IDENTIFICATION OF OUTLINE SOLUTIONS FOR THE CONNECTION AND OPERATION OF DISTRIBUTED GENERATION

Version 3.0

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1 INTRODUCTION

1.1 BACKGROUND

In order to implement the recommendations of the DTI/Ofgem report on Embedded Generation, a Distributed Generation Co-ordinating Group together with a supporting Technical Steering Group (TSG) has been established. A number of workstreams have been established by the TSG one of which, Workstream 3, is focussed on short-term network solutions. A key issue to be addressed by Workstream 3 is to establish how to increase the amount of energy generated from distributed generation. This is likely to be achieved by a combination of increasing the amount of generation plant connected to distribution networks and by increasing the amount of energy generated from new and existing plant by increasing the degree of network and /or generation management.

It is recognised that generators see the cost of connection and the costs of constrained operation as major barriers in connecting to distribution networks. Most of these connection issues can be traced to the three primary technical issues that have been identified as currently presenting fundamental limitations. In each case, whilst solutions are generally technical, they may have commercial and regulatory impacts. Hence, a key feature of any solution is the inter-relationship between the regulatory, commercial and technical aspects.

1.2 SCOPE & OBJECTIVES

The objective of this report is to identify the barriers to the connection and operation of distributed generation within distribution networks and identify solutions in outline that can be implemented in the both the short and longer term.

The report identifies the possible solutions to address the technical issues in the area of voltage control, fault level and power flow management that are currently being implemented by DNOs or generators, either in the UK or overseas, and those techniques which are currently being developed either by DNOs, generators or academia.

The focus is to be on those initiatives that can realistically be introduced into distribution networks within the next three years. Other solutions that are identified as part of this study that would take longer to introduce will be progressed in Workstream 5, which is addressing longer term network solutions.

Solutions include methods, practices and technological solutions which can be used to:

- manage fault levels
- control network voltage levels
- manage network power flows

The scope of work comprises three main parts: the confirmation of the barriers, the identification of existing and possible future solutions in outline, and the prioritisation of these for both the short term and long term implementation.

Beyond the scope of this report is the detailed implementation plan for these outline solutions. Short term solutions will be taken forward as the next phase of this Workstream 3 project. Longer term solutions will be addressed by Workstream 5. In both cases the commercial and regulatory aspects will be considered alongside each solution.

The Terms of Reference for this work is attached as Appendix 1.

1.3 METHODOLOGY

The methodology used in this study has been to identify the barriers to the connection and operation of distributed generation within distribution networks and then identify the existing solutions that are currently being implemented by network operators or generators, either in the UK or overseas to determine industry "Best Practice". In addition, techniques which are currently under development by network operators, generators and academia are also identified.

The gathering together of UK industry best practice was made possible by the valuable contributions provided by members of the TSG Workstream 3.

2 THE BARRIERS

It is recognised that Generators perceive the cost of connection, together with any subsequent constraint on operation, as major barriers in connecting to the distribution networks. Most of these connection issues can be traced to three primary technical issues that have been identified as currently presenting fundamental limitations. These fundamental technical limitations are:

- fault level
- voltage control
- power flow management

Generally speaking, the mechanisms available to provide solutions in the short term are known in theory and may have seen some practical application. These include such things as changes to industry standards and operational practices. For example, this could involve reviews of the:

- current network design principles
- current connection principles

Short-term solutions also include options that are collectively described under the banner of "basic active network management". This implies more flexible operation of current network assets and generation plant. It could also include the installation of additional network plant or control equipment to facilitate more flexible operation of the network.

Identification of current best practice within UK network operators as well as best practice from overseas can be used as the basis for revision of industry standards (such as Engineering Recommendations and guidelines) and internal company procedures. Harmonisation of industry practice in line with identified best practice, where possible, is one of the most efficient and effective solutions that can be introduced in the short term. This, combined with more transparent internal company procedures should go a long way towards facilitating the connection of distributed generation.

This report aims to identify the technical issues associated with the application of industry standards and practices so that linkage can be made to the underlying cause of the barriers, enabling practical solutions to be identified.

The technical barriers to the connection and operation of distributed generation with distribution networks are described in the following sections in terms of fault level, voltage control and power flow management. However, it is recognised that these issues are often inter-linked such that a solution to one barrier may need other issues to be addressed in parallel.

2.1 FAULT LEVEL

The growth of the network in response to increasing load (and load density) has traditionally been met by "reinforced" (i.e. incremental) rather than completely "new" supply networks, since this is the more economical short-term solution. However, this causes a trend of asset concentration, leading to increased fault level. Increasing fault level is acceptable, and often provides a least cost network design, as long as network plant remains within its ratings. Indeed, increased fault level can also help to improve customers' quality of supply by reducing the magnitude of voltage disturbances. However, if there is a risk of exceeding fault level ratings, this can then have major cost implications over a wide area of network.

Distributed generation from both synchronous and asynchronous machines makes a contribution to fault levels. Thus, the connection of distributed generation to the network could cause a distribution network, which happens to be close to its fault level limit, to exceed it. Circuit breakers will be the most obvious plant affected by increasing fault levels (both break and make duty), although other plant such as transformers and cables may be affected through electro-mechanical and/or thermal mechanisms.

Where fault levels are close to existing limits, the most immediate issue from the addition of distributed generation is that circuit breaker ratings are exceeded. The risks when fault levels are exceeded are of damage and failure of the plant, with consequent risk of injury to personnel and interruption to supplies.

However, the absolute fault level margin of installed plant may not be readily ascertainable, due to uncertain knowledge of fault contribution from other secondary sources. Estimation methods do exist to cover the technical aspects of fault level contribution from secondary sources (in the form of ER G74 and ETR120) but the specified allowance factors are considered to be in need of review to more accurately reflect the actual fault current infeed . Also, although the use of a "worst-case" methodology may be more acceptable to the Health and Safety Executive (HSE), this precludes the use of alternative risk management strategies.

2.2 VOLTAGE CONTROL

Distribution network operators have a statutory obligation under the Electricity Supply Regulations[1] to provide electricity to customers within fixed statutory limits (i.e. 230 Volts, +10%, -6%). There is also a European Norm standard, EN50160, which is based on a probabilistic approach to voltage variations and therefore is not directly compatible with fixed statutory limits.

The distribution network voltage is typically regulated at two positions within the network; at the 33kV source busbar in the Supply Point substation and the 11kV busbar at the Primary substation. Regulation is typically achieved using an on-load tap changer (OLTC), controlled by an Automatic Voltage Control (AVC) scheme. This control scheme would usually incorporate some form of line-drop compensation or negative reactance compounding.

The voltage level will drop with distance from the source on a traditional radial feeder. Therefore, the voltage in all parts of the feeder is managed within specified limits by maintaining a high level on the busbar (i.e. source end) so that the voltage on the far end of the feeder is still within limits at times of high power flow. Connecting a generator to the

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[1] To be replaced by Electricity Safety, Quality and Continuity Regulations in January 2003

distribution system will affect the flow of power and therefore the voltage profile. The voltage on the feeder may rise outside the specified limit when distributed generators export more than a certain amount of power back up the network.

The OLTC is normally rated for step-down operation, since distribution networks were designed to feed from the higher voltage network to the lower voltage. Distributed generation may lead to step-up operation and some tap changers have uncertain or limited reverse power flow capability. A secondary effect is that the workload of the tap changer, due to handling a wider range of voltage steps over shorter periods of time (e.g. from intermittent sources of energy such as windfarms) will reduce the life expectancy of the OLTC.

Local match of real generation and load can lead to the substation busbar being presented with unusual reactive power demands (i.e. very low power factors). This can lead to incorrect operation of the OLTC with certain compounding techniques. Low power factors can also cause excessive wear of tap changer contacts – so shortening life expectancy and requiring increased maintenance.

In addition to steady-state voltage control requirements, there is also a need to limit the impact of "transient" voltage variations, such as a single step change in voltage due to loss of larger generators or demand.

To support the statutory voltage requirement, each network operator will have its own policy on voltage control. These policies will generally be similar in nature, but may well differ in detail, taking into account local factors. Thus, each individual company will take its own view on such aspects as appropriate tap changer set points, bandwidth settings, time delays between series OLTCs, etc. These company policies have probably changed little in recent years. This has led to an amount of "individual interpolation and extrapolation" of the written policies. This is often necessary, for example, to take into account some equipment obsolescence or to accommodate some new technology. However, this situation does not promote transparency and openness to those outside the DNO organisations.

2.3 POWER FLOW MANAGEMENT

Distribution networks are currently designed to accept power at the grid supply point (GSP), for distribution to customers. Thus, the flow of power within distribution networks has been designed to be uni-directional from higher to lower voltage levels. Significant levels of distributed generation will cause the power to flow in both directions through the network.

The issue of power flow management relates to the capacity and security of the network for both normal operation and following an outage. One of the roles of the network operator is to manage the risks associated with power flows. For example, power flow becomes a risk management issue when the distributed generation capacity connected to the network could exceed the firm capacity of the upstream network to which it is connected. Under these circumstances, network assets are at risk of being operated above their rating (and therefore failing) following a circuit outage.

A “first circuit outage” event can be either be a planned event (e.g. due to network maintenance or network development) or unplanned (due to faults). A “second circuit outage” event almost always refers to a fault occurring during a planned outage. Contingencies for these events vary, according to the magnitude of the risk and the speed of operational response required to maintain the integrity of network equipment. They may include temporary network constraints and/or inter-tripping. Additionally, whenever the network is exposed to the risk of being operated above its rating, some form of back-up procedure is normally required.

Traditionally, generators have been connected on a ‘fit and forget’ basis, with the system often reinforced to allow full output of the generation capacity and with little or no operational constraint. Power flow management should allow greater volumes of generation to connect, and to be less constrained in an operational timeframe. This is particularly true where there is a net export of generation onto a local network.

The introduction of power flow management for distributed generation would have an effect at both planning and operational levels. At the planning level, network power flows would have to be considered under both normal and abnormal operating conditions, allowing for (n-1) security considerations. The generator connection could be provided on a firm or non-firm basis with combinations of network re-inforcement and/or generator curtailment/inter-tripping to provide the most appropriate connection in terms of cost and security (i.e. “firmness”). The selection of a non-firm option can result in significant system reinforcement costs being avoided.

At the operational level, a lower cost of connection would require some form of generator constraint. Timing and control issues become important here. For example, pre-fault action is taken in anticipation of an outage. Alternatively post-fault action could be deployed (such as inter-tripping of the generator). For example, post-fault measures could allow the generator to reduce output within the timescales associated with the short-term ratings of the network plant, or may require “instantaneous” compliance through intertripping.

There are a number of commercial and regulatory issues to be considered in connection with constraint management and intertripping schemes. The use of an “unfirm” connection with the necessary constraints and intertripping also represents a risk to the future income received by a generator, and the generator may require a risk analysis. This would include estimates of planned maintenance activity and fault occurrences as well as estimates of plant short-term over-rating and the possibility of accelerated plant ageing. The complexity of these solutions increases as the numbers of generators on a network increases. Regulatory issues associated with deep and shallow connection policies need to be considered in ensuring the correct investment decisions are made.

3 THE SOLUTIONS

In this chapter summaries of the solutions are presented. These solutions aim to address the technical barriers of fault level, voltage control and power flow management.

3.1 SOLUTIONS TO FAULT LEVEL PROBLEMS

3.1.1 Uprate network

Circuit breakers or circuit breaker panels associated with the connection may have to be uprated. This can be a large proportion of the total connection cost. However, sometimes uprating work can be extensive if cable networks and switchgear remote from the connection point are involved (a particular issue for meshed networks) and/or where there are existing customers, connected to the same network, and their plant need uprating also. In other situations the switchgear may already have been uprated and therefore cannot be uprated further. The timing of asset replacement can take place either when plant ratings become exceeded or as part of longer-term asset replacement programme.

3.1.2 Increase impedance of network components

It is possible to specify a higher impedance for certain network and generator components (e.g. substation transformers, generator impedance). This will reduce the fault level and is a low cost solution for new installations, but is more costly as a retro-fit option. However, reduction of fault levels may have an impact on customer power quality and voltage control

New components can be introduced into the network to increase network impedances, such as fault limiting reactors. The addition of a series reactor to link bus sections uses established technology. Their insertion can allow a compromise between fault level, system losses, source impedance and security. Reactors may also be used at other network locations, either to limit infeed from a single source (generator or network transformer) or to add impedance to the interconnectors between network areas. The questions that need to be answered in each case are (a) whether the addition of a reactor is feasible and effective at an existing bus section or close to a generator; and (b) whether the addition of a reactor would generally increase losses and reduce the power quality to the general mass of customers connected to that network.

3.1.3 Converter interface technologies

Increasingly, generators are becoming available which use a power electronics converter interface. This is partly due to a number of dc source generators available (such as fuel cells and photovoltaics) as well as some generators which benefit from operating at variable speed (e.g. variable speed wind turbines) or non-synchronous speed (e.g. micro-turbines). Power inverters have a much lower fault current contribution than both synchronous and asynchronous machines. Thus, although the power electronics converter increases the cost of the generator, the extra cost could be outweighed by the benefits of reduced fault current contribution.

3.1.4 Network reconfiguration

Reconfiguration of the network can reduce fault levels by reducing the number of network feeds through parallel paths. One way of achieving this for radially-designed networks, without physical network change is by opening the substation bus section circuit breaker / bus coupler so that each half is fed only by its own source transformer (or transformers). Alternatively, one of a pair of transformers can be operated in open standby. In both cases, an auto-close scheme would be needed to close the breaker for upstream faults.

This configuration can reduce the fault level at the busbar by up to 50%. However, this action will also increase system losses, harmonic voltage levels, voltage dips, flicker and power quality in general because of the increased source impedance. Also, the risk of supply failure would increase and the number of transient interruptions seen by customers would also increase. It is important to note that once a number of generator connections have been permitted following the permanent opening of the bus section, the options for restoring the substation configuration, should the resulting power quality prove to be unacceptable, could be expensive.

Another issue to be considered with this solution is that the busbar sections have to be coupled prior to a transformer being switched out for maintenance. This usually requires generation to be constrained off for this period.

In addition, several questions need to be answered. For example:

- If a network is reduced to single infeed to limit fault level when generation is active, what additional measures can be taken to maintain network security?
- What criteria should be used to increase network impedance to allow for an increased fault infeed from new local generation?
- Are there circumstances where operation under normal conditions is safe, but not after fault or during plant maintenance?

3.1.5 Non-linear limiting impedances

A non-linear device, such as a saturated reactor, will increase its impedance to higher currents. The device is normally operated in saturation, sustained by a dc field. Excessive current moves the core into the linear region, increasing impedance. The applicability to utility scale application is not clear. It may overall require a similar size to a conventional reactor, but with the advantage of lower impedance at normal currents. This is in a research stage and not yet commercially developed.

3.1.6 Is limiters

Instead of disconnecting bus sections they may be linked by an Is limiter. This maintains the original low source impedance. The Is limiter senses current and fires a pyrotechnic charge to open the main current path. The current is then limited and cleared by a parallel fuse. Whilst bus section location is typical for Is limiters, other locations may be effective, as for reactors.

This method is well established, but there is only one supplier. Also, additional isolation and earthing is required in order that the devices can be replaced after operation. Fitting to an existing switchboard may not be straightforward. As the Is modules must be replaced after each operation there are issues of operating costs.

However, a significant consideration is that the correct operation of the limiter cannot be tested without destroying the limiter. This introduces concerns over safety, since the device is not "intrinsically" safe (i.e. fail-safe). Application procedures therefore need to be developed to ensure appropriate and safe use of the device. This would involve input from the HSE.

3.1.7 Superconducting fault current limiters

There has been much interest in the development of superconducting fault current limiters at least partly because of their inherent low losses and intrinsically fail-safe operation. The technology is still new, costly, and generally unavailable. For the more common 'resistive' types, conduction time may be limited, and a series breaker is required. Direct heating losses are low (<30W for an 11kV device) but refrigeration plant must be run and maintained. They would be located similarly to the above devices.

3.1.8 Fast switching devices

This includes both solid-state and mechanical solutions. Static transfer switches have grown out of the UPS (uninterruptible power systems) arena. They give a seamless bypass to a failing supply. They could conceivably be used in an auto-close scheme to give "immediate" availability, but are likely to be expensive. (An early system including a suite of 3 3-phase switches cost over $1M). An example of a fast mechanical switch is a Joslyn vacuum interruptor.

3.1.9 Sequential switching

A sequential switching scheme, where parallel feeds are interrupted sequentially before any circuit breaker operation in the full current path may be possible. This could keep circuit breakers within breaking capacity but through-fault capability of breakers, cables and transformers would not be changed. The implications for the closing of circuit breakers (make duty) onto faults would also need to be considered. Complexity and backup difficulty are challenges. This could be achieved by suitable inter-operation and programming of existing relays, or by purpose-designed hardware.

3.1.10 Fault level management procedures

There is some scope to develop industry best practice in terms of assessing the risks associated with high fault level, along with greater transparency of the evaluation process to allow generators to better understand the calculation of the fault level contribution of their distributed generator.

For example, estimation methods exist to cover the technical aspects of fault level contribution from secondary sources (in the form of ER G74 and ETR120) but the specified allowance factors are considered to be in need of review to more accurately reflect the actual fault current infeed from other sources. Using a "worst-case" methodology may be more acceptable to the Health and Safety Executive (HSE), but this precludes alternative risk management strategies, such as constraint management and optimal management of business risk. ER G74 and ETR 120 only represent a technical estimation method for fault level contribution and so network operators manage the associated business risks associated with fault level management in different ways (for example, using different network scenarios).

3.1.11 Active fault level management

The management of fault level could be carried out within operational as well as a planning timescales by developing the evolution of the network from “fit and forget” to “actively managed”. For fault levels to be managed at the operational level, a reliable method of real-time fault level measurement is required, whereby the actual fault level is monitored and actions are carried out to maintain fault levels within specified limits. The fault level monitoring provides closed loop feedback for the active fault level management and the corrective actions would include many of the solutions previously described. There is scope for some basic active fault level management here. For example, for intermittent resources it may be possible to monitor the fault level and control the bus section isolator accordingly. However, further R&D is required for more sophisticated fault level management schemes.

Note though, any ‘reduction’ in fault level by the use of measurement rather than estimation, and/or more accurate assessment of the contribution from secondary sources, is likely to be small (i.e. substantially less than 10%).

3.1.12 Summary of solutions

A summary of the solutions in terms of materiality, costs, implementation, practicality and timescales is given in the following tables:

Table 1a: Solutions to fault level problems with distributed generation

	Uprate Network	**Increase component impedances**	**Converter Interface Technologies**
Materiality	High. Where available, probable 20-40% fault level increase. (if previous margin 10%, 30% increase quadruples capacity). Effect on transformers and cables needs to be assessed	Medium.	Medium to High.
Capital & Revenue Costs	Medium to V High	Medium	Medium
Impact on DNO	Other customer FL increased. Customer may not agree to upgrade, creating legal/commercial issue.	Reduced power quality for other customers. Network changes.	Reduced FL contribution from generator Low inertia = stability problems for network
Impact on Generator	Own breaker to be adequately rated.	Potential high local voltage if impedance between local loads and distribution network	Higher cost, but increased generator output (variable speed operation possible)
Framework change (commercial/ Regulatory)	Deep vs shallow charging policy	Increased Losses	None
Applicability to network and generator types	All voltages but higher voltages easier because fewer customers	Interconnected networks can't change single transformer. PQ issues greater for some generator types	All types, especially wind turbines
Practicality	Some impact on customers during upgrade process	Increase impedance of existing components or add an impedance device	Commercially available for some generator types already. Includes back-to-back MVDC (HVDC-Light)
Time to implement	Short-term	Short-term	Short-term (if available)
Linkage to Future	Potential increase strictly limited by other plant and breaker upper limits	Limited scope for increasing network impedance – PQ implication	Good for the long-term also. Local DC networks, Utility-scale energy storage.

Table 1b: Solutions to fault level problems with distributed generation

	Reconfigure network	**Non-linear limiting impedances**	**Is limiter**
Materiality	High. Potential to halve bus fault level at best. (10% margin becomes 55% margin)	Medium. Depends on impact on Quality of Supply (QoS).	High (as bus link). Comparable to reconfigure network
Capital & Revenue Costs	Low. Auto-close scheme needed for upstream faults.	Probably comparable to conventional reactors (but lower losses and better QoS)	Active element requires refurbishment for each operation (£3k - set)
Impact on DNO	Serious adverse affect on power quality, risk of supplies to customers and short-term interruptions for customers	Retro-fit not easy (space & connection) Spare parts availability could be a problem	Costs. Retro fit space required. Backup difficult. Nuisance tripping.
Impact on Gen.	Lower firm capacity for generation. Risk to generator stability.		Load dump required if at generator site
Framework change (commercial/ regulatory)	CML and CI affected. Trade-off cost savings against degraded network performance		Significant safety issues with HSE. Industry type approval required. CML and CI affected
Applicability to network and generator types	All voltages. Interconnected networks different.	Network level not clear – probably scalable to all. All generators	Typically 11kV, 40kV max. All generators.
Practicality	Currently recommended only as a (temporary) remedial measure when existing fault levels are discovered to be exceeded	Network substation location may be difficult	Well established (not UK), typically bus section location or generator connection. Network substation location may be difficult – larger than conventional breaker, requires isolators too.
Time to implement	Short-term.	Long-term. Research stage (Inductors biased to saturation for lo-Z until fault current flows.)	Short-term. Commercially available but application confidence required and safety (and other) issues to be resolved.
Linkage to Future	Further work required to quantify costs savings versus performance degradation. New technology in development to overcome shortcomings.		

Table 1c: Solutions to fault level problems with distributed generation

	Add superconducting devices	**Add switching devices – Solid – State & low tech**	**Sequential switching**
Materiality	High (as bus link). Comparable to reconfigure network	High (as bus link). Comparable to reconfigure network	Medium. Reduces cb breaking requirement, not through rating of cb, cable & tfr., so limited increase in capacity depending on ratings
Capacity & revenue costs	High initial cost. Direct losses low but cooling plant has running costs inc maintenance.	V High for semiconductor devices. ("Low-tech" development potential unclear.)	Low/medium cost for scheme implementation
Impact on DNO	High initial cost until mass produced. Unknown maintenance commitment	Retro fit – space required. Semiconductors have inevitable power loss. Unknown maintenance commitment	Protection scheme not developed. Not "failsafe", therefore safety (HSE) implication
Impact on Gen.			
Framework change (commercial/ regulatory)			HSE issue
Applicability to network and generator types	Generally a <=11kV device. All generators.	Probably 11kV initially – higher possible later. All generators	All types
Practicality	Space for equipment inc refrigerant plant and maintenance commitment required. H&S issues.	Larger than conventional breaker. (Potential for bolt-together low tech development with current technology, potentially smaller?)	Could be implemented using conventional relays. Some development and test required.
Time to implement	Long-term. Probably three years to full commercial devices, but market needs to be clarified before commercial development	Long-term. SS developments continue in US. "Low-tech" solution currently not being progressed.	Short-term.
Linkage to Future	Some cost reductions, more voltages covered. Running costs always remain	Consider "low tech" solution for the UK market	Develop, simulate and test required.

Table 1d: Solutions to fault level problems with distributed generation

	Modify Fault Level Design Procedures	**Active Fault Level Management**
Materiality	Medium	Medium / Low
Capital & Revenue Costs	Low	Low to Medium
Impact on DNO	Significant industry resource required	More “management” effort required
Impact on Gen.		Possible constraints
Framework change (commercial/regulatory)	Implications for safety and HSE	Would benefit from “network ancillary services” agreements in the longer term
Applicability to network and generator types	All	Probably 11kV initially – higher possible later. All generators
Practicality	Could take a long time to put in place.	Inter-trip during network outages (as power flow management) Actively monitor fault level – new equipment to be developed.
Time to implement	Consistent interpretation of G74: short-term Review of G74: long-term	Could be short-term
Linkage to Future	Related to other fault level safety issues	Economies of scale with the management system. Complexity increases with numbers.

Note: In all cases where a busbar is split or linked through any limiting device (including reactors, Is limiters and superconducting fault current limiters), the possibility of the open point or the limiting device being bypassed can arise in at least two circumstances:

1 When a customer has dual supplies, one from each side, which he can parallel (even if only temporarily). This arrangements is common for larger industrial sites.

2 Network switching, for instance to transfer load before a maintenance outage, may require a temporary parallel through a feeder.

3.2 SOLUTIONS TO VOLTAGE CONTROL PROBLEMS

Voltages within distribution networks are governed by Ohm's Law and the simplest representation is shown in Figure 1.

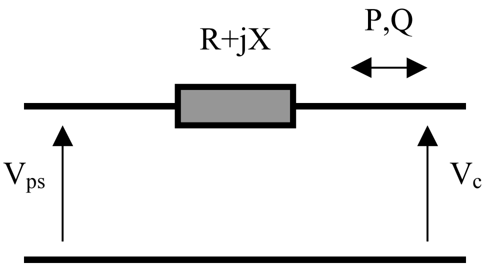

Figure 1: Simplified feeder representation

where the voltage drop, ΔV, is given by:

$$\Delta V = V_{ps} - V_c \approx \frac{RP + QX}{V_{ps}}$$

Thus, the voltage at the remote end of the feeder is dependent on the voltage at the source end and the voltage drop can be reduced by changing:

- the line resistance, R
- the line reactance, X
- the reactive power, Q, imported by the generator
- the real power, P, exported by the generator

Therefore, solutions to voltage control problems include:

- Line re-conductoring
- Dedicated line construction
- Generator reactive power control
- Generator real power control
- Line voltage regulation
- Installation of StatCom devices
- Active voltage control

3.2.1 Line re-conductoring

Re-conductoring the line with lower resistance cables or overhead lines can increase the voltage margin available and therefore increase the amount of distributed generation that can be connected, but this is likely to be an expensive solution.

This could be carried out at time of asset replacement, where the marginal cost of using higher rated cables or lines may not be so great. Also, new networks have the option of using different design criteria, such as incorporating network designs with shorter cable lengths (but more, smaller transformers). Such an approach needs further study to quantify the costs and benefits and to optimise the design. The cost framework (i.e. regulatory incentives) would also need to be examined.

Thus, line reconductoring is a solution that can be adopted in the short term, but the introduction of new network design philosophies could be considered in the longer term.

3.2.2 Build a dedicated line or network

Building a dedicated line or network for new generation, effectively separating load customers from generation customers is an approach which has merits under certain circumstances, for example, where the load density is low relative to the local distributed generation resource. The advantage of this arrangement is that normal load customers are not subject to the voltage conditions arising from generation. This enables the DNO to agree voltage limits outside statutory limits with the generator. These so-called “reception networks” may be particularly applicable in rural networks with few load customers, but many potential generation customers in the form of windfarms, small-scale hydro and biomass generation.

Since the network would be designed specifically for the needs of the distributed generation, this solution should provide the minimum barrier in terms of technical difficulty, but can be an expensive option unless all the network capacity is utilised. The technique has been used with some success in Germany. Such a solution may have merits within specific geographical areas in the UK, as identified in Ofgem’s idea of “Power Zones”, which describes the concept of “generator-friendly” networks.

3.2.3 Generator reactive power control

Reactive power control is a technique commonly used in transmission networks to maintain voltage profiles along a line. However, generally-speaking transmission lines tend to be longer than distribution lines and their X/R ratio greater, which means that reactive power control is not so effective within distribution networks, but can provide some benefit. Presently, however, it is normal practice for DNO’s to require generators to operate at (or close to) unity power factor.

A practical example might be a windfarm with asynchronous generators. These would normally require power factor correction capacitors to be fitted to provide for generator starting. The capacitors would remain connected to allow the windfarm to operate close to unity power factor. However, if the capacitors were switched out after the windfarm had started, then the windfarm would import reactive power, helping to maintain a flatter voltage profile on the network. However, this could also give rise to poorer power factor conditions on the remainder of the network and hence voltage control problems. Obviously, system studies would be required in any particular case to assess the possibility, but it is a very cost-effective solution when it can be applied.

3.2.4 Generator real power control

Control of the generator to constrain power output can be a way of enabling more generation to be connected and increasing the overall financial performance of a

development. If the level and frequency of generator curtailment is relatively small, then this can be a very attractive solution.
Consideration would have to be taken of the market implications of constraining energy. Constraining the outputs of more than one local generator adds both flexibility and complexity. For example, the management of generators competing for available network capacity adds complexity, but the available options (i.e. which generator to curtail, to what extent and when) adds flexibility. Therefore, the control of a single generator is a short term solution, whilst the control of multiple generators is likely to require further study.

3.2.5 Line voltage regulation

The use of line voltage regulators can be viewed as an extension to active voltage control out onto the network. Line voltage regulators can be placed strategically within a feeder, such that the voltage regulator and the generator work together to control the downstream voltage, whilst the existing substation OLTC and AVC controls the rest of the passive network in the conventional manner. Line voltage regulators are used by several DNOs to help manage voltage profiles on long feeders. However, the use of voltage regulators in conjunction with distributed generation is a fairly recent application in the UK. Experience is still developing concerning the interactions between the OLTC AVC, the voltage regulator and the generator controller. Monitoring of DNO experiences to maintain best practice is recommended.

3.2.6 StatCom

Static VAR Compensators (or StatComs) are used in transmission networks to control reactive power flows and network voltage profiles. Such devices could also be used in distribution networks. The function is similar to reactive power control of the generation, except that a StatCom provides a solution that is independent of the generator. The high costs of a StatCom solution mean that control of the generator reactive power import would normally be considered first. Therefore, this is likely to be a longer-term solution.

3.2.7 Active voltage control

There are several additional options which involve changes to the OLTC AVC control arrangements. The first of these is the use of cancellation CTs to remove the feeder with generation connected to it from the AVC control mechanism when line drop compensation is used. Cancellation CTs and interface are already available from manufacturers (e.g. load exclusion module from VA Tech), but there are no currently known examples of its use in the UK. The application of the technique would be limited by the number of circuits that could be ‘excluded’ from the control scheme whist still maintaining voltage control on the remaining feeders.

Another option is to use the MicroTAPP relay with a virtual VT, to control the voltage on the primary-side of the Primary transformer, with the voltage on the secondary-side controlled by the connected generation. The implications of this scheme, where the local voltage is controlled by local generators, are technical, commercial and regulatory. The reader is referred to the manufacturer for more details.

Additionally, remote voltage sensing could be used to provide an area-based voltage control system. This arrangement relies on communications. The cost and reliability of the communications and outstation may be an issue. Alternatively, state estimation methods could be used to remove the need for the remote voltage sensing. The success of this method is dependent on the accuracy of the state estimation methods employed.

3.2.8 Summary of solutions

A summary of the solutions in terms of materiality, costs, implementation, practicality and timescales are given in the following tables:

Table 2a: Solutions to voltage rise on the feeder with DG

	Re-conductor Line	**Dedicated Line**	**Generator Reactive Power Import (Q)**
Materiality	Medium to high	High. Suitable for concentrated sources	Low to medium. Limited by the Q capacity
Capital & Revenue Costs	High	High.	Low
Impact on DNO	Network re-inforcement benefits	Network re-inforcement benefits	Voltage step change. Poor substation PF Losses? (global/local)
Impact on Generator	Cost (deep connection)	Cost (deep connection)	Lower connection cost, but reduced real power export.
Framework change	No	No	Change to generator PF set point in connection agreement.
Apply to DN DG types	O/H, Cable	O/H, Cable 33kV, 11kV	Urban & Rural
Practicality	Current Practice	Planning and wayleave issues	Direct for synchronous generators, Capacitor banks and reactor banks for asynchronous
Time to implement	Short-term	Short-term	Short-term
Linkage to Future	Cost re-allocation may be needed if connection cost rules change.	Incentives needed to construct new network for generation	Can be part of future fully active networks

Table 2b: Solutions to voltage rise on the feeder with DG

	Reduce Generator Real Power	**Voltage Regulator**	**StatCom**
Materiality	High	High.	Medium
Capital & Revenue Costs	Low	Medium. E.g. £40,000 (2xVR32) typical for 11kV o/h line	High
Impact on DNO		Maintenance Reliability DNO Voltage control policy Protection grading additional protection either side of VR	Cost (who pays?)
Impact on Generator	Larger capacity, but reduced utilisation due to constraints	Cost (deep connection)	Cost (who pays?)
Framework change	Not essential, but changes to NETA would help	None	None
Time to implement	Short term	Short term (basic) Long-term (integrated)	Long-term
Apply to DN DG types	Most (CHP less flexible if needed to maintain steam demand)	O/H line	Probably most suitable for higher voltage
Practicality	Simple schemes are possible. E.g. voltage-following for synch. machine	Current Practice	Used at transmission level
Linkage to Future	Can be part of future fully active networks. Consider DSM also. Links to power flow management	Can be part of future fully active networks	Can be part of future fully active networks

Table 2c: Solutions to OLTC AVC control with DG

	Cancellation CTs	DG voltage Control OLTC control primary side	Active network voltage control
Materiality	Medium Gives correct OLTC operation	Medium	High
Capital & Revenue Costs	Low	Low	Medium to High
Impact on DNO	Change of AVC wiring	Lose direct voltage control	Maintenance, Reliability for multi sites DNO Voltage control policy
Impact on Generator	No	Step voltage changes	Cost . Avoid conn. Cost
Framework change	No	No	Incentives to facilitate change
Apply to DN DG types	O/H, Cable	Large generators	All networks, All Generators
Practicality	Easy to implement	Applicable only when there is high reverse power	Research, development & test
Time to implement	Short-term	Short-term	Short or Long term.
Linkage to Future	Yes	If reverse power is excessive, question as to whether generator is connected at correct voltage level	Can be part of future fully active networks and network ancillary services

3.3 SOLUTIONS TO POWER FLOW MANAGEMENT PROBLEMS

If the generation connected to the network exceeds the network firm capacity, then the following options are available:

- Network enhancement
  - Network firm capacity
  - Network unfirm capacity
- Generator constraints
  - pre-fault constraint
  - post-fault constraint (immediate), i.e. inter-tripping
  - post-fault constraint (to short-term network ratings)

3.3.1 Network enhancement

3.3.1.1 Enhance firm capacity

The conventional solution is to enhance the firm capacity (i.e. the network capacity for the first circuit outage), either by uprating the capability of the existing equipment (e.g. changing transformer pairs) or by adding in an extra transformer or circuit up to the fault level design limit of the network (including generator contribution). This will allow the generator to operate unconstrained during the first outage and provides the lowest risk to the network. Some form of constraints may be necessary under second circuit outage conditions. However, this option can be a costly solution.

3.3.1.2 Enhance unfirm capacity

It is possible to enhance the unfirm capacity of the network without increasing the firm capacity. Enhancing the unfirm capacity will increase the amount of generation that can be connected under normal operating conditions, but if the firm capacity is not enhanced then the generator will generally be subject to constraints during a circuit outage. Thus, this solution solves only part of the problem, since outage conditions also have to be addressed.

3.3.2 Generator constraints

Generator constraints can be considered in terms of pre-fault constraint and post-fault constraint. For post-fault constraint, the action may be immediate (i.e. intertrip) or delayed (i.e. operate temporarily at the short-term circuit ratings).

This is summarised in Table 3.

Table 3: Generator Constraints and Network Operation

	System Normal	First Circuit Outage (FCO)	Second Circuit Outage (SCO)
Pre-fault constraint	Constrained to FCO rating	Constrained to SCO rating	
Post-fault constraint (immediate)		Intertrip if FCO rating exceeded	Intertrip if SCO rating exceeded
Post-fault constraint (to short-term ratings)		Constrained to FCO short-term rating, with inter-trip backup	Constrained to SCO short-term rating, with inter-trip backup

3.3.2.1 Pre-fault constraint

Pre-fault constraints can be used as an alternative to enhancement of the network firm capacity. Here, under normal system conditions, the generator is constrained to the FCO (i.e. firm) rating of the network. This works particularly well in examples where there is a variety of intermittent generation sources connected to the same network. The diversity in generation profile would mean that the level of constraint would be less than that predicted by a "worst-case" analysis.

Following the first circuit outage, the generator is constrained to the network "second circuit outage" capacity. In this way, the network is not placed at risk should a second circuit outage occur. Unfortunately, the second circuit outage capacity may place significant restrictions on the generator output. For example, a second circuit outage on a dual circuit supply in a rural network would almost certainly mean "no supply".

Generators are often content to consider at the design stage reducing output capacity to the network capability following a first circuit outage, rather than face high reinforcement costs of achieving full output for this condition.

3.3.2.2 Immediate post-fault constraint

The use of an immediate post-fault intertrip following a circuit outage would allow the generator to operate at the full circuit rating under normal operating conditions and at the network firm capacity for the first circuit outage. The intertripping scheme is triggered by an appropriate monitoring of network circuits and trips the generator circuit breaker, so that the generator is tripped as soon as a fault occurs. Thus, the generator can operate at a higher output, but the risk to the network is greater. To minimise this additional risk, some form of backup arrangement may be necessary. For example, there will be periods when the inter-tripping scheme may be out of service and so the scheme would need to revert to the pre-fault constraint condition described in the previous section.

3.3.2.5 "Time delayed" post fault constraint

The application of a "time delayed" post fault constraint following a circuit outage may be permitted provided that the export from the generator, before it can be reduced to the "circuit outage" capacity, is within the appropriate short term rating of the network equipment. This is particularly useful in enabling a controlled shut-down of a generator. Again, some form of back-up procedure is necessary, such as delayed inter-tripping.

For both forms of 'post fault' constraint there are issues of the complexity arising from the use of intertripping schemes. For post fault constraints they must also be 'fail safe'. In practice when there are more than 2 or 3 generators requiring post-fault constraints the intertrip scheme may become too complex to engineer (See G75/1 for further information on this issue).

3.3.3 Demand-side management

Power flows can also be managed by the management of demand as well as generation. It is normally easier to shed load than it is to ask load to increase on demand. Unfortunately, network constraints normally require an increase in local load rather than a decrease. However, developments are taking place in the field of utility-scale energy storage, which could provide the necessary functionality. This is an option for the longer term.

3.3.4 Summary of solutions

A summary of the solutions in terms of materiality, costs, implementation, practicality and timescales is given below:

Table 4a: Solutions to Power Flow Management

	Enhance firm capacity	**Enhance unfirm capacity**
Materiality	High	Medium to High
Capital & Revenue Costs	High	Medium
Impact on DNO	Cost . Who pays?	Cost Who pays?
Impact on Generator	Cost Who pays ? Second comer	Cost Who pays? Second comer
Framework change	Deep vs shallow	Deep vs shallow
Apply to DN DG types	All	All
Practicality	Current practice	Current practice
Time to implement	Short-term	Short-term
Linkage to Future	Legacy of costs. Provided enhanced network that can be actively managed in the future	Legacy of costs

Table 4b: Solutions to Power Flow Management

	Pre-fault constraint	**Post-fault intertrip**	**"Time delayed" application of post fault constraint**	**Demand-side Management**
Materiality	Medium to High	Medium to High	Medium to High	Medium
Capital & Revenue Costs	Low	Low	Low	Unknown
Impact on DNO	More complex maintenance planning Second comer	Inter-trip operation, Complexity Co-ordination Voltage step change	Understanding of short-term ratings Inter-trip operation, Complexity	
Impact on Generator	Constraint Second comer	Constraint Second comer	Constraint Second comer	Increases export potential, especially when otherwise constrained
Framework change	Planning, Operation & Connection Agreement	Planning, Operation & Connection Agreement	Planning, Operation & Connection Agreement	
Apply to DN DG types	All	All	All	All
Practicality	Best practice developing	Best practice developing	Best practice developing	Difficult to find loads that can be called upon to switch on
Time to implement	Short-term	Short-term	Short-term	Long-term
Linkage to Future	Links to fully active networks and network ancillary services	Limits to complexity of inter-trip scheme. E.g. up to 5 ends?	Links to fully active networks and network ancillary services	May also include utility-scale energy storage

4 CONCLUDING REMARKS

In general, network operators (both prior to and after privatisation) did not design distribution networks to accommodate significant levels of distributed generation. The growth of distributed generation presents a new challenge to network operators.

A number of technical solutions exist to overcome the barriers in the short-term, and facilitate the connection of distributed generation, some of which are already in place with individual network operators. Some require further development.

Solutions that aim to overcome constraints by improving asset utilisation rather than physically increasing network capacity will have limitations as to how much additional capacity they can release. The investment signals must be clearly understood for network reinforcement required to create additional capacity beyond this initial capacity release.

The impact on the system needs to be understood in terms of system performance and network security. Where safety issues exist, risk analysis in line with BS EN 61508 (electrical, electronic and programmable electronic safety-related systems) may have to be considered.

The effect of more than a single generator utilising such short term solutions needs to be considered as technical complexity increases. Care must be taken to ensure that any short-term solution does not become a barrier in the future to longer-term growth of distributed generation.

Once these issues have been addressed, the range of technical solutions can be utilised as appropriate in the design of the connection and operation of distributed generation.

This report identifies outline solutions for both the short and longer term, which should facilitate the connection of new distributed generation and relieve some of the potential operational constraints. Some of the solutions are already being utilised by network operators and represent best practice to be adopted by all network operators. Other solutions need further development or associated commercial or regulatory issues to be addressed. This forms the basis of the next stage of work.

5 NEXT STAGES

The objective of this report has been to identify the barriers to the connection and operation of distributed generation within distribution networks and to identify solutions in outline that can be implemented in both the short and longer term.

Technical solutions have been identified in outline in the area of voltage control, fault level and power flow management. The next stage is in two parts. The detailed implementation plan for short term solutions will be taken forward as the next phase of Workstream 3 project. Longer term solutions will be addressed by Workstream 5. In both cases the commercial and regulatory aspects will be considered alongside each solution.

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