that may be required to fully integrate distributed generation into electricity networks of the 21st century. It finally discusses the factors that influence the potential for applying best practices throughout the APEC region.

Acronyms

AC	alternating current
APEC	Asia-Pacific Economic Cooperation
APEC EWG	APEC Energy Working Group
BASIX	Building Sustainability Index
BPL	broadband over power lines
CHP	combined heat and power
CRIEPI	Central Research Institute of Electric Power Industry
DC	direct current
DCI	dynamically controlled inverter
DG	distributed generation
DISPOWER	Distributed Generation with High Penetration of Renewable Energy Sources
DOE	Department of Energy
EMI	electromagnetic interference
EMS	energy management system
EPRI	Electric Power Research Institute
EU	European Union
EVs	electric vehicles
FiT	feed-in tariff
GHG	greenhouse gas
HEVs	hybrid electric vehicles
Hz	hertz
IEA PVPS	International Energy Agency Photovoltaic Power Systems Programme
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
kV	kilovolt
kVA	kilovolt-ampere
kVAr	kilovolt-ampere reactive power
kW	kilowatt
kWh	kilowatthour
LAN	local area network
LDCs	line drop compensators
LEED	Leadership in Energy and Environmental Design
LVRT	low voltage ride-through techniques
MIR	minimum import relay
MIRI	Mizuho Information and Research Institute
MW	megawatt

MWh	megawatthour
NDZ	nondetection zone
NEDO	New Energy and Industrial Technology Development Organization
NREL	National Renewable Energy Laboratory
PCSs	power conditioning subsystems
PLCC	power line carrier communications
PSOC	partial state of charge
PV	photovoltaics
PVPS	Photovoltaic Power Systems Programme
R&D	research & development
R/X	resistance to reactance ratio
REC	Renewable Energy Certificate
REGIS	Renewable Energy Grid Integration Systems
RESPOND	Renewable Electricity Supply Interactions with Conventional Power Systems, Network and Demand
RMS	root mean square
RPR	reverse power relay
SEGIS	Solar Energy Grid Integration Systems
SMES	superconducting magnetic energy storage
STATCOMS	static synchronous compensators
SVCs	Static VAr Compensator
T&D	transmission and distribution
THD	total harmonic distortion
UPS	uninterruptible power supply
US	United States
VAr	volt-ampere reactive
WAN	wide area network

Table of Contents

1 INTRODUCTION

With the ongoing focus on reducing emissions from energy production and use, renewable energy is being deployed at an increasing rate worldwide. In addition to reducing greenhouse gas emissions, renewable energy's other benefits include employment creation, reduced use of non-renewable resources, reduced atmospheric (particulates, sulphur oxides, nitrogen oxides, mercury, and a range of other toxins) and water-based (acid mine drainage) pollution, increased energy security through diversification and improved national balance of payments.

For most countries, increased energy security, improved trade balance and reduced dependence on imported fossil fuels are the main drivers for use of renewable energy, although environmental aims, especially greenhouse gas reduction, also play a role. As the fuel price spike of 2008 showed, oil price increases can immediately impact on national economies. In light of this experience, there has been a new impetus amongst many governments to develop, endorse and implement renewable energy development policies, strategies and roadmaps.

Broadly speaking, renewable energy can be described as either centralised large-scale plants (e.g. wind farms, geothermal, large-scale hydro, marine, solar thermal, bioenergy) or distributed generation (e.g. photovoltaics, small-scale wind, micro-hydro, small-scale bioenergy). Distributed generation (DG) connects to the distribution network and is the focus of this report. It has some additional benefits to large-scale centralised renewables in that it can help defer network augmentation, reduce line losses and, being smaller, is more modular and so can be gradually installed as required.

Of the distributed generation technologies, micro-hydro and bioenergy have very constant and predictable energy output and small-scale wind is relatively rare, and so they have little impact on the distribution network. Where small-scale wind is used at higher penetrations, such as on remote mini-grids, well developed technologies such as battery storage and diesel generator backup are currently used. Photovoltaics on the other hand, are being rapidly deployed at an increasing rate and are often based on a source of energy that can fluctuate daily, hourly and even over shorter periods. Photovoltaics can also have significant power quality impacts if appropriate measures are not implemented. As a result, solar power is the predominant focus of this report. Nonetheless, the grid impacts discussed in this report capture all those that other DG technologies (such as wind) are likely to have.

The potential impacts include voltage fluctuations, voltage rise and reverse power flow, power fluctuation, impacts on power factor, frequency regulation and harmonics, unintentional islanding, fault currents and grounding issues.

As a result of these potential problems, in countries where DG has been deployed at increasing levels of penetration, utilities as well as governments have developed standards to which DG systems are required to conform. These standards have often been developed as and when required, either by utilities themselves or in collaborative efforts between utilities, governments and industry associations. In many cases they are a work in progress: as experience in DG increases and new technologies are developed, the standards also develop and change. However, sometimes the requirements can be onerous, and in some cases utilities place restrictions on the total amount of DG that can be connected. Thus, it is critical that the lessons learned regarding these technical issues are shared, so that increasing deployment of DG is well managed and overly prescriptive requirements are avoided, while maintaining a reliable and safe electricity distribution network.

1.1 Report Methodology

This report involved a desk-top review of the available literature from:

- the APEC workshop Renewable Energy Grid Integration Systems (REGIS), as well as other work by the workshop participants,
- the US National Renewable Energy Laboratory (NREL) Distributed Energy and Electric Reliability Program,
- the US DOE's Distributed Energy Program,
- the US DOE's Office of Electricity Delivery and Energy Reliability,
- the US Office of Energy Efficiency & Renewable Energy's Solar Energy Technologies Program, the System's Integration subprogram and the Solar Energy Grid Integration Systems (SEGIS) Subprogram,
- Sandia National Laboratories,
- the Electric Power Research Institute (EPRI),
- the Oak Ridge National Laboratory,
- the Transactions of the Institute of Electrical and Electronics Engineers (IEEE),
- Japan's New Energy and Industrial Technology Development Organization (NEDO) projects,
- Japan's Mizuho Information and Research Institute (MIRI),
- Japan's Central Research Institute of Electric Power Industry (CRIEPI),
- the EU's R&D project DISPOWER (Distributed Generation with High Penetration of Renewable Energy Sources),
- the EU Intelligent Energy Europe Programme RESPOND (Renewable Electricity Supply Interactions with Conventional Power Systems, Network and Demand),
- the International Energy Agency Photovoltaic Power Systems Programme (IEA PVPS),
- activities occurring in Australian universities, and
- refereed journal papers.

New journal papers are released every week and so it is not possible to summarise all the latest research outcomes in this area. Although a number of reviews are also published each year, they also cite the difficulty in keeping up to date with such a rapidly expanding area, and so focus only on one aspect. Here we have attempted to include papers that are broadly most relevant, rather than papers that report detailed outcomes – for example, an advance in a particular type of control algorithm or a modification to an inverter design to address a particular grid condition. Future APEC reports of the kind presented here may find it useful to focus on a particular aspect of grid integration (eg. voltage rise) if a detailed summary is required.

Much of the information available from some of the relevant APEC research organisations is highly descriptive, with little focus on the technical outcomes. It is clear that placing more effort into publishing the outcomes of the research in a publicly accessible form would be of significant benefit to the renewable energy industry in all APEC economies.

1.2 Report Structure

Section 2 reviews the issues faced by integrating distributed generation into electricity grids, as well as the approaches being used to overcome them. This section includes both what is currently being implemented as well as the latest research and development activities. There is often overlap between these two because the R&D activities are often performed on 'real life' examples of utility grids.

Section 3 draws on Section 2 to summarise best practices to overcome the issues identified. It also includes a section on non-technical approaches to encourage best practice integration of DG.

Section 4 summarises what various research establishments have proposed is required for DG to be fully integrated into the electricity networks of the 21st century.

Section 5 assesses the potential for applying best practices in APEC economies.

Appendix A summarises the research projects that have been or are currently being undertaken in APEC economies, and **Appendix B** briefly describes the characteristics of different types of grids found in APEC economies.

2 ADDRESSING GRID INTEGRATION ISSUES IN APEC ECONOMIES

Electricity grids must have standard conditions of supply to ensure that end-use equipment and infrastructure can operate safely and effectively. These conditions are commonly referred to as power quality requirements and are defined in standards or by supply authorities. They most commonly relate to voltage and frequency regulation, power factor correction and harmonics. Other issues related to the connection of DG to a network include voltage rise, unintentional islanding, fault currents, grounding and power output fluctuation, where the latter can have significant impacts on power quality and system safety, security and control.

The following discusses these issues as they relate to DG, as well as ways that are currently used to address them, or are proposed and are in the research and development stage and/or undergoing trials. A significant amount of work has been and is being undertaken in these areas, and so the following focuses on the most recent developments – in part because the older work assumes power systems controls (eg. inverters) that are not as relevant to current day operations. For an historical literature review of these issues, see Whitaker et al. (2008).

Integrating DG into existing networks has to take into account:

- The existing structure of the network;
- The size and location of existing generation;
- The size and location of loads;
- The impedance of the various sections of the network;
- The time availability and the variability of the DG;
- Type and location of existing protection systems;
- The effect of DG at the proposed locations in the network.

This is by no means a trivial task and it is not made easier by the existing design of networks generally not taking into account the possible connection of DG at the distribution or sub-transmission parts of the network.

Networks with low impedance connections and short feeders are generally easier for DG integration, whereas rural networks with long feeders and generally higher impedance make integration more challenging. The location and distribution of loads and generation and the time of availability of the generation with respect to the loads can play a very large role in determining the ease of DG implementation. In many cases electricity utilities have to consider integration issues on a network by network basis.

The role of smart grids has been briefly included in Section 3 *Best Practices to Overcome Grid Connection Issues*, and research and development requirements relevant to smart grids have been included in Section 4 *Required Research and Development Activities*. An assessment of the architecture of distribution power systems[1], power system planning methodologies and the technical operation of

---

[1] This includes, for example, the mesh/loop network structures explored in DISPOWER (2006), the Autonomy-Enhanced PV Clusters (AE-PVC) (Kurokawa et al., 2009), and the technologies that are a integral part of that architecture, such as the loop power flow controller (LPC) developed by CRIEPI (Okada et al., 2007). An excellent review of the various topologies for parallel operation of inverters is

smart grids are considered outside the scope of this report. Here in Section 2 we have focussed on the various technical solutions that may be incorporated into smart grids, but not on the detailed mechanics of how smart grids may be operated and controlled.

2.1 Voltage fluctuation and regulation

Voltage fluctuation is a change or swing in voltage, and can be problematic if it moves outside specified values. It affects the performance of many household appliances and can consist of variations in the peak or RMS (root mean square) voltage on the line. Supply authorities or government regulators stipulate the maximum acceptable deviation from the nominal voltage. Effects on loads are usually noticed when the voltage fluctuates more than 10% above or below the nominal voltage, and the severity of the effects depend upon the duration of the change. Extended undervoltage causes “brownouts” – characterised by dimming of lights and inability to power some equipment. Extended overvoltage decreases the life of most equipment and can damage sensitive electronic equipment.

Voltage instability can occur on the supply or distribution end of a network. At the supply end, it can be caused by:

- Weather events such as storms damaging power lines;
- Lightning strikes;
- Line and capacitor switching within the network;
- Asymmetry in transmission lines or transformers;
- Faults on local feeder transformers;
- Rapid changes in the output voltage of a generator.

At the distribution end of the network, voltage instability can be caused by:

- Sudden connection of large loads such as motors (leading to voltage sag);
- Unequal distribution of single phase loads across three phases (leading to unbalancing of phases);
- Poor wiring or grounding in a building or installation (leading to high voltages on the neutral line);
- Large power electronic loads such as computers, fluorescent lighting, air conditioning fans with poor power factor correction;
- Injection of voltage by distributed generation.

DG systems are relevant to voltage regulation because they are both affected by voltage fluctuations that occur on the grid, and can cause voltage fluctuations themselves – where the latter can be divided into voltage imbalance, voltage rise

---

given in Mohd et al. (2010). These include master/slave control techniques, current/power sharing control techniques and frequency and voltage droop control techniques. This latter one includes three main categories: adopting conventional frequency/voltage droop control, opposite frequency/voltage droop control and droop control in combination with other methods.

due to reverse power flow, and power output fluctuations. These are discussed below.

2.1.1 *Grid-derived voltage fluctuations*

Inverters are generally configured to disconnect DG when the grid voltage moves outside set parameters. This is both to help ensure power quality as well as being one way to protect against unintentional islanding (Hudson, 2010).

Some inverters are configured to simply operate in grid voltage-following mode while others may be configured to actively attempt to influence the grid voltage at the point of connection – which allows them to regulate the grid by providing reactive power support with or without storage. This is discussed in more detail in Section 2.2. All inverters have limits on their operation and even in voltage-regulation mode other factors on the grid may force the voltage outside normal limits - as described in Section 2.1.4 (McGranaghan et al., 2008)

Where there are large numbers of DG systems or large DG systems on a particular feeder, their automatic disconnection due to voltage being out of range can be problematic because other generators on the network will then have to provide additional power (SEGIS, 2007). For example, where there is voltage sag on the grid due to a sudden increase in demand, inverters may disconnect while the loads do not, exacerbating the problem, potentially causing a brownout or blackout (Miller and Ye, 2003). This has recently happened in the Alice Springs Solar City in Australia.

To avoid this happening, voltage sag tolerances could be broadened and where possible, low voltage ride-through techniques (LVRT) could be incorporated into inverter design. LVRT allows inverters to continue to operate for a defined period if the grid voltage is moderately low but they will still disconnect rapidly if the grid voltage drops too low. In Germany, LVRT standards are now incorporated into grid-connection standards (Tröster, 2009), however most inverters in the APEC regions are unlikely to currently have this capability.

2.1.2 *Voltage imbalance*

Voltage imbalance is when the amplitude of each phase voltage is different in a three-phase system or the phase difference is not exactly 120° (PVPS-T10, 2009). Phase-to-neutral over voltage may develop with load/generation imbalance or with phase to neutral faults. Voltage imbalance will have a negative impact on small distributed generators, such as temperature rise of rotors, noise, and vibration. It will also have an impact on motors and power electronic devices (PVPS-T10, 2009). Single phase systems installed disproportionately on a single phase may cause severely unbalanced networks leading to damage to controls or transformers (SEGIS, 2007). Thus, care should be taken to ensure that, at high PV penetrations, the cumulative size of all systems connected to each phase is as equal as possible. All systems above a minimum power output level of between 5-10kW typically should have a balanced three phase output. The maximum single phase power rating will depend on local conditions and the network to which they are connected.

2.1.3 *Voltage rise and reverse power flow*

Traditional centralised power networks involve flow of power in one direction only: from power plant to transmission network, to distribution network, to load. In order to accommodate line losses from power generator to load on transmission networks, voltage is usually supplied at 5-10% higher than the nominal end use voltage.

Voltage regulators are also used to compensate for the voltage drop and maintain the voltage in the designated range along the line (Mizuho, 2008).

The introduction of distributed generation changes the dynamic of the network because power can flow in both directions. In other words, the network becomes an active system with power flows and voltages determined by the mix of centralised and distributed generators as well as the load. With significant levels of DG, localised overvoltage can occur, and the voltage at the load end may be greater than the voltage on the normal supply side of the line – this is known as voltage rise and can result in reverse power flow (Demirok et al., 2009).[2]

Voltage rise is exacerbated when customer demand is at its lowest and generation at its highest, and is especially likely to be a significant issue on long feeders in rural areas (SEGIS, 2007). According to McGranaghan et al. (2008), the amount of voltage rise is affected by the reactance and resistance of the power system from the injection point back to the nearest regulator, the phase angle of the DG source current with respect to the utility source voltage, and the magnitude of the current injected.

As discussed in Whitaker et al. (2008), different authors have reported different acceptable levels of penetration of PV systems depending on conditions – see Table 1. It can be seen that there is a wide diversity of opinion on limits to penetration levels. It must be noted that this table does not give details about the networks involved or the location of the DG within the networks or the type of existing generation on the network. These factors will significantly affect penetration levels.

As can be seen from Figure 1, the safe level of penetration can depend on the particular impact being assessed. This figure presents ratios that can be used to assess the impact of different penetrations of DG on different types of power quality issues (Barker, 2010).

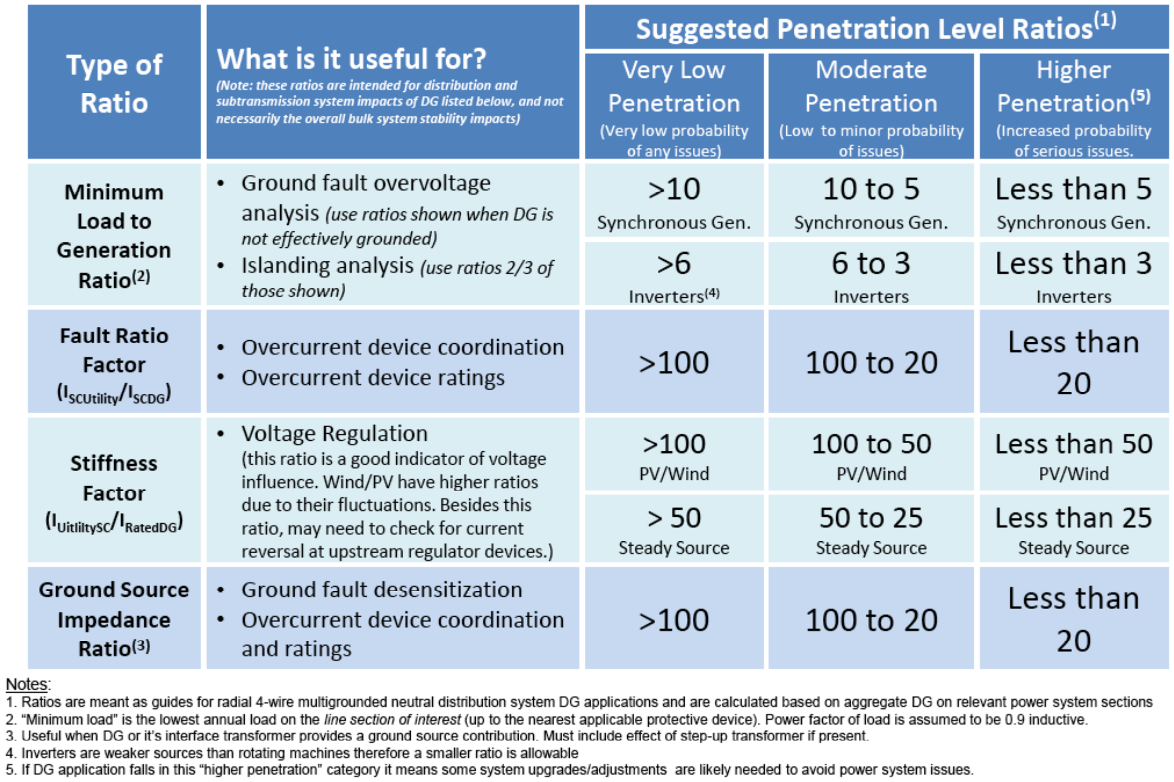
Table 1 Summary of Maximum PV Penetration Levels Suggested in the Literature
(Whitaker et al., 2008)

Source	Maximum PV Penetration Level	Cause of the Upper Limit
Chalmers et al. (1985)	5%	Ramp rates of mainline generators. PV in central-station mode.
Jewell et al. (1988)	15%	Reverse power swings during cloud transients. PV in distributed mode.
Cyganski et al. (1989)	No limit found	Harmonics.
EPRI (1990)	> 37%	No problems caused by clouds, harmonics, or unacceptable responses to fast transients were found at 37% penetration. Experimental + theoretical study.
Barker et al. (2008)	Varied from 1.3% to 36%	Unacceptable unscheduled tie-line flows. The variation is caused by the geographical extent of the PV (1.3% for central-station PV). Results particular to the studied utility because of the specific mix of thermal generation technologies in use.

---

[2] Similarly, power injection at the load end of a line can result in overcurrent conditions (SEGIS, 2007).

Asano et al. (1996)	Equal to minimum load on feeder	Voltage rise. Assumes no LTCs in the MV/LV transformer banks.
Povlsen (2002), Kroposki and Vaughn (2003)	< 40%	Primarily voltage regulation, especially unacceptably low voltages during false trips, and malfunctions of SVRs (step voltage regulators).
UCTE (2004)	5%	This is the level at which minimum distribution system losses occurred. This level could be nearly doubled if inverters were equipped with voltage regulation capability.
DISPOWER (2006)	33% or ≥ 50%	Voltage rise. The lower penetration limit of 33% is imposed by a very strict reading of the voltage limits in the applicable standard, but the excursion beyond that voltage limit at 50% penetration was extremely small.
Thomson and Infield (2007)	≥ 33%	At 50% penetration, voltage rise above allowed limits was small, and reverse power flows at the subtransmission-to-distribution substation did not occur. Voltage dips caused by cloud transients might be an issue at 50% penetration.



Type of Ratio	What is it useful for? *(Note: these ratios are intended for distribution and subtransmission system impacts of DG listed below, and not necessarily the overall bulk system stability impacts)*	Suggested Penetration Level Ratios[(1)]		
		Very Low Penetration (Very low probability of any issues)	Moderate Penetration (Low to minor probability of issues)	Higher Penetration[(5)] (Increased probability of serious issues.
Minimum Load to Generation Ratio[(2)]	• Ground fault overvoltage analysis *(use ratios shown when DG is not effectively grounded)* • Islanding analysis *(use ratios 2/3 of those shown)*	>10 Synchronous Gen.	10 to 5 Synchronous Gen.	Less than 5 Synchronous Gen.
		>6 Inverters[(4)]	6 to 3 Inverters	Less than 3 Inverters
Fault Ratio Factor ($I_{SCUtility}/I_{SCDG}$)	• Overcurrent device coordination • Overcurrent device ratings	>100	100 to 20	Less than 20
Stiffness Factor ($I_{UitlitySC}/I_{RatedDG}$)	• Voltage Regulation (this ratio is a good indicator of voltage influence. Wind/PV have higher ratios due to their fluctuations. Besides this ratio, may need to check for current reversal at upstream regulator devices.)	>100 PV/Wind	100 to 50 PV/Wind	Less than 50 PV/Wind
		> 50 Steady Source	50 to 25 Steady Source	Less than 25 Steady Source
Ground Source Impedance Ratio[(3)]	• Ground fault desensitization • Overcurrent device coordination and ratings	>100	100 to 20	Less than 20

Notes:
1. Ratios are meant as guides for radial 4-wire multigrounded neutral distribution system DG applications and are calculated based on aggregate DG on relevant power system sections
2. "Minimum load" is the lowest annual load on the *line section of interest* (up to the nearest applicable protective device). Power factor of load is assumed to be 0.9 inductive.
3. Useful when DG or it's interface transformer provides a ground source contribution. Must include effect of step-up transformer if present.
4. Inverters are weaker sources than rotating machines therefore a smaller ratio is allowable
5. If DG application falls in this "higher penetration" category it means some system upgrades/adjustments are likely needed to avoid power system issues.

Figure 1 Suggested Penetration Levels for DG (Barker, 2010)

As well as affecting end-use equipment, reverse power flow can affect the normal operation of the grid. The US NREL's study *Photovoltaic Systems Interconnected onto Secondary Network Distribution Systems – Success Stories* provides an interesting example. It focussed on reasonably large PV systems connected to electricity networks, where distribution grids are not radial[3] but use multiple feeders and multiple transformers to serve each customer in order to provide greater reliability. They most commonly serve 'high demand' areas such as central business districts. They contain network protection devices installed on the low-voltage side of the network transformer and are designed to detect and stop current flow 'upstream' towards the transformer – that can occur if there is a fault on the high voltage side of the line. However, such network protection devices will also be activated if there is reverse current flow because of DG in the distribution network. Thus, in these situations, DG will decrease the reliability of the network (NREL, 2009).

Another example of reverse power flow affecting the normal operation of the grid can be seen in the operation of tap changers when reverse power flow is detected and when a voltage-following DG is connected to the network. According to McGranaghan et al. (2008), if the DG results in reverse power flow through the regulator, tap changing control systems may become unstable. Care must be taken in the design of tap changing control systems to maintain stability under forward and reverse power flow conditions.

Reverse power flow can also have customer equity impacts. In Japan, inverters are designed with additional power quality enhancing features and so are called Power Conditioners or Power Conditioning Subsystems (PCSs). When the line voltage exceeds set limits, the PCS restricts DG output. This results in PV output being lost and is unfair to system owners towards the end of the line as the voltage rise will be greater at that point (Mizuho, 2008).[4] A similar equity issue exists in all PV-connected systems (because voltage limits are set to maintain power quality levels) where customers towards the end of a feeder experience voltage rise of a greater magnitude and more often than those closer to the voltage regulator, and consequently the PV system disconnects during these voltage events.

The converse problem to voltage rise, voltage drop, can also occur when DG is connected just downstream of a voltage regulator, and as a result, customers at the end of the line can experience low voltage (SEGIS, 2007). This is because such DG can mask the line drop compensators (LDCs)[5] from seeing the full load current and so will not boost the voltage adequately to compensate for the voltage drop. In such situations, the voltage regulators need to be appropriately calibrated to take into account the installed DG (McGranaghan et al., 2008). However, where several distribution lines are connected to a transformer LDC, the output voltage from the transformer cannot be controlled on each line independently, and so ensuring that one line doesn't go overvoltage may mean that another goes undervoltage (Mizuho, 2008).

Current approaches to address voltage rise and reverse power flow

The NREL study *Photovoltaic Systems Interconnected onto Secondary Network Distribution Systems – Success Stories* summarised four different approaches that

---

[3] Note that here, radial grids can be in an open-loop design, where feeders are interconnected on the high voltage side of the transformer.

[4] Inverters in European countries such as Germany and Spain do not have features that control voltage by reducing output because the Feed-in Tariff policies used to drive uptake promote maximum output (PVPS-T10, 2009).

[5] Used to measure current at a regulator terminal and calculate the downstream voltage drop.

utilities in the US currently take to avoid DG tripping network protection devices. They are paraphrased below (NREL, 2009):

1. Keep the PV system sized lower than the minimum daytime load at the customer meter – and so the site load will always draw power from the utility grid with essentially no chance of exporting energy from the PV system to the network.
2. Install a minimum import relay (MIR) or a reverse power relay (RPR). The MIR will disconnect the PV system if the power flow from the utility (ie. the load) drops below a preset threshold value, while the RPR will disconnect the PV system if the power flow from the utility drops to zero or if it reverses direction.
3. Install a dynamically controlled inverter (DCI). This inverter ramps down the PV energy production if the load drops below a specific threshold. This system would be a more desirable alternative than a minimum import relay as the amount of energy being generated can be governed rather than the PV system being disconnected. According to Whitaker et al. (2008), this approach may be undesirable because it may interfere with positive feedback-based anti-islanding (that relies on changes to voltage), because folding back has a voltage regulation effect and could reduce an overvoltage that might otherwise indicate islanding or another abnormal condition.
4. Encourage smaller PV systems to connect to the network. Most small PV systems, of 30 kilowatts (kW) or less, on secondary networks will have limited opportunity to feed back toward the utility, and such small amounts of energy may be acceptable to the local utility.

Note that all of these measures do limit voltage rise but severely limit the potential penetration of PV systems and would not generally be considered to be viable alternatives for moving towards a more sustainable future and higher penetration levels.

Whitaker et al. (2008) proposed the following additional ways of dealing with voltage rise. It seems they are not currently used, but could be implemented if desired without additional research.[6]

1. Decrease the utility's series impedance by designing service drops and distribution systems to have very low impedances (low voltage drops), using larger or multiple conductors, and larger derating factors on transformers or simply more transformers. This would increase capital cost, and may also increase the system short-circuit current strength at the point of common coupling, and overcurrent protection would have to be modified accordingly. This approach reduces voltage drop problems in both directions and reduces losses. Theoretically, reconfiguring conductors to reduce parasitic capacitances and inductances might also help in some cases, but this is likely to be of little importance in distribution systems.
2. Require customer loads to improve their power factors. Again, this would allow the utility to reduce its sending-end voltage, leaving more headroom for the PV.

---

[6] The following are paraphrased from Whitaker et al. (2008).

3. Customers downstream of the DG or on adjacent feeders originating from the same substation bus (in other words, those who cause the low voltage condition that requires increased substation voltage) could use an energy management system (EMS) that incorporates a load-shedding scheme. Non-critical loads could be equipped with load-shedding switches activated by either a low voltage threshold or a communications signal (power line carrier or otherwise). Then, the utility's voltage setting at the substation could be reduced, leaving more headroom at the PV end. This is likely to be a very cost-effective solution, but it requires the customer to put up with the occasional loss of load caused by low voltages.
4. Use diversionary or dump loads at times of high PV power production and low load. This is essentially the equivalent of a load-shedding regimen under low-voltage conditions; one switches in extra loads at times of very high voltage. From the grid's perspective, it provides the same effect as the storage and fold-back methods above. Facility EMS controls could also be integrated with the PV system controls to provide a more robust solution that could operate discretionary loads as needed. For example, the system could automatically start and stop a washing machine and clothes dryer during peak PV generation/peak voltage conditions. However, in many grid-connected PV applications, suitable dump loads may not be easily identified.

New inverter control schemes can allow for phasing back the output on voltage rise rather than an instantaneous trip, and allow extended operation on voltage sag to allow for ride-through. Of course this does assist with voltage regulation but system design should try to avoid voltage rise on the network via other means, otherwise there can be considerable loss of generation and many equity issues for generators distributed along a feeder.

Basically it comes down to either investment in lower impedance infrastructure or investment in complex monitoring and control functionality to achieve voltage regulation throughout the distribution system to achieve high levels of DG penetration.

The use of storage to address voltage rise and reverse power flow is discussed in Section 2.1.4.3.

2.1.4 Power output fluctuation

Fluctuations in power output are an inherent problem for DG reliant on renewable energy resources such as sunlight and wind. Short-term fluctuations (seconds) can cause problems with power quality (both voltage and power factor, that can manifest as light flicker or variable motor speed for example), while longer term fluctuations require back-up generation to maintain power supply. Short-term fluctuations can also result in tap-changers and capacitor switches continually 'hunting' as they attempt to maintain power quality, which results in increased wear of these devices, as well as an increased number of switching surges (McGranaghan et al., 2008).

Three approaches to minimise the impact of such fluctuations are geographical dispersal, forecasting and storage, and these are discussed below. Options to manage such fluctuations, that are specifically related to voltage control, are discussed in Section 2.2.

Although the impacts of large-scale renewables connected to the transmission network are outside the scope of this report, very interesting studies on the impact of high penetration renewables can be found at GE Energy (2010), Lew et al. (2009) and Milligan and Kirby (2010).

It should be noted that the affects of power flows due to large-scale wind are generally considerably different to the affects of small distributed wind or PV generation because of the dispersed nature of small generation and the location in the network where small systems are generally connected.

2.1.4.1 *Geographical dispersal*

Short term intermittency can be reduced through geographical dispersal. However, while this may be useful over very large areas, it may not be effective in some cases (for example, wind changes can affect a very large area), and this approach is less successful in relatively small areas that are subject to the same weather conditions (for example, on network feeders) (Eltawil and Zhao, 2010; Mills et al., 2009; Mills and Wiser, 2009). As a result, both solar forecasting and storage are currently areas of intensive research.

2.1.4.2 *Solar forecasting*

The effect of weather can vary on timescales from minutes to seasons, can be quite location-specific and hence can effect where installations would be sited in terms of diversity of the region and the location of the grid. Once installations are operational the impact of inevitable supply fluctuations must be predicted and managed.

Solar forecasting is a technique that is currently being developed through international efforts to provide better forecasting and management tools to manage the variability of intermittent solar energy (both PV and solar thermal). Forewarning that output is likely to diminish could be used to prepare alternative sources of power. Output by solar plants could even be preemptively curtailed in order to reduce the ramp rate required by backup generation (Whitaker et al., 2008).

However, solar forecasting is still in its infancy and there is much work to be done before solar forecasting can make a significant and effective contribution to management of solar power plants. For example, current prediction systems are generally lacking the small scale resolution that is required for location-specific forecasts, and also an understanding of the relationship between the weather conditions and the specific technology for which forecasts are required (Archer and Jacobsen, 2005).

2.1.4.3 *Storage*

Various types of batteries (eg. lithium-ion batteries, lead-acid batteries, flow batteries), electric double-layer capacitors, Superconducting Magnetic Energy Storage (SMES), flywheels, compressed air and pumped hydro can be used to regulate power output.

In addition to reducing the amount of voltage rise on feeders, storage can be used to provide services such as peak shaving, load shifting, demand side management and outage protection. Storage can help defer upgrades of transmission and distribution systems, and can help with ‘black starts’ after a system failure (Denholm et al., 2010). It can also provide several ancillary services, including contingency reserves (spinning reserve, supplemental reserve, replacement reserve), and voltage and frequency regulation (Kirby, 2004; Whitaker et al., 2008; Inage, 2009).

These functions may make a battery more cost-effective for a DG system, and similarly, installation of a battery specifically to provide one or more of these functions may provide an opportunity for a DG system to be installed and receive a degree of backup (SEGIS-ES, 2008).

As a result of these various benefits, there has been increasing interest in the use of storage at the distribution level but care must be exercised to consider the costs, benefits, maintenance, reliability and life cycle of storage systems

Systems having individual batteries associated with each DG system, individual batteries associated with each DG system but under coordinated operation, and a single battery at the community level have been investigated (Kurokawa et al., 2009). The following summarises some recent projects that evaluated the use of storage in the AEPC region.

The NEDO study *Verification of Grid Stabilization with Large-scale PV Power Generation Systems* at Wakkanai involved a 5MW PV system and a 1.5MW NaS (sodium-sulphur) battery, together with an operational control that incorporated solar forecasting. It successfully smoothed system output to the grid (achieving a greater than 80% reduction in fluctuations) – although they report that some improvements still need to be made (Ueda et al., 2008; Nakama, 2009).

The NEDO *Clustered PV Project* in Ota City assessed the impact of using batteries to store surplus power produced by residential PV systems during the day that can then be returned to the grid at a later time. They assessed three different modes of operation: Voltage control (battery charged when the grid voltage exceeds a set point), Reverse flow (battery charged when system would otherwise export to the grid), and Scheduled control (battery charged at preset times of the day). They found that (Ueda, 2007; Nishikawa, 2008):

i) The voltage control modes resulted in the lowest loss of power (due to PV output suppression and charge/discharge loss[7]), however the voltage rise experienced by each house differs considerably due to differences in impedance and interconnection conditions, which influences the battery lifetime.

ii) With the reverse flow mode, the batteries were more likely to become fully charged part way through the day and so would no longer be able to absorb PV output.

iii) The scheduled control mode resulted in slightly higher power loss compared to the voltage control mode but resulted in lower fluctuation of battery charge level.

iv) This general approach will only be financially viable once battery costs are reduced by at least 70% compared to 2008 levels.

A modelling study, again in Japan and so based on Japanese data, used demand and insolation forecasting to optimise the use of battery storage. It found that in a residential area consisting of 389 houses consuming 2,390 MWh/year and with

---

[7] The maximum battery charge/discharge efficiency was 85.8% kWh (DC), 68.9% kWh (AC), 96.2% Ah (DC).

2,390kW PV systems, 8.3MWh of battery capacity was required to satisfy the relevant planning requirements and to limit PV losses. The results also showed that forecasting reduced the required battery capacity by 51%, and increased the allowable amount of PV by 110% (Shimada et al., 2009).

A US study assessed the ability of a combination of battery storage and PV in terms of their impact on three reliability indices: average duration of critical load interruptions, average number of interruptions per customer, and annual unserved critical load (kWh) on a circuit. Three geographic regions and three sizes of community were assessed and it was found that approximately 5 kWh of battery capacity per home reduced each index to nearly zero, while 50% PV penetration resulted in an approximately 25% reduction in each index (Manz et al., 2008).

It has been suggested that to effectively use storage would require a control algorithm to be developed that could intelligently manage storage capacity. The algorithm would take into account historical PV output and load to predict optimum load dispatch set points to capture demand charge savings. The algorithm would have predictive capabilities based on ambient temperatures, and solar output to forecast net loads (loads less expected PV output). An additional function of such an algorithm could be to store energy at times of low prices and dispatch it at times of high prices (Whitaker et al., 2008).

An alternative to the use of storage is to moderate loads so that they increase when DG output is high and decrease when DG output is low, thereby making the DG/load combination more constant. Of course, this would only be appropriate for the types of loads that can be varied, but these include many heating and cooling loads, which can be significant (SEGIS, 2007).

While a summary of global advances in storage technology is beyond the scope of this report, Table 2 summarises battery technologies that can be used with grid-connected DG, while Table 3 summarises the non-battery options. The current application ranges of different types of batteries on the grid are illustrated in Figure 2. For small-scale RE systems, lead-acid batteries remain the lowest cost and most reliable option, with fly-wheels and flow batteries now being demonstrated on medium sized systems and nickel-cadmium batteries used for smaller applications. For recent reviews of the technology options for storage see (Bradbury, 2010), and for the use of large-scale storage to regulate power output as well as power quality see Inage (2009) and Denholm et al. (2010), while Perez et al. (2010) present costings of the storage requirements of large-scale PV penetration.

Table 2 Battery Technologies for Electric Energy Storage in Residential and Small-commercial Applications (SEGIS-ES, 2008)

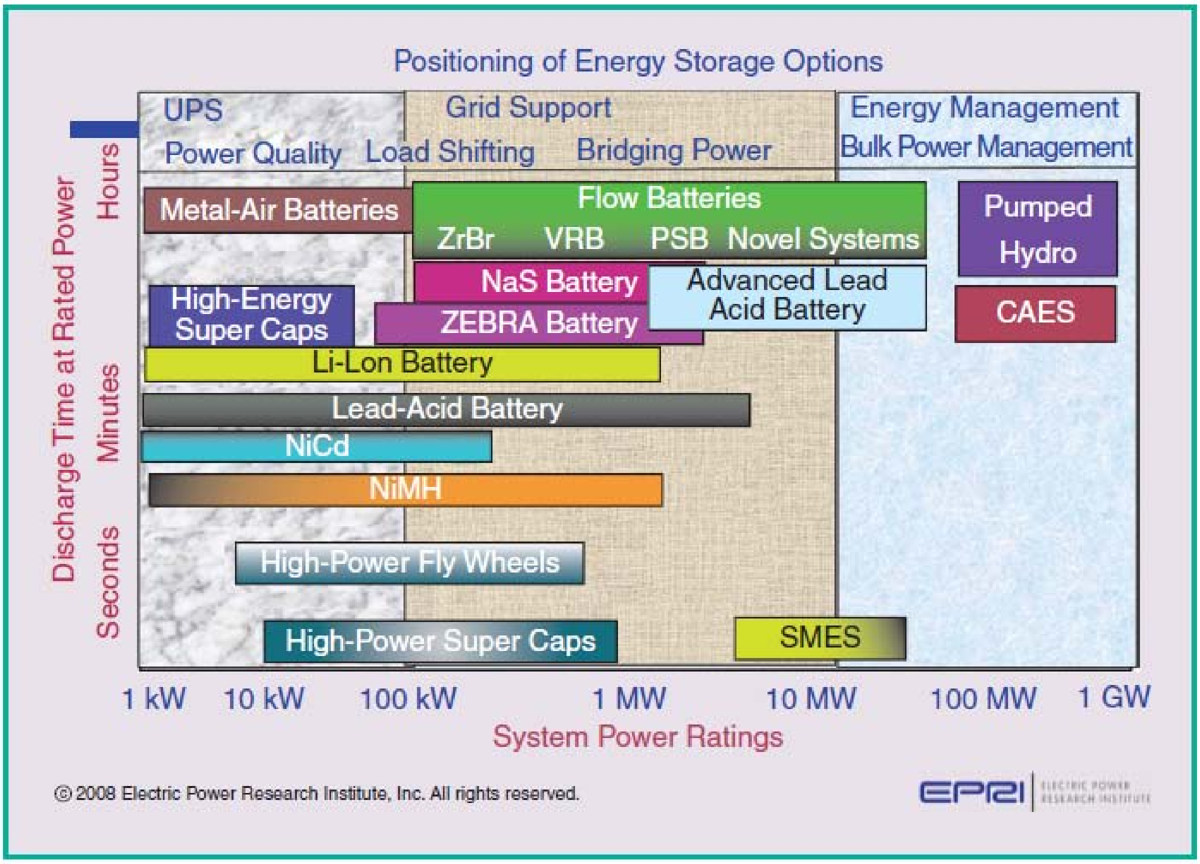
Technology	Advantages	Disadvantages	Commercial Status	Current R&D	Applications
Flooded Lead-acid	• Cost effective • Mature technology • Relatively efficient	• Low energy density • Cycle life depends on battery design and operational strategies when deeply discharged • High maintenance • Environmentally	• Globally commercial • Over $40B in all applications • Estimated $1B in utility applications worldwide	• Focused on reducing maintenance requirements and extending operating life.	• Motive power (forklifts, carts, etc.) and deep-cycling stationary applications Back-up power Short-duration power quality • Short-duration peak reduction

		hazardous materials			
VRLA	• Cost effective • Mature technology	• Traditionally have not cycled well • Have not met rated life expectancies	• Globally commercial • Over $40B in all applications • Estimated $1B in utility applications worldwide	• Improving cycle-life and extending operating life, such as using carbon-enhanced negative electrodes.	• Limited motive power applications (*e.g.,* electric wheelchairs) • Back-up power • Short-duration power quality • Short-duration peak reduction
NiCd	• Good energy density • Excellent power delivery • Long shelf life • Abuse tolerant • Low maintenance	• Moderately expensive • “Memory Effect” • Environmentally hazardous materials	• Globally commercial • Over $1B in all applications • Over $50M in utility applications worldwide	• None identified.	• Aircraft cranking, aerospace, military and commercial aircraft applications • Utility grid support • Stationary rail • Telecomm back-up power • Low-end consumer goods
NiMH	• Good energy density • Low environmental impact • Good cycle life	• Expensive	• Globally commercial for small electronics • Emerging market for larger applications	• Bipolar design.	• Electric vehicles (EVs), hybrid electric vehicles (HEVs) • Small, low-current consumer goods
Li-ion	• High energy density • High efficiency	• High production cost • Scale-up proving difficult due to safety concerns	• 50% of global small portable market	• Batteries for use in EVs and HEVs are currently being developed.	• Small consumer goods
Li-FePO^{4}	• Safer than traditional Li-ion • High power density • Lower cost than traditional Li-ion	• Lower energy density than other Li-ion technologies	• High-volume production began in 2008	• Focused on improving performance and safety systems.	• Small consumer goods and tools • EVs, HEVs
Na/S	• High energy density • No emissions • Long calendar life • Long cycle life when deeply discharged • Low maintenance • Integrated thermal and environmental management	• Relatively high cost • Requires powered thermal management (heaters) • Environmentally hazardous materials • Rated output available only in 500-kW/600-kWh increments	• Recently commercial (2002) in Japan • Estimated $0.4B in utility/industrial applications worldwide	• Focused on increasing manufacturing yield and reducing cost.	• Utility grid-integrated renewable generation support • Utility T&D system optimization • Commercial/ industrial peak shaving • Commercial/ industrial backup power
Zebra Na/NiCl	• High energy density • Good cycle life • Tolerant of short circuits • Low-cost	• Only one manufacturer • High internal resistance • Molten sodium electrode • High operating	• Globally commercial for traction applications.	• Focused on cost reduction and systems for stationary applications.	• EVs, HEVs, and locomotives • Peak shaving

	materials	temperature			
Vanadium Redox	• Good cycle life • Good AC/AC Efficiency • Low temperature/low pressure operation • Low maintenance • Power and energy are independently scaleable	• Low energy density	• Commercial production since 2007	• Focused on cost reduction.	• Firming capacity of renewable resources • Remote area power systems • Load management Peak shifting
Zinc/bromine (Zn/Br)	• Low temperature/low pressure operation • Low maintenance • Power and energy are independently scaleable	• Low energy density • Requires stripping cycle • Medium power density	• Emerging commercial products	• Focused on system integration.	• Back-up power • Peak shaving • Firming capacity of renewables • Remote area power Load management

Table 3 Non-battery Technologies for Electric Energy Storage in Residential and Small-commercial Applications (SEGIS-ES, 2008)

Storage Type	Advantages	Disadvantages	Commercial Status	Current R&D	Applications
Lead-carbon Asymmetric Capacitors (hybrid)	• Rapid recharge • Deep discharge • High power delivery rates • Long cycle life • Low maintenance	• Lower energy density than batteries • Lower power density than other ECs	• Non-commercial prototypes	• Laboratory prototypes Field demonstration planned for FY08 in NY.	• Peak shaving • Grid buffering
Electrochemical Capacitors	• Extremely long cycle life • High power density	• Low energy density • Expensive	• Commercial in US, Japan, Russia, and EU, emerging elsewhere • Over $30 million in all applications • $5 million in utility applications by 2006	• Devices with energy densities over 20 kWh/m^3 are under development.	• HEVs • Portable electronics • Utility power quality • T&D stability
Flywheels	• Low maintenance • Long life • Environmentally inert	• Low energy density • High cost	• Commercial in US, Japan, Europe, emerging elsewhere • Projected to sell over 1,000 systems per year, estimated rated capacity of 250 MW • Retail value exceeding $50 million by 2006	• Focused on low cost commercial flywheel designs for long duration operation.	• Aerospace • Utility power quality • T&D stability • Renewable support • UPS •Telecommunications



© 2008 Electric Power Research Institute, Inc. All rights reserved.

Figure 2: Application range of different types of batteries (Roberts, 2009)
CAES: Compressed air, SMES: Super-conducting magnetic energy storage

2.2 Power factor correction[8]

Poor power factor on the grid increases line losses and makes voltage regulation more difficult. Most inverters are configured to be voltage-following and have unity power factor. However, many inverter topologies are readily adaptable to provide current that is out of phase with the grid voltage and so provide power factor correction, whether that be a simple fixed power factor or one that is automatically controlled by, for example, the power system voltage.

In fact, many inverters may be able to be controlled to operate in all four quadrants but are constrained by their software control to only provide unity power factor injection of real power into the grid. Changes to the software control can enable many inverters to supply positive or negative reactive power (they can behave as either a capacitor or an inductor and so provide reactive power (VAr) control) as well as real power, with the limitation being the current rating of the inverter. For example if a PV inverter is rated at 10kVA then it may inject real power of 10kW and no reactive power, or it may inject 10kVAr (reactive power) and no real power, or combinations of lesser real and reactive power. According to Demirok et al., (2009),

---

[8] Unless otherwise stated, much of the following on power factor is paraphrased from Passey et al. (2007).

over-rating the inverter by 17.64% extends its range to between 0.85 lagging to 0.85 leading power factor.

Inverters operating in voltage-regulating mode can thus help boost network voltage by injecting VAr during sags,[9] as well as reduce network voltage by drawing reactive power during voltage rise.[10,11] To provide reactive power injection while supplying maximum active power, the inverter size must be increased. For example, increasing the inverter size by 10% means the reactive power capability can be increased from zero to nearly 46% in the maximum PV power generation condition (Liu and Bebic, 2008). According to Whittaker (2009), to significantly reduce voltage increase, the PV inverter would need to be designed for additional apparent power capability (e.g., a 5-kilowatt inverter might need a 6- to 7-kilovolt-ampere rating. At Kalbarri in Western Australia, the inverter is rated at 75kVA and the connected PV is rated at 20kW and so even when injecting all the real power associated with the PV, the inverter has significant reactive power capability (72kVAr) still available for VAr compensation.

The provision of VAr compensation comes at an energy cost.[12] For example a 10kVA inverter, which is 94% efficient at full power output, will be dissipating 600W. While that same inverter is delivering 10kVAr and no real power, the inverter is 0% efficient and will still be consuming 600W (or probably a little more because the section of the conduction path that is in the inverter passes through reverse conducting diodes with slightly higher voltage drop than the forward conducting transistors). The owner of the inverter may not directly benefit from the VAr compensation it provides but they will bear the cost of the energy loss incurred by the inverter in providing the compensation.

If an inverter is to be used for VAr compensation, possible methods to activate this compensation are:

- Measuring the power factor at the point of connection and attempting to unity power factor correct the load at that point.
- Providing voltage support using VAr compensation.
- Using time of day VAr injection to assist with voltage control.

Simple VAr compensation can probably be provided more cost-effectively by capacitors. The energy loss in capacitor banks is also considerably less than for the equivalent inverter VAr compensation. The main advantage of inverter VAr compensation is that it is infinitely variable and very fast in response to changes in the power system. In areas where rapid changes in voltage are experienced due to

---

[9] For example due to disturbances in the grid or sudden changes in the renewable energy resource (eg. cloud cover).

[10] Note that this capability is not allowed under current IEEE Connection Standards, and Australian Standard AS4777.2 requires that inverters operate at close to unity power factor (ie inject only real power into the grid) unless they have been specifically approved by electricity utilities to control power factor or voltage at the point of connection.

[11] This capability can also be provided by SVCs (Static VAr Compensator) or STATCOMS (static synchronous compensators). STATCOMS are also known as 'self-commutated SVCs' and are better than SVCs because their ability to provide reactive power is independent of the voltage magnitude. In contrast, an SVC's reactive power output decreases as the voltage decreases.

[12] Inverters can provide reactive power in the absence of DG output. The energy cost would then be drawn from the grid.

large load transients (eg. motor starts) an inverter VAr compensator may be justified.

The efficiency of inverters generally increases with their rating and so the losses associated with VAr compensation decrease in $/VAr terms. Thus it is probably better to use a single large inverter, whether it is a single large PV inverter or a single purpose built static VAr compensator (SVC), than to use multiple smaller units (eg. multiple small PV inverters with VAr control). Nevertheless, where many smaller PV systems are installed by building owners, the cost is not borne by the utility but the benefits would still accrue.

This sort of reactive power compensation for voltage control is effective on networks where system impedances comprise a relatively low ratio of resistive to reactive (R/X) loads. In many distribution networks and at fringe of grid locations, however, system impedances seen at the point of connection are considerably more resistive, and the higher the resistance to reactance (R/X) ratio of the line, the less effective VAr compensation becomes for voltage control. This is because with high R/X ratios, large amounts of reactive currents controlled by the inverter only contribute small changes to the voltage magnitude, making it ineffective and uneconomic to use these techniques. In these situations, real power injection is more effective for voltage regulation. Thus, PV inverters connected to fringe of grid lines can provide voltage regulation at the point of connection provided the real power input of the inverter (which can only occur when there is sufficient solar insolation or some form of storage backup) correlates in time with the load on the system (Passey et al., 2007; Demirok et al., 2009).

In summary, PV inverters are capable of VAr compensation to assist with voltage control on the grid, although this comes at an energy cost. How the VAr compensation is valued and who pays for the energy has generally not been addressed. A single large inverter will be a more energy efficient option than multiple small PV inverters. Although large load transients may justify an inverter, capacitors are likely to be a more cost effective source of VAr compensation. The alternative options to achieve the same results as a PV inverter are fixed or switchable capacitors, or SVCs for fast voltage control.

A number of studies have recently assessed the impact of voltage regulation capability provided by DG inverters – in terms of PV penetration levels as well as control methodologies.

A modelling study by Liu and Bebic (2008) found that in all the cases they assessed, PV inverters configured to provide reactive power positively contributed to feeder voltage regulation and resulted in an improved voltage profile, ie.

i) At a low PV penetration level (5%), inverters did not make a significant impact on the feeder's voltage regulation during peak load,

ii) At a medium PV penetration level (10%), inverter voltage support helped reduce the size of the voltage support capacitors by nearly 40%.

iii) At high PV penetration levels (30% – 50%), PV inverters might entirely displace voltage support capacitors.

However they noted that: "With respect to reactive power supply to the system, PV inverters are disadvantaged because their reactive power injection may be limited by the feeder voltage limits. This can be resolved by coordinated control of utility equipment and inverters, and in some cases additional utility equipment might be needed to take full advantage of the inverters' reactive power capabilities" (Liu and Bebic, 2008).

CRIEPI (Central Research Institute of Electric Power Industry) have used system models to investigate the use of what they termed 'autonomous voltage control', which was where, in addition to a standard voltage threshold for voltage control, a reactive power threshold was used. Up to a 'moderate' level of PV penetration, line voltage was effectively controlled and the total power generation improved by up to approximately 7%, and each household by up to 60% compared to existing methods. In combination with the use of SVCs and step voltage regulators (SVRs), line voltage was effectively controlled with autonomous voltage control up to a PV penetration level of 30%. However, where there was an instantaneous voltage disruption, the SVRs could not respond rapidly enough and so remote voltage control was required. Such an approach could maintain line voltage within acceptable limits with PV penetration of 60% in the CBD and 80% in a residential area - although running costs were comparatively high (PVPS-T10, 2009; Uemura, 2008; Morozumi et al., 2008).

Sulc et al. (2010) and Turitsyn et al. (2010) have also investigated the potential for local autonomous control of inverters to provide voltage regulation, and have found that in order to achieve optimal operation of the network as a whole, some form of centralised control is also required. For example, a local control scheme that simply supplies the local reactive power consumption achieved almost 80% of the savings in losses when compared to a centralised control scheme. Like the CRIEPI research, they also found that the inclusion of local real and reactive power flows, in addition to local voltage, leads to better control system performance.

2.3 Frequency variation and regulation

Frequency is one of the most important factors in power quality and it must be uniform throughout an interconnected grid. The frequency is controlled by maintaining a balance between connected load and generation. It is controlled within a small deviation: for example, in Japan the standard is 0.2-0.3 Hz; in the U.S. it is 0.018-0.0228 Hz; and in the European UCTE it is 0.04-0.06 Hz (Inage, 2009). Power systems contain a number of sources of inertia (e.g. large rotating generators and motors) which result in considerable time constants involved in frequency movements when there is a mismatch between load and generation. The time constants depend of course on the size of the system and how well it is interconnected.

Disruptions in the balance between supply and demand lead to frequency fluctuation - it falls when demand exceeds supply and rises when supply exceeds demand (Inage, 2009). Frequency regulation is maintained by control loops built into the power generating sources on the network. In conventional grids, generators and turbines use an actuator to control the flow of fuel, gas or steam to maintain the required frequency. It is the performance of these actuators, turbo devices and inertia of the generators that give the frequency sturdiness (Asano et al., 1996; Kirby, 2004).

With the increasing penetration of intermittent energy sources such as wind and solar, frequency control becomes more difficult. Although the extent of power fluctuation from PV systems is currently much smaller than that from wind generators, as the number of grid-connected PV systems increases, the issue of frequency fluctuation will become more noticeable (PVPS-T10, 2009). However, one study found that increasing levels of PV penetration required a disproportionate increase in the need for frequency control from conventional sources – 10% penetration of PV required only a 2.5% increase in conventional frequency control, while a 30% PV penetration required only a 10% increase (Asano et al., 1996).

As well as increasing the need for frequency regulation, DG may be able to help with frequency control. Inverters can provide frequency control in milliseconds, which is significantly faster than conventional generation, but do so in different ways depending on whether they are voltage source or current source types. Regardless, both types can only provide frequency control when they can inject power into the network – thereby increasing the value of energy storage (Whitaker et al., 2008).

According to Inage (2009), the faster response provided by DG would mitigate frequency excursions faster, reducing the effective capacity needed for the service. However, special control algorithms would need to be developed to take advantage of the fast response times, and DG has not historically been used and is unproven in this application. DG linked to combined heat and power (CHP) are restricted in their ability to provide frequency regulation because of their thermal loads (Kirby, 2004).

In summary, frequency limits are set in different sectors of the network to control load shedding under contingency conditions. This is important to maintain system stability. At present, small inverter-connected DG systems have simple frequency limits, where if the frequency falls outside these limits the distributed generation has to disconnect instantaneously. These frequency limits can in some cases be fundamental to the operation of anti-islanding algorithms. There will in the future need to be changes to these types of simple control as the penetration of DG increases. The result of these simple frequency limits is that if the power system has lost generation for some other reason (e.g. a lost transmission line) and the system load is greater than the connected generation, then the frequency will start to fall. If it falls outside the trip limits then all the DG will also disconnect, exacerbating the power imbalance and leading to a need to shed more load to avert a complete system shutdown. New frequency ride through systems will need to be developed to cope with this situation as the penetration level increases. Care will have to exercised to make sure ride-through provisions do not circumvent the anti-islanding protection system's operation.

2.4 Harmonics[13]

Harmonics are currents or voltages with frequencies that are integer multiples of the fundamental power frequency. The standard frequency is 50Hz or 60Hz depending on the country, and so a harmonic in a 50Hz country could be 100Hz, 150Hz, 200Hz, etc. Electrical appliances and generators all produce harmonics[14] and are regulated under the International Electrotechnical Commission (IEC) Electromagnetic Interference (EMI) standards. However in large volumes these harmonics can add up to cause interference that can result in the vibration of

---

[13] Unless otherwise stated, much of the following on harmonics is paraphrased from Passey et al. (2007).

[14] This is because they need direct current (DC) power or AC at a different frequency to that supplied, and use power electronics technologies to change the grid AC to the desired current waveform, and in doing so generate harmonics in the grid.

elevators, the flickering of TV monitors and fluorescent lamps, the degradation of sound quality, malfunctioning of control devices and even fires (PVPS-T10, 2009). This has not been reported to be a common problem as it is largely managed by the EMI standards.

The existing inverter standards in Australia (AS4777.2) and in the US (UL1741) for small PV systems require that the inverter must produce less than 5% total harmonic distortion (THD) on injected current with tight limits on specific harmonics. This is much more stringent than for loads of equivalent rating (as specified in the IEC61000 series[15] of documents). In Europe and the UK they rely on similar standards to those for loads, ie. the IEC 61000 series of standards.

Even at high penetration levels of PV systems the harmonic distortion appears to be very low (Infield et al., 2004). Most grid-connected inverters for DG applications output very low levels of harmonic current, and with diversity in their distribution on the network are unlikely to cause harmonic issues. The main sources of harmonics on the network are loads, particularly a range of electronic loads that are commonly available (e.g. computers and compact fluorescent lamps) and which have simple rectifier inputs that draw large harmonic currents. However, because they are small the allowances for harmonics in the IEC61000 series are generous. Unfortunately, the effect of large numbers of these loads combined in an installation can result in very large harmonic currents drawn from the power system.

These harmonic currents can lead to distortion of the voltage waveform which can lead to problems developing in other loads. It is interesting to consider what affect, if any, inverter-connected DG has in assisting with this situation.

The NEDO *Clustered PV Project* in Ota City, with 553 PV systems with a combined power of 2,129 kW, found that even if the harmonic current of all systems synchronised, the THD increases by less than 2% (Nishikawa, 2008). Modeling of an 11kV residential distributor indicated that inverters that conformed to Australian Standards could reach penetration levels (in terms of rated current) of 21% (even harmonics) and 27% (odd harmonics) before harmonic distortion limits were reached. Where filtering was used to reduce the harmonic current by 30%, penetration levels of 29% (even) and 38% (odd) could be reached (Latheef et al., 2006). It has even been suggested that since the harmonics generated from modern inverters are much lower than from other appliances, it is possible they help filter the harmonics from other electronic loads to improve the power quality (PVPS-T10, 2009).

However, two complications that have arisen relate to many loads not being ideal sinusoidal current loads and the equity impacts of harmonic correction. These are discussed below.

There are generally two types of control schemes used in PV inverters. One type operates as a sinusoidal voltage source behind an inductive impedance and the other operates as a sinusoidal current source. Most PV inverters at present are the current source type because this control scheme makes it easier to meet grid-connection standards and provide rapid overcurrent protection on the output stage of the inverter.[16] This type of PV inverter operates as an ideal source of sinusoidal

---

[15] IEC: International Electrotechnical Commission

[16] For more information see Appendix 6.7 of Passey et al. (2007)

current (to the degree that a PV resource is available). However, many loads are not ideal sinusoidal current loads. Loads expect the power system to be a sinusoidal voltage source and many of them demand non-sinusoidal currents and currents out of phase with the supply voltage. The net effect of a large number of loads of this type is that the supply system has to provide a considerable amount of out of phase and harmonic currents, and the flow of these currents on the network creates harmonic voltages that then can affect other loads. Adding PV inverters which provide sinusoidal currents at unity power factor means that the inverters supply the in-phase sinusoidal component of the loads and the grid is left to still supply out of phase current and harmonics. Thus, while the current source PV inverter generally does not make the situation worse, it does not contribute to the supply of the out of phase and harmonic currents required by loads. The voltage source type of inverter would assist by contributing the harmonic currents required by loads but this type of inverter is at present not common in the market place, and may be illegal in some jurisdictions. Currently inverters are not required to be characterised as being voltage source or current source and hence it is very difficult for purchasers of equipment to select a particular type.

Another complicating factor is that when a voltage source inverter is connected to a grid which has poor harmonic voltage, and the inverter produces harmonic currents to assist in correcting the grid voltage (within the limits of its rating), its energy output is reduced. This is equitable provided the owner of the inverter is also the cause of the harmonics on the grid and so they are assisting with correction of their own problem. However, the owner of the inverter may be experiencing high harmonic flows, and so reduced energy output, because of the poor harmonic performance of other customers on the power system. This is another reason why current source inverters are common - their output is not generally affected by the grid's voltage harmonics.

According to SEGIS (2007), inverters using pulse-width-modulation schemes to regulate their output typically do not contribute to lower order harmonics. However, the higher frequencies associated with the power electronics do inject higher order harmonics. At this stage it is not known whether there is likely to be any impact on equipment connected to a distribution network and mitigating the impact by filtering is generally simple but will impact cost and performance.

Both passive and active filters can be used to eliminate harmonics. Passive filters are composed of passive elements such as capacitors or reactors and absorb harmonic current by providing a low-impedance shunt for specific frequency domains. They come in two forms: tuned filters (which are targeted to eliminate specific lower-order harmonics), and higher-order filters (that can absorb entire ranges of higher-order harmonics). Active filters detect harmonic current and generate harmonics with the opposite polarity for compensation. They are better than passive filters because they can eliminate several harmonic currents at the same time, they are smaller and quieter, and they do not require a system setting change even when a change occurs in the grid (PVPS-T10, 2009).

In summary, while the most common type of inverters (current source) do not create harmonic distortion, they also do not provide the harmonic support required by the grid. Voltage source inverters can provide harmonic support but do so at an energy cost and there are a variety of harmonic compensators that are likely to be cheaper. Labeling that identified the type of inverter (voltage or current source) would help the purchase of voltage source or current source inverters as required, as would financial compensation for reducing energy losses if voltage source inverters are installed. Note that, unless specially configured, PV inverters disconnect from the grid when there is insufficient sunlight to cover the switching losses, meaning that no voltage support would be provided in the evening.

2.5 Unintentional islanding

Unintentional islanding occurs when distributed generation delivers power to the network even after a network interruption where circuit breakers have disconnected the DG from the main grid and associated generators. This can cause a number of different problems (SEGIS, 2007; McGranaghan et al., 2008; Coddington et al., 2009):

(i) Safety issues for technicians who work on the lines, as well as for the general public who may be exposed to energised conductors;

(ii) It may maintain the fault conditions that originally tripped the circuit breaker, extending the time that customers are disconnected;

(iii) Possible damage to equipment connected to the island because of poor power quality (eg. where inverters are in voltage-following mode);

(iv) Transient overvoltages caused by ferroresonance and ground fault conditions are more likely when an unintentional island forms;

(v) Inverters could be damaged if the network is reconnected while an island of DG exists;

(vi) It is possible for a network that does not have synchronising capabilities to reclose in an out of phase condition, which can damage switchgear, power generation equipment and customer load.

Since islanding is a well-known problem, grid inverter technology has developed to include anti-islanding features as are required by local regulations and standards. According to Eltawil and Zhao (2010), islanding detection methods can be divided into five categories: passive inverter-resident methods, active inverter-resident methods, passive methods not resident in the inverter, active methods not resident in the inverter, and the use of communications between the utility and DG inverter.

i. Passive inverter-resident methods involve the detection of the voltage or frequency at the point of grid connection being over or under specified limits.[17] These methods also protect end-users' equipment.

ii. Active inverter-resident methods involve active attempts to move the voltage or frequency outside specified limits – which should only be possible if the grid is not live.[18]

iii. Passive methods not resident in the inverter involve the use of utility-grade protection hardware for over/under frequency and over/under voltage protection.

---

[17] They may also detect the rate of change of power and voltage, and trip the inverter offline if these exceed a preset value. Harmonic detection methods (that detect either the change of total harmonic distortion or the third harmonic of the PV output voltage) and phase jump detection methods (that monitor the phase difference between PV output voltage and the output current) can also be used (Yu et al., 2010).

[18] Active methods can also include monitoring changes in grid impedance after the injection of a particular harmonic or a sub-harmonic (Trujillo et al. 2010).

iv. Active methods not resident in the inverter also actively attempt to create an abnormal voltage or frequency or perturb the active or reactive power, but the action is taken on the utility side of the inverter connection point.

v. Communications between the utility and DG inverter methods involve a transmission of data between the inverter or system and utility systems, and the data is used by the DG system to determine when to cease or continue operation.

As discussed below, each of these approaches has strengths and weaknesses.

When a cluster of inverters are connected to the network, interference may occur and result in passive islanding detection equipment malfunctioning (NEDO, 2006; SEGIS, 2007).

Passive inverter methods may also fail to detect islanding when the reactive power of the DG system and the load on the customer side of the inverter are the same (this is known as the nondetection zone (NDZ)). According to Yu et al (2010), as the resonant frequency of the local load approaches the local grid nominal frequency the potential formation of the islanding also increases. In these situations the inverter cannot detect that the line voltage has cut and the automatic cutoff feature does not function. Although Whitaker et al. (2008) think this is extremely unlikely to occur, others disagree. Many inverters have variable power factor features incorporated, and this allows them to best match load and supply to maximise efficiency throughout the day. It has been found that at high penetration levels, PV inverters with variable power factor can increase the probability of islanding because there are more cases in which load and supply within a distribution network can be balanced (Eltawil and Zhao, 2010).

Where inverters are designed to help boost network voltage by injecting reactive power during sags, this capability can conflict with both passive and active islanding detection and adds complexity to the control algorithms (Whitaker et al., 2008; PVPS-T10, 2009).

Both passive and active islanding detection methods can fail when the DG uses voltage regulation and governor control characteristics, because the DG output may adapt to the islanded system load demand without reaching the voltage or frequency trip points. However, such control characteristics are not generally used for DG, except when they are used as backup power sources independent of the grid (Walling and Miller, 2003).

Active islanding detection methods can in theory have a minor but negative impact on grid power quality when there are a number of inverters on the same line and interference from the signals occurs. Pulses associated with impedance detection for anti-islanding can accumulate in high penetration scenarios and may cause out-of-spec utility voltage profiles. Such power quality impacts could then interfere with islanding detection capabilities. However, most inverters incorporate internal controls to minimise these problems and no practical impacts have been reported so far (Whitaker et al., 2008; PVPS-T10, 2009).

Active islanding detection methods are considered to be incompatible with microgrids because (i) they cannot readily be implemented at the point of connection of the microgrid to the main grid and (ii) the active attempts to move the voltage or frequency outside specified limits work against a seamless transition between grid-connected and stand-alone modes (Whitaker et al., 2008).

There are no uniform standards on active islanding methods used in inverters. The result of this is that there is a diverse mixture of algorithms now existing on networks. Some algorithms attempt to drift the up, some attempt to drift the frequency down, some depend on the load generation match and some do not drift but use impedance measuring current pulses. The problem with this situation is that there is an increased risk of forming a stable island because a stable frequency operating point may be reached. It appears that this may have happened in Spain on a 20kV feeder (Pazos 2009). There is a need going forward to develop more uniform standards on anti-islanding algorithms or adopt other communication based systems to reduce the risk of unintentional-islanding occurring.

On a weak grid, an inverter may cut out prematurely or, more likely, may not reclose (ie. reconnect to the grid). For example, Australian Standard AS4777 specifies that the autoreclose function needs the grid to be stable for 60 seconds, which on a weak grid may not occur for some time. Networks are generally designed to reclose after 10 seconds and so for the next 50 seconds the DG will not be providing network support. To increase DG's ability to provide line support, the network operator could specify more reasonable tolerance limits and shorten the reclose time. Some form of short-term storage could also be used to bridge the gap between the network and the PV inverter reclosing. The whole area of inverter ride-through, inverter voltage and frequency windows raises important issues of islanding prevention, timing and stability which are emerging as issues to be further investigated as the number of grid-connected PV systems increases in the distribution system (Passey et al., 2007).

According to Whitaker et al. (2008) and McGranaghan et al. (2008), the best options to improve islanding detection are based on improved communications between the utility and the inverter. These would help overcome the problems associated with failure to detect an island condition, with false detection of island conditions, and failure to reclose and so provide grid support. Whitaker et al. (2008) suggested:[19]

1. Power line carrier communications (PLCC)[20] could be used as a continuity test of the line for loss-of-mains, fault, and islanding detection – but only once technical challenges such as having a continuous carrier are solved. Almost no information content is required in the PLCC signal. It can still be used for other control functions without interfering with the loss-of-mains detection function. The use of PLCC would mean that voltage and frequency trip settings could be widened to better accommodate utility transients and provide better ride-through, or even adjusted dynamically depending on whether the inverter were in grid-tied or stand-alone mode. The PLCC receiver need not be in the inverter; the loss-of-mains detection function

---

[19] The following points are paraphrased from Whitaker et al. (2008)

[20] Considerably more detail on options for communications are given in Section 4.5.1 of Whitaker et al. (2008). Typically, power line carrier communications (PLCC) method for anti-islanding uses a low-energy communication signal along the power line, and supervisory control and data acquisition (SCADA) systems monitors auxiliary contacts on all circuit breakers on the utility system between its main sources of generation and the DG (Yu et al., 2010).

could be implemented at the point of common coupling, which would facilitate AC modules and microgrids. This functionality is similar to a watchdog system in critical computing applications in that it can be made to be failsafe so that a lack of signal for a defined period will result in disconnection of the generation.

2. Integrate PV inverters into utility supervisory control and data acquisition systems or AMI systems. Inverters could be tied into utility communications systems, which would issue a warning to inverters in sections of the utility isolated from the mains. This would require that utility communications systems reach to all distribution-level endpoints, which is not presently the case. There may be other reasons to connect inverters to AMI systems, such as enabling PV systems to respond to real-time pricing signals. This would require the inverters to be connected to a high-bandwidth communications system that could, if properly configured, handle the anti-islanding function as well.

The NEDO *Clustered PV Project* in Ota City developed a communications-based islanding detection system that has variously been described as using a ‘wave clock signal’ (Inoue et al., 2007) and a GPS signal (Nakama, 2007) and detected islanding within 100ms (Morozumi et al., 2008).

However, any centralised control system is unlikely to be perfect. Thus, according to McGranaghan et al. (2008), “The danger of any control scheme involving communication links to a central controller is that it is only as reliable as the central controller and the communication links. To avoid problems if either should fail, the system will include redundant links among specific utility voltage regulation devices and several layered “fallback” control methodologies that can manage the regulation (to a lesser degree but still with acceptable quality) without the oversight of the main controller“. Whitaker et al. (2008) identify and describe a number of features that are relevant for a communication-based control system: latency,[21] bandwidth, reliability, accuracy, distance limits, capital cost, and operating cost. In addition to islanding detection, such control systems could be used to manage voltage regulation, demand response strategies, backup power (intentional islanding), management of spinning reserve, frequency regulation and control fault current modes – for more detail see Whitaker et al. (2008).

Ropp (2010) also criticised PLCC for being high cost as it would require a separate transmitter for each feeder, and to date there has been low adoption because of limited bandwidth. He suggested synchrophasors may be used in the future for islanding detection although at present they are unproven, of uncertain cost and have uncertain bandwidth requirement.

2.6 Fault Currents

In conventional distribution systems, fault protection is based on the assumption that current flows from centralised generation outwards to the loads. According to (McGranaghan et al., 2008), the presence of DG introduces new sources of fault currents that can change the direction of flow, introduce new fault-current paths, increase fault-current magnitudes, redirect ground fault currents in ways that can be problematic for certain types of overcurrent protection schemes, and increase the

---

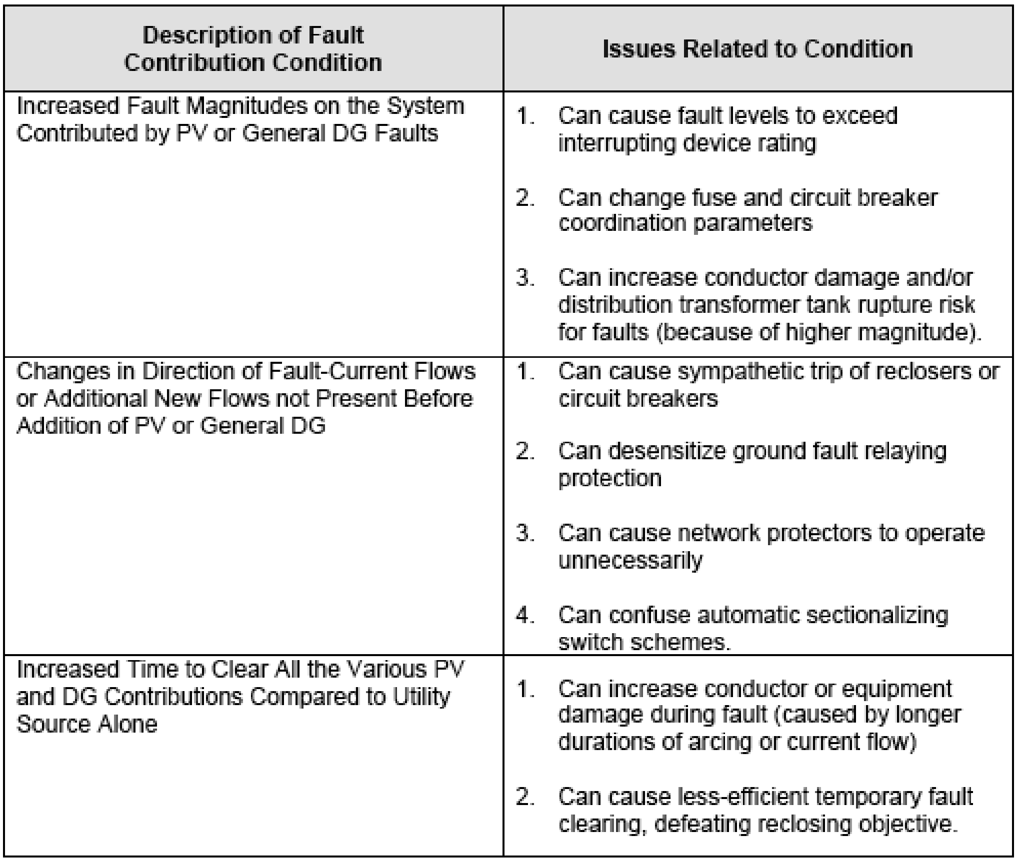
[21] Latency can occur at the inverter (which requires time to process commands and then act), in the communication network itself, as well as the protocol employed (Boyd et al., 2009).

time taken to correct faults. These issues only become significant at high penetration levels of DG, and are summarised in Table 4. Rotating synchronous generators were identified as the 'worst offenders', with DG such as PV, fuel cells and some microturbines that connect via inverters being less of a problem.

However, according to Kroposki et al. (2010), DG connected to the grid through a modern power electronics interface should be able to respond to fault conditions at the subcycle level, and so quickly eliminate fault contributions before any impact on existing coordination occurs. This means that DG should have no effect on fault current, grounding, and overvoltages resulting from faults. This is supported by (PVPS-T10, 2009) who state that inverters that meet international standards should disconnect from the grid as soon as an overcurrent (1.1–1.5 times the rated short-circuit current) is detected.

Intersystem faults[22] have also been identified as an issue for DG, because inverters will only recognise there is a problem when the substation opens a breaker and an island is formed. Communications-based islanding detection methods have been suggested to overcome this problem (see Section 0).

Table 4 How Fault Contributions from PV and/or General DG Equipment Influence the System (From McGranaghan et al., 2008)



Description of Fault Contribution Condition	Issues Related to Condition
Increased Fault Magnitudes on the System Contributed by PV or General DG Faults	1. Can cause fault levels to exceed interrupting device rating 2. Can change fuse and circuit breaker coordination parameters 3. Can increase conductor damage and/or distribution transformer tank rupture risk for faults (because of higher magnitude).
Changes in Direction of Fault-Current Flows or Additional New Flows not Present Before Addition of PV or General DG	1. Can cause sympathetic trip of reclosers or circuit breakers 2. Can desensitize ground fault relaying protection 3. Can cause network protectors to operate unnecessarily 4. Can confuse automatic sectionalizing switch schemes.
Increased Time to Clear All the Various PV and DG Contributions Compared to Utility Source Alone	1. Can increase conductor or equipment damage during fault (caused by longer durations of arcing or current flow) 2. Can cause less-efficient temporary fault clearing, defeating reclosing objective.

---

[22] This occurs when high and low voltage wiring in the transformer come into contact with each other.

2.7 Interconnection Transformer and Grounding[23]

How a distributed generator is connected into a network, and the selection of a transformer configuration and grounding system, are key areas of difficulty in terms of the compatibility of the network design with distribution-connected PV and other DG types (Khan, 2008; Khan, 2009). Distribution systems can be categorised into several types by the nature of their grounding design: Three-wire ungrounded; Three-wire unigrounded; Four-wire unigrounded neutral; and Four-wire multigrounded neutral.

By far the predominant type of system in the United States, Australia and many other countries today is the four-wire multigrounded neutral system (sometimes known as multiple earth neutral system).

Although the four-wire multigrounded neutral system offers advantages over classical three-wire systems for types of load-density patterns found in the United States, it is not a good design for the application of distributed energy sources such as PV. The four-wire system protection works best when the main substation source is the predominant "grounding source" on the circuit. This causes zero-sequence currents associated with ground faults to originate and flow back to that location. Placing energy sources that act as a grounding source (such as PV) on a four-wire multigrounded neutral system creates a problem in that zero-sequence flows start to originate from and return to these other grounding sources. Grounding energy sources can become significant in size in relation to the main substation grounding source. In this case, zero-sequence current can be diverted and zero-sequence current flows can be changed sufficiently to keep the relays and protective devices that measure this current (such as feeder ground fault-detection relays located at substations) from sensing adequate current and tripping or coordinating properly with the protection scheme on the feeder. For small and even medium amounts of PV interfacing to the system, the effect is either insignificant or can be controlled by using grounding reactors and relaying adjustments made to mitigate the issue. At high penetration levels on the system, though, the effects can become complex and difficult to mitigate without major power system upgrades.

It might seem that the simple solution to having too many grounding sources on the power distribution system would be to connect PV and other DG sources to the distribution system in a "nongrounding" fashion (through a delta winding on the high side of the DG interface transformer). Ideally, this would allow the PV and DG sources to feed only in the balanced positive-sequence current component (ignoring the zero-sequence neutral current). This does solve the issue of PV grounding sources interfering with the main substation ground fault protection; however, an even more severe new issue—ground fault overvoltage—can arise. Ground fault overvoltage is a condition where, during a line-to-ground fault, the voltage on the unfaulted phases rises to a much higher value than normal because of neutral shift. For example, an ungrounded energy source, such as one that feeds in through a delta transformer winding, can cause a serious phase-to-neutral ground fault overvoltage of as much as 182% of the nominal level. Note that there are other arrangements that also can act as ungrounded sources.

"Effective grounding" describes a method that ensures that the impedance of the generator neutral grounding (zero sequence) with respect to the positive sequence

---

[23] The following section on grounding is paraphrased from McGranaghan et al. (2008).

impedance of the system is not so high that overly severe ground fault overvoltages (caused by neutral shifts) occur during ground faults. Effective grounding does not entirely eliminate the overvoltage that occurs on unfaulted phases during a ground fault, but it is good enough to limit overvoltages to a safer level of about 125% to 135% (for comparison, an ungrounded situation would be about 165% to 182% of nominal).

As PV penetration levels grow, so will the issue of ground compatibility. This issue arises from the conflict where, on the one hand, ground fault overvoltage is undesirable and an effective grounding approach is preferred, and, on the other hand, too many effectively grounded sources pose the challenge of uncoordinated ground fault protection. This issue of grounding incompatibility for high-penetration PV applications can be managed in a number of ways within the framework of the existing power distribution system design (such as careful timing of utility source and PV inverter separations from the system, changes to relay pickup settings, and other methods). In the long run, though, the most effective method is a comprehensive power distribution design and grounding philosophy change that is part of the 21st-century distribution system. This can make the system fully compatible at all levels of PV penetration without complex measures or quasi-effective modifications (McGranaghan et al., 2008).

2.8 Subtransmission issues

According to McGranaghan et al. (2008), although the focus of problems associated with DG is currently on distribution networks, at higher levels of penetration, problems can occur on subtransmission networks as well. This is because of the level of current that could be fed back up into the subtransmission networks. They state “One of the biggest issues is ground fault overvoltage on the subtransmission lines. This can occur because substation transformers are usually delta on the high side and grounded-wye on the distribution side. Even though the PV located on the distribution system is usually effectively grounded with respect to that system, it will not be effectively grounded with respect to the subtransmission system after passing through that delta winding of the substation transformer. Because subtransmission lightning arrester ratings and insulation levels are usually based on effectively grounded sources, the overvoltages created could cause surge arrester failure and equipment damage on that side of the system.“

They propose methods for mitigating subtransmission ground fault overvoltages. They include:

(i) Timing the tripping of the subtransmission source grounding transformer so that it is last to clear (after all distribution system energy sources). This may require special high-speed transfer trips to all PV sites from the subtransmission circuit breakers.

(ii) Limiting the PV and/or DG capacity feeding into the subtransmission line, which would keep the capacity in safe defined penetration limit in relation to the load on the subtransmission line (heavy load causes voltage drop to cancel out the ground fault overvoltage effect), and

(iii) Specifying insulation coordination and arresters on all cables and devices to handle ground fault overvoltages. This last method, however, is probably practical only for new construction because it would be costly and difficult to retrofit on existing systems.

Other potential problems on subtransmission networks include unintentional islanding, interference with sectionalising switching schemes, and overcurrent protection coordination issues . On the latter problem, McGranaghan et al. (2008) suggest that “aggregation of many distribution substations with each substation having large amounts of generic DG and/or PV..... can lead to total fault contribution of several thousand amperes into the subtransmission system. This is likely to confuse various cascaded recloser and sectionalizing switch schemes, shift the apparent locations of faults for certain impedance-based zone-relaying schemes, and result in unintentional islanding conditions that threaten the subtransmission reclosing operations. Standard anti-islanding techniques based on UL 1741 and IEEE 1547 requirements will likely not be able to clear the subtransmission islands fast enough, resulting in reclosing problems and other issues”. The solution they propose is “appropriate communication-based high-speed transfer trips between generating devices and all key switchgear”.

2.9 Other issues

DC injection: While DC injection from inverters into the grid is possible, inverters are currently designed to minimise it, and disconnect when it exceeds very low levels (PVPS-T10, 2009).

High frequency waves: It is possible that electromagnetic noise associated with the high frequency used by inverters to convert DC to AC may have a negative impact on other electronic devices, however few problems have been reported to date (PVPS-T10, 2009).

3 BEST PRACTICES TO OVERCOME GRID CONNECTION ISSUES

As discussed above, approaches to address the technical issues associated with integration of DG into electricity networks are in a constant state of flux, with new approaches being developed and tested on an ongoing basis. This is especially true for high penetration of DG. The line between what could be considered 'current best practise' and what is 'research and development' is often blurred because the R&D is often undertaken on real life examples of what (depending on the outcomes of the R&D) may then be considered best practices.

There is also not necessarily one example of 'best practices' because what is most appropriate at a particular location will depend on local circumstances eg. nature of grid design, and location and size of both loads and DG. There may also be more than one approach that can be used simultaneously eg. geographical dispersion, forecasting and storage to smooth out power fluctuations.

The following firstly extracts what are likely to be best practices from Section 2 *Addressing grid integration issues in APEC* , summarises the potential and issues for smart grids, then summarises non-technical issues relevant to achieving best practices. Section 4 *Required Research and Development Activities*, continues this section by summarising what various research establishments have proposed is required for DG to be fully integrated into electricity networks.

3.1 Technical best practices

3.1.1 Voltage fluctuation and regulation

Voltage imbalance:

- Ensure that the cumulative size of all systems connected to each phase is as equal as possible.

Voltage sag:

- Voltage sag tolerances could be broadened and where possible, low voltage ride-through techniques (LVRT) could be incorporated into inverter design (as in Germany).
- Inverters can be configured to operate in voltage-regulating mode – although this is currently not allowed in many jurisdictions.
- Avoid putting DG immediately downstream of a voltage regulator, but where this occurs, configure the voltage regulator accordingly, including being able to control on each downstream line independently.

Voltage rise:

There are a number of approaches that can be used to reduce the incidence of voltage rise.

- Systems can be sized so that they are unlikely to be greater than the associated load.
- The DG can be disconnected from the grid using for example, minimum import relay (MIR) or a reverse power relay (RPR)

- A dynamically controlled inverter (DCI) can be used to ramp down the PV energy production if the load drops below a specific threshold
- Inverters can be configured to operate in voltage-regulating mode and so help boost network voltage by injecting reactive power – but it is essential to make sure that this is compatible with utility equipment. At the fringe of grid locations, inverters may need to be configured to provide voltage regulation through real power injection (but can do so only when there is sufficient solar insolation)
- The utility's series impedance could be decreased, which would give more 'headroom' for allowable voltage rise.
- Customers could be required to improve their power factors as well as decrease or increase their loads as appropriate, and have diversionary or dump loads.
- Storage associated with each DG power system could be used.

Of these, configuring inverters to operate in voltage-regulating mode, investing in lower impedance infrastructure and using storage are most likely the best options. However, voltage regulation is currently not allowed in many jurisdictions, lower impedance infrastructure is expensive and less useful for existing networks, and the use of storage is still in the R&D stage and is generally expensive. Voltage regulation by inverters may also require some form of centralised control to optimise their effectiveness - which adds to costs and complexity.

3.1.2 Power output fluctuation

Both geographic dispersal and forecasting of RE resource should be used where possible. Where they are either not possible or ineffective, storage can be used. However, this is still in the R&D stage and is generally expensive.

3.1.3 Power factor

Inverters that can provide power factor support can be used, although this may not be allowed in some jurisdictions. Real power injection is likely to be more effective for voltage regulation on the fringe of grid lines. Power factor correction can often be provided at lower cost using capacitors and inductors – for example SVCs or STATCOMS. Consideration should be given to implementing new standards for power factor for loads in order to reduce the out of phase currents on the network and thus make it easier for DG integration.

3.1.4 Frequency variations

Frequency variation are currently not a problem, and the impacts of higher penetrations can be addressed through conventional methods. Inverters may be able to provide frequency control themselves - but this still needs R&D to be fully realised. As penetration increases, careful consideration should be given to fault ride through, coordination of frequency trip limits with load shedding limits, and centralised control, particularly associated with larger DG systems and microgrids.

3.1.5 Harmonics

At current penetration levels harmonics are not a problem. However, the type of inverter control systems implemented can affect the network's ability to supply the harmonic currents sometimes required by loads. Consideration should be given to implementing tighter standards for harmonic currents required by loads.

3.1.6 Unintentional islanding

A centralised control system can be used to detect unintentional islands, and would overcome many of the problems associated with current passive and active detection methods. However, any centralised system is unlikely to be perfect and so should be integrated with redundant autonomous passive or active methods as appropriate. More uniform standards for autonomous anti-islanding algorithms should be investigated.

3.1.7 Fault currents

These are only a problem at high penetration levels, and inverters up to current standards should detect such faults and disconnect from the grid.

3.1.8 Grounding

Careful consideration and analysis of ground fault scenarios for feeders at significant DG penetration should be investigated. This will help establish the best grounding configuration for the generation present and coordinate this with overvoltage protection for medium voltage feeders - refer to section 2.7.

3.2 Smart grids

As discussed above, grid transmission and distribution network limitations can act as a barrier to the full use of DG, and renewable variability can cause reliability challenges at higher levels of penetration. Smart grids may offer methodologies of integration, in particular sub-areas of a grid where communication, control and protection may be implemented to achieve high levels of integration and reliability. These systems are most easily implemented in new developments where infrastructure and system design can be carefully planned from the ground up. Microgrid systems may also be retrofitted to subsections of an existing network where conditions and grid structure are favourable.

According to SEGIS (2007), the following are some of the elements that may be found in advanced distribution grids and microgrids:

- Electronically Controlled Distribution Systems. Today’s electro-mechanical control systems will be replaced by digital control with new electronic devices providing the controls and likely performing many of the high-speed switching functions. According to Whitaker et al. (2008), such distribution systems could incorporate new system architecture based on loops or meshes, instead of radial feeders. The loops or meshes would be interconnected by using power electronics similar to the power electronic transformers just mentioned that would precisely control the loop power flows, and could be centrally controlled. They could also include power electronic transformers in substations or along distribution feeders that could regulate voltage, control fault current, and improve power quality.
- Integrated Electricity and Communication Systems. The utility distribution system will incorporate communication systems to control distributed generation and storage systems and dispatchable power to improve system efficiency and stability while optimizing the value of renewable energy resources such as photovoltaics. They could include centralised control of distributed SVCs and

SVRs via a communications bus.

- Integrated Building Energy Management Systems. Energy management will be an integrated function when new distributed generation is employed. Building-integrated electrical generation will include energy management systems to optimize the building energy generation value while providing intelligent functions such as load shedding or shifting and energy storage to provide the most value to the consumer and dispatchability for the stability of the utility. Energy management will also likely include intelligent and adaptive logic that manages heating, cooling and lighting needs.
- Smart, End-use Devices. An integrated system that utilizes communications will enable the electric system to communicate directly with end-use devices, and would automatically optimize system operation.
- Meters as Two-way Energy Portals. The meter/service panel for a building will be transformed into an intelligent electronic gateway. Advanced meters/service panels that enable electricity suppliers and customers to communicate in real time and optimize the performance and economics of the system will interact with smart inverters and controllers.
- Combined Heat and Power: DG systems that enable production of both electricity and processing heat are efficient systems that can augment a central system to improve the quality of service.
- Direct Current in Microgrids. The concept of power systems that generate and deliver direct current, such as PV/energy storage systems, may be revived to serve DC loads in energy efficient microgrid infrastructures.

For more detail on best practices that is required for smart grids, see McGranaghan et al. (2008), and for more general descriptive requirements, refer to SEGIS (2007).

3.3 Non-technical issues relevant to uptake of DG

As renewable energy technologies develop and technical issues are addressed, non-technical ones, including governance and commercial arrangements, can still slow down or even stop deployment (Outhred et al, 2006). Nevertheless, as with technical issues, it is possible to learn from the experiences of others and to implement processes which eliminate or reduce non-technical barriers. Successful approaches are briefly discussed in this section. Figure 3 illustrates the possible role of different support strategies at different stages of technology development.

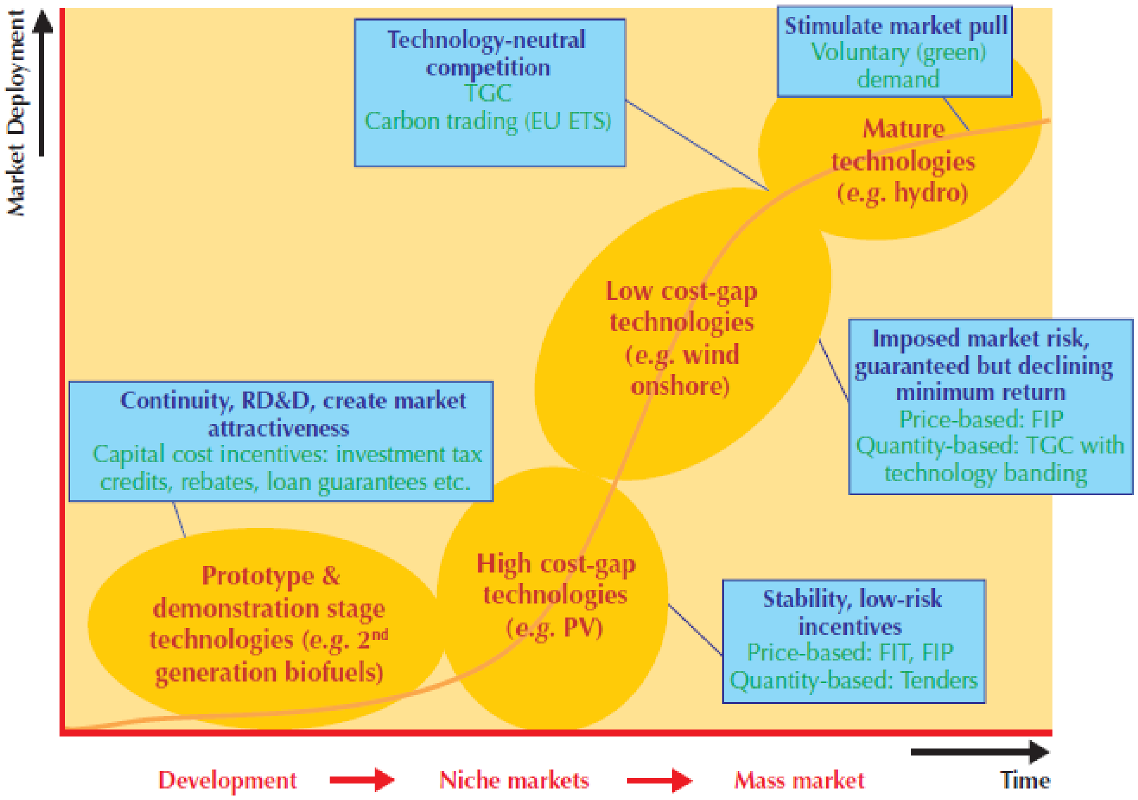


Figure 3: Policy Incentives as a Function of Technology Maturity (IEA, 2008)

3.3.1 Grid connection agreements

For both small-scale and larger renewable energy systems, the processes, costs and rights to connect to electricity grids can serve as a major deterrent. Hence, the development of standard grid connection agreements for different categories of connection can provide major benefits. Standard connection agreements help to simplify the grid-connection process, assist system designers, and provide greater certainty regarding performance, timing and costs for system owners, network service providers and electricity retailers. Development of such agreements requires input from all stakeholders and needs to consider technical, tariff, metering, and legal issues.

Generous support programs, such as the feed-in tariffs for renewables in Italy, were initially not sufficient to create market demand because the approval processes for even small systems were inconsistent and took many months or even years to negotiate (IEA-PVPS, 2009). When these barriers were reduced, the market grew strongly.

In Australia and the US, the standardisation of agreements for small-scale residential systems has taken several years, and is still not entirely consistent across the countries. Nevertheless, in Australia, the major elements are similar, including the right to connect, and the process now works smoothly in most instances, with little complication for the owner or interference from the utility.

The right to sell electricity excess of the system owner's needs, and the availability of minimum tariffs or net metering (where the price for exported power is the same as that for power purchased from the grid) for the exported electricity can also be standardised. Depending on the electricity market structure, this may require national legislation, or the agreement of different jurisdictions, but can be a powerful driver for RE system uptake in its own right. Tariff structures are discussed in Section 3.3.4.1.

3.3.2 Local government regulations

Local governments can play a useful role in streamlining processes, reducing costs and hence encouraging the use of renewable energy by (Watt et al., 2009):

- Providing training on renewable energy technologies and applications for staff likely to have to deal with public enquiries,
- Providing information on renewable energy technologies and applications to ratepayers, including lists of local accredited installers and components approved for use,
- Providing clear definitions of renewable energy systems which do not require local government consent,
- Providing a simple guide to the processes required for approval of renewable energy systems which do require development applications or other approvals,
- Working with other local governments and regional associations to standardise processes across districts,
- Waiving application and processing fees for renewable energy installations,
- Pre-approving technologies for heritage listed or other constrained areas,
- Better defining elevations from which renewable energy installations should not be visible in heritage or other restricted areas,
- Facilitating bulk purchase arrangements for RE systems which reduce renewable energy costs for ratepayers, and
- Supporting moves to standardise insurance for installers and systems, in line with normal building codes.

3.3.3 Solar Access

As more solar energy systems are installed, it becomes more important to consider the implications of solar access and maximising solar access benefits in land use planning and local environment plans. Typically, solar access is measured by the number of hours that the sun can shine onto north-facing (Southern Hemisphere) or south-facing (Northern Hemisphere) surfaces between the hours of 9 am and 3 pm on the shortest day of the year (winter solstice, 21st June in the Southern Hemisphere, and 21st December in the Northern Hemisphere). It is important to ensure that buildings do not infringe on the solar access provisions of a neighbouring property. The height of buildings, especially those located on a property’s boundary that faces the sun, can be a critical factor in ensuring good solar access. Neighbourhood agreements, such as covenants, may be entered into between property owners to protect solar access for PV, solar thermal systems and passive solar design (Watt et al., 2009).

To assist in avoiding conflicts, land use plans can take a lead in promoting good solar access zoning. Well orientated lots enable the future buildings to be more energy efficient, requiring less artificial heating, cooling and lighting and also have potentially greater roof space correctly orientated for solar water heaters and PV arrays. Sun-facing slopes improve opportunities for solar access; small lots are best suited to sun-facing slopes with gradients of less than 15% (or 1:6). Slopes that face away from the sun impose a penalty on solar access; large lots and lowest densities are therefore best suited to such slopes (ibid).

3.3.4 Renewable energy support strategies

Even where technical and non-technical issues can be resolved, initial deployment of new technologies may require a period of support, to facilitate public acceptance and overcome up-front capital cost barriers. A number of strategies have been used successfully (REN21, 2010).

3.3.4.1 *Feed-in tariffs*

The term feed-in tariff (FiT) refers to an explicit monetary reward for producing electricity from a renewable energy source, at a rate per kWh somewhat higher than the retail electricity rates being paid by the customer – which is why the measure is sometimes termed an “enhanced FiT”. In principle, the measure encourages the efficient production of renewable electricity with the output from the renewable energy system being monitored and recorded, and has consequently been promoted as a performance-based market support measure (IEA-PVPS, 2006; EPIA, 2005).

The FiT does not directly overcome the problem of the larger up-front costs associated with installing a renewable energy system. Successful FiT policies globally have overcome this problem by setting the FiT level at a rate that encourages a positive financial return over the lifetime of the policy and therefore enables the customer to access private sector finance to overcome the capital cost barrier. This provides a financial driver to ensure systems are designed and warranted to operate reliably over their lifetime.

There are two main variations of the FiT approach: in the first case, all the electricity produced by the renewable energy system, irrespective of how much is used by the customer or fed into the grid, qualifies for the feed-in tariff (a gross FiT). In the other situation, only the electricity generated that is surplus to the customer’s requirements is paid under the feed-in tariff (a net export FiT).[24] The remainder has the same value to the customer as their retail electricity rate. There are a number of reasons to use gross FiTs based on technical, equity and policy certainty criteria. However, in jurisdictions less supportive of DG, net FiTs may still be used. The attractiveness to the customer of the FiT is further reduced if net-billing is used and the grid import/renewable electricity export balance is calculated over an extended period of time, rather than on a half hourly or even instantaneous basis (IEA-PVPS, 2006).

---

[24] Note that this is different to net metering, where exported electricity is just paid the same rate as electricity used on-site.

The FiT can become more attractive for all parties when time-of-use metering and pricing are employed, reflecting the real benefits to the electricity network of reducing customer demand or adding power to the system when it is most needed. From the electricity utility's perspective this may be either when bulk power is most expensive to purchase or in locations where supply is constrained, or both. However, such locational signals may change over the lifetime of the feed-in tariff, while both calculating paybacks and estimating returns on investment may become more difficult if time-of generation rates are used.

Typically, funds for the FiT are raised through a levy on electricity bills across the board, which has two main attractions: the scheme is not subjected to the usual budgetary whims associated with government funds and, potentially, all electricity customers are contributing to improvements in their electricity supply system.

There are three distinct application segments that a FiT could target and support: residential applications (typically 1-3kW), commercial applications (typically <250kW) and large utility-scale power (typically >500kW). The level of the FiT necessary to stimulate uptake in each of these sectors will differ: larger systems will typically have a lower unit cost, but will also be competing against lower electricity prices. Commercial investments in PV require a commercial return, whilst residential installations may be done for a wider range of reasons.

Setting an appropriate FiT level

There are a number of ways that the level of the FiT can be set. Simple financial calculations can indicate the cash flow required to provide a certain return on investment for a given renewable energy system in a particular location – for example, to pay off the system within its warranty period, or within an investment timeframe considered suitable by the market, such as 5 years. Estimates of the value of externalities, such as the unfunded costs of pollution associated with traditional energy supply, can form the basis of the tariff. The specific electricity network benefits that may be relevant, such as peak demand reduction or line support, can also be monetised.

FiT schemes are becoming more widespread and are showing a variety of outcomes. While a high tariff level has been shown to be capable of driving substantial market growth, some of the controlling conditions that have been placed on different countries' schemes have resulted in difficulties in achieving such a result or sustaining high levels of investment. These controlling conditions have included:

- caps on capacity allowed under the scheme, which has resulted in the market being saturated within a very short time or created the risk of a collapse of the market when introduced retrospectively (eg. Korea, Spain)
- exclusion of certain types of projects, such as larger-scale plants (or lack of appropriate differentiation of tariffs), which creates market distortion and does not create the scale required to attract industry investment (eg. Australia)
- inadequate period guaranteed for the FiT
- overly complex administrative requirements.

Controlling the rate of deployment

A particular focus of policies that support deployment of technologies is to achieve a certain level of uptake. This is certainly not easy to predict. Where a FiT is used, if the pool of potential investors is not adequately understood – their motivations, financial positions and so on – overheated markets can result initially if the tariffs are set too high. Set the tariffs too low and the investments could be negligible, consequently wasting the time and effort that has been invested in the development of the scheme.

A FiT can of course be adjusted in response to changing circumstances and to help target a certain level of deployment. As long as these adjustments are well anticipated and not retrospective for existing customers, the key parameter of investment certainty can be maintained. It is also possible to use a system of price 'tiers' that reduce as certain levels of deployment are reached. Such adjustments avoid the need for setting a potentially problematic cap on the size of the scheme.

It is also possible to target the approach onto specific, limited market segments, which can then be expanded over time.

3.3.4.2 *Renewable energy targets or portfolio standards*

Many APEC economies already have renewable energy targets, typically in the range 5% to 20% by 2020 (REN21, 2010). Some of these are technology neutral, others specify targets (or portfolio standards) for each technology. In order to be effective, the targets need to be accompanied by support mechanisms to encourage uptake and by penalty clauses to ensure the target is not ignored. Successful mechanisms include renewable energy certificate schemes, based on kWh generated, tax credits, capital grants or feed-in tariffs.

Targets can be set locally – e.g. for a specific region, by state or for the entire country.[25] The most relevant and effective approach depends on issues such as the level of local (political and community) support, the structure and ownership of the electricity system, the tax structure, and the availability of renewable energy resources.

Technology-neutral targets are used where markets are expected to provide the most cost-effective solutions. Technology-based targets need different levels of support for each technology, depending on the state of development and current costs. They are therefore more complex to administer and may not achieve the lowest overall RE costs. Nevertheless, they can be more effective in ensuring a range of technologies is deployed, which can have other advantages, including a wider range of jobs and wider geographical dispersal.

The success of renewable energy certificate schemes to support targets is determined by the regulatory mechanism imposed, and how effectively and rigorously it is managed. The Australian Renewable Energy Certificate (REC) mechanism is one of the most successful, with the target increasing each year and the REC requirement allocated each year to the liable parties according to electricity sales, with set penalties imposed for non-compliance. However, one characteristic of renewables obligations that involve tradable certificates is that once the target is reached, there is little demand for certificates and so their spot market value approaches zero. This problem can be reduced with a continually increasing target, or sunset periods for the length of time that projects can earn certificates. However, depending on the electricity network's characteristics, there is a point beyond which additional renewable generation may not be desirable.

---

[25] See for instance www.dsireusa.org for a range of US policies.

Another problem for tradable certificate schemes can occur if targets are sufficiently high to significantly increase the marginal costs of generation – for example by driving the construction of wind farms in areas with less favourable wind regimes. This can result in windfall profits for generators that were constructed earlier in better wind regimes, and so reduces the scheme's efficiency. Limiting the time over which generators are eligible to create certificates can help limit this effect.

Other successful mechanisms include annual calls for renewable capacity, with the successful bidders (selected according to lowest cost, local jobs, or other criteria) provided with government support and grid access.

3.3.4.3 *Low interest loans and finance*

Performance based programs, such as feed-in tariffs, can be combined with zero or low interest rate loans to facilitate financing of renewable installations. It can be useful to raise awareness of PV in the finance sector, so as to encourage financial institutions to offer renewable energy loans. So-called soft loans reduce the impact of the high up-front capital cost of renewables and make it more attractive to a wider range of customers.

3.3.4.4 *Tax incentives*

Tax incentives are quite widely used in the US at federal, state and local government levels.[26] While many tax incentives are designed to encourage manufacturing, others target renewable energy application. For instance, in the US, the 30% Investment Tax Credit (ITC) helps cover the installation costs of a range of renewable energy technologies. Other tax incentives, such as reduced payroll taxes, can be used to encourage environmentally sustainable industries.

Grid-connection costs can be tax deductible to encourage rural development and tax benefits can appeal to many investors. Accelerated depreciation for businesses and tax rebates for individual taxpayers can be of considerable interest and can be used as delivery mechanisms for renewables.

It is also possible to offer reverse tax incentives, for instance reducing capital gains or exit taxes on property if renewables are installed. The latter represent much longer term potential benefits, however, and do not address the current problem of high initial capital cost.

3.3.4.5 *Building codes and energy performance standards*

For RE technologies which can be deployed on or as part of a building, the use of building codes or energy performance standards can be an effective means of increasing RE deployment. For instance, if new buildings need to achieve lower energy use per m^2 over time, it may become gradually more attractive to employ passive solar design features, with appropriate orientation to allow for the use of natural lighting, solar heating in winter and shading in summer. Stricter standards or mandates may encourage the use of solar water heaters and distributed generation, especially PV systems, but in the future may also encourage building-integrated wind generators, fuel cells and energy storage.

---

[26] See for instance the Database of State *(and Federal)* Incentives for Renewable Energy, www.dsireusa.org/

These approaches can be deployed at a local, state or country level, independently of electricity sector policies. They can be accompanied by support measures, preferably on a transitional basis only, to assist with higher up-front capital costs, to raise awareness and reduce customer concerns, or to up-skill the building sector workforce.

Building energy performance standards are often applied through the use of rating schemes. These may assess heat flow through the building envelope (walls, roof, doors, windows), or may also assess the main fixed energy using appliances in the building, such as water and space heaters and air conditioners. Schemes may set a score, such as a star rating, with new buildings required to achieve a specified level, or they may have a pass-fail criteria, where all new developments must pass before a development application is approved. The pass criteria may be tightened (i.e. energy performance improved) over time.

Rating schemes are useful because, in addition to facilitating the allocation of incentives, they provide some standardised means of measuring energy performance and hence inform and empower building designers and operators, who can then bring in innovative ideas (Pears, 2010). Successful schemes rate the most important criteria, and ensure consistency and compliance. For the latter, it is therefore important who runs the scheme, how credible they are and how the scheme complements other programs (such as government energy reduction, greenhouse gas or renewable energy targets). For this reason, such schemes are usually run through a local, state or federal government agency, or through the main building sector representative body. The key components of the scheme, what will be measured, as well as how it will be measured, should be clearly communicated to the building sector. User friendly tools which can be used to assess the impact of different structural, material or appliance changes should also be available. The latter should be well resourced and kept up to date (ibid). Successful schemes include the U.S. Green Building Council Leadership in Energy and Environmental Design (LEED[27]) and the NSW Government Building Sustainability Index (BASIX[28]). Moves are now underway to strengthen building targets further, with Europe aiming for net zero energy targets for new buildings by 2019 (ECEEE, 2009).[29] This means that energy production for the building will be required, in addition to efficient energy use, and distributed generation.

Every country has its own climate, building styles and construction types, so building codes and efficiency standards need to be locally developed. Nevertheless, lessons can be learnt from countries where successful programs have been implemented, and some aspects can be commonly applied.

3.3.5 Standards

Adequate safety and grid interconnection standards are necessary to ensure the successful integration of new energy technologies into existing infrastructure, and its widespread acceptance. Most countries adopt their own component and grid interconnection standards, but these can be based on available international

---

[27] http://www.usgbc.org/DisplayPage.aspx?CMSPageID=1988

[28] http://www.basix.nsw.gov.au/information/index.jsp

[29] http://www.europarl.europa.eu/sides/getDoc.do?language=EN&type=IM-PRESS&reference=20090330IPR52892

standards, or those already adopted by APEC economies, adjusted only to suit local conditions and technical requirements.

Implementing and maintaining standards reduces the risk of dangerous installations, but also facilitates the development of local technology, which is then compatible with international standards and suitable for export. The APEC Energy Standards Information System[30] facilitates standards sharing and consistency. It would be an appropriate site for renewable energy standards to be listed.

3.3.6 Training and accreditation

Along with the adoption of standards, successful renewable energy integration requires the availability of trained technicians and engineers, as well as sales staff, accountants, bankers and others in the supply chain (Pernick, 2009).

Initially, trained staff are often supplied by international component or project development companies. However, to ensure further development of the sector, and even the successful operation of plant installed by international experts, local staff must be trained. Many renewable energy projects installed in APEC economies via aid programs, or in response to renewable energy calls, have suffered from poor on-going maintenance, lack of spare parts and similar issues caused when the international experts leave. One important requirement to ensure that local expertise is built up and that projects operate successfully for their expected life, is to allocate on-going operating and maintenance costs, not just up-front capital, when projects are developed. This allocation can partly be used to train local staff. Experiences with the delivery of renewable energy in rural areas of developing countries are cited in PIAD (2005) and Saghir (2005).

It must be noted here that standards for these systems are changing and developing as they are being informed by research and practical implementation in the field. During this time of rapid development and expansion of the industry, it is absolutely essential to have a plan and capacity to implement a continuing process of education at all levels of the workforce.

3.3.7 Auditing and enforcement of standards

It is important, particularly in areas of new technology development and where a new industry is growing rapidly, that government agencies check the progress of the industry by auditing a significant sample of systems installed to monitor the implementation of standards and to feed back into and inform the education and training infrastructure.

3.3.8 Information and awareness

When a technology new to an area is introduced, it is important to ensure that the local people, both within the electricity sector and in the wider community, are included in the decision making, site selection and employment creation processes, and are given information about the technology, how long it will take to construct, how it will operate, what it will provide (and what it won't be able to provide), how it will be funded and what resources it will require to operate successfully (IEA-PVPS, 2003).

---

[30] See http://www.apec-esis.org

Community acceptance of renewables is one of the key criteria for its future success, so a budget allocation for this aspect should be included in any new projects. Community forums, where questions can be asked of the project developers, government officials and others, are a useful first step. It is important to take into account local concerns, and to modify the project if necessary in order to prevent future problems. The initial consultation should be followed by ongoing information as the project progresses. The Australian Bushlight program, initially developed for remote Aboriginal communities, is now being deployed in Indian villages.[31] It incorporates extensive community consultation, education and involvement in specification of the energy system.

3.3.9 Connecting central generating plants

Because renewable energy resources are site-specific, location of large-scale generators may require the construction of new transmission networks. In countries like the US, this is currently a favoured approach to RE integration into the generation mix, especially as electricity utilities are often the project developers (Maki and Pletka, 2010). Location and financing of new transmission lines can be a contentious and costly exercise, often taking many years to complete. Nevertheless, plans are under discussion in the US and Australia for construction of new transmission lines from sites with high RE resources to load centres. These sites tend to be areas with high wind, high solar insolation or large geothermal resources. In Europe, plans are being discussed to develop high voltage DC transmission lines connecting solar generating plants in north Africa into the European electricity market.

Best practices, in this context, is to have long-term strategic planning for the electricity sector, so that investments in significant infrastructure, such as new transmission lines, are planned for and approved well in advance. Typically both environmental and social impacts need to be addressed before final routes are decided. The aim should be to maximise the benefit of any new line - improving power supplies to grid-constrained areas, allowing for connection of a number of new generating plants and facilitating likely future grid extensions.[32]

Long-term strategic planning is also needed for successful installation of large-scale renewable energy generators. For instance, some proposed wind farm sites have encountered appreciable (or at least vocal) community opposition (Howatson and Churchill, 2006). Many of the technical arguments advanced by opponents of wind farms are misleading or inaccurate and so do not constitute a rational or legitimate basis for opposition. This is not to say, however, that opposition is wholly without merit. In some cases it appears that aggressive and/or insensitive tactics adopted by the proponents have been responsible for stimulating much of the opposition. Some opponents advance strong aesthetic grounds for opposing wind farms, though it is also true that others consider wind farms, at least in some cases, an aesthetic positive, and that ultimately, differences in aesthetic judgements come down to differences in personal tastes. In other cases it is clear that opposition to wind farms is motivated by fears about falling property values. Similar opposition, but with a stronger environmental rather than aesthetic component, has occurred for planned hydro dams and for biomass generators, the former for land alienation and habitat destruction; the latter for competition with food crops and the use of native

---

[31] See www.bushlight.org.au

[32] For example see www.desertec.org

forests. Long-term planning, extensive community consultation and a willingness to compromise some power output for more acceptable environmental and social impacts is usually key to a successful outcome.

4 REQUIRED RESEARCH AND DEVELOPMENT ACTIVITIES

This section summarises what various research establishments have proposed is required for DG to be fully integrated into electricity networks of the 21st century. Note that they often provide considerably more detail in the sources referenced, and the following essentially summarises the main points. The outcomes of recent research to date have been integrated into Section 2 and major projects are also summarised in Appendix A: *Summaries of APEC Research Projects*.

According to PVPS-T10 (2009), “Most of the potential problems indicated have yet to become tangible problems at the present time. Furthermore, even the issues with the potential to become problems in the future are generally not serious issues, and can either be dealt with sufficiently with existing technologies or else avoided with proper planning and design”.

4.1 Voltage fluctuation

PVPS-T10 (2009) considered overvoltage concerns a top priority, especially on rural grids and in areas such as Japan where inverters reduce outputs leading to social equity issues. They proposed focusing on designing distribution capacities and grid configurations to meet future capacity growth.

Whitaker et al. (2008) recommended research into developing “regulation concepts to be embedded in inverters, controllers, and dedicated voltage conditioner technologies that integrate with power system voltage regulation, providing fast voltage regulation to mitigate flicker and faster voltage fluctuations caused by local PV fluctuations”. They stated that “a cohesive technical and policy approach to allowing voltage regulation by DG will need to be developed to handle projected high-penetration scenarios. Slow regulation (for managing distribution system voltage profiles or microgrid operation) and fast regulation (for addressing flicker and cloud-induced fluctuations) will both be needed in high-penetration scenarios. Demonstrations of solid technical approaches for voltage regulating DG will provide support for updated standards that will streamline commercial product development and simplify utility interconnection”.

McGranaghan et al. (2008) divided their research priorities into near term and longer term. A near term priority was to “develop new voltage regulation schemes for steady-state (slow) regulation based on communication between LTC transformers, step-voltage regulators, capacitor banks, and DG..... The need for reactive power margins in PV inverters should be evaluated based on the potential economics of contributing to distribution voltage control and reactive power requirements”. Longer term research priorities were to “explore autonomous regulation concepts to be imbedded in DG inverters and dedicated voltage conditioner technologies and interact with power system voltage regulation for fast voltage regulation to mitigate flicker and faster voltage fluctuations caused by local wind and PV fluctuations”. Another longer term priority was to “study real-time integration of fast regulation resources and energy storage to provide voltage support for renewables interconnection across multiple control areas. Utility system models and data as have been developed in the western interconnect will allow consideration of new information sources such as wide-area phasor data for arming voltage control schemes”.

4.2 Power output fluctuation

US DOE (2009) thought that research effort should focus on solar variability and Intermittency as well as modelling the integration of PV generation. They suggested "standardised collection and analysis of sub-hourly data sets on solar variability (even sub-minute, especially from nearby systems)". This could be used in steady-state and dynamic models to simulate penetration levels, with a view to modelling more complex high-penetration scenarios in the future.

Having large data sets available for different weather regions, with a dispersed set of collection points equivalent to the distribution of DR, would be extremely valuable for modelling line flows and for estimating the value of storage systems and the duration of storage that is most cost effective.

4.2.1 Storage

The development of cheap and effective storage was seen as a priority by many research establishments because it can help with:

- peak shaving, load shifting, demand side management and outage protection,
- deferral of upgrades of transmission and distribution systems, and 'black starts' after a system failure, and
- several ancillary services, including contingency reserves, and voltage and frequency regulation.

According to SEGIS-ES (2008), there is a need to not only develop storage technologies, but to develop storage that is particularly suitable for PV. The focus should be on: increasing power and energy densities; extending lifetimes and cycle-life; decreasing charge-discharge cycle times; ensuring safe operation; and reducing costs. To achieve these aims, particular focus should be on improving operation under partial state of charge (PSOC) conditions, as well as optimising control electronics to ensure that batteries are charged and discharged according to the specifications of the manufacturer. Control systems are also required to integrate the operations of the PV system and inverter with storage, as well as the grid and possible loads.

Whitaker et al. (2008) suggested that efforts should be put into identifying "inverter-tied storage systems that will integrate with distributed PV generation to allow intentional islanding (microgrids) and system optimization functions (ancillary services) to increase the economic competitiveness of distributed generation. Energy storage subsystems need to be identified that can integrate with distributed PV to enable intentional islanding or other ancillary services".

McGranaghan et al. (2008) suggested similar priorities to Whitaker et al. (2008), having as a longer term goal the identification of "storage systems that will integrate with distributed generation to allow islanding and system optimization functions (demand control) to increase the economic competitiveness of the distributed generation. Investigate strategic and tactical application of energy storage (ultra capacitors, flywheels, pumped storage, batteries) to assist in solving many of the problems mentioned here.

The specific program objectives of the NEDO project "Development of an Electric Energy Storage System for Grid-connection with New Energy Resources (FY2006-2010)" are to (Morozumi et al. 2008):

- Establish technologies for a large-scale (MW) storage system
- Establish module level technologies to reduce costs and expand capacity (¥48000 ($480)/kWh if commercialized, 10 year lifecycle, 1 MW-scale
- Develop low cost, next generation storage technologies (¥15000($150)/kWh, 20 year lifecycle, 30 MW-scale), aiming for commercialization in the year 2030
- Conduct fundamental research study to evaluate safety, economics and lifecycle of storage technologies.

4.3 Frequency variation

McGranaghan et al. (2008) suggested that a longer term research priority should be to "assess schemes and develop analysis tools that allow a sufficient portion of DG to participate in bulk market dispatch operations, transmission power flow management and in the overall system frequency regulation so as to maintain system market and technical performance criteria within a high penetration DG framework". Such research could in particular focus on the use of inverters, possibly centrally controlled, to provide frequency control themselves.

4.4 Power factor

The major cause of out of phase currents on a power system is the connected loads. Many loads on the network, particularly in residential and business districts, are electronic and could, with changes in standards, be made to conform to unity power factor operation with sinusoidal current shapes. Further research should be carried out to establish and quantify the benefits to the power system in reducing out of phase currents and the voltage drops associated with these on the network. The benefits of modifying load behaviour would flow through to improved voltage range of operation for DG.

It is suggested that it is better to fix the source of the out of phase currents than to solve the problem in DG inverters with the associated costs, energy issues and equity problems.

In some limited application areas, microgrids or concentrated DG systems may be able to sell power factor correction services to parts of the distribution system by either providing VAr control or by importing or exporting real power at times when required by the network.

4.5 Harmonics

According to PVPS-T10 (2009), the "impact of harmonics is now extremely small with the recent advances in Power Control Systems and other technologies". However, given there does seem to be some scope for DC injection from transformerless inverters, they suggested the impact of transformerless inverters on even harmonics should be assessed in a future study.

The major cause of harmonics on the network are loads, not DG sources. To mitigate harmonic problems in the future and to reduce system losses there should be an investigation of significant changes to tighten the harmonic standards applied to appliances. This should particularly apply to small electronic appliances and computers where the total harmonic content is relatively small in absolute magnitude for each, but very high as a percentage of full load, leading to the situation that when summed the harmonics can be extremely significant.

4.6 Unintentional islanding

PVPS-T10 (2009) considered that, because of the significant differences between nations in the recognition of the importance of unintentional islanding, more emphasis should be placed on coordinating international efforts to address this issue.

McGranaghan et al. (2008) had the most to say about the needs of research into unintentional islanding. They summarised the aims of such research into three themes:

(i) Bulk system coordination of PV for market and bulk system control. Control of DG (including most PV) from the dispatch center will be needed. This will allow these resources to participate in and be aggregated into energy markets as well as to preserve system stability, power quality, and reliability at the bulk level.

(ii) Advanced islanding control. The system will employ smart, automated switchgear. Its enhanced islanding detection and communications will improve the ability to detect unintentional islands and reconfigure the power system, where appropriate, into reliability-enhancing intentional islands fed by properly configured PV and other DG resources.

(iii) PV interactive service restoration. Sectionalizing schemes for service restoration will allow PV and other DG resources to help pick up load during the restoration process and allow the system—if it has broken into islands—to self restore into a unified system. These schemes must deal effectively with cold load and inrush currents.

In terms of research efforts, they proposed two near term priorities:

- To solve the problem of unintentional islands on the sub-transmission and distribution system by developing improved autonomous anti-islanding algorithms or by using communication-based transfer tripping techniques.
- To investigate the communication technologies that can be reliable and secure and can provide sufficient bandwidth and cost effectiveness to meet the first two objectives. (These technologies could include broadband over power lines (BPL), wireless local area network/wide area network (LAN/WAN), power line carrier, low frequency pilot signaling, and optical fiber, among others.)

And two longer term priorities:

- Over the next 5 to 20 years, research objectives should be to plan and demonstrate communication infrastructure for distribution systems for implementation of overall system controls that will allow controlled islanding and other optimizing functions to take full advantage of distributed resources.
- To evaluate advanced methods for intentional islanding to improve reliability (controls, relays, switchgear, power generation, storage and communication requirements).

4.6.1 *Fault currents*

McGranaghan et al. (2008) considered that a near term research objective should be to “find ways to adapt the protective relaying and fusing in the distribution system to deal with fault currents that arise from larger quantities of DG (issues to solve include sympathetic circuit breaker or recloser operations, fuse-saving coordination, fault levels that exceed device limits, distribution transformer case rupture issues, network protector reverse power issues, sectionalizing switch interaction, and so on). Although the contributions are not as significant for PV, research should look at further inverter developments that could prevent high-penetration PV from being a factor in fault current coordination.”

These measures will allow short to medium term goals for DG penetration to be met, but longer term goals of larger penetration need significant investment in system design and coordination with large area communication for control and monitoring.

4.6.2 *Improved grounding compatibility*

McGranaghan et al. (2008) considered that a near term research objective should be to “study the effective grounding compatibility problem associated with DG and determine the best path (equipment technologies and system changes) to most cost effectively reduce the need to effectively ground all DG on the four-wire multigrounded neutral distribution systems. All possibilities are up for consideration including upgrading voltage withstand of loads and equipment, returning to a modified three-wire system, strategic use of grounding bank transformers, and timing-coordinated breaker tripping.“

A significant effort again is required here to solve the problems related to protection coordination associated with ground faults.

4.6.3 *Subtransmission*

McGranaghan et al. (2008) considered that a near term research objective should be to “solve the problem of ground fault overvoltage on the subtransmission system by investigating the use of grounding bank transformers, special switchgear timing considerations, transfer trips in switchgear operations, and upgraded voltage ratings of devices”.

4.7 Smart Grids

Like storage, the development of smart grids, or microgrids, was seen as a top research priority by many researchers.

US DOE (2009) identified the following as research priorities:

- Near-term: Demonstrations of low-cost, high-speed, and secure two-way controls and communications via smart metering.
- Mid-term: Demonstrations of bundling additional smart grid components (e.g., storage) and grid integration (controls and communications).
- Long-term: Demonstrations of energy management systems (EMS) that include standards for communications and controls, interoperable components, and ancillary services at high-penetration levels.

Whitaker et al. (2008) identified the following as research priorities:

- Solar energy grid integration systems that incorporate advanced integrated inverter/controllers, storage, and energy management systems that can support communication protocols used by energy management and utility distribution level systems.
- Hardware and algorithms that incorporate communication protocols used by EMS and utility distribution systems. When hardware is available that can accept input from advanced utility distribution systems and control loads and generation, algorithms can be developed that optimise economic use of energy sources.
- DC power distribution architectures as an into-the-future method to improve overall reliability (especially with microgrids), power quality, local system cost, and very high-penetration PV distributed generation.
- Advanced communications and control concepts that are integrated with solar energy grid integration systems. These are key to providing sophisticated microgrid operation that maximises efficiency, power quality, and reliability.
- Control strategies to manage microgrids. This area is related to grid-connected voltage regulation requirements, but it will most likely need to be augmented with communications to coordinate the transition between grid-connected and isolated modes of operation.
- Further investigation into the regulatory issues. For example, the customers who would benefit from the intentional island as a secondary source would have increased reliability relative to customers who would not be connected to the microgrid.

McGranaghan et al. (2008) identified the following as longer-term research priorities:

- To investigate DC power distribution architectures as longer term method for obtaining improved reliability, power quality, local system cost and very high penetration DG.
- To develop controllers for DG that implement the information models described above and interact with overall distribution management systems and higher level system controls. The master controller considers economic, environmental, comfort, and other end-use objectives as well as physical and regulatory constraints in day-to-day microgrid operation.
- To investigate opportunities in communication of the synthetic signals (as demonstrated with price signals in the case of the Olympic Peninsula GridWise project). There is potential to coordinate demand and generation at the distribution level for overall feeder reliability and safety as well as coordination with transmission-level needs.

4.7.1 Standards and Codes

There are important developments in terms of standards for communications within DG plant areas and between DG and other nodes of a electricity network. The IEC technical committee 57 “Power systems management and associated information exchange” has developed a number of standards that are looking to the future control and communications required for distributed resources. Of particular interest are:

- IEC 61850 series – “Communication networks and systems for power utility automation” and in particular IEC 61850-7-420 “Basic communication structure – Distributed energy resources logical nodes”
- IEC 61970 series “Energy management system application program interface (EMS-API)”

According to US DOE (2009), “standards for inverter operation and performance (e.g., IEEE 1547) need to be revised and developed to enable ancillary services such as local voltage regulation. These changes in standards are expected to be near- to mid-term activities, depending on the availability of technical evidence to support changes”. This is clearly a country-specific issue, with for example, the German standards incorporating a requirement for low voltage ride through, whereas the IEEE standards do not.

New standards will be required in the future to promote more uniform anti-islanding local inverter control and later to incorporate utility control of inverters including anti-islanding. At present there are generally only test protocols in country standards for single inverter testing for anti-islanding. This includes IEC standard IEC 62116 “Testing procedure of islanding prevention measures for utility interactive photovoltaic inverters”. Problems with the interaction of different anti-islanding algorithms establishing unintentional islands might be mitigated with more uniform algorithm requirements for directions of frequency drift. Further research is required here.

4.7.2 Inverter reliability

Whitaker et al. (2008) considered that inverter reliability should be improved. They stated that effort should be put into developing “advanced integrated inverter/controller hardware that is more reliable with longer lifetimes, e.g., 15 years mean time before failure and a 50% cost reduction”. They stated that the ultimate goal should be to develop inverter hardware with lifetimes equivalent to PV modules, closer to 20 to 30 years.

Measures to incorporate single point fail-safe grid disconnection under fault conditions within the inverter would also be welcomed by electricity utilities.

5 POTENTIAL TO APPLY BEST PRACTICES IN APEC ECONOMIES

This section discusses the factors that influence the degree to which the lessons learned, best practices and research outcomes may be applied throughout the APEC region in order to foster greater use of renewable energy sources. It is likely that different APEC economies will have different potential need for implementation of such measures and different technical capability for uptake in the short, medium and longer term. In fact, for countries with diverse regional economic development and/or varying geographic attributes, the potential for uptake may differ within the economy, depending on localised circumstances.

However, whatever the particular conditions within a country, the bottom line is that it is up to governments to ensure that best practices are applied. Irrespective of the country in question, if governments choose to put in place appropriate regulation, standards and agreements, and put in place the related mechanisms for enforcement, then best practices are more likely to be implemented.

Government and educational institutions may need to assist with information dissemination (regarding new rules and regulations), promotion of the use of best practices and facilitation of training for the appropriate public entities and private companies. This could be an important factor in some countries, because inadequate technical capability will restrict the uptake of best practices, even if the willingness is there. Governments will need to balance the introduction of the regulations and standards with provision of adequate training.

The types of best practices likely to be required may be different in different economies, simply because of different types of electricity networks, different renewable energy sources, different mixtures of conventional and renewable energy generators, different matches between generation and load, government priorities and ultimately, the technical capacity within government and the private sector. The following discusses the types of factors that influence both the need for best practices and ease of their implementation.

5.1 Role of government, regulator and electricity utilities

Arguably, the first step in the application of best practices for grid-connected DG is that a government knows what needs to be done, in terms of enacting suitable standards and regulations, based on industry research and expert advice. The next step is to formally adopt these standards and regulations within national legislation and put in place accompanying enforcement mechanisms. This assumes a certain level of capacity within government, and if this is not immediately available then delays in developing and establishing standards and enforcement may affect the timeline of best practices take up. Poor delivery early on may then impact longer-term confidence in the measures proposed.

Whether electricity utilities are privately or government owned should not in itself be an issue, assuming that government utilities are subject to and held to the same standards and regulations.

This leads to a factor which may affect enforcement levels of any best practice standards and regulations – the existence and independence of an energy regulator. If utilities still retain a regulatory role, then they may find themselves in a situation of conflict of interest with regard to regulations for grid-connected DG, in particular when it comes to the setting of feed-in-tariffs, regulations for Independent Power Producers (IPPs) and negotiation of Power Purchase Agreements (PPAs). For this reason a fully independent energy sector regulator is preferable.

It should be noted that, where electricity retailers – whether publicly or privately owned – rely on kWh sales, DG can be seen as a threat to revenue (as can energy efficiency) and hence the electricity sector may hinder DG proposals. Regulatory change may be necessary to overcome this.

5.2 Institutional and regulatory barriers

The main barrier of this type appears to be existing standards that were originally developed for DG when it was at relatively low penetrations. The standard most commented on is IEEE 1547, which needs to be revised and developed to enable ancillary services such as local voltage regulation. Low voltage ride through requirements could also be included into standards, as they are in Germany.

Similarly, as research in DG is published and international standards change over time, it is important to prevent national regulations which may be out of date from obstructing the application of new best practices developments in DG. A possible solution is national committees which follow developments of international standards and research and update relevant national standards when required.

Otherwise, either a lack of appropriate standardised grid-connection agreements and requirements, or the presence of inappropriate agreements and requirements, can inhibit the uptake of best practices. For example, utilities may place limitations on the amount of DG that can be connected to their networks (eg. limiting the amount of DG to being less than the minimum expected load) if they feel that their network is inadequately protected from low quality renewable products and installations or if they are unaware of the latest best practice technological advances which make grid-integration safer and easier. Existence and dissemination of installation and product standards can engender more “trust” in renewables from the utility side.

It is possible to achieve a virtuous cycle, where application of best practice can help to overcome institutional and regulatory barriers, since the use of best practice should gradually allow much higher penetrations. As more best practice applications are demonstrated, there will be increased confidence in grid-connected renewables and even utilities that might be generally opposed to DG would have the opportunity to visit existing best practice installations before deciding on their future DG policy.

5.3 Existing electricity infrastructure

Where growth in demand requires new infrastructure to be built, there is an opportunity for that infrastructure to be constructed from the ground up with the most appropriate technologies and grid architecture, and so best practices can be applied – ideally up to the standard of a smart grid. Where demand growth requires existing infrastructure to be augmented, this may also provide an opportunity for best practices to be applied. It is worth noting that there may be conflicts of interest between the need for energy efficiency to limit growth and then reduce demand in absolute terms, and the ease of applying best practices. Where best practices can be retrofitted to existing infrastructure, demand growth is not required and the nature of the existing infrastructure is less relevant.

For example, all the approaches that can be integrated into newly connected DG, such as ancillary service capabilities in inverters, storage and geographical distribution of DG, can be applied independent of the existing infrastructure - as can avoiding voltage imbalance by connecting the same amount of new DG to each phase of a network.

Applying best practices to existing DG would not so much be limited by the existing network infrastructure as by the existing systems, especially inverters, as these would need to be either reconfigured or replaced. The addition of storage to existing DG should not be affected by existing infrastructure, as long as there is room for it to be installed. Again, ensuring that the same amount of existing DG is connected to each phase of a network can be retroactively applied.

Addressing unintentional islanding by using active detection methods can be included into new DG but would require inverter replacement for existing DG. Integrated communications-based control systems are most likely to be readily applied to new-build networks, such as smart grids, but can still be applied to existing networks. Fully integrating a communications-based control system with redundant autonomous passive or active methods, would again be easier (and cheaper) in new-build networks, but could still be done for existing infrastructure.

Best practice approaches that would be most restricted by the existing infrastructure are those that require changes to the infrastructure itself, such as reducing its series impedance.

Of course, a fully integrated smart grid, that included best practices in system architecture, including possible mesh/loop network structures and the technologies required to operate them, could only be purpose-built from the ground up. In this case the nature of the existing infrastructure is also irrelevant, as such a smart grid could only be built to meet increased demand.

5.4 Relative availability of conventional and renewable resources

The relative availability of conventional and renewable resources actually has the most impact on the *need* for best practices to be applied, rather than on the *likelihood* of their introduction. Generally, the greater the uptake of renewables, the greater the need for best practices. Where no formal regulation and standards are in place, utilities may restrict uptake of renewables to the grid (see above Section 5.2). This could create a bottle-neck for renewable energy applications until regulations and standards are put in place which comply with best practices.

To the extent that the use of conventional resources is restricted, the rate of uptake of renewable energy will be increased. The use of conventional resources may be restricted for a variety of reasons including: access to the resources themselves (eg. through lack of indigenous resources or restrictions on imports); the impact that importing them has on the national balance of payments; the relatively high cost, especially if a price is placed on carbon; any pollution impacts; and conventional power stations being too large-scale for the purpose required.

The need for best practices to then be used to address any grid impacts will depend on the type of renewable energy resource to be used. Resources such as bioenergy, geothermal and hydro, that are more likely to be dispatchable and able to provide constant power output, should have little requirement for anything beyond standard inverter technology and grid architectures. Solar thermal electricity technologies are unlikely to be of the scale to be connected to distribution networks, but will have a greater requirement to the extent they do not include some form of storage. Similarly, small-scale wind is deployed at relatively low levels, but where it is deployed, is more likely to result in the need for best practices to be applied, as is PV, as both these resource are intermittent in nature and can affect, for example, voltage and frequency of grids.

The nature of the load profile will also influence the need for best practices. Where it is well matched to renewable energy supply there will be less need for storage or demand management, and voltage rise may be less of a problem. In these circumstances, DG will also be better placed to provide ancillary services and so implementation of best practices will provide more value to the electricity network.

5.5 Stages of economic and technical development

Different APEC economies are in different stages of economic and technical development, which means that different issues may need to be addressed, and so different types of best practices are likely to be appropriate. Even within countries, different regions, with different renewable energy resources, socio-economic conditions and technical capacities may need different treatment.

For example, it is possible that grids will not be so robust in less developed areas and economies, and so will be less able to withstand rapid fluctuations in power output. This implies that they are more likely to be in need of best practices that can deal with such fluctuations. However, there may also be lower economic and technical capacity to apply best practices options. These areas would have to be targeted for technical capacity building so best practices can be applied.

5.6 Local expertise in renewable and associated technologies

As discussed in Section 3.3.6, of most relevance here is the local expertise in DG technologies and the impacts of different types of DG technologies on the networks. In large part this can be driven by requirements laid down by governments (provided they are enforced), as such requirements will drive the development of the expertise required to meet them. Adequate training should also be made available for energy professionals by appropriate government, industry and educational bodies.

Industry associations, if they exist, can help lobby for application of best practices. These are often renewable energy resource-specific (e.g. hydropower associations, solar PV associations) but sometimes there are groups that are not technology-specific. These associations can provide services such as information dissemination, training and promotion of best practices for the technologies they represent.

To a certain extent, the installation of DG in developing countries is undertaken by external expertise. Such expertise can bring in the knowledge from developed countries, but it is important that knowledge transfer occurs to drive capacity building in local expertise and to allow the gradual scaling down of reliance on external expertise in the medium to long-term.

What has been found to be critical, in both developed and developing countries, is ongoing maintenance of DG. This means that appropriate mechanisms need to be in place to ensure that best practice inverters and any other enabling technologies (eg. batteries) are maintained on an ongoing basis. This can be a difficult issue if project finance is based on up-front capital cost only, with separate provision needed for ongoing maintenance. This has been typical of aid-based finance.

Ultimately, the ability to apply best practices in design, installation and maintenance of grid-connected renewables in the long-term will depend on the local expertise available. This means that energy professionals in the public and private sector need to be trained on an on-going basis, so that as technologies, products, installation methods, standards, regulations and best practices evolve, knowledge in the national industry also evolves.

6 CONCLUSION

When considering increasing levels of penetration of DG in electricity networks, it must be remembered that the original design of networks did not envisage DG in the distribution system. The design of networks was based on more centralised generation sources feeding into the transmission system, then subtransmission and distribution systems. The security, control, protection, power flows and earthing of the network was predicated on a centralised generation model with a small number of source nodes, with communication and control linking major generators and nodes. When installing DG, very low penetration (typically 5-10% of connected load) on a distribution system can generally be tolerated without significant problems as described in this report (refer to Table 1 and Figure 1). The threshold where problems occur depends heavily on the configuration of the network, length of lines involved (and hence impedances) and the concentration and time dependence of the load and generation in the area.

When penetration of DG rises above the minimum threshold to moderate levels of penetration (typically 10-20% of connected load) more significant issues arise in the network. More DG may be accommodated by making changes to the network such as minimising VAr flows, power factor correction, increased voltage regulation in the network and careful consideration of protection issues such as fault current levels and ground fault overvoltage issues. In many countries, the level of penetration is already at this middle stage and significant network modification is under consideration to allow expansion of DG without taking the next significant step of major design and infrastructure change.

At high levels of penetration, a point is reached (which is very network dependent) where significant changes have to be made to accommodate these higher levels of DG. This will probably require significant overall design and communications infrastructure changes to accommodate coordinated protection and power flow control. This third stage is very much in the research area and, although there are a number of communications protocols developed for distributed generation, the use, coordination and the design philosophy behind this are very much under research and development, the microgrid concept being one example. The full use of microgrids within the wider electricity network is again still very much in the research and development stage.

There is increasing pressure to quickly implement DG on electricity networks, but to do this without careful preparation beyond a relatively low penetration level will require considerable expenditure on the development of safe and carefully integrated protection and control coordination. The research and development areas highlighted in this report are critical to future DG implementation at high levels.

6.1 Recommendations for further work

The following recommendations should be read in addition to those discussed in Section 4 regarding technical R&D.

6.1.1 Technical projects

6.1.1.1 *High penetration of larger-scale RE into transmission networks*

This project would be similar to the project reported here but would focus on the transmission-level impacts of larger-scale intermittent RE. It would again involve a desktop review of work undertaken worldwide that identified the issues along with the various approaches being used to minimise any negative impacts, then would identify best practices as well as required R&D activities.

6.1.1.2 *Standards*

There are many different renewable energy and grid connection standards in place in different countries and even within some countries. A comprehensive survey could be used to determine what standards exist across a range of Committees including PV, wind, utility committees within the IEC and in the US (IEEE). This could include an assessment of the degree to which they promote or inhibit uptake of RE and changes being made in some countries to accommodate more renewables. The project could then comment on possible improvements and where there needs to be more discussion and/or research to identify best practice. This project could also comment on possible improvements to standards for end-use equipment that would assist with DG penetration (eg. harmonics and power factor). In addition to focusing on technical standards, it could look at non-technical issues such as grid-connection agreements with utilities.

6.1.1.3 *Case study projects of high penetration RE DG in remote areas*

Case studies can be used to highlight both best practice and worst practice, but possibly most importantly, how to turn a substandard project into best practice. The following case studies are for particular locations and projects but here are used as examples of how to highlight best and worst practice in three different scenarios: (i) high penetration PV, (ii) integration of battery storage with wind and solar, and (iii) a comparison of projects that have wind/flywheel storage, PV/ flywheel storage and PV/no storage. There are many other projects that could be drawn on to illustrate best and poor practice. These should be chosen to be representative of the different types of projects in different APEC economies. They could be made available through a web-based searchable database in a standardised format that could include contact details of people closely involved with the project. Such a database could even allow project operators to enter their own project's details, which could then be vetted by a moderator. This could allow very rapid development of a comprehensive database with reduced effort.

High penetration PV

At Umuwa solar farm in Australia a 300kWp solar system has been connected to a 600-1200kWp grid. This has resulted in 40-50% RE penetration that has resulted in poor quality control, outages and diesel stations not generating at optimal efficiencies. As a result, the government is more reluctant to develop remote RE systems. Similarly, high penetration of renewables on the Hawaii islands have had benefits of reduced fuel use but have also created grid management issues. By reviewing the history of such projects, including the processes that were followed for project development, as well as the technical outcomes, valuable lessons may be learned for others who are considering similar projects.

Integration of battery storage with wind and solar

At King Island in Australia a combined wind/solar system with battery storage is a good example of poor integration of these technologies on a remote grid, and it is preventing further integrated projects of a similar nature. It would be useful to understand why the battery storage did not work as expected, as well as carry out a theoretical assessment of other viable storage/integration technologies that could be used (eg. flywheels). This could be compared to projects considered to have been more successful, or trials which have more carefully examined the issues, such as those at McAlpine Creek or Sacremento Municipal Utility District, USA.

Comparison of different projects with high renewable penetration (wind/flywheel storage, PV/ flywheel storage and PV/no storage)

The RE system at Coral Bay in Australia uses wind/flywheel storage, the Marble Bar system uses PV/flywheel storage, while the Norfolk Island uses only PV with no storage. US examples use Li-ion and ZnBr batteries, with and without load and grid management changes. A comparison of such systems would provide valuable information regarding their relative effectiveness and costs. This may help identify the storage issues on small grids that are too large for batteries, but have a significant penetration of RE. This would be applicable to remote areas of the US, Australia, Russia, China as well as many island locations.

6.1.2 Non-technical projects

6.1.2.1 *A handbook of best practice policies*

Appropriate policies are not only required to directly drive uptake of RE but also enable the development of the industry more generally, especially in terms of innovation. Staged development of the renewable energy industry requires a framework of policies that changes over time as the industry moves through different stages of development. The most appropriate policy framework is likely to be differ depending on the particular country's characteristics and circumstances. In addition to policies that drive uptake, such a framework needs to help with the development of other aspects of industry development such as grid-connection agreements, local government regulations including solar access, the application and enforcement of standards, training and accreditation of technicians, and information and awareness raising etc. Many different policies and variations of policies are currently used worldwide with differing degrees of success, and it can often be the details of a policy design that can distinguish between success and failure. There is a need for a concise summary of the different policies that are available, their pros and cons and the circumstances in which they are most likely to be required and effective. This should include how such policies can be managed over time as the RE industry moves through different stages of development. Policy-makers are generally very time poor and so it is possible that rather than a hard copy handbook, the outcomes of this project may be better communicated through a web-based resource, the core of which was a concise summary with links to more detail on particular policies as required. The outcomes of this project could be updated annually through such a database to take account of latest best practice developments in technologies, products, installation methods, standards and regulations.

6.1.2.2 *Training package for regulators and policy-makers for best practice RE*

Policy makers and regulators do not necessarily have access to information on best practice RE technologies and how to promote it in their own countries. In order to enhance the regulation and policy-making capacity of APEC economies a short/intensive training package could be developed covering the basics of regulation/policy making and promotion of best practice RE. This could be based on the handbook of best-practice policies above but could include more technical information and be structured in a format suitable for training, most probably through workshops. It could also be targeted to suit particular audiences depending on where the workshop is held. As a result, policy-makers & regulators will be more aware of types of best practice RE which are likely to suit the way their own energy system is regulated. This will enable faster adaptation of energy policies and regulations to facilitate uptake.

6.1.2.3 *Assessment of APEC economies legislative and institutional frameworks*

There is a need to be more aware of current best practice legislative and institutional frameworks. The focus here is not so much on the design of particular policies but on government organisational structures and how the responsibilities for RE are divided between them. Such divisions can create difficulties for RE if artificial barriers are created or exist due to prior energy structures that restrict both policy development and project approval processes. Increased exchange of experiences between countries on their legislative and institutional frameworks could help streamline the processes required for RE uptake. This would involve as assessment of the different legislative and institutional frameworks for energy (not just RE) in representative APEC economies in terms of whether they are promoting or obstructing RE, as well as recommendations for legislative and institutional reform to promote RE in both urban and rural areas.

6.1.2.4 *Training package for utilities and RE installers for best practice RE*

Utilities and RE installers do not necessarily have access to information on best practice RE and how to promote it in their countries. In order to enhance the technical capacity of APEC economies a short training package could be developed covering the basics of best practice technical options for RE. This could include:

i) Review of advantages of RE for urban and rural areas, with a focus on best practice

ii) Review of current technical best practice for selected APEC economies.

iii) Case studies, examples and an analysis of the current situation in a number of countries/ projects involving RE

iv) Examples of where adoption of best practice has proved to be effective for the development of sustainable energy technologies

v) Tools/suggestions for utilities and RE installers to take appropriate and tailored actions.

vi) Workshops for the outcomes of this project to be communicated to utilities and RE installers

Utilities and RE installers will be more aware of best practice RE. This will enable faster adoption of best practice RE. This could take the form of a handbook as well as workshop materials that could be updated annually to take account of latest best practice developments in technologies, products, installation methods, standards and regulations.

6.1.2.5 *Community ownership of RE projects*

In different countries various models have been used to promote and enable community ownership of RE systems. This allows ownership by people that may not be able to afford their own system or have the space or technical capacity to develop one. It can also help reduce system costs through economies of scale and can, for example, result in PV systems being placed on non-residential networks where the output is better matched to demand. It would be useful to survey the different approaches taken globally to enable community-ownership of RE systems, and so develop models that could be applied in different APEC economies depending on their circumstances.

7 REFERENCES

Archer, C.L. and Jacobson, M.Z. (2005) Evaluation of global wind power *J. Geophys. Res*, 110, *D1211, doi:10.1029/2004JD005462*

Asano, H., Yajima, K. and Kaya, Y. (1996) Influence of photovoltaic power generation on required capacity for load frequency control. *IEEE Transactions on Energy Conversion*, 11(March(1)), p188–93.

Baker, P., McGranaghan, M., Ortmeyer, T., Crudele, D., Key, T. and Smith, J. (2008) *Advanced Grid Planning and Operation*. NREL/SR-581-42294. Golden, CO: National Renewable Energy Laboratory, January 2008.

Barker, P. (2010) *Defining High Penetration PV – Multiple Definitions and Where to Apply Them*, High Penetration Photovoltaics Workshop, May 20 2010, Denver Colorado.

Boyd, C., Johnson, K., Torres, J. and Hernandez, J. (2009) *APEC Workshop on Renewable Energy Grid Integration Systems - Workshop Summary*, APEC Energy Working Group, March 2009.

Bradbury, K. (2010) *Energy Storage Technology Review*, Duke University.

Bründlinger, R., Mayr, C., Fechner, H., Braun, M., Ogimoto, K., Frederiksen, K., Kroposki, B., Graditi, G. and MacGill I.F. (2010) *Bringing together international research on high penetration PV in electricity grids*, Task 14 IEA-PVPS, presented at 5th World PV Conference, Valencia, September 2010.

Chalmers, S., Hitt, M., Underhill, J., Anderson, P., Vogt, P. and Ingersoll, R. (1985) *The Effect of Photovoltaic Power Generation on Utility Operation*, IEEE Transactions on Power Apparatus and Systems; PAS-104, 1985, pp. 524–530.

Coddington, M., Kroposki, B., Basso, T., Lynn, K., Sammon, D., Vaziri, M. and Yohn, T. (2009) *Photovoltaic Systems Interconnected onto Secondary Network Distribution Systems – Success Stories*, National Renewable Energy Laboratory.

Cyganski, D., Orr, J., Chakravorti, A., Emanuel, A., Gulachenski, E., Root, C. and Bellemare, R. (1989) *Current and Voltage Harmonic Measurements at the Gardner Photovoltaic Project*, IEEE Transactions on Power Delivery; Vol. 4, 1989, pp. 800–809.

Demirok, E., Sera, D., Teodorescu, R., Rodriguez, P. and Borup, U. (2009) *Clustered PV inverters in LV networks: An overview of impacts and comparison of voltage control strategies*, Electrical Power & Energy Conference (EPEC), 2009 IEEE, Montreal, QC, 22-23 Oct. 2009, p1-6.

Denholm, P., Ela, E., Kirby, B. and Milligan, M. (2010) *The Role of Energy Storage with Renewable Electricity Generation*, NREL Technical Report NREL/TP-6A2-47187, January 2010.

DISPOWER (2006) *Distributed Generation with High Penetration of Renewable Energy Sources, Final Public Report*, 2006.

ECEEE (2009) *Net zero energy buildings: definitions, issues and experience. Steering through the maze*, European Council for an Energy Efficient Economy, Issue 2, September 2009.

Eltawil, M. and Zhao, Z. (2010) Grid-connected photovoltaic power systems: Technical and potential problems - A review, *Renewable and Sustainable Energy Reviews*, 14, p112-129.

EPIA (2005) *Position Paper on a Feed-in Tariff for Photovoltaic Solar Electricity*, European PV Industry Association.

EPRI (1990) *Photovoltaic Generation Effects on Distribution Feeders, Volume 1: Description of the Gardner, Massachusetts, Twenty-First Century PV Community and Research Program*, EPRI report EL-6754.

GE Energy (2010) *Western Wind and Solar Integration Study*, prepared by GE Energy for NREL.

Gyuk, I. (2008) *Frequency Regulation Using Fast Energy Storage*, Energy Storage Research, US Dept of Energy.

Howatson, A. and Churchill, J. (2006) *International Experience with Implementing Wind Energy*, The Conference Board of Canada.

Hudson, R. (2010) *PV Inverters with VAR Control, LVRT, and Dynamic Control*, High Penetration Photovoltaics Workshop, May 20 2010, Denver Colorado.

IEA (2008) *Empowering variable renewables – options for flexible electricity systems*, International Energy Agency, OECD, Paris

IEA-PVPS (2003) *PV for Rural Electrification in Developing Countries: A Guide to Capacity Building Requirements*, IEA-PVPS T9-03, 2003.

IEA-PVPS (2006) *Feed-in Tariff Principles*, PVPower Issue 26, www.iea-pvps.org.

IEA-PVPS (2009) *Trends in PV Applications*, 1992-2008, IEA PVPS T1:18, 2009.

Inage, S.-I. (2009) *Prospects for Large-Scale Energy Storage in Decarbonised Power Grids*, International Energy Agency.

Infield, D.G., Onons, P., Simmons, A.D. and Smith, G.A. (2003) "Power Quality from Multiple Grid-Connected Inverters", IEEE Transactions on Power Delivery, 19(4), p1983-1989.

Inoue, N., Morozumi, S. and Arashiro, Y. (2007) *Large-scale PV Demonstration Projects in Japan*, 2nd International Symposium for Distributed Electricity Generation and Smart Grids, 17th –18th October 2007.

Jewell, W., Ramakumar, R. and Hill, S. (1988) *A Study of Dispersed PV Generation on the PSO System*, IEEE Transactions on Energy Conversion; Vol. 3, 1988, pp. 473–478.

Khan, U.N. (2008) 'Impact of Distributed Generation Electrical Power Network', Proceedings of the 7th Int. Conference EEEIC 2008, Cottbus, 5-11.05.2008, pp. 82-85

Khan, U.N. (2009) 'Distributed Generation and Power Quality', *International Conference on Environment and Electrical Engineering*, 2009, pp 273-276

Kirby, B.J. (2004) *Frequency Regulation Basics and Trends*, prepared by the Oak Ridge National Laboratory for the US Department of Energy.

Kroposki, B. and Vaughn, A. (2003) *DG Power Quality, Protection, and Reliability Case Studies Report*, NREL/SR-560-34635. Golden, CO: National Renewable Energy Laboratory. General Electric Corporate R&D, 2003.

Kroposki, B., DeBlasio, R. and Simões*, M. (2010)* Benefits of Power Electronic Interfaces for Distributed Energy Systems, IEEE Transactions on Energy Conversion, 25(3), p901-908.

Kurokawa, K.; Kawasaki, N.; Ito, M. (2009) "Particularity of PV aggregations incorporating with the power grids - Development of a power router", *Photovoltaic Specialists Conference* (PVSC), 34th IEEE, 7-12 June 2009, p1632-1637.

Latheef, A.A., Gosbell, V.J. and Smith, V. (2006) *Harmonic Impact of Residential Type Photovoltaic Inverters on 11kV Distribution System*, Australian Universities Power Engineering Conference, 10-13 Dec 2006, Melbourne, Victoria, Australia.

Lew, D., Milligan, M., Jordan, G., Freeman, L., Miller, N., Clark, K. and Piwko, R. (2009) *How do Wind and Solar Power Affect Grid Operations: The Western Wind and Solar Integration Study*, 8th International Workshop on Large Scale Integration of Wind Power and on Transmission Networks for Offshore Wind Farms*,* Bremen, Germany, October 14–15, 2009.

Liu, E. and Bebic, J. (2008) *Distribution System Voltage Performance Analysis for High-Penetration Photovoltaics*, National Renewable Energy Laboratory.

Maki, S. and Pletka, R. (2010) 'California's Transmission Future', *Renewable Energy World*, 25th August, 2010.

Manz, D., Schelenz, O., Chandra, R., Bose, S., de Rooij, M. and Bebic, J. (2008) *Enhanced Reliability of Photovoltaic Systems with Energy Storage and Controls*, *GE Global Research Niskayuna, New York.*

McGranaghan, M., Ortmeyer, T., Crudele, D., Key, T., Smith, J. and Barker, P. (2008) *Renewable Systems Interconnection Study: Advanced Grid Planning and Operations*, Sandia National Laboratories.

Miller, N. and Ye, Z. (2003) *Report on Distributed Generation Penetration Study*. NREL/SR-560-34715. Golden, CO: National Renewable Energy Laboratory.

Milligan, M. and Kirby, B. (2010) *Utilizing Load Response for Wind and Solar Integration and Power System Reliability*, Presented at WindPower 2010, Dallas, Texas, May 23–26, 2010.

Mills, A and Wiser, R. (2009) *Spatial and Temporal Scales of Solar Variability: Implications for Grid-Integration of Utility-Scale Photovoltaic Plants*, at the Utility-scale PV Variability Workshop, Cedar Rapids Oct 7 2009.

Mills, A., Ahlstrom, M., Brower, M., Ellis, A., George, R., Hoff, T., Kroposki, B., Lenox, K., Miller, N., Stein, J. and Wan, Y. (2009) *Understanding Variability and Uncertainty of Photovoltaics for Integration with the Electric Power System*, at the Utility-scale PV Variability: Workshop Cedar Rapids Oct 7 2009.

Mizuho (2008) *Visualisation Tool for PV Operating on Grids*, produced for IEA PVPS Task 10 by the Mizuho Information and Research Institute.

Mohd, A., Ortjohann, E., Morton, D. and Omari, O. (2010) Review of control techniques for inverters parallel operation, *Electric Power Systems Research* 80, p1477–1487.

Morozumi, S., Nakama, H. and Inoue, I. (2008) *Demonstration projects for grid-connection issues in Japan*, Elektrotechnik & Informationstechnik (2008) 125/12: 426–431.

Nakama, H. (2009) *NEDO Research Related to Large-scale PV-related Grid-connection Projects*, NEDO.

NEDO (2006) *Demonstrative Project of grid-interconnection of clustered photovoltaic power generation systems*, presentation by New Energy and Industrial Technology Development Organisation (NEDO).

Nishikawa, S. (2008) *Demonstrative Research on Clustered PV Systems*, IEA PVPS Workshop 'The Role of PV in Smart Grids', November 2008.

Okada, N., Takasaki, M., Sakai, H. and Katoh, S. (2007) *Development of a 6.6kV-1 MVA transformerless loop balance controller* , 2007 IEEE Power Electronics Specialists Conference, Vols 1-6, p1087-1091.

Outhred, H. and Spooner, T. (2002) *Network Issues Associated with Distributed Generation***,** Australian CRC for Renewable Energy, The University of New South Wales.

Outhred, H., Howse, R., van Bork, P. and Bull, S. (2006) *Integration of Renewables into Electricity Grids*, a Scoping Paper for IEA Experts Working paper.

Passey, R., Watt, M., Outhred, H., Spooner, T. and Snow, M. (2007) *Study of Grid-connect Photovoltaic Systems - Benefits, Opportunities, Barriers and Strategies*, for The Office of Energy, Western Australian Government.

Pazos, F. J. (2009) 'Failure of anti-islanding protections in large PV plants', Presentation in conjunction with paper: 'Power frequency overvoltages generated by solar plants', C I R E D 20th International Conference on Electricity Distribution Prague,

Pears, A. (2010) *Green ratings for buildings and appliances: the critical imperative for local government*, presented at Sustainable Councils 2010, 6-7 September, Sydney.

Perez, R., Hoff, T.E. and Perez, M. (2010) Quantifying the Cost of High Photovoltaic Penetration, at the American Solar Energy Society 'Solar 2010 Conference', May 17-22, Phoenix, Arizona.

Pernick, R., Wolder, C., Gauntlett, D. and Winnie, T. (2009) *Clean tech Job Trends 2009*, Clean Edge, October 2009.

PIAD (2005) *Best Practices in Sustainable Rural Energy Development: Five International Case Studies*. Pembina Institute for Appropriate Development.

Povlsen, A. (2002) *International Energy Agency report, IEA PVPS T5-10*: February; 2002.

PVPS-T10 (2009) *Overcoming PV grid issues in the urban areas*, IEA PVPS Task 10, Activity 3.3 Report IEA-PVPS T10-06 : 2009 October 2009.

REN21 (2010) *Renewables 2010, Global Status Report*, Renewable Energy Policy Network for the 21st Century.

Roberts, B. (2009) *Capturing Grid Power – Performance, Purpose and Promise of Different Storage Technologies*, IEEE Power & Energy Magazine, July/August 2009.

Ropp, M. (2010) *Moving PV from negative load to distributed generation*, High Penetration Photovoltaics Workshop, May 20 2010, Denver Colorado.

Saghir, J. (2005) *Energy and Poverty: Myths, Links and Policy Issues*, Energy Working Notes No.4 May 2005, World Bank.

SEGIS (2007) *Solar Energy Grid Integration Systems "SEGIS": Program Concept Paper*, US Department of Energy and Sandia National Laboratories, Oct 2007.

SEGIS-ES (2008) *Solar Energy Grid Integration Systems – Energy Storage (SEGIS-ES)*, US Department of Energy and Sandia National Laboratories, July 2008.

Shimada, T., Kawasaki, N., Ueda, Y., Sugihari, H. and Kurokawa, K. (2009) *Study on Battery Capacity for Grid-connection Power Planning with Forecasts in Clustered Photovoltaic Systems*, IEEJ Transactions on Power and Energy, 129(5), pp. 696-704 (2009).

Sulc, P., Turitsyn, K., Backhaus, S. and Chertkov, M. (2010) *Options for Control of Reactive Power by Distributed Photovoltaic Generators*, arXiv, Cornell University, New York, USA.

Thomson, M. and Infield, D. (2007) "Impact of Widespread Photovoltaics Generation on Distribution Systems." *IET Journal of Renewable Power Generation*; 1, 2007, pp. 33–40.

Tröster, E. (2009) *New German Grid Codes for Connecting PV Systems to the Medium Voltage Power Grid*, 2nd International Workshop on Concentrating Photovoltaic Power Plants: Optical Design, Production, Grid Connection, 9-10 March 2009.

Trujillo, C.L., Velasco, D., Figueres, E. and Garcerá, G. (2010) Analysis of active islanding detection methods for grid-connected microinverters for renewable energy processing, *Applied Energy*, 87, p3591–3605.

Turitsyn, K., Sulc, P., Backhaus, S. and Chertkov, M. (2010) *Local Control of Reactive Power by Distributed Photovoltaic Generators*, arXiv, Cornell University, New York, USA.

UCTE (2004) *Final Report of the Investigation Committee on the 28 September 2003 Blackout in Italy*. Union for the Coordination of Transmission of Electricity 2004, p. 121.

Ueda, Y., Kurokawa, K., Tanabe, T., Kitamura, K., Akanuma, K., Yokota, M. and Sugihara, H. (2007) *Study on the Over Voltage Problem and Battery Operation for Grid-Connected Residential PV Systems*, 22nd European Photovoltaic Solar Energy Conference, 3-7 September 2007, Milan, Italy.

Ueda, Y., Suzuki, S. and Ito, T. (2008) *Grid Stabilization by Use of an Energy Storage System for a Large-Scale PV Generation Plant*, NEDO.

Uemura, S. (2008) *Development of Operation and Control Method for Autonomous Demand Area Power System: Study on Method for Regulating Voltage according to Interconnection rate of Dispersed Generation*, CRIEPI Report R07018.

US DOE (2009) *High Penetration of Photovoltaic (PV) Systems into the Distribution Grid*, Workshop Report, February 24-25, 2009 Ontario, CA, sponsored by the U.S. Department of Energy, the Office of Energy Efficiency & Renewable Energy, the Solar Energy Technologies Program, and the Systems Integration Subprogram.

Walling, *R.A.* and Miller, N.W. (2003) *Distributed Generation Islanding – Implications on Power System Dynamic Performance*, *Power Engineering Society Summer Meeting*, 2002, IEEE 1: 92-96.

Watt, M., Passey, R., Nance, A., Bradbrook, A., Snow, M., Oliphant, M., Frearson, L., Cowley, P., Franklin, S. and Troman, S. (2009) *Best Practice Guidelines for Local Government Approval of Photovoltaic Installations*, for the Department of the Environment, Water, Heritage and the Arts, Commonwealth of Australia

Whitaker, C., Newmiller, J., Ropp, M. and Norris, B. (2008) *Renewable Systems Interconnection Study: Distributed Photovoltaic Systems Design and Technology Requirements*, Sandia National Laboratories.

Yu, B., Matsui, B. and Yu, G. (2010) A review of current anti-islanding methods for photovoltaic power system, *Solar Energy*, 84 p745–754.

8 APPENDIX A: SUMMARIES OF APEC RESEARCH PROJECTS

Project title: Demonstrative Project of Regional Power Grids with Various New Energies	**Organisation:** NEDO **Year:** 2003-2007
Objective: The purpose of this project was to study the interaction of different new energy sources on small regional grids, and level out the fluctuations in the power outputs to a level comparable to the national electricity grid. Three sites were studied at Aichi, Kyotango, and Hachinohe. The Aichi mini-grid was previously located at the NEDO pavilion at the World Expo in 2005. The mini-grids included power supply from various sources, such as fuel cells, grid-connected PV arrays, sodium-sulphur batteries, wind turbines, and gas turbines. All sites had a connection to the national electricity grid.	**Results:** The Aichi site's main source of power came from fuel cells and a PV array, and used sodium-sulphur batteries for modelling out power fluctuations. It used two molten carbonate fuel cells (MCFC) with capacities of 270 kW and 300 kW, a 25 kW solid oxide fuel cell and four 200 kW phosphoric acid fuel cells. The fuel cells were fed primarily from the urban gas network, but some of the fuel for the MCFCs came from a methane fermentation system and a gasification system. The 300 kWp PV array was composed of mono- and polycrystalline silicon modules and amorphous silicon modules. The system was demonstrated at EXPO 2005 from December 2004 to September 2005, then moved near the Chubu International Airport and resumed operation from August 2006 to December 2007. The target of 3% of power imbalances per 30-minute interval was achieved and exceeded; the imbalances were reduced to 3% per 10-minute interval by the end of the project. The mini-grid operated in grid-independent mode twice during the study period, and power quality was stable with voltage and frequency fluctuations of 1.5% and 0.5% respectively. The Kyotango site was set up as a "virtual mini-grid", with supply facilities and end-users all connected to the national utility grid. The main source of electricity for the site was a series of gas generators (400 kW capacity) fed by a biogas plant. Furthermore, a 250 kW MCFC and a 100 kW lead-acid battery system were installed, as were two PV systems and a 50 kW wind turbine in remote locations. The power management system was done over a standard connection to the internet as this was the only method

	available in this rural area. The power imbalances were reduced to less than 3% by the end of the project. The Hachinohe site consisted of three 170 kW gas engines, a 100 kW PV system, and a 100 kW battery system. The 50 kW inverters used for the PV system compensated for power imbalances across the three phases. The site was located at a sewage treatment plant, which needed the addition of a wood waste steam boiler to create the heat necessary for the bacteria to generate methane for the gas engines. The sewage plant was located away from the buildings that received power from the mini-grid, so a 5.4 km dedicated distribution line was installed. The control system that was used aimed at a power imbalance of less than 3% over a six minute interval. This was achieved by the end of the project. The system was operated in grid-independent mode for one week, and no difference between the mini-grid and the national grid was observed.

Project title: Demonstrative Project on Grid-interconnection of Clustered Photovoltaic Power Generation Systems	**Organisation:** NEDO
	Year: 2002-2007
Description: This project was initiated in anticipation of an increasing number of clustered residential grid-connected PV systems. The main objectives were to develop technologies to deal with the variable output of a group of PV systems, develop better modelling of clustered PV systems (including harmonic interaction of multiple inverters), and develop systems to prevent unintentional islanding.	**Results:** The project installed PV systems on 553 homes in Ota City, Gunma prefecture, for a total of over 2.1 MW$_p$. Battery systems and power conditioning units were installed on each home to smoothen power output when insolation changes dramatically. An economic analysis found that to use lead-acid batteries for reducing output fluctuation, their cost had to decrease by 70%. The anti-islanding devices met their target of disconnection within 100 ms of an islanding event. However, they were found to interfere with one another, so further research is underway to develop improved anti-islanding systems. Finally, NEDO will initiate a project to standardise testing methods related to clustered PV systems, so that their uptake

	can be accelerated.

Project title: Verification of Grid Stabilization with Large-scale PV Power Generation Systems	**Organisation:** NEDO **Year:** 2006-2010
Objective: This project aimed to evaluate the adverse impacts of large-scale PV power generation systems connected to the power grid and to develop power conditioning systems with integrated battery storage. Two sites were chosen: Wakkanai City, which is the northernmost city in Japan and therefore is subjected to the largest variation in daylight hours, and Hokuto City, which receives the highest annual solar radiation in Japan. Various parameters of the power output of the system were analyzed (such as voltage, frequency, state of charge of the battery), as well as environmental parameters such as snow accumulation on the PV modules.	**Results:** A 5 MWp PV system was installed in Wakkanai, along with a 1.5 MW sodium-sulphur battery storage system (7.2 hour capacity). The batteries were found to have sufficient capacity and charge/discharge rate to compensate for rapidly fluctuating PV power. This allowed the Wakkanai site to stabilise its power output. Furthermore, an inverter that compensates for overvoltage and that suppresses harmonics was also developed and installed. The Hokuto site used 2MW PV and an inverter with reactive power compensation. The goal was to keep voltage fluctuations under 2% of the voltage nominal value. The inverter design is currently being optimised. The resulting inverter and battery technologies from these two sites will be used to stabilise voltage levels on fragile rural grids.

Project title: Wind Power Stabilization Technology Development Project	**Organisation:** NEDO **Year:** 2003-2007
Objectives: Due to the unstable nature of wind power, NEDO launched a project that investigated the use of short-term energy storage to reduce power output fluctuations at wind farms. A sub-project investigated methods of more accurately predicting the wind resource in Japan, so that utilities and wind farm operators can better predict power output from wind farms.	**Results:** A 6 MW (6 MWh) redox flow battery was installed at the 30.6 MW Tomamae Winvilla Wind Park in Hokkaido. Output data from six other wind farms was evaluated for the purposes of estimating the benefit of installing the same battery system at these locations. The cost of the battery storage system was compared against the benefit of a smoother power output. Another Japanese organisation found that to be cost-effective, a battery storage system for reducing power

	fluctuations should be less than ¥12,000/kWh (approximately USD 130/kWh). The wind forecasting system used data collected from ten different wind sites in Japan since 2005. It will be made public so that utilities and wind farm operators have access to more reliable information and so that they can develop their own forecasting methods. The redox flow battery was taken apart in 2008 to inspect it for signs of long-term damage.

Project title: Demonstrative Project on New Power Network Systems	**Organisation:** NEDO
	Year: 2004-2007
Objectives: This project developed new distribution network technologies for the electricity grids of the future. Two sites were chosen, one at Akagi and one at Sendai.	**Results:** The Akagi site used static VAr compensators, step voltage regulators, and loop balance controllers (LBCs). These units were occasionally used in parallel with the national grid. The LBCs are a new type of network equipment, and are used for controlling power flow between two distribution feeders using a back-to-back inverter. Two of these were developed, a 500 kVA unit with a transformer, and a 1,000 kVA unit without. Since LBCs are to be used on utility poles, their weight needs to be reduced considerably. To be cost-effective, LBCs should be half the cost of static VAr compensators. Most distribution systems could be adequately served by LBCs of 300 kVA. In Sendai the focus was on power delivery for customers of different service levels. A power supply system was constructed using two 350 kW gas engines and a 250 kW molten carbonate fuel cell. Compensating equipment (to compensate for voltage sags or for power outages) was also installed, with different types of equipment being used for customers at different service levels. The equipment was first tested on dummy loads, then moved to actual loads (the university in Sendai, and various Sendai City buildings) in 2007.

	Artificial voltage sags were created to test the effectiveness of the equipment. The project found that the cost of this compensating equipment may be lower than having an uninterruptible power supply (UPS) at each site.

<table>
<tr><td rowspan="2">Project title: Development of an Electric Energy Storage System for Grid-connection with New Energy Resources</td><td>Organisation: NEDO</td></tr>
<tr><td>Year: 2006-2010</td></tr>
<tr><td colspan="2">Photovoltaic and wind power generation systems are likely to suffer power output fluctuation problems, and so the development of low-cost and long-life energy storage systems, such as batteries, is a high priority to facilitate installation of these systems. To absorb the power fluctuations associated with wind-farm-scale new energy generation systems, a megawatt-class, high-performance and low-cost electric energy storage system will be developed in this project, based on the following:
(1) Technology development to contribute to the practical application of large-scale power storage systems
(2) Development of elemental technologies to reduce the cost and extend the usable life of power storage systems
(3) Technological development related to new, next-generation electric energy storage
(4) Fundamental study to evaluate various factors, including the safety and usable life of energy storage systems</td></tr>
</table>

<table>
<tr><td rowspan="2">Project title: Development of Islanding Prevention Methods under Clustered PV Conditions and Improvement of Electricity Quality</td><td>Organisation: NEDO</td></tr>
<tr><td>Year: 2004-2006</td></tr>
<tr><td colspan="2">NEDO is demonstrating power quality maintenance methods and equipment that controls voltage fluctuations caused by reverse power flows from clustered PV power generation systems when they are connected to large-scale grids in urban areas of Thailand, as well as new islanding detection methods and technology to prevent islanding.</td></tr>
</table>

<table>
<tr><td rowspan="2">Program title: Electric Power Systems</td><td>Organisation:
SERL CRIEPI</td></tr>
<tr><td>Year: Current</td></tr>
<tr><td colspan="2">To improve the security and efficiency in operating power systems and to prepare for major changes toward a low-carbon society such as the large-scale introduction of renewable energies, SERL has been developing new technologies for supporting the planning and operation of power systems and control technologies for maintaining the stability of power system in the case of system disturbance. The two major technologies are:
- Technologies for more efficient management of aging power system</td></tr>
</table>

equipments: which focuses on techniques based on the concept of asset management to support the development of maintenance and replacement strategies for aging power system infrastructure.

- Technologies for real-time wide area monitoring and control system: which focuses on developing technologies for monitoring the power system stability in real time and stabilizing the power system through wide area measurements obtained by Phasor Measurement Units (PMUs).

Program title: Customer Systems	**Organisation:** SERL CRIEPI
	Year: Current

SERL is developing various technologies to assist customers, including new distribution technologies (autonomous demand area power system technologies) to allow large-scale penetration of various small-capacity distributed generation, power electronics technologies, and design support technologies to achieve a good balance between energy-saving and amenity in city, building, and housing fields. The three areas of focus are:

- Autonomous demand area power system technology for large-scale penetration of distributed power generation: which aims to maximize the use of renewable energies while ensuring the stability and safety of the power system by controlling not only distributed power generation but also customer loads and other equipments such as heat and electricity storage devices.
- Low-loss compact power conversion technologies: which is conducting R&D for reducing the losses, decreasing the size and improving the control capability of power electronics system by using silicon carbide (Sic) devices.
- Technologies for supporting more efficient energy utilisation: which is conducting R&D for improving the benefits from energy utilization such as amenity and productivity while improving the efficiency of energy utilization (particularly by switching to electricity).

Program title: Communication Systems	**Organisation:** SERL CRIEPI
	Year: Current

SERL is developing technologies related to the design, operation and analysis of information and communication systems (computers and wired/wireless communication networks) used for the operation and maintenance of power system infrastructure. Specific examples include demand area power system communication networks and systems for collecting information from substation devices. The two areas of focus are:

- Core communication technologies for the next-generation grid (TIPS): which is developing technologies for secure demand-area communications network to communicate and cooperate interactively with customers, wide-area and high-speed control networks for emergency control in the case of power system disturbances, sensor networks for equipment maintenance and operation, and supervisory control of power delivery infrastructure.
- Communication media and networking technologies: which is developing

techniques for analyzing propagation characteristics and technologies for communications network control.

Project title: Renewable Electricity Supply Interactions with Conventional Power Systems, Network and Demand (RESPOND)	**Organisation:** EU Intelligent Energy Europe programme
(Note that this is not an APEC research project but has been included because of its relevance)	**Year:** 2007

Objectives: The purpose of RESPOND was to develop policy responses and regulatory roadmaps for five EU countries in order to facilitate the integration of renewable energy into their electricity system. RESPOND investigated the issues at the generation, transmission/distribution, demand, and market levels.

Results: The RESPOND project analyzed the effects of integrating variable output renewable energy technologies into the transmission and distribution networks. The findings of this study were presented in the report *Impact analysis of increasing (intermittent) RES and DG penetration in the electricity system*:

Transmission

The technology with the most impact on the transmission system is wind power (both on- and offshore). Other distributed generation technologies (such as PV) generally tap in to the distribution network. RESPOND found that although grid reliability was traditionally the most important parameter for when designing the capacity of the grid, the grids of the future will be designed with economic considerations taking on more importance, as wind is a lower capacity source of energy.

The RESPOND simulations showed that as the capacity of wind on the grid increased, the marginal amount of displaced conventional capacity decreased; adding more wind made less and less of an impact on displaced conventional generation. This was particularly true for wind generators that had a non-diverse profile (e.g. in sites where the wind speed is constant); for a diverse wind profile (e.g. in sites where the wind speed varies) the decrease in marginal displaced conventional capacity was lower (i.e. a diverse wind profile could contribute more to displacement of conventional capacity than a non-diverse wind profile). In both cases, however, the load to be secured by the wind generators is not proportional to the wind capacity added to the grid. The conclusion of this simulation was that increasing the capacity of the transmission network was not necessary when wind penetration levels increase in areas exporting wind power. This is because wind has a low capacity value and cannot be relied upon to contribute to generation for remote loads at times of peak demand. However, in areas that import power and have wind generators nearby, an increase in capacity may be warranted to secure local demand.

RESPOND undertook two case studies for wind in Great Britain, with one being for on-shore wind and one being for offshore wind. In the case of on-shore wind, the capacity of each transmission boundary in the Great Britain network was sized for reliability, economics, and the Great Britain Supply Quality and Service Standard (GBSQSS), which was designed for large-scale load-following generation and accommodates the simultaneous peak output from all generation plants. The case study showed that it is not economically efficient to size transmission systems to accommodate peak output from both conventional generation and wind generation, but rather have the transmission capacity shared by both forms of generation. Onshore wind generation is useful for saving on conventional fuels by displacing conventional energy generation, but it should not be used to displace conventional capacity. Because of wind's low capacity value, reliability will not be as important a driver for grid expansion as economics, as system operators will want to minimize the curtailment of their wind farms and customers will want access to low marginal cost electricity generation.

In the offshore case study, RESPOND noted that there are currently few rules for the design of offshore networks. However, the high cost of connecting offshore wind farms to the transmission grid means that it is not economical to make the connection redundant. However, due to the relatively low voltage of undersea AC cables (132 kV vs. 400 kV on overhead transmission lines) wind farms are connected to the shore by multiple cables, meaning that there is some level of security.

The report concluded with the following points with regards to integration of wind energy on transmission networks:

- Wind can displace energy created by conventional generation, but cannot displace capacity;
- Where there is a mix of wind and conventional generation, transmission capacity can be shared. In areas with low wind penetration, the capacity of the transmission network may not need to be increased at all; if an increase is required, it is not proportional to the capacity of the wind generator. Sizing the transmission network for the peak generation of both conventional and wind generators is uneconomic;
- The transmission lines connecting the wind farm to the main electrical system need to be sized for the maximum capacity of the wind farm, as it is not economic to limit wind power during times of peak wind;
- Local wind generation may help to reduce the need for increased transmission capacity; conversely, high demand in remote locations will increase the need for transmission capacity;
- Networks with a high penetration of wind will have high capacity margins because wind cannot effectively displace capacity from conventional plants.

Distribution

Traditionally, power on distribution networks flowed from high-voltage areas to low-voltage areas. However with the advent of distributed generation connected to the distribution grid, the power flows may be reversed. This means that the voltage on the distribution network is determined by both generators and loads. The RESPOND study investigated the impacts on distribution networks associated with integration of distributed generation.

1. *Voltage rise*. This problem is at its worst when customer demand is at its lowest and generation at its highest. To minimize this, network operators prefer to connect the distributed generation to the high-voltage transmission lines. However, this is expensive and increases the cost of distributed generation considerably, as distributed generation projects tend to be small. Consequently they are connected to the low-voltage distribution network. Rural areas at the end of long feeders are particularly prone to voltage rises. Active management of the grid (using on-load tap changers - OLTCs) reduces the voltage rise, and despite the cost in the communications hardware to manage the OLTCs, can be cheaper than a passive grid.
2. *Rise in the number of faults*. This problem is due to the current rises from the distributed generation confusing the protection equipment on the distribution

network. To reduce these false faults, the switchgear needs to be upgraded, and the network actively managed.

3. *Power losses*. As most of the power losses occur on the low voltage distribution network, distributed generation is well-suited to assist in reducing losses. However, in the case of PV, increasing the penetration beyond a certain point will no longer assist in reducing losses, and may even increase them due to reverse power flows. If the output of the distributed generators and the demand are matched during the day, a reduction in losses occurs as well.
4. *Increasing security of supply*. Distributed generation can also increase the security of supply on a power network. For intermittent generation (e.g CHP) the contribution will be driven by the number and availability of the individual units. However, for intermittent generation (PV, wind, hydro), persistence time needs to be factored (i.e. the time during which the generator will be operating at or above a certain level to provide system security).
5. *Reduction of power flows at high voltage*. The presence of distributed generators can reduce the power demand from the transmission network and therefore defer upgrades in capacity. However, the capacity credit of the generator comes into play. CHP, which can generally be dispatched and its output predicted, may be able to displace capacity. However, due to its unreliable nature, wind cannot be expected to reduce grid capacity.

The RESPOND report concludes that although the introduction of renewable energy on an electricity grid saves money on fuel, it does not displace capacity from conventional generation. Active management of the grid will be necessary to integrate diverse sources of renewable energy, as a passive approach would cost more due to the upgrading of infrastructure.

Project title: *Photovoltaic Systems Interconnected onto Secondary Network Distribution Systems – Success Stories*	**Organisation:** NREL
	Year: 2009

Aims: Electric utilities in the US operate secondary network systems, separated from primary networks by a protection device. This project aims to illustrate successful examples of medium to large rooftop PV installations onto secondary networks, to record interconnection requirements and evaluate the performance of the systems with respect to network requirements.

Results:

1. No faults in the network have been observed to be caused by the PV system. There was no reverse flow from the PV system into the network. There has been an increase in the number of relay operations in the network transformer. This is a result of reduced loads causing the transformer to drop out of service temporarily. It can be rectified by replacing the older electromagnetic relays with modern microprocessor based relays.

2. All power is consumed by the building and no power is exported to the grid

3. Big Sue (Brooklyn) project was the first in the US to incorporate net metering to export power into the secondary network. Initially the network did not allow this, so their rules were changed to allow for it. No problems have been observed.

4. Convention centre, Colorado: No electricity from the PV system is allowed to flow back into the area network. The system employs dynamic output-control inverters

that reduce the PV output when the building load is low. There is an additional protection relay that cuts out when the building load is too low to consume all PV power.

Methodologies identified:

1. Identify minimum load – size PV system to provide for the building load only
2. Install minimum import relay or reverse power relay – to prevent export of power into the network where export is deemed unacceptable
3. Install dynamic controlled inverter system – to reduce the power out of the inverter when the building load drops below a minimum threshold. This is not an optimal solution because it lowers the productivity of the PV system overall
4. Allow net metering – on area networks, net metering can be allowed to return some power into the area network. This is the optimal solution as it makes best use of the energy produced and gives economic benefits to the owner.

Project title: *California Intermittency Analysis Project*	**Organisation:** California ISO
	Year: 2007

Description: This project examines the effects of intermittent generation including wind turbines and PV on the California grid. California is a world leader in the introduction of renewable generators to the grid and has a relatively high penetration of wind and solar. Wind turbines have been used in the Californian grid since the 1980s, giving a longer period of analysis and providing opportunity for improvements in technology to be observed.

Results: The study has highlighted a number of technical and market related issues associated with higher penetration of wind into electricity grids. Improvements in wind turbine technology since the 1980s have addressed most power quality problems and variable speed wind turbines have become standard in newer installations. Variable speed wind turbines provide greater energy capture at partial load and continuous power factor control. Older constant speed machines provided poor voltage and power factor control. Further improvements in balance of system components include dynamic reactive power compensation and ring bus switching interconnection stations. Ramp rate control for times of rapid change in wind speed is being further investigated and there is a need for more advanced predictive modeling of turbine output so that wind generators can trade in the day-ahead markets with lower levels of risk. Further issues being investigated include:

- Transmission issues arising from higher wind penetration
- Need for PFC compensation
- Short circuit duty contribution
- Transient stability
- Ramp rate control
- Wind turbine modeling needs to be improved

Project title: *Renewable resources and the California Electric Power Industry: System Operations, Wholesale*	**Organisation:** California ISO

Markets and Grid Planning

Year: 2009

Description: This report analyses the increased penetration of renewable generators into the California grid with respect to the wholesale electricity market, scheduling and dispatch, and grid planning.

- Risk for renewable generators trading in the day-ahead market
- Unreliability of predictive modeling leads to excessive commitment of backup generation
- Increased requirement for hydro/storage
- Matching of localised supply with demand
- Smart grid to assist in supply-demand management

Project title: *Integration of Renewable Resources*

Organisation: California ISO

Year: 2007

Description: The California ISO is working with Participating Transmission Owners, the California Energy Commission, the California Public Utilities Commission, industry experts, adjacent control areas and owners/developers of renewable resources to identify integration issues and solutions for the integration of large amounts of renewable resources into the ISO Control Area. This is an ongoing project aimed at identifying issues that arise when larger renewable generators are connected to the grid, and providing guidelines for generators connecting to the grid so that major changes to grid infrastructure can be avoided.

There is an emphasis on wind energy due to high levels of penetration in the California grid, however as solar penetration increases this will play a larger role.

Project title: *National Laboratory Support of Solar Technology Development*

Organisation: EERE

Year: Current

Description: This subprogram at EERE conducts R&D focused on hardware requirements for addressing grid interconnection issues for PV.

Key research is conducted by Sandia National Laboratories and NREL, and includes inverter evaluation and inverter modeling for utility compatibility issues including voltage regulation, intentional islanding, and utility-level protection coordination.

One component of the Systems Integration subprogram's activities concentrates on the fundamental research and development (R&D) at the U.S. Department of Energy (DOE) national laboratories to develop and test inverters, controllers, balance of systems, and energy management systems.

To enable the electric grid to handle large penetrations of solar electricity, the Systems Integration subprogram is tackling grid integration issues including voltage regulation, (e.g., when solar photovoltaic (PV) systems can still power an electrical grid using low-voltage ride-through with utility consent), and utility-level protection coordination.

Two national laboratories lead the R&D efforts in these systems integration areas: Sandia National Laboratories (SNL) and the National Renewable Energy Laboratory (NREL).

Testing and Evaluation Support for Industry

Inverter evaluation has focused on utility compatibility issues, PV array usage, safety, and reliability issues. National laboratories such as SNL work with industry partners to evaluate inverter conformance to standard.

As a product nears commercialization, the national laboratories provide technical expertise to evaluate new inverter and balance-of-systems designs and validate the system's design and performance.

New hardware is tested for factors such as conversion efficiency, maximum power point tracking (MPPT), and anti-islanding detection functionality. MPPT is the ability of an inverter or controller to track and use the maximum power operating point on a PV array. The testing ensures that the product will meet utility interconnect standards, performance requirements, and safety requirements.

Advanced inverter, controller, and interconnection technologies include hardware that allows solar systems to operate and interface safely with the utility and to act as a grid resource, providing stability to both the utility and the owner.

Inverter Performance Modeling

Once an inverter developmental model is completed, it can enhance the developmental and performance models of inverters and solar systems at the national laboratories' testing facilities. The inverter performance model is a tool that can indicate how well a device can use available solar energy and convert that available energy into usable electricity. Once finalized, the model will be used to improve algorithms for MMPT, anti-islanding, and multi-inverter control and communications.

The model will be available to industry partners for their R&D use.

Project title: *Grid Integration for Systems Integration*	**Organisation:** EERE
	Year: Current

Description: This program is focused on software and modeling analysis of interaction of solar energy systems with the grid with the goal of developing a complete understanding of issues that arise when high penetration renewable energy is connected to the grid.

To accomplish this goal, the Systems Integration subprogram efforts encompass the following activities in the Grid Integration research area:

- Developing new transmission and distribution system modeling approaches and tools that take into account bi-directional power flow, load control, demand response, distributed energy sources, and energy storage.
- Updating models for photovoltaic (PV) inverters and systems to use in commercial load-flow and fault-current calculation software to handle multiple distributed energy sources on the system.
- Evaluation of real-world, high-penetration solar case studies throughout the United States and internationally.
- Creating a set of benchmark cases to test models and the associated software.
- Developing recommended practices and handbooks on integrating high penetrations of solar into the electric power system. This can include screening tools that will evaluate benefits and impacts of solar installations.

Within these categories, research is focused on developing software that can accurately model the performance of PV systems in electrical distribution modeling packages.

Project title: *System Testing and Demonstrations for Grid Integration*	**Organisation:** EERE
	Year: Current

Description: The EERE conducts laboratory based and field testing of photovoltaic technologies. Lab testing is conducted at dedicated test bed sites and Field testing is conducted at existing large scale PV plants at various locations across the southern US. Testing is designed to characterize the performance and reliability of the systems and support standards development.

To accomplish this goal, the Systems Integration subprogram efforts encompass the following activities in the Grid Integration research area:

- Developing new transmission and distribution system modeling approaches and tools that take into account bi-directional power flow, load control, demand response, distributed energy sources, and energy storage.
- Updating models for photovoltaic (PV) inverters and systems to use in commercial load-flow and fault-current calculation software to handle multiple distributed energy sources on the system.
- Evaluation of real-world, high-penetration solar case studies throughout the United States and internationally.
- Creating a set of benchmark cases to test models and the associated software.
- Developing recommended practices and handbooks on integrating high penetrations of solar into the electric power system. This can include screening tools that will evaluate benefits and impacts of solar installations.

Within these categories, research is focused on developing software that can accurately model the performance of PV systems in electrical distribution modeling packages.

Project title: *Photovoltaic Hardware Testing, Evaluation and Reliability*	**Organisation:** EERE
	Year: Current

Description: This program is developing a Solar Advisor Model (SAM)for assessing the performance of solar technologies. This model is based on results collected through testing and evaluation of products and processes to establish performance and reliability benchmarks for PV products, processes and materials.

The Testing and Evaluation program is run in collaboration with US solar companies to gather data on PV products and processes, improvements and cost reductions within the industry. Performance parameters can be established from gathered data, and test protocols can be improved through collaborative work with the PV companies.

The reliability R&D sub-program aims to monitor and benchmark long term performance of PV modules and systems, to provide good information to customers about the performance of the system over time. This will assist the solar industry by providing project developers with better information for predicting and modeling

system performance accurately.

Project title: *Renewable Energy Systems Analysis*	**Organisation:** EERE
	Year: Current
Description: This program is aimed at modeling and full systems analysis of high levels of renewable energy on the electricity grid. The Testing and Evaluation program is run in collaboration with US solar companies to gather data on PV products and processes, improvements and cost reductions within the industry. Performance parameters can be established from gathered data, and test protocols can be improved through collaborative work with the PV companies. The reliability R&D sub-program aims to monitor and benchmark long term performance of PV modules and systems, to provide good information to customers about the performance of the system over time. This will assist the solar industry by providing project developers with better information for predicting and modeling system performance accurately.	

Project title: *High Penetration Solar Deployment Projects*	**Organisation:** EERE
	Year: Current
Description: The High Penetration Solar Deployment activities focus on increasing the growth of grid-tied solar photovoltaic systems. The goal is to accelerate the placement of these systems into existing and newly designed distribution circuits in the electrical grid. The High Penetration Solar Deployment project supports the mission of the Solar Energy Technologies Program (SETP or Solar Program) to increase widespread commercialization of clean solar energy technologies. Project success requires developing both modeling tools and actual performance and validation data, so the focus is on three research and development areas: improved modeling tools development, field verification of high-penetration levels of photovoltaics (PV) into the distribution grid, and demonstration of PV and energy storage for smart grids. This effort has three goals: - Develop modeling tools and database of experience with high penetration scenarios of PV on a distribution system; - Develop monitoring, control, and integration systems to enable cost-effective widespread deployment of small modular PV systems; - Demonstrate integration of photovoltaics and energy storage into Smart Grid applications.	

9 APPENDIX B: ELECTRICITY GRIDS IN APEC ECONOMIES

9.1 Basic Grids

A basic grid is defined in this document as a single electricity source supplying power to a localised area. Because they supply such a small area, they may also be referred to as 'off-grid' systems, although this term generally refers to systems with batteries. Basic grids are found in remote communities and developing countries and will typically provide power to a small community or a temporary site. Basic grids are usually constructed at low cost and are not designed to provide redundancy or reliability of supply, so loss of power is common. These grids are characterised by:

- **Power Station**: A single power station, typically a diesel generator or a small photovoltaic array, usually sized at less than 1MW with minimal automated control mechanisms and minimal redundancy.
- **Distribution**: Customers are supplied by mains connected in a radial topology to the power station. This avoids the cost of redundant power cables. However, no alternative path is available if a fault occurs in the network. Customers have to wait for detection, repair and restoration before power can return. Fault protection consists of pole top fuses and main circuit breakers, so on-call electricians are required to reset breakers and fuses in the event of a fault. Distribution is often single-phase to households, with only some buildings receiving three-phase supply.

9.2 Mini Grids

A mini grid is a small, localised grid similar to a basic grid, with additional control and automation features to provide better quality and reliability of power. Mini grids are located in remote areas not accessible to main grids and are usually powered from one central power station, or several small power stations. They are typically found in established townships, groups of towns and other remote applications such as mines that required some level of automation and reliability. They are characterised by the following features:

- **Power Station**: One localised power station, or several small power stations distributed over the area supplied. Generation is usually from diesel generators and/or gas turbines as well as renewable options such as wind and PV, and includes some redundancy of supply to minimise the frequency of blackouts. The power stations may include some advanced automated features such as feeder load shedding and automatic feeder reclosing.
- **Transmission**: Usually consists of several medium voltage feeds leaving the power station. A ring mains topology is often used to provide alternative paths to distribution transformers, so that sections of the network may be shut down for servicing without disrupting the entire network. This is done manually by field crew operating pole top isolators and transformer fuses. Voltage regulation is managed by setting tap changes on distribution transformers.

- **Distribution**: Customers are supplied power from step-down distribution transformers from the transmission network. The distribution usually services a block of houses though ring mains. All distribution will typically be three-phase.

9.3 Large Grids

Large grids connect multiple power stations to cities and towns via an extensive network of transmission lines. Power is mostly generated at large power plants, often located far away from end users, and is transmitted across large distances at high voltage. Due to the large number of generators and end users, and the variations in demand, power is generally controlled through the grid using a central dispatch process. A high level of reliability is required; due to the large network of generators, a high level of redundancy is usually achieved. Supply and trading in large grids are closely monitored and controlled by a centralised monitoring organisation. Large grids are characterised by the following:

- **Power Station**: Multiple large power generators including coal, nuclear, gas, oil and a variety of renewable technologies. They usually generate in the medium voltage range and are then stepped up to high voltage for transmission. They will also generally include generation embedded throughout the distribution network, which can range in size from tens of MW to kW systems.
- **Transmission**: The transmission network consists of a mesh of high voltage overhead transmission lines which may span hundreds of kilometres across a country. The mesh grid connects power stations to medium voltage transformers at cities and towns. A failure in the transmission network is automatically detected and bypassed to an alternative supply source. Disturbances may include brief voltage sag as the network reconfigures. Major failures in the transmission network are rare due to the high diversity of supply, but can result in large regional blackouts when they do occur.
- **Distribution**: Power is distributed from medium voltage transformers through cities and towns, to low voltage transformers, and from low voltage transformers to groups of houses via ring mains. Power from embedded generation is injected throughout the distribution network. In high-density CBD areas, mesh networks comprising a number of interconnected nodes may be used for added supply reliability.

9.4 Smart Grids

A smart grid includes an intercommunication network to allow communication between end users, the distribution network and distributed power generators. Smart grids have the potential to improve load demand management, make distribution paths more efficient, and pre-empt power generation requirements. Smart grids are currently in the research and development phase, and have only been implemented on the scale of small demonstration projects. They are expected to play an important role in the integration of renewable energy into the grid. Smart grids are characterised by the following:

- **Power Station**: Like large grids, smart grids may use multiple large power stations; however, the emphasis is on a larger number of smaller generators embedded through the grid, forming a network of supply. Generators will be able to communicate directly with the network to determine current and predicted demand. This facilitates better power generation scheduling and uptake of intermittent power generation into the grid.

- **Transmission**: To date, because smart grids are relatively small demonstration projects, they do not include transmission networks. The expectation is for smart grids to expand, and when they do, the transmission network will be equipped with fully automated controls which will allow the network to automatically calculate the best electricity routes depending on demand. This is expected to improve transmission efficiency and allow the network to quickly identify and avoid faulty lines.

Distribution: Customers will be equipped with “smart” meters which can communicate with the grid to determine instantaneous demand and tariffs. The meters then determine the best times to switch on equipment and allow customers to view tariffs and schedule their equipment use appropriately. Smart grids are expected to have the added potential benefit of allowing the grid to access battery storage devices distributed throughout buildings and electric vehicle systems.

APEC Project EWG 02/2009

Produced by

IT Power (Australia) Pty Ltd
ABN 42 107 351 673
PO Box 6127, O'Connor, ACT 2602, AUSTRALIA
telephone: +61 (0)2 6257 3511
facsimile: +61 (0)2 6257 3611
email: itpau@itpau.com.au
web: www.itpau.com.au

Ref Number: *ITP/Ref: A0032*

For

Asia Pacific Economic Cooperation Secretariat

35 Heng Mui Keng Terrace

Singapore 119616

Tel: (65) 68919 600

Fax: (65) 68919 690

Email: info@apec.org

Website: www.apec.org

APEC#210-RE-01.16