Innovation in Electricity Distribution Networks Final Report

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Innovation in Distribution

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Glossary

AVR	Automatic Voltage Control
DG	Distributed Generation
DNO	Distribution Network Operator in England, Scotland and Wales
DPCR4	Distribution Price Control Review No.4 for the period 2005/10
EPRI	Electric Power Research Institute (USA)
IFI	Innovation Funding Incentive
LDC	Line Drop Compensation
NEDL	Northern Electric Distribution Limited
PLC	Power Line Communications
PV	Present Value
RCM	Reliability Centred Maintenance
RPZ	Registered Power Zone

1 Summary

Mott MacDonald and BPI have been appointed by Ofgem to undertake an analysis of the scope for innovation in the electricity distribution systems of DNOs.

Ofgem is considering the adoption of two incentive mechanisms in the current distribution price control review (DPCR4): Registered Power Zones (RPZ) and the Innovation Funding Incentive (IFI). This report forms part of a Regulatory Impact Assessment (RIA) developed by Ofgem to assess the costs and benefits of these initiatives.

The key aims of the study are as follows:

- to ascertain whether there is scope for innovation in distribution systems
- to assess the potential financial benefits of the RPZ and IFI initiatives.

To achieve the aims, the study has taken the following steps:

- compiled a list of RPZ and IFI innovation opportunities (more details in Section 2)
- quantified the reduced connection and network reinforcement costs that could accrue from the RPZ solutions identified above using a generic UK distribution system model. The present value of these savings is then calculated taking into account the time taken before the benefits are likely to flow. A success factor to represent the uncertainty of the R, D&D process is also applied and the total PV value for the life time of the innovations is calculated (more details in Section 3).
- the IFI innovations are more difficult to model due their generic nature. The potential savings that may result from their introduction are assessed using industry knowledge. Once the savings are determined for each innovation, the process is the same as that followed for the RPZ opportunities and a total PV is calculated (more details in Section 4)
- The quantification of the potential benefits reflects a realistic approach.

The key conclusions are summarised below:

- there is scope for innovation in the distribution networks but as a result of evidence gathered through the interviews, it seems that some institutional barriers may slow the initial take-up of the incentive scheme.
- the RPZ and IFI incentive schemes are likely to be value for money as indicated in Table 1-1. Nevertheless, there is no guarantee that the full potential benefit identified will be delivered. Some of the innovation opportunities included may not be taken up and others that have not been assessed in this analysis may provide higher returns.

Table 1-1: Key Conclusions

	Present Value (£m)	
	RPZ	**IFI**
Potential Savings	121	443
Cost to Customers of initiative	29	57
Net Benefit	**92**	**386**

2 Scope for Innovation

2.1 Sources of Information

A literature review was carried out to identify innovation opportunities. The following sources were searched:

- CIRED proceedings
- DGCG web site
- Eurelectric web site
- COGEN Europe web site
- PLCForum web site
- WADE (World Alliance for Decentralised Energy)
- KEMA web site
- Itcom web site
- TDWorld web site
- E2I (USA) web site
- EPRI web site - Distribution/Distribution Operations
- EPRI Journal
- Manchester University Power Distribution Engineering Research web site

Interviews were held with two key players in research (a research institution and a commercial research provider), a DNO and a manufacturing representative to discuss developments relevant to DNOs in the innovations arena.

In general the visits did not reveal any likely areas of benefit that had not already been identified from the literature search activity. However, the visits were very useful in identifying the perspective of key organisations and the difficulties of promoting technical innovation and development in the context of the present industry structure and price regulation environment.

The information gathered has also helped to inform the areas of innovation to which the RPZ and IFI initiatives are likely to be best applied and in assessing the time scales over which particular innovations might reasonably be expected to deliver benefits.

The following paragraphs set out the key points made by the parties interviewed:

- A view was put forward that take-up for the incentive may be undersubscribed through the DNO(s) due to a combination of DNOs not seeing research as a core task and/or not having sufficient and/or appropriately trained staff to deliver. From our experience of working closely with DNOs on a number of projects in recent years we tend to support this view, which is likely to originate from changes in the DNOs' understanding of their business, responsibilities and commercial focus since privatisation. A slow initial take-up may only be a short term problem particularly if DNOs perceive value and become more involved in R&D. This may provide the vehicle to recruit staff with the right approach and skills.

- A view was expressed that DNOs have a significant role in bringing new products into the market. This can be described as 'pace setting'. At present the DNOs have little incentive to become pace setters in areas where benefits are delivered beyond the scope of the current price control period. A key issue identified was the need for DNOs to be directly involved in R&D as only DNOs have the practical network availability to deliver field development tests and trials.
- The interviewees perceived the process for managing the incentives and allocating the R&D funds as very important. Opinions differed as to how research funds should be allocated and controlled. One party proposed that funds should be allocated to a centrally funded organisation involving DNOs and academics and manufacturers . However, most parties interviewed were of the opinion that if money from electricity customers is to be directed at research then that funding must remain within the control of Ofgem to ensure its application to the benefit of end consumer, and withdrawal if research does not proceed in accordance with an approved research programme. It therefore follows that relevant research funding should be made available only to DNO licensees and not directly to independent research organisations. This does not preclude research companies or manufacturers from delivering the research programme in collaboration with DNOs. Innovative approaches to product development partnerships could be implemented and issues such as ownership of intellectual property rights being distributed in proportion to stakeholding. A view was expressed that a number of research "facilitators" could emerge, bidding in a competitive way to co-ordinate research programmes with potentially a number of organisations making input to any programme.

The results of the literature search and discussions are summarised in Section 2.2.

2.2 List of Innovations

The RPZ innovations identified fall into three main categories depending on the problem area they are likely to impact upon:

- measures to control voltage
- measure to improve fault levels
- innovations that improve power flow management

The list is included in Table 2-1.

Table 2-1: RPZ Innovations

Innovation		Description
Voltage Control		
VC1	Active voltage control	A combination of a number of voltage measurements with a state-estimator computation permits voltage optimisation on all parts of the controlled network
VC2	Cancellation CTs	A scheme for correcting traditional Line-Drop Compensation (LDC) voltage control by netting-out any outgoing feeders with connected generation
VC3	Virtual VTs	A transformer AVR with the facility to monitor current, power flow and local voltage. It can control voltage on either side of a transformer with a target selected according to power flow direction
VC4	FACTS (Flexible AC	A range of products such as the SVC which can modify real and reactive power flows on

	transmission systems)	networks
VC5	Line voltage regulation	A device for controlling voltage on an 11 kV feeder according to local voltage measurements
VC6	Upgrade conductors	Installing larger conductors has benefits in improving voltage regulation and reducing losses
Fault Level Management		
FL1	Network reconfiguration (network splitting)	Opening bus-section and/or coupler circuit breakers in normal operation to reduce prospective short-circuit levels, and permit the addition of generation without exceeding fault levels.
FL2	Is limiters	A device in common use in industrial and some overseas distribution networks to detect and cut-off prospective short-circuit currents higher than a circuit breaker's capacity
FL3	Superconductivity (HTS) fault limiter	A device in development for limiting short-circuit currents, using the intrinsic property of some high-temperature (i.e. liquid nitrogen temperatures) superconducting materials which will lose their superconducting properties when the magnetic field exceeds a limiting value due to the passage of short-circuit current
FL4	Sequential switching	A scheme for limiting total prospective fault current by switching out one or more infeeds before the circuit breaker which must operate to clear the fault is allowed to open
FL5	Increase network impedance – e.g. bus section reactors	Bus-section reactors introduce impedance between two halves of a switchboard, reducing the total fault current. Offers better security and power quality than just opening a bus-section circuit breaker
FL6	Active fault level management – controlled bus section isolators	A scheme whereby the topography of the network and currently operating generation is monitored so that fault levels can be monitored and action taken e.g. switching bus section/coupler breakers automatically to control fault levels.
FL7	Converter interface technology	Converters are used with a variety of distributed generators to convert DC or non-standard AC to mains frequency. Being electronic devices there is potential to ensure that the designs can detect and limit fault current contribution from the generators in timescales better than circuit breaker make and break durations
FL8	Fault anticipators	An innovation published by EPRI, whereby electrical activity, such as partial discharging, is monitored and on detection of abnormal levels a circuit is disconnected prior to a fault.
FL9	Fault level monitor	NEDL suggestion for a device which monitors fault levels in real-time and could either permit reinforcement to be deferred or could be used to constrain off generation pre-fault when necessary
Power Flow Management		
PF1	Post-fault constraint (intertripping) – multiple generators	Intertripping scheme with intelligent response to the occurrence of a fault in terms of post-fault switching or removal of generators.
PF2	Post-fault constraint (dynamic, including use of short-term ratings) – multiple generators	A more versatile version of post-fault network management which monitors power flows and utilises equipment short-time ratings to minimise the need to constrain-off generation
PF3	Energy storage technologies	A number of technologies using chemical storage, flywheels, hydrogen production etc. in tandem with distributed generation of an intermittent nature.

The review of innovations that might potentially be candidate areas for DNOs under the proposed IFI indicates that these can be divided into three categories:

- asset management improvement: Innovations in this area would be aimed at reducing operational costs in control and emergency services, and in the reduction of maintenance costs. DNOs have in recent years done a great deal to reduce these costs through the introduction of new information technology, working practices, and use of modern plant and equipment. The scope for significant savings is diminishing. However, if failure rates were to rise significantly in future it may be possible to justify work aimed at reducing the rate of increase of costs.
- communications improvement: Whilst the development of communications technology is not a core DNO skill, the use of better communications technology has the potential to deliver savings in the operations and maintenance costs of networks. There may also be potential for DNO networks and infrastructure to be used to support communications technologies e.g. power line communications for the delivery of internet connections of customers. Such applications would have the potential to generate rental revenue for DNOs.
- other more general areas where DNO networks can be developed to deliver customer benefits: these are more general or longer term candidates for research and development effort in areas of improved products and network management.

The list of innovation opportunities is presented in Table 2-2.

Table 2-2: IFI Innovations

Innovation		Description
Asset Management Improvement		
AM1	Improved Tap Changers	Fast on-load transformer tap changing with reduced arcing and contact wear.
AM2	Stored Coolth for Transformers	Cryogenic plant in substations to charge ice banks during low load periods and release cooling to control transformer temperatures during high load periods.
AM3	Online Condition Monitoring	Linking in continuous remote monitoring devices as an improvement to offline sample testing.
AM4	End-of-Life Recognition	Predicting when to replace overhead lines, underground cables and distribution system plant. Developing methods to minimise risk of faults based on the assessment of condition and location of network components.
AM5	Data management and improved decision making	Examination of areas where decision making might be improved and investigating how such improvement might be made. It includes expert systems e.g. KEMA MainMan and RCM: reliability centred maintenance.
AM6	Cost effective asset management strategies	Development of improved standards of operation, maintenance, and design. It also includes strategic development recognising uncertainty.
AM7	Network Automation	e.g. ABB Trafostar Electronic Control (TEC) product - Life extension by optimising performance.
AM8	Move away from air-breathing transformers	Extend transformer life through permanent drying and degassing of transformer oil.
AM9	Melting ice on power cables	Prevent ice build up on overhead lines and thereby reduce occurrence of related faults.
AM10	Asset replacement development	Research optimum ways of replacing obsolete and worn out assets.
Communications Improvements		
C1	Power Line Communications (PLC)	Fitting DNO plant items and distributed generators with PLC modules would enable their status to be continuously monitored and would facilitate Active Network Management.
C2	Use of mobile telephone	Fitting DNO plant items and distributed generators with mobile telephony data

	technology capable of supporting bi-directional and broadcast data communications	communications would enable their status to be continuously monitored, and would facilitate Active Network Management when combined with automated switching devices.
C3	Move SCADA networking to TCP/IP suite and associated technologies.	TCP/IP (Transmission control protocol/internet protocol) is used to deliver internet and corporate intranets using connectionless networking.
General Areas		
G1	Superconductivity	Reduce energy losses.
G2	Demand Side Management	Manage peak demands and balance distributed generation to demand thus reducing the need for network reinforcement.
G3	Intelligent Transformers	Solid state power transformers – replacement for conventional coil wound transformer technology.
G4	Solid State Switching	Solid state circuit breakers and switches – replacement for conventional mechanical circuit breaker technology.
G5	Self Healing Cables	Replace failed or life-expired conventional underground cables with alternatives that are more resistant to faulting.

3 Potential Savings from Innovation in DG Connections

3.1 Methodology

A present value (PV) for each of the RPZ innovations listed in Table 2-1 has been determined by combining the following parameters:

- the potential capital and/or operating cost benefit
- the timescale to successful adoption
- the success probability
- the duration of the benefit once deployed.

In the calculations it has been assumed that the areas of innovation can be treated separately and their present benefits simply added up to give an overall total.

An adjustment has also been made for competing technologies. Where some technologies are considered as alternative solutions to a common problem, e.g. voltage control of networks, an adjustment has been made, so that only a single value equal to the average of all the competing technologies is carried forward to the overall total benefit.

3.1.1 Potential Capital /Operating Cost Benefit

(i) Overall Costs

The savings that may be obtained from introducing innovations in the RPZ are analysed in the context of the overall cost of developing the distribution network in order to satisfy the Government's 2010 target[1]. These costs have been estimated as between £720 and £780 million over the seven years 2003-2010, giving an average spend around £107 million p.a.[2] This estimate has been uplifted by the element of the developers' costs which might be avoided if the installation of voltage control measures permitted shorter connections to the generator, but this is a small adjustment only (£2m p.a.) giving a total cost of £109 million p.a..

The costs are derived from a generic model of the UK distribution network that assesses the potential for the connection of distributed generation (DG). Costs are extrapolated for the UK as a whole, based on an assessment of the existing asset base and estimates within the various regions of the UK as to what proportion of DG could be served by existing networks with a minimal degree of extension or reinforcement. In some areas new construction is required to accommodate the anticipated amount of DG.

[1] This is an objective to supply 10% of the UK's electrical energy requirements by renewable generation by 2010.

[2] These costs compare to £380-583m (£76-117m p.a.) that the DNOs predict will be spent in the period 2005-2010 due to DG.

The situation in 2010 is based on two scenarios, one with the preponderance of new wind generation on-shore in Scotland, the other assuming a substantial development of off-shore wind generation around the English coastline. Both scenarios are based on actual existing and planned renewable projects which form approximately 70% of the total 2010 target.

The generic distribution network model is based on typical practice in rural areas (these being likely to see the greatest impact of DG, particularly wind generation) from the 132 kV terminals of a 400 kV or 275 kV Bulk Supply Substation down to the 11 kV network. It assesses the requirements to be satisfied for the connection of generation of up to 100% of the notional network firm capacity, based on winter peak load.

The generation is connected to the model in the same proportion as used in the two 2010 scenarios, taking the mean. This gives a realistic estimate of the quantity of generation connected to each level of the network, e.g. at 132 kV, 33 kV and 11 kV, at the step-down substations or out on the networks.

(ii) Opportunities for Benefits from RPZ Innovations

The UK generic distribution model was tested with regard to:

- capacity
- voltage regulation
- transformer capability
- fault levels

Certain features were introduced to overcome the limitations imposed by conventional distribution equipment and installation practices. In particular the size of generator which could be connected to the 11 kV network was limited to 1.8 MW from voltage considerations, and at the primary substations the generation connected to the existing 11 kV busbars was limited to 5 MW (in total), for the purposes of limiting fault levels. Larger 11 kV generators were assumed to require a dedicated step-up transformer to 33 kV at the primary location to avoid fault level problems, also to overcome the problem of an unsuitable tap-range on an existing transformer that was intended for supplying downstream load only.

Similar features were included for generators connected to the 33 kV network.

Hence it proved possible to make an estimate of Capex savings if the voltage and fault level relieving measures were undertaken. Further checks on loadings and security under outage conditions demonstrated the feasibility of the proposals.

The final calculation of benefits was undertaken by applying these savings to the generic model and using the same procedure as previously developed to calculate total investment costs across the UK. This takes into account the varying situation whereby, for example, the North of Scotland will require a much greater degree of new construction as opposed to the Midlands and South of England.

The results from the generic model are summarised below.

Voltage Control

The two scenarios "band" generation into a number of groups according to the MW rating of each project. The schemes are then connected to 11 kV, 33 kV, or 132 kV network or substation according to the banding.

These bands have been modified to identify the number and quantities of generators which could be connected to the 11 kV or 33 kV networks in place of needing dedicated feeders, using typical feeding distances. Technical checks demonstrated that voltage variations could be contained within acceptable limits assuming that the voltage control scheme had benefits comparable to a conventional LDC scheme, e.g. the ±3% voltage variation without LDC shown in the original study could be halved (or the quantity of generation approximately doubled).

Estimated cost savings were approximately £360,000 on the model, based on avoided costs of dedicated 11kV and 33kV lines otherwise required to meet statutory voltage limits. This value is scaled up to a UK-wide benefit as discussed below.

Fault Level and Power Flow Level Management

In the original model it was presumed that a typical rural primary substation had sufficient fault level "headroom" to connect 5 MW of generation at 11 kV, but analysis of actual projects had shown a need to connect up to 12.5 MW at an 11 kV primary in an area where "clustering" resulted from site choices in favoured locations. Provision was included in the overall estimate of the costs of connecting distributed generation for the DNO to provide a dedicated step-up transformer to 33 kV at such locations, to avoid excessive fault levels.

Although wind generation is generally connected via individual transformers to an 11 kV (or higher voltage) network, the usual practice for "conventional" generation above approximately 1 MW rating is to connect the machine directly at 11 kV. This results in a higher fault level than the assumed 5 MVA per MW which suffices for generation connected via dedicated generator transformers. Directly connected 11 kV machines may contribute in the order of 8 MVA/MW, but in a RPZ with an anticipated mix of directly connected generators, wind generators (with transformers) and some generators connected via solid state inverters or frequency converters (usually taken as continuous fault current no greater than full load current), the overall assumption of 5MVA/MW is probably sufficiently accurate for this assessment.

If measures are taken to remove this limitation it will generally be possible to connect the 11 kV generation directly to the primary bus, thus avoiding the cost of a dedicated step-up transformer and its associated switchgear and connections.

The model also presumed a similar arrangement at 33 kV, with dedicated step-up transformers to 132 kV provided in order to overcome fault level limitations at 33 kV. The costs of these transformers and associated switchgear and connections could be deducted.

Estimated cost saving from removing dedicated step-up transformers for generation where fault levels would otherwise be exceeded was £1.07 million on the model network. This saving is scaled up for the UK as a whole as discussed below.

Overall Savings on the UK Distribution System

The savings summarised above for improved voltage control, fault level and power flow management were applied to the UK system as a whole, assuming the saving could be made on both existing and new networks. The savings from fault level reduction would not necessarily arise on a completely new network built to connect distributed generation, since new switchgear could be specified with higher fault ratings at relatively small additional cost. However it is probable that in most instances the new networks will interface with the existing networks, and fault level constraints will still be present.

A saving of £1 million on the model network translated to £28.8 million on the UK as a whole over 2003-2010 inclusive, taking into account the mix between reinforcement and new construction at 2010. This equates to 3.8% of the total estimated expenditure required to accommodate planned distributed generation by 2010.

Hence voltage control measures could expect to save 1.35% or £1.5 million p.a. over this period. Similarly, the benefit of fault level management could save 4% or £4.3 million p.a.

The list of innovations (Table 2-1) also includes energy storage. The savings corresponding to the introduction of energy storage are based on the potential to create substantial savings on investment on the network for intermittent energy sources such as wind and tidal.

In theory energy storage installed in association with distributed generation permits a better load factor at the point of connection and a reduction in the DNO's capacity required to connect the generation. In practice, however, the energy storage facility will be operated according to both the available generation at any time and the current price signals. Overall, energy storage is expected to reduce the net capacity required to connect intermittent generation by approximately 10%. Taking into account the approximate mix between intermittent and continuous distributed generation; the net benefit is estimated to be in the order of 7%. There may be a relatively long period before energy storage technologies are technically and economically viable. This is taken into account in the detailed analysis.

The calculated savings will also have associated Opex and fault-related Capex reductions as there will be fewer assets to maintain or repair and replace if they fail. As set out in Table 4-1, DNO expenditure on operating costs is running at approximately 75% of annual capital expenditure. In a RPZ area it is expected that the relatively high rate of construction required to accommodate renewable generation will result in a (relatively) lower Opex, and a notional rate of 20% has been assumed. Hence associated savings from RPZ innovations have been estimated at 20% of the Capex reductions, i.e. 0.3%, 0.8% and 1.4%.

The likely level of future returns as a percentage of the current level of investment to accommodate distributed generation to meet the government's 2010 target is summarised in Table 3-1.

Table 3-1: Percentage Cost Savings from RPZ Innovations

	Percentage Savings		
Innovation Type	**Capex**	**Fault Related Capex**	**Opex**
Voltage Control	1.5%	0.3%	0.3%
Fault Level and Power Flow	4.0%	0.8%	0.8%

Management			
Energy Storage	7.0%	1.4%	1.4%

3.1.2 Timescale to Successful Adoption

Assuming that the R, D&D process is successful, the study considers the time taken until a particular innovation delivers the expected benefit. Innovations are assessed in 3 year, 7 year, or 12 year periods depending on whether benefits flow on a Short, Medium, or Long time scale. These periods represent the points in the future when a significant level of dissemination has taken place and the estimated percentage saving can be obtained across the network. The adoption process is likely to start slowly and ramp-up as the innovation is proven, costs come down or in-situ assets are replaced. In cases where implementation depends on asset replacement, time scales may be long due to the large scale of the distribution networks and the correspondingly slow rate of evolution. In other instances, when the innovation is already at the end of the development process and only testing is required, a short time scale is appropriate.

The present value for each type of RPZ innovation is calculated by combining the savings obtained (as a percentage of total costs, as explained in section 3.1.1) and the likely deployment timescale discounted at 6.5%. The results are summarised in Table 3-2.

Table 3-2: RPZ Innovations Savings

			Savings (at 6.5% discount rate) (£m)		
Timescale	**Innovation type**	**Descriptor**	**Capex**	**Fault Related**	**Opex**
Long (12 years)	Energy Storage	LH	3.60	0.26	0.74
	Voltage Control	LL	0.77	0.06	0.16
	Fault Level & Flow Management	LM	2.05	0.15	0.42
Medium (7 years)	Energy Storage	MH	4.93	0.35	1.01
	Voltage Control	ML	1.06	0.08	0.22
	Fault Level & Flow Management	MM	2.82	0.20	0.58
Short (3 years)	Energy Storage	SH	6.34	0.45	1.30
	Voltage Control	SL	1.36	0.10	0.28
	Fault Level & Flow Management	SM	3.62	0.26	0.74

3.1.3 Success Probability

The values shown in Table 3-2 are scaled by a success factor to reflect the probability that a particular area of innovation might bear fruit. The R, D&D process is inherently uncertain and it is not possible to predict in advance whether its outcome will be a successful innovation that is widely adopted in the market place. This study tries to capture the uncertainty surrounding the process by applying a multiplying factor of 75%, 50%, or 25% to the potential benefits depending on whether the relevant probability of success is High, Medium, or Low respectively.

Even though some innovations may meet or even surpass expectations held when the project was conceived (i.e. cost, performance, development time-scale and up-take), this study has not assigned 100% success probability to any innovations. This is because the success probability factors aim at capturing uncertainty in the R, D&D process and to provide a balanced and realistic view of the potential benefits.

When assessing success probabilities, consideration has been given to the technical and commercial factors that may influence adoption. For example, the superconducting fault limiter is a device in development where considerable research has already taken place. Nevertheless, there are strong commercial barriers that still need to be overcome for full general adoption of this technology within distribution networks. In this case, it is considered that the probability of success will be low. In turn, the success probability of using cancellation CTs is considered high as these are existing technology that could be developed quickly at low costs.

3.1.4 Duration of the Benefit Once Deployed

To calculate the overall PV for the lifetime of the innovation, the study also considers the period of time over which the benefits from a particular innovation are likely to flow:

- 5 years – for communications related technologies because these are areas developing rapidly where technology becomes obsolete quickly
- 10 years – for IT and communications technologies combined with plant items
- 20 years – for innovations requiring applications of additional plant and involving ancillary plant with a shorter life, such as cryogenic equipment
- 40 years – for innovations providing replacements for traditional assets

3.2 Results

The savings as described in Table 3-1 are calculated for each of the innovations listed in Table 2-1. These are then adjusted to reflect the level of uncertainty over the innovation being successfully adopted and discounted over the expected life of the benefit. The results are presented in Table 3-3.

The table shows that the total PV of RPZ innovations is £121 m. This compares to £29m (discounted to PV); the maximum cost of the RPZ incentive as proposed by Ofgem [1].

[1] *Ofgem, December 2003: Electricity Distribution Price Control Review – Second Consultation. Paragraph 5.52*

Table 3-3: RPZ Innovations Present Value

Innovation	Qualitative Assessment	Savings			Success Factor	Life	PV	Total PV
		Capex	Fault	Opex		Years	£m	£m
Voltage Control								
VC1: Active Voltage Control*[1]	Two pilot schemes planned. Needs development to cater for real networks, which may be re-configured periodically to meet maintenance or extension needs and also is required to demonstrate a high level of integrity	ML		ML	M	10	4.57	
VC2: Cancellation CTs*	Uses existing technology and could be trialled quickly at low cost. Disadvantage to consumers on the same feeder as the generator, who could see high voltages as the LDC responds only to consumers on other feeders	SL		SL	H	20	13.52	
VC3:Virtual VTs*	Proposal based on, for example, VA Tech "Microtapp" AVR Potential for use on weak networks or where Islanding is a possibility	ML		ML	H	20	10.51	
VC4: FACTS	Static Var Compensators are well proven on Transmission applications, and have potential to be applied at distribution level. Other FACTS devices are less well established. Technology such as used in "ABB Light" (transistor converters) could have wider application	SL		SL	H	20	13.52	
VC5: Line Voltage* Regulators	Conventional technology but use with distributed generation needs further work on optimising the interaction between Primary, regulator and generator voltage control facilities	SL		SL	H	20	13.52	
VC6: Upgrade Conductors*	There are problems involved with re-conductoring existing lines with larger conductors which would warrant further investigation and trials	SL		SL	H	20	13.52	**24.64**
Fault Level								
FL1: Network Configurations*	A simple solution, but further work required to quantify costs for monitoring, and adding features to restore security as close as practicable to that provided with closed circuit breakers	SM		SM	H	20	36.06	
FL2: Is Limiters*	A well proven technology but with a small but finite risk of failure which could lead to overstressing circuit breakers and consequent safety fears. Further investigation to find ways of addressing this problem may be considered.	SM		SM	H	20	36.06	

[1] * Indicates that innovations are alternative solutions to the same problem. The results are corrected to eliminate double-counting.

FL3: Superconductivity Fault Limiter*	Potentially a useful device with benefits such as improving generator ride-through of external faults as well as protecting equipment from high fault levels. Likely to be costly to install and monitor in any trials	LM		LM	L	20	6.82	
FL4: Sequential Switching*	Can be applied with conventional technology, but research necessary to prove the integrity of such a scheme	SM		SM	M	20	24.04	
FL5:Increase Network Impedance*	An alternative to the option of operating with bus-section breakers normally-open, with improved security to consumers. Conventional technology but could have wider application as D-G is installed more widely	SM		SM	H	20	36.06	
FL6: Active Fault Management*	Requires some development of software and interfacing to plant before a trial could be put into place.	MM		MM	M	20	18.68	
FL7: Converter Interface Technology	Responsibility devolves principally to manufacturers, but field trials will be essential because of safety implications	LM		LM	M	20	13.64	
FL8: Fault Anticipators [1]	An innovation with the potential to improve CML and power quality	LL	LL	LL	L	20	2.71	
FL9: Fault Level Monitor	Further development of this concept required, and it is likely to be a long time before benefits would be realised	LL	LL	LL	L	20	2.71	**45.36**
PF1: Post-fault Constraint (intertripping)*	The principle has been used at transmission level, but needs further development for application with extensive distributed generation.	SM		SM	H	20	36.06	
PF2: Post-fault Constraint (dynamic, including use of short-term ratings) *	This scheme is potentially a more sophisticated form of network management, with a longer time-scale in development and eventual application.	MM		MM	M	20	18.68	
PF3: Energy Storage	The potential of energy storage for the relief of networks at peak load times has long been recognised, and there is further potential of high worth in association with intermittent generation, but needing a long time for development.	LH		LH	M	20	23.87	**51.24**

[1] Although FL8 and FL9 are innovations that are linked to fault levels, the cost savings are estimated to be low rather that medium because in the case of the fault anticipator it doesn't directly affect the prospective fault level and in the case of the fault level monitor, its benefit is in deferring expenditure rather than avoiding it.

Total PV (£m)	**121.24**

4 Potential Savings from IFI Innovations

4.1 Methodology

The methodology followed for the calculation of the PV for each of the IFI innovations listed in Table 2-2 is the same as that followed for RPZ innovations with the following parameters being combined:

- the potential capital and/or operating cost benefit
- the timescale to successful adoption
- the success probability
- the duration of the benefit once deployed.

These are described below with reference to the assumptions that are specific to IFI innovations.

4.1.1 Potential Capital /Operating Cost Benefit

(i) Overall Costs

The savings that may be obtained from introducing IFI innovations are analysed in the context of allowed revenue and cost information obtained from the Distribution Price Control Review [1]. This information is summarised in Table 4-1.

Table 4-1: DNO Cost Information

	Percentage	£million
Capex	42	840
Fault related Capex	15	300
Opex	43	860
Total costs		2000

(ii) Opportunities for Benefits from IFI Innovations

The innovations listed in Table 2-2 are assessed according to whether they are expected to have a 3%, 1.5%, or 0.5% impact on the present DNO cost base and therefore their benefit potential is classified as High, Medium, or Low respectively.

These levels of benefit are based on industry knowledge rather than on mathematical modelling. The technology used in electricity networks has been established for many decades, evolves slowly, and is always likely to be capital intensive. In addition much has already been done by DNOs to reduce costs through the application of IT and communications technologies and in improved flexibility and

[1] Ofgem, December 2003: Electricity Distribution Price Control Review – Second Consultation. Figure 6.1

efficiency of working practices. For these reasons, the maximum impact of any single innovation is never likely to be more than a 5% overall cost reduction; 3%, 1.5% and 0.5% have been adopted in the study as average values given the likely spread of benefits and the desire to adopt a realistic approach rather than overstate the benefits. It is worth noting that in the present evaluation the high rating has only been used for two innovation areas, which is perhaps reflective of the limited scope for radical technology change and significant cost reduction in the electricity distribution business.

4.1.2 Timescale to Successful Adoption

The time taken for potential savings to be realised is assessed for each IFI innovation and the benefits discounted accordingly using the same periods as for the RPZ innovations:

- Short: 3 years
- Medium: 7 years
- Long: 12 years.

As with the RPZ innovations, the present value for each type of IFI innovation is calculated by combining the savings obtained and the timescales before such savings are accrued. The results are summarised in Table 4-2.

Table 4-2: IFI Innovations Savings

			Savings (at 6.5% discount rate) (£m)		
Timescale	**Saving Potential**	**Descriptor**	**Capex**	**Fault related**	**Opex**
Long (12 years)	High (3%)	LH	11.84	4.23	12.12
	Low (0.5%)	LL	1.97	0.70	2.02
	Medium (1.5%)	LM	5.92	2.11	6.06
Medium (7 years)	High (3%)	MH	16.22	5.79	16.60
	Low (0.5%)	ML	2.70	0.97	2.77
	Medium (1.5%)	MM	8.11	2.90	8.30
Short (3 years)	High (3%)	SH	20.86	7.45	21.36
	Low (0.5%)	SL	3.48	1.24	3.56
	Medium (1.5%)	SM	10.43	3.73	10.68

4.1.3 Success probability

The same multiplying factors as those employed for the RPZ innovations are used to capture the uncertainty associated with the R,R&D process:

- High Success Probability: 75%
- Medium Success Probability: 50%
- Low Success Probability: 25%

4.1.4 Duration of the Benefit Once Deployed

As with RPZ innovations, present value is calculated over the period of time over which the benefits from a particular innovation are likely to flow:

- 5 years – for communications related technologies because these are areas developing rapidly where technology becomes obsolete quickly
- 10 years – for IT and communications technologies combined with plant items
- 20 years – for innovations requiring applications of additional plant and involving ancillary plant with a shorter life, such as cryogenic equipment
- 40 years – for innovations providing replacements for traditional assets

4.2 Results

Potential savings as described in Table 4-2 are calculated for each of the innovations listed in Table 2-2. These are then adjusted to reflect the level of uncertainty over the innovation being successfully adopted and discounted over the expected life of the benefit. The results are presented in Table 4-4.

The table shows that for the innovations listed in this study, the present value of the potential savings is in the order of £443m. This compares with a PV for the cost to consumers of the IFI incentive of £57m (see Table 4-3).

Table 4-3: Cost of IFI Innovations

Year	1	2	3	4	5	Total £m	PV £m*
Percentage pass-through	**90%**	**85%**	**80%**	**75%**	**70%**		
Cost to consumers	15.43	14.57	13.71	12.86	12.00	68.57	57.44
Cost to shareholders	1.71	2.57	3.43	4.29	5.14	17.14	13.80

* Discount rate of 6.5%

Source: Ofgem, December 2003: Electricity Distribution Price Control Review – Second Consultation. Paragraph 5.52

Turnover estimated to be £3,400m to give Ofgem estimated IFI cost of £85m – non discounted

Table 4-4: IFI Innovations Present Value

Innovation	Qualitative Assessment	Savings			Success Factor	Life	PV
		Capex	Fault	Opex		Years	£m
Asset Management							
AM1: Improved Tap Changers	This is likely to have a high probability of success over a medium time scale. However benefits will be low as tap changers are not a significant cost driver for DNOs. Benefits would be in reduced maintenance cost for tap changers.			ML	H	40	29.36
AM2: Stored Coolth for Transformers	There may be potential in urban areas as an alternative to transformer replacements where thermal loadings are increasing. There are existing products in the H&V industry that could be used for this. However, considerable technology transfer development work is needed and since the products are likely to be both expensive and bulky their practical application may be limited. Benefits are therefore assessed as low.	LL			M	20	10.87
AM3: Online Condition Monitoring	Techniques for condition monitoring are already proven so the success probability is high. However, considerable development work is needed to allow these to be automated for remote access. The time scale to delivery is therefore assessed as medium. The impact on DNO costs is likely to be low in the areas of Opex and Fault related Capex.		LL	ML	H	10	18.72
AM4: End-of-Life Recognition	The likelihood of successfully developing a robust end of life assessment methodology acceptable to DNOs to cover high cost elements of the network is low. Savings in this area are related to the extent to which DNOs maintain or replace assets before strictly necessary. Since DNOs have now moved away from purely time based asset maintenance and replacement programmes the potential for savings in this area has already been reduced significantly. In addition, taking pre-emptive action on the basis of an end of life prediction rather than fixing things when they go wrong may lead to increased costs. For these reasons, the potential benefits in this area and the associated delivery time scales are classified as medium.	LM	LM	LM	L	20	38.81
AM5: Data management and improved decision making	Combination of GIS based network asset information, fault statistics, and component life information would give potential for maintenance and emergency services cost savings. Data management and expert systems have been developed and applied successfully in recent years so the likelihood of success in this area is assessed as high. Associated timescales to delivery would be short as the application of portable computers in the field is already widespread in the industry. Savings would be in reduced Opex for e.g. fault location, maintenance management, but potential level of benefit is assessed as low since DNOs have already reduced costs significantly in these areas.			SL	H	10	19.19
AM6: Cost effective asset management strategies	There may be significant potential for alternative design standards that could save Capex, but savings in Opex from improved strategies are less likely as DNOs have already achieved significant reductions in Opex through improved management strategies in recent years. The probability of success is assessed as medium, and the time scale to	LH	LM	LL	M	40	112.95

	delivery as medium.						
AM7: Network Automation	Since there are already potential products on the market the success probability is assessed as medium. The rollout program for automation is likely to be extended and is therefore assessed as medium. Improved network automation is likely to have medium potential to reduce Capex through active network management, and low potential in the Opex area through reduced need for field switching operations.	MM		ML	M	10	39.09
AM8: Move away from air-breathing transformers	Benefits would potentially be in the areas of maintenance costs and in the reduction of transformer related faults. This development has been the subject of research for some years already and so the potential for success as medium. Timescale for delivery of benefits is likely to be medium as troublesome plant items are replaced and extra Capex is likely to be offset to give low levels of return in the areas of fault related Capex and Opex.		LL	LL	M	40	19.27
AM9: Melting ice on power cables	Reduction in Emergency services costs may be significant in some areas, but for most of UK DNOs the costs of faults relating to ice build up is low. The likelihood of success is low and would be related to only a low component of fault related Capex and Opex. If successful the rollout could be achieved over a medium time scale.		LL	LL	L	20	7.50
AM10: Asset replacement development	Success probability is likely to be high and time scales to delivery short. Returns would be in the area of Capex, but would be low as application areas are restricted to those where obsolete assets cannot be replaced directly with modern equivalents.		SL		M	20	19.16
Communications							
C1: Power Line Communications (PLC)	PLC has been the subject of much research over the past two decades and there appears to have been at least one "false dawn" of a proven product. The likelihood of success is low and the time to deliver long. If successful there may be low level Capex savings for DNOs relative to other communications methods, and a high level of Opex earnings through the rental of DNO lines for e.g. internet service provision.	LL		LH	M	5	29.28
C2: Use of mobile telephone technology	Since there is already proven technology in this area the likelihood of success is high and the timescale to deliver benefit as short. It is likely that there would be only be low Capex and Opex benefits from this.	SL		SL	H	5	21.93
C3: Move SCADA networking to TCP/IP	Since the technology is already there the success is probability as high. The time scale to delivery will be medium as the decision to update or replace major existing systems, e.g. SCADA related, would not be made by DNOs until the relevant financial trigger points were reached.			LL	H	5	6.29
General Areas							
G1:Superconductivity	This has been the subject of considerable research in recent decades and is still to a large extent "blue sky". Probability of success is therefore assessed as low. Since extra cryogenic plant will be needed it is likely that any returns will be low and will roll out over a long time scale.	LL			L	20	5.43
G2: Demand Side Management	This area has been the subject of considerable effort by the industry. Cost drivers on customers to modify load patterns need to be stronger and in the absence of direct regulation (c.f. insulation improvements required in successive revisions of building regulations) further DNO R&D is likely to have a low probability of success. If	MM			L	10	14.57

	successful a medium level of savings through deferred Capex would be possible, and could potentially be delivered over a medium time scale.						
G3: Intelligent Transformers	The probability of delivering a large scale solid state alternative to the traditional power transformer is low. Cost savings are also likely to be low and rolled out over a long time scale.	LL			L	40	6.98
G4: Solid State Switching	The probability of delivering a large scale solid state alternative to traditional switches and circuit breakers is low. Cost savings are also likely to be low and rolled out over a long time scale.	LL			L	40	6.98
G5: Self Healing Cables	The development of a cable that would self correct after faulting seems to be a long way off. Rollout of a successful product would take a long time. Extra Capex could potentially be offset to give high levels of savings in the area of fault related Capex and medium levels of savings in Opex.		LH	LM	L	40	36.38
Total PV (£m)							442.8

5 Conclusions

The key conclusions are summarised below:

- there is scope for innovation in the distribution networks but as a result of evidence gathered through the interviews, it is apparent that some institutional barriers are present that may slow the initial take-up of the incentive scheme
- the RPZ and IFI incentive schemes are likely to be value for money as indicated in Table 5-1

Table 5-1: Key Conclusions

	Present Value (£m)	
	RPZ	**IFI**
Potential Savings	121	443
Cost to Customers of initiative	29	57
Net Benefit	**92**	**386**

- the results are based on a methodology that reflects a realistic case for the evaluation of benefits
- there is a degree of uncertainty which is inherent to the R, D&D. Accordingly, there is no guarantee that the full benefit identified will be delivered. Some of the innovation opportunities included may not be taken up and others that have not been assessed in this analysis may provide higher returns. Also, some of the RPZ innovations studied may have application in a wider network context and not just as a result of DG. This would add to the benefits.