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REGISTERED POWER ZONES (RPZ)

Assessing the feasibility of establishing Power Zones on Northern/Yorkshire Electricity

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ASSESSING THE FEASIBILITY OF ESTABLISHING REGISTERED POWER ZONES ON NORTHERN/YORKSHIRE ELECTRICITY NETWORK

K/EL/00333/00/00
URN NUMBER: 06/1084

Contractor

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EXECUTIVE SUMMARY

Background

In April 2005, Ofgem (the UK electricity industry regulator) established a set of integrated methods to provide incentives in the efficient access to, operation of and reinforcement of the distribution network. The aim of these methods was to facilitate the development of distributed generation, which will support government objectives to increase the amount of renewable energy produced in the UK. Registered Power Zones (RPZ) are one of the methods established, which have been conceived as a mechanism to facilitate demonstration projects.

This project has undertaken both conceptual and actual studies of the issues associated with the development of “Registered Power Zones” within a distribution network, which will provide Ofgem and distribution network operators (DNOs) with a more fully developed conceptual model.

Objectives

This report has been produced as part of a Department of Trade and Industry (DTI) funded research project. Its objectives are as follows.

- Research the technical, regulatory and commercial possibilities associated with the concept of Registered Power Zones
- Conduct feasibility studies on two potential RPZ sites in the CE Electric network region (northeast England)
- From the results of the feasibility studies, draw out generic designs, rules and techniques that could be useful in any RPZ, and disseminate the results from this research project

The research project was not intended to assist in creating a particular RPZ, as its aim was to examine the key issues to be addressed when an RPZ is created, nevertheless, it is likely that the results of this research project will help CE Electric to create an RPZ, if they decide to do so in the future.

The benefits of this project include the records of actual network studies and cost benefit analysis results, which are of use to any organisation trying to cater for the practical aspects of establishing RPZs.

Work carried out

A review of the RPZ framework was carried out at the start of the project, which established that its main aim is to stimulate innovation in the connection of distributed generation (DG) in order to reduce connection costs, by avoiding some or all of the network reinforcements that would otherwise be required. It is a framework that allows DNOs to demonstrate innovative techniques on a real network, which if successful, would subsequently become adopted as standard practice. The framework enables DNOs to claim additional financial revenues in order to mitigate the risks inherent to innovation.

The project work included an investigation of the innovations that could be demonstrated in an RPZ. It also identified generic types of RPZ, and explored the definition, risks, benefits and financing of RPZs, as well the process for registering an RPZ.

Technical and cost benefit analysis studies were carried out for two potential RPZ sites, and generic rules, issues and techniques were derived from the results of the studies. In addition, the project work included generic cost benefit analysis studies of energy storage systems.

The two sites that were studied in this project are defined below.

- Site 1: a proposed 38MW wind farm in the Teesside area. This site is confidential at the time of writing of this report, and will be referred to as Site 1 in this report
- Site 2: a urban regeneration site at Victoria Harbour, Hartlepool, in the Teesside area, where energy efficiency measures and on-site generation is being considered as part of the residential and commercial property development

Both sites were investigated for suitability as an RPZ, with thermal issues for existing network assets being the main barrier to their connection.

Results for Site 1

We investigated the connection of Site 1 to the surrounding network at the 132kV, 66kV and 11kV voltage levels. The results from an initial assessment showed that the wind farm could be connected to the 132kV network without triggering network reinforcements, whilst connection to the 66kV network triggers reinforcements and connection to the 11kV network does not provide enough capacity to accommodate the full output of 38MW. The technical issue to be overcome, for 66kV and 11kV voltage levels, is that of providing sufficient network capacity for the required wind farm output power flow, and energy storage has been identified as a potential innovation to help solve this problem.

The use of energy storage has been examined against the RPZ framework. A full review of utility-scale electrical energy storage options currently available on the world market has been carried out. Redox batteries and hydrogen storage systems have been selected for investigation of their potential use at Site 1. Consideration has been given to the connection and control method for the energy storage system, and to the methodology for sizing the energy store with respect to the wind farm capacity.

The results of the cost benefit analysis for connecting the wind farm showed that using energy storage systems to help solve power flow issues at Site 1, whilst technically possible, was not an economically viable option within the current RPZ framework. The capital cost of installing an energy storage system, in order to reduce the amount the power being exported from the wind farm onto the CE Electric network, was of several orders of magnitude higher than the capital cost of connecting to the 132kV network. The analysis of the results showed that Site 1 might not represent the best arrangement for applying energy storage systems, so we extended the scope of work to include generic studies of energy storage systems.

Results for generic studies of energy storage systems for use in RPZs

We considered the circumstances under which an energy storage system would be cheaper than the cost of reinforcements to the distribution network. This approach lead us to explore possible scenarios where the costs of reinforcement of the distribution network would be significantly higher than they would be at Site 1.

We created and studied a range of scenarios, where there would be the requirement to connect a generating plant to the distribution system at a given voltage level, and the nearest connection point at that voltage level was a considerable geographical distance from the generating plant, necessitating the construction of a new circuit of significant length. We carried out a series of cost benefit analyses for circuits of length between 10km and 70km, and for a range of energy storage technologies including battery and hydrogen systems.

We drew the following conclusions from the results of the cost benefit analysis.

- It is difficult to find a scenario where the use of an energy storage system to alleviate network issues would prove to be cheaper than the mitigation methods currently utilised by network operators.
- We have found a few scenarios for small generation plants where this may be true. Such generation sites tend to have small project budget, so it may be that a small generation site requiring such connection would not be viable, even taking into account the cost reduction when using an energy storage system compared with conventional means of reinforcement.
- There may be potential sites in remote Northumberland and Scotland that would be suitable for connection with an energy storage system, but typical distances of distribution system circuits back to primary substation tend to be under 70km in the UK because of the density of population. We are however aware of an example of a successful application of a Redox battery system in USA, where the length of the circuit was in excess of 300km.
- The cost of the energy storage system is very dependent on the variability of the generation plant output and for how long the energy has to be stored in order to capture all the export from the generation plant. We have analysed the variability of a 2MW wind turbine with a 667kW (33%) rated connection and concluded that the associated energy storage system would need to provide up to 2 days of storage at full wind turbine export capacity.
- The results of the cost benefit analysis clearly show that, for medium size wind farms in the UK (10MW to 40MW), it is unlikely that energy storage systems, when considering their application within the current RPZ framework, would provide suitably economical alternatives to “business as usual” network reinforcements in the foreseeable future.

Results for Site 2

We have conducted a range of studies and cost benefit analysis for assessing the option of creating an RPZ around the Victoria Harbour site in Hartlepool. We started with the site developer’s specification for the proposed loads and generation plants for the site (energy mix 1), and updated our studies in line with the changes in the developer’s plans (energy mix 2), which arose from the impracticality of installing some of the proposed generation plants.

We have considered two main types of innovations to avoid reinforcements due to power flow and voltage issues: demand side management and generation to support load. We identified that the only suitable demand side management techniques would be those where the load customers were not aware of the management technique, as we have assumed that these customers would not have any particular incentive to have their electrical loads managed, and the commercial drivers for them to do so would not be obvious to them. We have explored in detail the use of generation to support load, which we considered to be a practical option and we found that the site developers could be expected to respond positively to the increased levels of generation (energy mix 2 was the lowest payback option).

The results from the studies for energy mix 1 and 2 did not prove conclusive in terms of cost benefit analysis compared to the "business as usual" solution. We then devised energy mix 3, which aimed to minimise the reinforcement costs by having more generation than load on the site. We were successful in reducing the reinforcement costs very significantly, although not completely. We have checked that the payback on the total generation plant capital, operation and maintenance cost, including the connection costs was beneficial to the site developer.

We drew the following conclusions from the results of the work carried out for the Victoria Harbour site.

- The use of on site generation as an innovation measure for mitigating network reinforcement has to make financial sense in its own right.
- The RPZ option is centred around the DNO controlling the generation plants when the network limits are exceeded, leaving the customer to run their generation as they find most advantageous commercially when the network is within limits.
- When developing the budget for a site like Victoria Harbour, the total capital costs should include the connection costs, so that the balance of generation plant costs and initial connection costs can be optimised as a whole. This optimisation work could be complex and extensive, as many parties may need to be involved to provide the specialist knowledge into a complex sequence of decision-making.
- In a staged development, where all properties would be not developed at the same time, then connection costs could be deferred until later phases of development if the balance of load and generation is shown to be advantageous in the earlier phases of development.
- Reductions in initial connection costs may not be visible to the customers purchasing properties in the later stages of development. These customers would be liable, directly or indirectly, for the operation and maintenance costs of the generation plants, and for the ongoing use-of-system charges for the connection of these generation plants, the latter including a proportion of the RPZ surcharge.

Generic designs, rules and techniques

One of the objectives of this research project is to attempt to draw out some generically applicable designs, rules techniques that have become apparent from the two specific studies.

Energy storage systems as an innovative solution for connection

There are several issues to consider when attempting to use energy storage systems as an alternative to network reinforcements.

- The reinforcements costs must be at least of the same order of magnitude as the cost for the generation plants, on a per MW basis. This balance may result from the use of reasonably long route lengths of new circuits, or from the use of relatively expensive circuit constructions.
- The time for storage of energy from the generation plants must be estimated as accurately as possible. This requirement is driven by the cost of an energy storage system, which is dominated by the cost associated with the storage capacity

element of that system. For generation from wind energy, the method used in this report can be used to work out how much storage capacity is required to capture nearly 100% of the energy so generated, provided that the raw wind data is available for a representative length of time, typically over several months.

- There are regulation issues to be resolved with Ofgem, associated with the questions of whether a DNO can own an energy storage system, and if the losses associated with such a system can be accounted as network losses.

Generation plants to support load as an innovative solution for connection

There are several issues to consider when attempting to use on-site generation to support loads as an alternative to network reinforcements.

- For a site where on-site generation is used to support loads in order to reduce connection costs, and where the connection options for the site include the 11kV voltage level, one option for connection is to divide the site into a series of plots, with groups of plots connected to an existing 11kV/LV substation on or in the vicinity of the site. This arrangement may lead to many connection points for the site as a whole.
- Where network issues associated with the connection of a site include thermal and voltage problems on the existing circuits, using on-site generation to reduce or eliminate these problems is likely to give rise to fault levels issues. It is therefore expected that some reinforcements of the existing network may be required to connect the site, but this could be kept to a minimum.
- Where the size of on-site generation approximately matches the size of loads on the site, then it is likely that network issues would arise when the loads on the site are at or towards their minimum value. If this is the case, then a method of reducing these network issues is to control the on-site generation. The owners of the generation plants would want to operate them to their maximum financial advantage, with DNO initiated control only taking place where the site would cause the existing network to go outside limits.
- A rule of thumb for the feasibility stage of a site development is to take the total size of loads (in MW), divide it by a percentage factor to obtain the minimum amount of generation that would be required to ensure that the site as a whole does not increase the loading on the existing 11kV network to which it may be connected. For Combined Heat and Power (CHP) plants, the percentage factor can be 80%, whereas for other types of plants the percentage factor can be calculated from Engineering Recommendation P2/6.
- Where the site is to be developed in stages, then installation of generation plant in the earlier phases of development may defer some or all of the connection costs for the site as a whole.
- The connection studies need to evaluate the feasibility of connecting the site as a whole, and also the feasibility of connecting each phase of the development, in the order in which the phases will be developed. This process will require a large number of feasibility studies, with associated engineering costs.
- Where the site includes domestic customers, who do not form a community with green objectives, then the most practical form of demand side management is one that is transparent to the user. This concept of transparency means avoiding the concept of controlling the electricity supply to domestic dwellings. The heat for the dwelling is, however, a potential candidate for demand side management, particularly if a heat network, coupled with heat storage, is installed on the site.

- Where on-site generation is an objective for the site development, without reference to any potential for RPZ, then it can be advantageous to include the requirements for connection to a local 11kV network as part of the payback calculations for the capital costs of the generation plants. The amount of on-site generation can be optimised in terms of payback (in years) for the generation plant capital and running costs, together with costs allocated to CO_2 emissions (if this is an objective) and connection costs.

Other generic RPZ findings

Other generic findings include the following.

- We expended a significant amount of time trying to find a way forward for the two sites that we have chosen and to create the specification for an RPZ for each site. DNOs may not find it practical to expend similar effort on attempting to create an RPZ for a site, given the time constraints for DNOs to process connection applications. It is possible that DNOs will seek additional funding through the Innovation Funding Incentive (IFI) scheme in order to provide resources for the required studies.
- We have found that for the two sites that we have studied, introduction of innovative solutions would be technically possible but the economical case either cannot be made or is not very clear-cut.
- There is only one official RPZ at the time of writing this report. We believe that this singularity exists partly because of the time taken to establish the site requirements and partly due to the difficulty in finding the right combination of generation site, network issue and innovation that will solve that network issue. The fact that the normal rules of network operation apply in an RPZ in the same way as they do outside an RPZ may increase the difficulty of this task.
- For the two sites that we have studied, we have found that the developer may be better placed than the DNO to apply innovation to their electrical connection schemes. We would like the opportunity to examine the RPZ framework conditions in terms of how they could be amended to account for innovation on the developer’s side.

Conclusions

We have investigated two potential RPZ sites on the CE Electric distribution network. For Site 1 we attempted to connect a 38MW wind farm using an energy storage system as an innovative method of connection. For Site 2 at Victoria Harbour, Hartlepool, we attempted to connect the new loads for the site using on-site generation as an innovative method of connection. In both cases we investigated the use of innovative methods primarily to overcome issues of thermal limits for the assets on the existing network.

In conclusion, we have found it difficult to justify the innovations that we considered on a cost benefit basis, even though from a technical point of view the introduction of such innovations would be practical. We have expended a significant amount of resources in attempting to create an RPZ on both sites, with mixed results. It may not be acceptable for DNOs to commit the same level of resource to establishing a site as an RPZ and we are uncertain that the RPZ framework is achieving its objectives in terms of demonstrating innovation, although it is a fact that DNOs are actively looking for RPZ sites and this activity in itself raises the profile of innovation within the electricity distribution industry.

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1 INTRODUCTION

Background
The concept of Registered Power Zones (RPZ) [1] has arisen from the UK government objectives to promote renewable energy generation, which is part of the UK commitment to reduce CO_2 emissions. Extensive development of wind generation in Germany and Denmark, for example, has been achieved by significant network development, with high costs to all electricity customers. In contrast, the UK government, in collaboration with the industry regulator (Ofgem), is encouraging the use of innovation to minimise the economic impact on all customers of overcoming the network connection barriers, with the aim of improving utilisation efficiency and lowering the overall cost of running the network. This is in contrast to carrying on with the current “fit and forget” methods of developing passive networks, which leads to expensive network reinforcements and development [2]. The concept of Registered Power Zone (RPZ) is part of a range of Ofgem initiatives to provide financial incentive to DNOs to take part in innovation to enable the connection of more distributed generation (DG) to their network.

Aims and objectives
The aims and objectives of this research project were:

- Research the technical, regulatory and commercial possibilities associated with the RPZ concept
- Identify key issues applicable to generic types of RPZ. Consult with Ofgem the electricity industry regulator, and CE Electric the distribution network operator (DNO) partner in this project, to ensure that the identified key issues are relevant and practical
- Identify with the help of CE Electric two potential RPZ sites in the Northern/Yorkshire Electricity network area, which is operated by CE Electric
- Consult key stakeholders associated with the two selected sites
- Study the feasibility of establishing an RPZ around each of the selected sites, considering connection requirements, control techniques and cost/benefit analysis
- Draw generic design rules and techniques from the results of the feasibility studies
- Disseminate the results of the research through consultations, report and seminar

The two sites that were studied in this project are defined below.

- Site 1: a 38MW wind farm in the Teesside area. This site is confidential at the time of writing of this report, and will be referenced as Site 1 in this report
- Site 2: a urban regeneration site at Victoria Harbour, Hartlepool, in the Teesside area

The research project was not intended to assist in creating a particular RPZ as its aim was to examine the key issues to be addressed when an RPZ is created, nevertheless it is likely that the results of this research project will help CE Electric to create an RPZ, if they decide to do so in future.

The benefits of this project include the records of actual network studies and cost benefit analysis results, which are of use to any organisation trying to cater for the practical aspects of establishing RPZs.

Consultation and dissemination

During this project, the following consultation and dissemination activities have taken place.

- Consultation with Site 1 representative
- Consultation with the Victoria Harbour site developers
- Consultation with CE Electric
- Consultation with and dissemination of information to Ofgem
- Dissemination seminar open to all interested UK parties, held at NaREC offices in Blyth, Northumberland on 19 January 2006.

Project collaborators

The collaborators on the project described in this report were Econnect Ltd, the New and Renewable Energy Centre (NaREC), and CE Electric. Econnect Ltd, a consultancy specialising in innovating solutions for the grid integration of renewable energy, was the project manager. NaREC, a research centre in renewable energy, was a project collaborator and provided technical support and research studies in energy storage systems and energy systems suitable for urban regeneration projects. CE Electric, the DNO for northeast England, was a project partner and provided technical guidance, supplied network data and validated network models, and ensured the practicality of the technical and commercial studies.

Acknowledgements

The project team is pleased to acknowledge the very valuable support that Mr. David Miller of CE Electric has provided to this project. We would also like to acknowledge the support to this project of Mr. Peter Loftus of Renew Tees Valley and the team at Tees Valley Regeneration for their help in finding suitable sites for studies, providing information about the sites and allowing us to conduct our research in a constructive way. We would also like to thank Mr. Gareth Evans of Ofgem for his guidance during the project.

This project has been partly funded by the UK Department of Trade and Industry, and that Department's support is also acknowledged.

Source of information

The following information has been used for this research project.

- 33kV, 66kV and 132KV network data from CE Electric Long Term Development Statement (LTDS), November 2004. The information contained in the CE Electric LTDS statement, including geographical maps of the network, have been used in this project with the permission from CE Electric
- 11kV network data, supplied free of charge by CE Electric as part of this research project
- Asset costs from manufacturer's estimated costs, validated by Econnect
- Reinforcement costs, supplied free of charge by CE Electric as part of this research project
- The maps in this report are copyright and have been obtained from the following sources
    - 1:50 000 raster set, reproduced by permission of Ordnance Survey on behalf of HMSO. © Crown Copyright and database right 2005. All rights reserved. Ordnance Survey Licence number ESRI OS 100019086

- Outline Planning Application, provided by Tees Valley Regeneration in CD format (OPA 05: Phasing strategy, Victoria Harbour Master Plan, Hartlepool, 21 June 2004), which is in the public domain

2 THE RPZ FRAMEWORK

Definition of an RPZ

An RPZ is a defined electrical area that is selected and proposed to form an RPZ by the DNO and is then treated as a bounded network zone. The RPZ framework has been introduced under the UK Distribution Price Control Review in April 2005, and enables DNOs to claim additional financial revenues in order to mitigate the risks inherent to innovation. The RPZ initiative is to run initially for a period of 5 years, with a review after 2 years (in 2007) to assess its effectiveness.

In order to be eligible a site proposed for treatment as an RPZ must meet the following criteria.

- An RPZ must involve the connection of new distributed generation, which is eligible for the existing DG incentive, or the connection of an incremental increase in MW for an existing generation site. The generation technology may be of renewable type or non-renewable type, and there is no limit to the capacity of the generation plant
- An RPZ must demonstrate innovation
- The innovation must be shown to be of value to the DG customers connecting within the RPZ, as well as to UK electricity customers in general
- Generation sites that will be impacted commercially/technically by an RPZ must be informed of the risks, costs, innovation used and existing alternative connection options. While it is preferable to gain the consent of the developers for these sites, this is not a mandatory requirement.
- An RPZ connection must have a contingency measure if quality of supply to existing customers in and around the RPZ could be affected
- An RPZ must be registered with Ofgem
- DNOs are required to prepare an annual report for all approved RPZs in their area, and such reports are to be made publicly available. The aim is to share and promote good practice between DNOs
- The RPZ funding can be combined with other grant funding
- All usual electricity codes and standards apply in an RPZ, and the DNO is able to apply for derogation to these codes & standard in the same way as for non RPZ sites
- DNOs must comply with the Good Practice Guide [3] for RPZs that has been approved by Ofgem

More detailed information about the RPZ framework is given below.

- In the first two years of the RPZ framework, RPZ applications for registration will be limited to two per DNO per year. This limit will be reviewed along with the RPZ incentive in 2007.
- An RPZ is not restricted to new sites as it may contain existing generation sites, although only the MW increases to existing generation sites will qualify for the RPZ incentive.
- It is possible to commission an RPZ in stages. In this case each stage must have a connection energisation date before 31st March 2010. Each stage will receive the RPZ incentive for the five years following its connection date.

- RPZ applications can be made in response to a specific connection application, or proactively as a draft application to investigate the connection opportunity for a particular part of the distribution network.
- Each DNO has a license obligation to make a connection offer in 3 months. If this obligation would affect the development of an RPZ opportunity, Ofgem may, following a request from the DNO in the usual manner, consent to an extension of the timescale for that particular connection.

Definition of innovation

Innovation can be demonstrated in a number of ways.

- *New technology trial*: demonstration of new designs of equipment
- *New technical solutions trial*: demonstration of new system designs and topologies, including control and protection systems, to increase the utilisation of network assets
- *New operating practices trial*: demonstration of new approaches to system operation and control (e.g. management of voltages, power flows, fault levels) to increase the utilisation of network assets
- *New structures trial*: demonstration of using distributed generation to enhance supply continuity and/or quality, reduce losses, and minimise constraints to generator operation

Whilst the degree of innovation cannot easily be quantified, it can be categorised as one of the following: incremental innovation, significant innovation, technological substitution and radical innovation [3].

Benefits of RPZs

The benefits to the parties involved in an RPZ are set out in Table 1.

Interested party	Benefits
Generation site developer	• **Cost savings**: a potentially cheaper alternative to existing connection methods if network reinforcements are avoided • **Time savings**: a potentially shorter time to energising if network reinforcements are avoided • **Make or break**: projects that would not be economically viable due to high connection costs may be able to complete and connect • **Increased capacity**: a potential increase to the capacity which can be connected, thus reducing the relative connection cost per MW, making the generation scheme more financially rewarding • **Development of innovative technologies** to solve common and particular problems encountered by DG. These innovative technologies may I eventually become best practice, thus benefiting all generation sites, not just those in an RPZ
DNO	• **Additional direct financial revenue**: an extra income proportional to the amount of DG connected, to mitigate the risks of innovation, enabling the development of effective risk management • **DG friendly network service**: an opportunity to offer higher connection capacity to DG at reduced costs, thus potentially increasing the customer base and revenue to DNOs. • **More efficient network**: efficiencies in infrastructure provision by avoiding network reinforcements, in line with Ofgem and government aspirations • **Facilitating competition in generation**: helping DNOs to meet the statutory and licensed obligations including facilitating competition in generation
All customers in UK	• Lower cost of developing and operating the electrical network means lower bills compared to continuing with current more expensive network reinforcement methods

Table 1: Benefits of RPZ

Risks of RPZs

The main risks associated with demonstrating innovation in an RPZ are detailed below.

- The innovation may fail during the trial, and contingency plans would need to be activated at additional costs, negating the anticipated value of the innovation
- The innovation may lead to reduced security of supply
- The innovation may lead to reduced power quality
- The innovation may lead to increased safety issues

The DNO is expected to take full responsibility for the management of any risks associated with an RPZ scheme, and to offer any connecting generation plant commercial terms reflecting these risks. The benefit and risks of an actual RPZ can only be estimated on a case-by-case basis, where appropriate feasibility studies and cost benefit analyses are carried out and where the innovation is applied for the particular circumstances of the actual network, existing customers and generation site. The innovations considered in this project do not in general provide a generic solution applicable to any distribution network, and the right set of circumstances need to be met for a particular innovation to be selected.

Generic types of RPZ

The definition of generic types of RPZ may help in the identification of actual sites that would qualify for RPZ status. An analysis of the potential benefits of RPZ has led us to identify three generic types of RPZ, which are detailed in Table 2.

Type of RPZ	Description
Asset light	An "asset light" RPZ would enable the connection of an individual generation scheme using "fewer assets than conventional means of reinforcement", which means in practice avoiding some or all of the network reinforcements that would otherwise be required, leading to a lower connection cost than the costs of connection based on conventional network reinforcement. For example, fault current limiters (see section 3) could be used locally to the generation plant to avoid reinforcement of switchgear at the substation and to allow lower ratings of switchgear to be used for the generation site substation than would otherwise be necessary.
DG reception	A "DG reception" RPZ would enable the connection of more embedded generation capacity for the "same assets" i.e. either the same as the quantity of assets that existed before the connection of new DG, or the same as the quantity of augmented assets required for the connection of new DG using conventional network reinforcement techniques. Thus the connection cost per MW would be less than the cost per MW when using conventional connection techniques. An example of a DG reception RPZ would be the installation of fault current limiters at a primary substation to permit the connection of significantly more generation capacity than could be connected if fault current limiters were not used. Note that Ofgem does not allow for "prospective" network development leading to assets being installed but not used ("stranded assets"). There must be generation plants and/or load that require connection in order for a DNO to be able to develop a part of their network. This situation could occur if a single generation scheme required connection initially and was connected using an innovative technique, which allowed additional generation to connect in the future, without further network modification, and the potential additional generation never materialised. Such a situation would represent a potential conflict with the concept of this type of RPZ.
Green park	A "green park" RPZ would enable the connection of generation plants that would otherwise not be connected, through the integration of active generation and load control within the RPZ. In this case, the RPZ designation would be applied to a newly designed section of the distribution network, where network assets, generation plants and loads were actively controlled to ensure that all technical limitations and regulatory requirements were met. For example, an urban regenerations scheme where new housing and commercial outfits are planned could be connected with the help of on-site generation in order to avoid or reduce network reinforcements.

Table 2: Generic types of RPZ

Establishing an RPZ

To establish an RPZ, the DNO must register the RPZ with Ofgem. The main steps in the RPZ registration process, as known at the time of writing of this report, are given below.

- The DNO submits an application form to Ofgem, as detailed in the ENA good practice guide [**3**]. All applications are considered against the same criteria. DNOs can submit RPZ applications from 1st April 2005 until 31st March 2009 and must commission the project between 1st April 2005 and 31st March 2010.
- Ofgem acknowledges receipt of the application within 10 working days, advising if the application is complete and valid. If the application form is complete, Ofgem uses the receipt date for the form as the start date for the application.
- Ofgem considers the application against published assessment criteria, giving a result within 15 working days. If advice from an independent panel is needed, the applicant will be advised of the additional time required.
- If the project is granted RPZ registration, there is a duty on the DNO to inform Ofgem of any change to the RPZ proposal after registration. The RPZ registration may be withdrawn if Ofgem judges that the changes cause the RPZ registration criteria to be no longer met.

There is an RPZ independent panel of four members drawn from industrial, commercial and academic backgrounds and chaired by Ofgem. When appropriate Ofgem will seek advice from the panel in relation to the innovation and potential benefits of a proposed RPZ. Ofgem will use the panel's advice to inform its decisions but Ofgem will make all final decisions regarding registration.

DNOs are required to carry out a comprehensive assessment of the impacts of an RPZ on existing customers, and to submit their findings in the application for RPZ. Where potential negative impacts are identified, mitigation measures will be established, and where relevant these measures will include the deployment of monitoring equipment to ensure that existing customers' interests are protected.

When applying for an RPZ registration, a DNO will be required to identify the risks and financial exposure it is managing in relation to the RPZ, and inform Ofgem of these. This information may be used to support the DNO's case to claim the additional RPZ revenue.

Financing of RPZs

The RPZ additional revenue will be collected through distribution charges by DNOs who have successfully completed the registration process. These charges have recently undergone a review and a new charging structure has been introduced (along with the RPZ incentive) in April 2005.

The DNO is able to collect an additional £3.0 per kW per year for generation connected in RPZs on its network, and the total revenue is capped at £0.5M per annum per DNO. There is an existing DG incentive scheme, where DNOs are able to collect £1.5 per kW per year for generation connected to their network and the additional RPZ revenue can only be collected for those generation sites that already qualify for the existing DG incentive scheme. It is not clear at the time of writing this report whether the cost of the RPZ will be payable by all generation developers connecting to the DNO's network after 1st April 2005, or whether the cost will fall only to those generation developers connecting in the RPZ.

3 INNOVATIONS FOR AN RPZ

This section reviews the issues associated with connecting a generation plant to the distribution network, and the innovative methods that are available, at the time of writing this report, for demonstration in a real network and where such innovations could qualify for RPZ status.

Connection issues

The main technical difficulties encountered by generators when negotiating connection agreements with DNOs are as follows.

- *Voltage rise issues*: customer exposure to steady-state voltage rise resulting from the connection of DG
- *Power flow issues*: inadequate thermal rating of existing network equipment and inadequate reverse power flow capability of existing network transformers to meet the demands of new DG
- *Fault level issues*: excessive fault levels resulting from the connection of DG
- *Power Quality*: voltage step, flicker and harmonics issues resulting from the connection of DG
- *Security of Supply*: increased risks of interruptions to existing customers' supplies resulting from the connection of DG

Scope for innovation

Mott Macdonald and BPI have carried out a detailed study on the scope for innovation in the Electricity Distribution networks [4] and the benefits to be gained from this. The key conclusions of that report were:

- There is scope for innovation in the distribution networks, but institutional barriers may slow the initial uptake of the incentive scheme.
- The RPZ framework as a whole could deliver an estimated present value of £121M savings during the lifetime of the innovations considered in the Mott Macdonald study, although there is no guarantee that the full benefit of this potential will be delivered.

The current RPZ framework is designed to allow DNOs to trial innovative methods for DG connection. The fundamental research and development for the innovation must already be completed and its feasibility established. For this reason, only innovation that is ready, or near ready, for demonstration in a real network has been considered in this project. There is a separate Ofgem initiative to support DNOs in the development of applied research, called the Innovation Funding Incentive (IFI).

A list of potential innovative methods for DG connection that is suitable for demonstration in an RPZ is presented in Table 3. This list of innovations may not be complete and there are almost certainly to be new innovations becoming available in the future, however the list in Table 3 is a starting point for a guide to the use of currently available innovations.

The innovations in Table 3 are classified according to the following types.

- *Equipment, denoted "Kit"*: new equipment and new designs of equipment
- *Technology, denoted "Techno."*: new network designs and topologies (including control and protection systems)

- *Operational, denoted "Opera."*: new approaches to system operation and control (e.g. management of voltages, power flows, fault levels) to increase the utilisation of network assets
- *Commercial, denoted "Com."*: new contractual frameworks. Note these can only be used in association with technical innovations, as a secondary benefit of the RPZ

Innovation	**Brief description**	**Type**	**Solution to**	**Source**
Cancellation CTs	They control the voltage at the primary substation via the transformer tap changer control system. Cancellation CTs are current transformers that are installed on feeders containing DG to compensate for the changes to transformer load and power factor caused by the DG. The CTs work in tandem with LDC AVC relay transformer control systems. No remote measurement is required, as the scheme relies only on parameters of the network at the primary substation.	Techno.	Voltage	Solutions for connection & operation of DG [2]
Virtual voltage transformers	They control the voltage at the primary substation via the transformer tap changer control system. Virtual voltage transformers are voltage transformers that work in tandem with MicroTapp AVC relays. They operate tap changers to reduce voltage fluctuations on the feeders where there is no DG. No remote measurement is required, as the scheme relies only on parameters of the network at the primary substation.	Kit	Voltage	Solutions for connection & operation of DG [**2**] VA Tech "Microtapp" [**6**]
Active voltage control systems	They control the voltage at the primary substation via the transformer tap changer control system. They are fitted and operate as complete systems with a central control unit and remote sensors. They work with any type of transformer AVC relay and any number of feeders. They keep the voltages on the whole network within limits, using parameters measured from the local and remote parts of the network.	Techno. & Opera.	Voltage	ETR 126 [**5**]
FACTS	They control the voltage on a feeder. They consist of a power electronics system controlling the currents flowing in shunt connected capacitors and reactors. Their operation modifies real and reactive power flows in feeders, and they can be set to maintain feeder thermal loadings and voltage profiles within pre-set limits. They are already used in transmission voltage networks, but are a novel technique for controlling GB distribution voltage networks.	Kit & Techno.	Voltage	Solutions for connection & operation of DG [**2**] All manufacturers e.g. ABB static Var Compensator [**8**], Westinghouse FACTS [**9**]
Line voltage regulators	They control the voltage on a section of a feeder. They are series autotransformers with dynamic voltage control for the downstream section. Network voltages elsewhere are controlled in a conventional manner from the primary substation (using transformer tap change controls). Line voltage regulators have already been used for controlling loads, but their use for connecting DG	Kit	Voltage	Solutions for connection & operation of DG [2] ETR 126 [5]

Innovation	Brief description	Type	Solution to	Source
	is so far limited to less than 5 instances in the UK.			
Synchronous compensators	They are used in a similar manner to FACTS and are also used control the voltage outputs of induction generators. In the latter application they consist of standard synchronous generators electrically coupled to induction generators, and they help to maintain the voltage at the generator point of connection within preset limits by controlling the flow of reactive power. Synchronous compensators are normally freewheeling mechanically.	Kit	Voltage	Synchronous compensators for mini-grids and islanding [10]
Increase network impedance	This method for limiting the fault contribution of DG adds permanent impedance to the network, via series connected devices (reactors or transformers). The disadvantage to their use lies in an increase in network losses and less accurate voltage regulation compared with other available schemes.	Techno.	Fault	N/A
Network reconfigu-ration	This method of managing high fault levels increases the permanent impedance of the network, by reconfiguring the network, either within the primary substation or more widely on the network. The disadvantage is an adverse impact on security of supply and possibly power quality.	Opera.	Fault	The Performance of Networks using Alternative Splitting Configurations [**11**]
Fault current limiters (FCL)	These devices add temporary impedance to the network, where and when needed at the time of a fault. Under normal conditions, a reactor is bypassed by the FCL elements. Immediately (less than 10ms) after a potential high-energy fault, the FCL elements are destroyed bringing the series reactor into circuit. However it must be noted these standard (explosive type) fault current limiters are one-off use devices and are not considered sufficiently failsafe to meet the UK ESQCR regulations. Note that standard fault current limiters can also be used as fault interrupters.	Kit & Techno.	Fault	Several manufacturers e.g. ABB Is Limiter [**12**]
Supercon-ducting fault current limiters	These devices add temporary impedance to the network, where needed and when needed at the time of a fault. Superconducting fault current limiters are reusable devises that are either of the resistive or reactive type. There are concerns about the reactive type not being fail-safe as they involve power electronics.	Kit & Techno.	Fault	Applied Superconduc-tor Limited [13]
DC links (voltage source type)	They consist of close-coupled converter and inverter devices changing AC to DC. They are used at transmission voltage level to increase economic power transmission distances by converting AC to DC at one end and back again at the other end, or in a "back to back" configuration for interconnecting two networks, each having different operating frequencies. Their operating regimes allow them to be used to control the fault	Kit	Voltage Fault Power quality	Many manufacturers For e.g. Siemens HVDC [**14**], ABB HVDC Light™ [**15**]

Innovation	Brief description	Type	Solution to	Source
	current flows between one part of an interconnected network and another.			
Upgrade to new types of conductors	The method involves the use of new types of overhead line conductors that have a ceramic core for support, thus leading to low conductor expansion under load current, reducing conductor sag per unit load and providing additional capacity compared with conventional conductors. Their use to date is mainly limited to transmission networks.	Techno.	Power flow	N/A
Line sag monitoring with a line replicator	The method involves the use of a replica of a short section of an overhead line, which is loaded and its sag measured, allowing overhead lines to be operated closer than before to their maximum thermal capacity.	Techno.	Power flow	Shaw Power Technology [16]
Power Flow Management	DG installed capacities may be increased through the implementation of active management schemes to constrain DG output levels when necessary to avoid overload on existing network assets. Constraints are signalled to the DG operator when the associated distribution network is operating in abnormal configurations, due to circuits being out of service for maintenance or fault, and monitored power flows indicate that thermal limits may be breached. The increased DG connected capacity can be as high as the difference between summer minimum loads and winter maximum loads on that part of the network. A reliable communications system is necessary for the successful implementation of this technique.	Opera. & Com.	Power flow	ETR 124 [17]
Energy storage technologies	These systems control power flow by absorbing and releasing energy to keep assets within their thermal limits. They can be installed anywhere on the network, subject to land availability	Kit, Techno. & Com.	Voltage Power flow Power quality Security of supply	Future Energy Storage Seminar [18]
Demand side management	This system controls power flow by balancing load and generation, particularly at times of maximum generation.	Opera. & Com.	Voltage Power flow Security of supply	Kema “Scoping study” [19]
Generator to support load	This method uses on-site generation to supply loads, reducing the impact of these loads on the thermal capacity of existing network assets.	Techno., Opera. & Com.	Power flow Power quality Security of supply	Standard P2/6 [20]

Table 3: List of innovations

4 STUDIES FOR SITE 1

Introduction

Site 1, located in the area between Middlesbrough and Hartlepool in northeast England, is being considered for the development of a 38MW wind farm. This site is the potential location of a practical connection enquiry by a wind farm developer, which whilst still confidential at the time of writing this report, reflects a reasonably foreseeable level of generation for the site.

This site was originally selected because of the favourable conditions for the use of energy storage systems, as it is located in a part of the UK where there is already an existing hydrogen economy. There are large hydrogen generating plants in the vicinity and an existing hydrogen pipeline. There are also underground storage cavities suitable for hydrogen storage near the proposed wind farm. The site has good wind resources and is located in a heavily industrialised area, making it a realistic DG development site. The existing distribution network in the area is operated near to saturation, thus giving the opportunity to explore an innovative solution for the connection of the wind farm

Options for connection

In order to determine the connection options for the 38MW wind farm it is necessary to establish the limitations of the local distribution network. Studies for conventional reinforcement “fit and forget” solutions have been carried out to establish the nature and level of these limits. “Fit and forget” solutions are those network capacity improvements currently used by UK network operators, where generation and load are connected to the distribution network and once connected, no active management of the connection takes place, and the network assets are sized to cope with the worst-case loading and voltage scenario.

The connection options considered for Site 1 are detailed in Table 4.

Connection voltage	Connection point	Nature of limitation	Maximum capacity that can be connected without reinforcements
Option 1: 132kV	Tee connection onto 132kV circuits	Excess generation in the area	38MW
Option 2: 66kV	Direct connection onto 66kV Busbar	Power flow (thermal capacity) Excess generation in the area	0MW
Option 3: 11kV	Direct connection onto 11kV Busbar	Power flow (thermal capacity) Excess generation in the area	12MW (0MW)

Table 4: Connection options for Site 1

The most economic voltage for connection of a 38MW generation plant would be 66kV. The thermal rating of the 66/132kV substation transformers prevents any new generation being connected to the existing 66kV busbar because the transformer capacity is fully taken up by the generation plants already connected to the local 11kV and 66kV networks. Indeed the generators already connected are subject to constrained connection agreements.

The 132kV network has the capacity to accept the proposed 38MW of generation, whilst there is capacity on the 11kV network itself for up to 12MW of generation. The 11kV network is supplied from the 66/132kV substation containing the fully loaded transformers, so that transformer and network reinforcements would be required to raise the practical limit for connection at 11kV above the present capacity limit of zero.

The estimated budget costs for the three connection options are given in Table 5.

Connection Option	Estimated Electrical Connection Cost	Potential Capacity	Approx. £/MW installed
Option 1: 132kV	£1,513k (exclusions apply)	38MW	£40k/MW
Option 2: 66kV	£2,067k (exclusions apply)	38MW, with reinforcements	£54k/MW
Option 3: 11kV	£565k	12MW, with reinforcements	£47k/MW

Table 5: Connection costs for Site 1

The connection to the 132kV circuits appears to be the cheapest option, providing a firm connection for the proposed 38MW of generation at an estimated cost of £40k/MW. This option has therefore been used as the base case for the RPZ cost benefit analysis.

Innovations for Site 1

The potential innovations that could be used to alleviate issues of power flow were reviewed in section 3. These innovations are listed below and are examined for their suitability for Site 1.

- “Upgrade to new types of conductors”: this innovation is not suitable for Site 1, as the thermal issue is one of transformer capacity rating, not circuit (conductor) capacity rating
- “Energy storage technologies”: this innovation is potentially suitable for Site 1, and is investigated in detail in this report
- “Demand side management”: this innovation is not suitable for Site 1, as there is an excess of generation capacity connected to the CE Electric network in the area, and therefore all loads in that area are already fully supplied by the existing generation plants
- “Generation to support load”: this innovation is not suitable for Site 1 for the same reason as the “Demand side management” innovation

The type of RPZ considered for this site is an “Asset Light” connection, as defined in section 2, and the aim is to investigate the use of energy storages systems to alleviate power flow issues on the network.

Energy storage systems and RPZs

For energy storage systems to qualify for RPZ status under the current framework the following issues have to be considered.

- Ownership: The energy storage system may be owned by the DNO or rented by the DNO from a third party. That third party could potentially be the generation site developer.

- Point of connection: the energy storage system may be connected on the DNO side or on the generation plant side of the DNO settlement meter. It could also be connected elsewhere on the network, away from the connecting generation plant.
- Alternative uses: the primary use of the energy storage system may be to store and regenerate or release electricity, acting as both a load and power generation source, or it may be used primarily for generating a separate income stream from selling a by-product like hydrogen, acting primarily as a dispatchable load.
- Categorisation: the energy storage could be considered as a generation plant during the time it is restoring electricity onto the network, and as such might qualify for RPZ status as a generating plant.

At the time of writing this report, Ofgem has not clarified the issues of ownership, point of connection, alternative uses or categorisation.

From a financial perspective, a DG connection using an energy storage system would involve the owner of the energy storage system having a supply agreement in place to purchase the stored electricity and a purchase agreement to sell the released electricity. At current prices, the owner would buy the electricity at approximately 7p/kWh and sell it at approximately 2p/kWh, giving a 5p loss/kWh. There are also financial penalties due to the round trip efficiency of the energy storage and production technology used, which can vary between 25% for hydrogen systems up to 80% - 90% for battery systems.

If the owner is the DNO, then it is not clear whether the DNO could account for these financial penalties as part of their network losses. If the owner is a third party, then these financial penalties would have to be balanced against the gains from renting the system to the DNO and any potential for other revenue streams, like the sale of by-products. If the owner is the generation site developer, then the issue of the price differential for buying and selling electricity may not arise.

Energy storage for Site 1

We have reviewed the utility scale electrical energy storage technologies currently available on the world market, and have assessed their application, cost, status and maturity. The key findings of this assessment are summarised in Table 6. The costs shown in Table 6 were obtained from one manufacturer for the technology that we have reviewed. The cost is given as a combination of the energy transformation cost (£/kW) and the energy storage cost (£/kWh), which is dependent on the capacity (length of time) required for the storage system. In Table 6, the operating temperature attribute is designated as "Op. Temp", and the grid connection type attribute as "Grid Conn.".

Technology	Maturity	Cost		Main Attributes
		Transform. £/kW	Storage £/kWh	
Lead Acid Battery	$5 billion sales per annum. 4 utility scale storage applications	361	194	Life: 5 Years Op. Temp: 0ºC – 38ºC Efficiency: 78% Grid Conn.: Inverter
Sodium Sulphur Battery	88 Projects	77	143	Life: 15 yrs or 2500 cycles Op. Temp: 300ºC Efficiency: 85% Grid Conn.: Inverter
Vanadium Redox Flow Battery	5 Projects	755	83	Life: 12 Years Op. Temp: 0ºC – 40ºC Efficiency: 70%-78% Grid Conn.: Inverter
Polysulphide Bromide flow Battery	1 Project, abandoned	350	69	Life: N/A Op. Temp: N/A Efficiency: 75% Grid Conn.: Inverter
Zinc Bromine flow Battery	4 projects	73	249	Life: 2000 Cycles Op. Temp: N/A Efficiency: 75% Grid Conn.: Inverter
Cerium Zinc Flow Battery	1 partial demonstration	234	44	Life: N/A Op. Temp: N/A Efficiency: 70% Grid Conn.: Inverter
Hydrogen Electrolysis & engine burning	1 demonstration	1330	88	Life: N/A Op. Temp: Wide Efficiency: 25% Grid Conn.: Inverter & synchronous
Super Capacitors	Sales of 600,000 units pa	50	22,124	Life: 500000 cycles Op. Temp: -40ºC/+ 85ºC Efficiency: 85% Grid Conn.: Inverter
Fly Wheels	Widely used	72	1440	Life: 100000 cycles Op. Temp: Wide Efficiency: 88% Grid Conn.: Inverter
Supercon-ducting Magnetic Energy Storage	Demonstration for power quality	N/A	N/A	Life: N/A Op. Temp: -77ºC Efficiency: 89% Grid Conn.: Inverter

Technology	Maturity	Cost		Main Attributes
		Transform. £/kW	**Storage £/kWh**	
Compressed Air Energy Storage	2 working projects	388	16	Life: N/A Op. Temp: Wide Efficiency: N/A Grid Conn.: Synchronous
Pumped Storage	90GW installed, 3% of worlds generation	546	41	Life: 100 Years Op. Temp: Wide Efficiency: 80% Grid Conn.: Synchronous

Table 6: Review of energy storage systems

The majority of the above energy storage technologies are still at the development stage. Those chosen for evaluation in this study were hydrogen electrolysis and storage coupled with a modified gas burning engine, because of the favourable conditions for the application of this technology at Site 1, and Vanadium Redox flow batteries as they are the most mature of the battery storage options reviewed, with several projects having already been built using these batteries in Australia, Japan and the USA.

A cost benefit analysis was carried out to compare the cost of connecting the 38MW wind farm to the 132kV network with the “business as usual” scenario, to the cost of connection of the same wind farm to the 11kV network using an energy storage system to ensure that no more than 12MW is exported onto the 11kV circuit. In the latter case, the energy storage system and the wind farm would work in tandem, with excess energy being stored when the output of the wind farm rose above 12MW and energy being restored to the network when the output of the wind farm dropped below 12MW.

There are two potential ways of operating the combined wind farm and energy storage system, either as a “capped” system or as a “fixed output” system, as described below

For a capped system, the aim is to ensure that the total combined power output of the wind farm and energy storage system is limited to the maximum power value that the circuit to which they are connected can accept whilst staying within thermal rating limits. When the energy storage system is full, then any further energy generated by the wind farm is lost. If there are long periods with insufficient wind for the wind farm to utilise the full capacity of the circuit, and the energy storage system is partly or totally empty, then the combined power output of the wind farm and energy storage system would drop below the capacity of the circuit.

For a fixed output system, the energy storage system is sized to be large enough to generate electricity for the longest expected period when the wind farm output is below the capacity of the circuit. In this case the utilisation of the circuit capacity is maximised, but the size of the energy storage system required is significant larger than in the case of the capped output system.

In the studies for Site 1 we assumed that the system would operate in a fixed output regime in order to fully utilise the capacity of the 11kV circuit. Later in the report, we investigate other scenarios where the system operates in the capped output regime.

In order to arrive at the size for the energy storage system to achieve a given fixed output, we calculated the relationship between the size of the wind farm and the size of the energy storage system. We took into account the capacity factor of the wind farm, the wind speed to energy conversion factor for the wind turbine, and the round trip efficiency of the energy storage system, assuming an average wind speed of 7m/s for the site. The relationship is illustrated in Figure 1. From Figure 1, a wind farm size of 59MW when using a Redox battery system and a wind farm size of 97MW when using a hydrogen system would be required to achieve a fixed output of 12MW. Conversely, given a wind farm size of 38MW, a fixed output of 7.7MW for a Redox battery system and 4.7MW for a hydrogen system can be achieved.

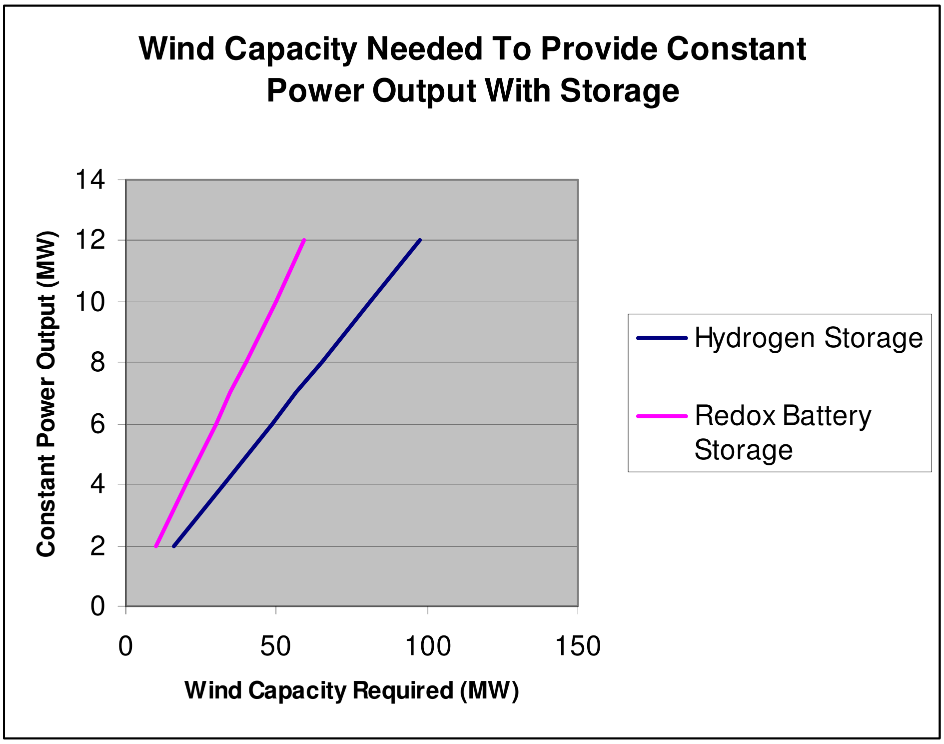

Figure 1: Wind capacity needed to provide constant power output with storage

Cost benefit analysis for Site 1

We calculated the cost of connecting a 38MW wind farm to the 132kV network, as we identified this option as being the most cost effective method of connection for that wind farm. We then calculated the cost of connecting the same 38MW wind farm to the 11kV network with a Redox battery system to achieve a constant output of 7.7MW and the cost of connecting the 38MW wind farm to the 11kV network with a hydrogen system to achieve a constant output of 4.7MW, using both today's prices as detailed in Table 6 and an estimation of future prices assuming that the technologies become more widely available. We used a method to estimate future prices known as the "learning factor" method, where it is assumed that each succeeding unit is cheaper to manufacture than the previous unit by a given factor, due to the fact that the manufacturing process has "learned" from the creation of the previous unit. We used a learning factor of 80% and calculated what the future costs would be for the 10th unit. We assumed that the energy storage system would need to be capable of storing up to 7 days of energy from the wind farm. The results of the comparison are shown in Table 7.

Connection Option	Estimated Electrical Connection Cost	Potential Capacity	Approx. £/MW installed
"Fit and Forget" Connection: Tee connection onto 132kV circuit	£1,513k	38MW	£40k/MW
RPZ option 1: Wind + Hydrogen system connected to 11kV – 1st Unit	£85,739k	38MW (4.7MW)	£2,256k/MW
RPZ option 1: Wind + Hydrogen system connected to 11kV – 10th Unit	£41,151k	38MW (4.7MW)	£1,083k/MW
RPZ option 2: Wind + Battery system connected to 11kV – 1st Unit	£130,819k	38MW (7.7MW)	£3,443k/MW
RPZ option 2: Wind + Battery system connected to 11kV – 10th Unit	£62,632k	38MW (7.7MW)	£1,648k/MW

Table 7: Cost benefit analysis for Site 1

From the results shown in Table 7 it is clear that the RPZ options are more expensive than the standard connection option by several orders of magnitude, even when a learning factor is applied to calculate an estimation of the future costs for the system. The costs for the RPZ options are dominated by the cost associated with the length of time during which the energy storage system is required to store energy.

Conclusions for Site 1

We concluded that using energy storage systems to help solve power flow issues at Site 1, whilst technically possible, was not an economically viable option within the current RPZ framework. The capital costs required for installing an energy storage system on the CE Electric network, in order to reduce the amount the power being exported from the wind farm onto the CE Electric network, was of several orders of magnitude higher than the capital costs required for reinforcing the 66kV network in the area.

We considered the circumstances under which the costs could be reduced. A cost reduction could be achieved by changing from a fixed output to a capped output system, which would enable us to reduce the length of time during which the energy storage system is required to store energy. The cost reduction resulting from this change proved insufficient to justify the use of energy storage systems to connect Site 1 at a lower cost than the alternative option of connecting to the 132kV circuits. There were no other innovative solutions immediately available for connecting Site 1, so with the agreement of the DTI we terminated the studies for Site 1 and extended the scope of work of this project to include generic studies of energy storage systems. The results of this extended study are detailed in section 5.

5 GENERIC STUDIES OF ENERGY STORAGE SYSTEMS

Introduction
We considered a generic approach to the study of energy storage systems within the RPZ framework, and considered the circumstances under which an energy storage system would be cheaper than the cost of reinforcements to the distribution network. This approach lead us to explore possible scenarios where the costs of reinforcement of the distribution network would be significantly higher than they would be at Site 1.

One possible scenario would be the requirement to connect a generating plant to the distribution system at a given voltage level, where the nearest connection point at that voltage level was a considerable geographical distance from the generating plant, necessitating the construction of a new circuit of significant length. As the distance between the generator and the nearest connection point at Site 1 was under 2km, we therefore considered circuit lengths of 10km and over.

This connection distance is potentially representative of generation plants of over 5MW capacity planning to connect to the Northumberland (north east England) 33kV or 66kV network. There are relatively few 33kV or 66kV circuits in Northumberland, so the distance to the nearest connection point at 33kV or 66kV could easily exceed 10km. A similar situation may be found in Scotland, where the distribution network is of similar density and distances to the nearest suitable connection point may easily be of 10km and over.

In order to investigate the use of energy storage systems to aid the connection of generation plants to the distribution system, we created a range of scenarios, which were then used as a base for performing a cost benefit analysis. Whilst these scenarios are fictitious and do not correspond to actual sites, they take into account the knowledge that we have developed during the project and CE Electric's knowledge about proposed generation sites in Northumberland.

Scenarios
We created a range of scenarios based on the following parameters:
- Proposed generation plant capacity
- Distance from the proposed generation plant to the nearest connection point at the voltage level voltage level that would normally be chosen for the full capacity of that plant

We have divided the scenarios in two categories:
- 20kV scenarios: where the nearest connection point normally chosen for the generation plant is rated at 20kV. Generation plant capacities of 1MW, 2MW and 5MW have been considered in these scenarios
- 66kV scenarios: where the nearest connection point normally chosen for the generation plant is rated at 66kV, Generation plant capacities of 10MW, 20MW, 30MW and 40MW have been considered in these scenarios

This separation is appropriate for the CE Electric network in Northumberland, which is primarily composed of 20kV and 66kV circuits. In other parts of the country, where the distribution network mainly consists of 11kV and 33kV circuits, these scenarios would have to be allocated between the 11kV and 33kV voltage levels.

We evaluated the cost of connection when the network is reinforced using “business as usual” methods against the cost of connection using an energy storage system.

In the “business as usual” reinforcement scenario, we assumed that there is a local 20kV circuit to which the generation plant cannot connect because the thermal rating of the circuit is not sufficient for the full export power capacity of the generation plant. For the purpose of this analysis we also assumed that a connection to the local 20kV circuit would lead to voltage issues on that circuit.

In the 20kV scenarios, the “business as usual” way to overcome this problem would be to either build a new dedicated 20kV circuit to connect the generating plant directly to the nearest 20kV/66kV substation, or to upgrade the existing 20kV circuit to a sufficient level of thermal capacity such that the generation plant could be connected to the upgraded circuit. For costing purposes we have used the costs for building a new 20kV circuit instead of the costs for upgrading an existing 20kV circuit, as the former are higher and the aim in this study is to find scenarios where the “business as usual” solution is as expensive as possible.

In the 66kV scenarios, the “business as usual” way to overcome this problem would be to build a new dedicated 66kV circuit to connect the generating plant directly to the nearest 66kV substation.

In the RPZ energy storage scenario, we assumed that there is a local 20kV circuit that is capable of accepting up to one third of the capacity of the generation plant, in addition to its maximum loading at the time the generating plant is commissioned, without the need to carry out any upgrade to the circuit. We then assumed that an energy storage system, capable of storing up to two thirds of the capacity of the generation plant, is installed on the network at or near to the point of connection.

The 20kV and 66kV scenarios are illustrated in Figure 2 and Figure 3 in section 9.

Energy storage and generation intermittency

As part of the studies for Site 1, we established that the dominant factor in the cost of an energy storage system is the length of time during which the energy must be stored. In order to estimate the storage time for the energy storage system in the generic studies, we used actual wind data for one of the 2MW wind turbines installed at Blyth harbour (on the Northumberland coast), close to the NaREC facility. This selection of wind turbine suited the project as NaREC is a partner in this project and they have access to the raw wind data for the Blyth harbour. This selection would also give confidence in the calculated costs for the energy storage system.

The results of the analysis of the wind profile and energy output for one of the 2MW wind turbine located at Blyth harbour are shown in Table 8.

Days storage at max power rating	0	1	2	3
Exported power	51%	77%	84%	85%
Power lost in storage process	0%	11%	14%	15%
Power lost due to lack of storage	49%	12%	2%	0%

Table 8: Energy storage requirements for a 2MW wind turbine at Blyth harbour

The calculation results shown in Table 8 lead to the following key findings.

- If no energy was stored, 51% of the energy produced by the wind turbine could be exported through a circuit rated at one third of the capacity of the maximum power output of the wind turbine
- Storing energy for one day would enable 77% of the energy produced by the wind turbine to be exported through a circuit rated at one third of the capacity of the maximum power output of the wind turbine. The remaining 23% would be lost through the energy storage process and insufficient capacity of the storage system
- Similarly, storing energy for two days would enable 84% of the energy produced to be exported. The remaining 16% would be mainly lost through the energy storage process with only 2% lost due to insufficient capacity of the storage system
- Increasing the storage capacity to three days would be sufficient to capture the whole of the energy produced by the wind turbine, but the losses of the energy storage system means that a maximum of 85% of the energy produced by the wind turbine could be exported through a circuit rated at one third of the wind turbine capacity

From the results above, we drew the conclusion that expenditure on energy system storage times in excess of two days brings diminishing returns to the amount of energy that can be exported through a circuit rated at one third of the wind turbine capacity. We therefore carried out cost benefit analyses for a storage capacity of 2 days. In addition, we conducted studies for a capacity of 8 hours, which corresponds to cases found in the literature describing existing installed energy storage systems [**21**].

Results

The methodology used for estimating budget costs for the “business as usual” reinforcement scenarios includes the following elements.

- The assets includes in the estimated budget costs include all the new assets between, and including, the new generation site substation and the point of connection to the existing distribution network. Assets required to connect the wind farm to the new wind farm site substation are excluded.
- We have assumed that a new dedicated circuit would be installed between the new wind farm site substation and an existing distribution network substation with a transformer of appropriate voltage.
- We have assumed that the new circuit required to connect to the existing distribution network substation would be constructed as an overhead line. For comparison we have also prepared estimates on the basis that the new circuit would be constructed as an underground cable.
- All costs correspond to capital costs. Operation and maintenance costs are excluded

The methodology used for estimating budget costs for the RPZ energy storage scenarios includes the following elements.

- Energy storage system capital costs for the duration of storage required (8h and 2 days)
- Energy storage system capital costs for the capacity of storage required. This is defined in the scenarios as being an input capacity of two thirds of the wind farm capacity and an output capacity of one third of the wind farm capacity
- Operation and maintenance costs are excluded. Connection costs to the local 20kV network are also excluded because we assumed that it was practical to site the storage system adjacent to the 20kV circuit

The following energy storage technologies were included in the cost benefit analysis:

- Lead acid batteries
- Sodium sulphur batteries
- Vanadium Redox flow batteries
- Hydrogen electrolysis coupled with a modified gas burning engine
- Hydrogen electrolysis coupled with a fuel cell

The results are shown in **Figure 4**, **Figure 5**, **Figure 6**, **Figure 7**, **Figure 8**, **Figure 9**, **Figure 10**, **Figure 11**, **Figure 12**, **Figure 13**, **Figure 14**, **Figure 15**, **Figure 16** and **Figure 17** in section **9**.

The results for the 20kV scenarios and for 8h storage duration indicate that

- For 1MW generation plants, the use of an energy storage system may be cheaper than paying for the reinforcement of a 20kV circuit when that circuit is more that 20km long.
- For 2MW, the circuit would have to be over 50km long
- For 5 MW, the circuit would have to be over 70km long

The results for the 20kV scenarios and for 2 days storage duration indicate that

- For 1MW generation plants, the use of an energy storage system may be cheaper than paying for the reinforcement of a 20kV circuit when that circuit is more that 30km long, but only if the circuit is constructed as an underground cable.
- For 2MW, the circuit would have to be over 60km long, but again only if the circuit were constructed as an underground cable.
- For generation plants of 2MW and above, there are no scenarios where the cost of reinforcing a 20kV circuit up to 70km long would be more expensive than the cost of an energy storage system.

The results for 66kV scenarios and for both 8h and 2 days storage duration indicate that there are no scenarios where the use of an energy storage system would be cheaper than reinforcing a 66kV circuit up to 70km in length.

For 8h storage, sodium sulphur batteries are the cheapest technology, whereas Redox flow batteries are the cheapest for 2 days storage.

Conclusions
The conclusions that we drew from the results of the cost benefit analysis are as follows.

- It is likely that there are very few scenarios where the use of an energy storage system to mitigate network thermal rating issues arising from the connection of embedded generation would prove to be cheaper than the mitigation methods currently utilised by network operators.
- We have however identified a small number of scenarios where the use of an energy storage system would appear to be beneficial and these relate to the connection of a relatively modest size of generation plant for which a long distance circuit would need reinforcing. Small generation sites tend to have small project budgets, so it may be that a small generation site requiring such a connection would not be economically viable, even when taking into account the potential cost reduction associated with an energy storage system.
- There may be potential sites in remote Northumberland and Scotland that would qualify, but typical distances of distribution system circuits from primary substations tend to be under 100km in the UK as a result of the density of population. We have identified an example of a successful application of a Redox battery system in USA, where the length of the distribution circuit was in excess of 300km.
- The cost of the energy storage system is very dependent on the variability of the generation plant output and on the duration of energy storage required to capture all the export from the generation plant. We have analysed the variability of a 2MW wind turbine and concluded that the energy storage system would need to provide up to 2 days of storage at full wind turbine export capacity.
- The results of the cost benefit analysis clearly show that for medium size wind farms in the UK (10MW to 40MW), it is unlikely that energy storage systems would provide a suitably economical alternative to “business as usual” network reinforcements in the foreseeable future, when considering their application within the current RPZ framework.

Energy storage systems as solutions outside the RPZ framework however may prove successful in the future if the cost benefit analysis relies on types of criteria other than used in these studies, these criteria being dictated by the current regulatory RPZ framework.

For example, the capital costs for energy storage systems are in the same order of magnitude as the capital costs for generation plants. Capital costs for wind farms may be typically in the range £750k to £850k per MW. The capital costs for a Redox battery system may be typically in the range £750k/MW plus £85k/MWh (depending on duration of storage required). The capital costs for a hydrogen electrolysis/gas engine storage system may be typically in the range £830k/MW, split as £330k/MW for the electrolyser, 500k/MW for the gas engine (typically rated at half of the electrolyser, full cost being £1000k/MW), plus £88k/MWh (depending on duration of storage required).

In addition to these capital costs, there are the costs of operation and maintenance that would need considering. There is little data for operation and maintenance costs for the majority of the energy storage systems that we have considered, as there is sparse operating experience for these energy storage systems with the exception of technologies like lead acid batteries, which have well-established performance data.

If a generation project could be found which would commercially benefit in its own right from an energy storage system, and if that energy storage system would in addition provide benefits for the connection to the distribution network, for cost, planning or scheduling reasons, then it may useful to consider an extension to the current RPZ framework to allow the energy storage system to be accounted for in an RPZ where the system is owned and maintained by the generation site developer/owner. An example of such a scenario would be the use of an energy storage system that would produce a by-product to bring revenue to the generation site project, for example the sale of hydrogen from a wind-hydrogen system, on the basis that the selling price of hydrogen would be competitive. We were unable to explore the application of energy storage systems outside the RPZ framework, because of project scope limitations, but our consultation with Ofgem has revealed that Ofgem would naturally welcome information on the use of any energy storage system that could be technically and economically justified but is outside the current RPZ framework.

6 STUDIES FOR SITE 2

Introduction

Site 2 at Victoria Harbour, immediately east of Hartlepool city centre, is being considered as an urban regeneration site, to include a range of new electrical loads and generation plants. This site forms the basis of a project that is being developed jointly by Tees Valley Regeneration and P&D Ports. The project benefits from the production of a master plan for outline planning application purposes. The developers are now preparing a full planning application for the site, and as part of their associated budgeting for the project they will include costs for the connection of electrical loads and for power generation for the site.

The developers aim to provide some form of on-site energy conversion scheme in order to offset part of the energy consumption for the planned residential and commercial buildings on the site. This energy conversion scheme would be established in harmony with a sustainable development aim for the site, so that some form of electrical energy production from renewable energy sources is being considered, together with the efficient production and use of energy.

The proposed load and generation development for the Victoria Harbour site is complex. The load and generation development is to be distributed over 30 plots throughout the site, which themselves are to be developed over four distinct phases, covering a planned time to completion of over 20 years. A map of the site is provided in Figure 18 in section 9.

In order to understand the geographical spread of the work and the programme for the site, it has been necessary to develop, as part of this research project, a detailed map for the site, using a GIS (Geographical Information System). Each level of complexity is represented as a layer in the GIS system, which has been used to produce the site maps shown in section 8.

At the start of the project, the site developers provided an initial specification for the planned type and size of loads and generation on the site. This specification changed during the course of the project, partly due to more detailed studies showing that some of the original plan was not practical or not cost effective, and partly due to the influence of the findings from this project. Following this specification change, we altered our model and ran the studies again to assess the impact of the changes. The results did not indicate clearly that the new specification would help to reduce significantly the connection costs, so we created a third specification which optimised the amount of load and generation on the site in an attempt to identify the lowest practical connection costs. This third approach proved successful in significantly reducing the costs of connection.

In addition to the studies for the two changes in specifications, we carried out studies on the capacity of the distribution network to accept new load and generation, checking if there were any existing circuits that would be overloaded and evaluating the maximum thermal capacity of each key circuit to accept new load and generation.

In this report we use the following notation.

- Energy mix 1: refers to the original specification from the site developers

- Energy mix 2: refers to the change in the original specification, which happened half way through the project.
- Energy mix 3: refers to the specification that we created in order to find the lowest connection cost.
- Grid capacity: refers to the studies carried out to check the existing network's circuit overload and thermal capacity

The specification of loads and generation plants for each of the three energy mixes is summarised in Table 9.

Energy mix	CHP (kW)	District CHP (kW)	Micro CHP (kW)	Micro Wind (kW)	Heat pumps (ground and air source) (kW)	Other electrical loads (kW)
1	1,639	-	-	575	3,977	19,372
2	-	7,309	1,579	-	2,012	18,546
3	-	15,550	-	-	-	11,923

Table 9: Loads and generation plants for each energy mix

In energy mix 1, the generation plants consists of CHP plants to provide heating and electricity to commercial properties, ground source heat pumps to provide heating to residential properties, and micro wind turbines to provide electricity to all properties on the site. The site developer provided the size of the other non-heat electrical loads and these loads would be supplied from the grid connection. The total size of generation is 2.2MW and the total size of loads is 24.4MW, giving a net load for the whole site of 21.1MW.

In energy mix 2, a district CHP scheme is introduced to serve all the commercial buildings and apartments and a micro CHP unit is introduced in each house. The ground source heat pumps are reduced to two areas where they can be practically installed and air source heat pumps are used as replacement for some of the ground source heat pumps that cannot be installed because of space restrictions. The micro wind generation is removed, as it was not found cost effective. The other non-heat electrical loads are as for energy mix 1. The total size of generation is 8.8MW and the total size of loads is 20.5MW, giving a net load for the whole site of 11.7MW.

In energy mix 3, the district CHP scheme is extended to serve all the buildings on the site, and the micro CHP units and heat pumps are removed, since the district CHP scheme would serve all residential properties. This scheme includes a heat network as well as heat stores in the form of water tanks. The other non-heat electrical loads are reduced to take into account diversification factors, in line with published data [22]. The total size of generation is 15.5MW and the total size of loads is 11.9MW, giving a net generation for the whole site of 3.6MW. This is the only scenario where there is more generation capacity than loads.

<u>Options for connection</u>

In order to determine the connection options for the Victoria Harbour site it is necessary to establish the limitations of the local distribution network around the Hartlepool area.

Studies for standard "fit and forget" solutions have been carried out to establish the nature and level of these limits. The results are provided in Table 10.

Connection voltage	Connection point(s)	Nature of limitation	Maximum capacity that can be connected without reinforcements
11kV	New 66kV/11kV substation on Victoria Harbour site	None	35MW of load
11kV or LV	Direct connection onto existing 11kV/LV substations on and around Victoria Harbour site (11 connection points in total)	Power flow (thermal capacity) Voltage drop	2MW of load

Table 10: Summary of network studies for "fit and forget" solutions for Victoria Harbour

Considering the data in Table 10, the building of a new 66kV/11kV substation to serve the Victoria Harbour site exclusively would provide enough network capacity to connect all the loads on the site, ignoring any on-site generation or energy saving measures. This option is taken as the "business as usual" connection option for the site.

The alternative is to connect to the existing 11kV/LV substations already present on the Victoria Harbour site and along its periphery. This option triggers reinforcements of both the existing 11kV circuits and an upgrade to the existing primary 66kV/11kV substation in Hartlepool city centre (at Amberton Road). We have noted that any problems with voltage control may be resolved by solution of the limitations on power flow. For the purpose of identifying potential innovations for this site, the solution to the problem of power flow is therefore the primary driver.

Studies

We carried out studies for standard "fit and forget" solutions to attempt to connect the Victoria Harbour site to the local 11kV network. We did not carry out any studies for connecting the site to a new 66kV/11kV substation, as we assumed that the substation would be specified with a capacity large enough to supply all the planned loads on the site.

In the studies we assumed that all the loads and generation plants would be connected to the network at the same time. In reality, these would be connected over time as the site is developed and properties are built and occupied.

For energy mix 1 and 2, we ran three scenarios.

- Scenario1: Zero generation, maximum load
- Scenario 2: Maximum generation, minimum load
- Scenario 3: Maximum generation and maximum non-heat load

For energy mix 3, we were able to apply a different criterion in terms of taking into account the much-increased amount of generation capacity on the site. Instead of assuming that all the generation plants could be non-operational at the same time, leading to zero generation as the criteria for minimum generation, we were able to use a minimum generation value of 80% of the total generation capacity. The 80% value was derived from the application of the new ENA standard P2/6 [20] following consultation with CE Electric, to allow the generating plants to provide 80% of their output as a contribution to security of supply.

For energy mix 3 we ran four scenarios.

- Minimum generation (80%), minimum load
- Minimum generation (80%), maximum load
- Maximum generation (100%), minimum load
- Maximum generation (100%), maximum load

An analysis of the following technical features was made in order to assess the impact of the connection of the Victoria Harbour site to the existing 11kV network.

- Thermal limits
- Voltage profile
- Fault levels

The assessment of the thermal limits for existing 11kV circuits was carried out following the principle of CE Electric design policy, which is to ensure that any load group rated between 1 and 12 MW, (which limits apply to most of the HV (11kV) system), can be supported with an outage of any one circuit component. The most onerous outage scenario occurs when the main circuit connection between the load group and the primary substation fails. In this case the load group, which would normally be supported by two circuits connections to the primary substation, would need to be entirely supported by the single circuit remaining in operation.

Studies based on this design policy would require detailed analysis of credible outage conditions, which are beyond the scope of the feasibility studies carried out in this project. We therefore agreed with CE Electric to use an alternative and simple approximation, which is to load cables up to a maximum of half their thermal rating. We also agreed that we would budget for one new circuit for each 5MVA of load. In practice, we would need to consider the actual route of both circuit connections from the load to the primary substation, and ensure that the capacity of each circuit would be available to support the load when the other circuit was out of service. Instead, we used an approximation for costing each section requiring reinforcement such that a single circuit replacement is budgeted for loadings of 0MVA to 5MVA, a double circuit replacement is budgeted for loadings of 5MVA to 10MVA and a triple circuit replacement is budgeted for loadings of 10MVA to 15MVA. We confirmed with CE Electric that this was an acceptable method of estimating the actual cost with sufficient accuracy for the purpose of the studies in this report.

Results of studies

A summary of the results of the studies is given in Table 11.

Assessment	Energy mix	Result	Details
Thermal limits	1	Circuits and transformers overloads	13.17km of existing 11kV underground cables are overloaded. The 66kV/11kV transformers at the primary substation are overloaded
	2	Circuits and transformers overloads	13.17km of existing 11kV underground cables are overloaded. The 66kV/11kV transformers at the primary substation are overloaded
	3	Circuit overloads	10.375km of existing 11kV underground cables are overloaded. The 66kV/11kV transformers at primary substation are not overloaded
Voltage profile	1	Severe voltage drop	Many voltage levels on the 11kV underground cables are beyond the lower statutory limit
	2	Severe voltage drop	Many voltage levels on the 11kV underground cables are beyond the lower statutory limit
	3	Minor voltage rise	A few voltage levels on the 11kV underground cables is just beyond the upper statutory limit
Fault levels	1	Fault levels exceeded	Fault levels at the primary 66kV/11kV substation are exceeded
	2	Fault levels exceeded	Fault levels at the primary 66kV/11kV substation are exceeded
	3	Fault levels exceeded	Fault levels at the primary 66kV/11kV substation are exceeded. In addition, fault levels on the existing 11kV network are also exceeded.

Table 11: Summary results of studies for Victoria Harbour site

For energy mix 1, a significant quantity of existing 11kV underground cable will need replacing. Significant voltage drops on the 11kV circuits have been observed, but since they occur in those parts of the network also affected by significant thermal overloads, the replacement of existing cables with cables of higher ratings may remove the voltage limit infringements. The rated fault level of equipment at the 11kV busbars at the primary substation is expected to be exceeded following connection of the site, and the existing 66/11kV transformers at the primary substation are not rated with a sufficient capacity to accept the proposed 21.1MW of net load. Due to space restriction at the primary substation, CE Electric advised that it would not be possible to install new transformers or upgrade the existing transformers to provide the level of capacity required to support this size of net load, and therefore a new 66kV/11kV substation is likely to be required, which would take us back to the “business as usual” solution.

For energy mix 2, the results are similar to energy mix 1, except the severity of the overloads on the 11kV circuits is less than for energy mix 1, which leads to some reduction in costs for circuit upgrades. The decrease in overload severity is due to the increase in generation capacity in energy mix 2 compared to energy mix 1. The transformers at the primary substation are overloaded, and the proposed 11.7MW of net load would trigger their replacements with larger units.

The length of circuits that would need replacing has decreased from 13.17km for energy mix 1 and 2 to 10.38km for energy mix 3, of which 6.78km is due to excess power being imported from the primary substation into the loads on the site and 3.6km is due to excess power being exported from the site toward the primary substation by the on-site generation. The length of 6.78km is dividing into 3.08km of circuits where the thermal overloads are 0.5MVA or less, and 3.7km of circuits where the thermal overloads are more than 0.5MVA. .

For energy mix 3, the transformers at the primary substation are not overloaded and the voltage levels on the 11kV network are mostly within limits. The fault levels are exceeded not only at the primary substation but also at the existing 11kV/LV, due to the large amount of generation in energy mix 3.

Innovations for site 2

Some of the conditions under which circuit thermal capacity and voltage levels are exceeded in energy mix 3 correspond to the minimum load scenarios. The reason for some of the overload, as qualified above, is the excess of generation that is exported onto the existing 11kV network when there are not enough loads to absorb the energy generated on site. It would also frequently be the case that under low electrical demand, the heat demand would also be low. In this case, the on-site generation could be constrained without adverse impact on the site electrical customers.

There would be times of day, however, when low electrical demand coincided with high heat demand. This situation would arise with residential customers who require their heating to switch on in the morning before they awake so that their electricity demand would remain the same as overnight (i.e. low) for up to 1 hour before they arose. This situation would also occur for the operation of commercial properties where the buildings would be heated before the staff arrived. In this case, it would be possible to move the peak of the heating load by the use of heat stores, in the form of water tanks, which would store heat for several hours overnight in order to provide heat in the morning. These stores could also be used to store excess heat, which would not be required when the electrical demand rises, as it would in the evenings for domestic customers, when the buildings are already at their desired temperature. Such heat stores would require a venting system in order to dissipate excess heat when the stores are full and the buildings are at their required temperature.

The basis for the RPZ proposal for the Victoria Harbour site is to use generation to support loads in order to avoid some of the reinforcements to the existing 11kV circuits. In order for this to be acceptable, the network operator has to be able to constrain the generation at times when the load on the site is low and there is a risk of excess generation being exported toward the existing 11kV circuits. A mean of controlling the generation in this manner will ensure that both thermal loading on the existing circuits and voltage profiles remain within required limits.

The network operator would only need to control the generation plants when limits on the network are exceeded. At all other times, the people owning the properties on the site could run their generation in a manner to suit their needs. They may want to run the generation at a level higher than required to supply the loads, in order to obtain revenue from the sale of the electricity not required by the site, or they may prefer to match the generation exactly to their electrical and heat requirements, saving on the cost of the fuel for the CHP plants. The decision would be driven by the economics benefits of each scheme.

We also considered demand side management as an additional innovation for connecting the Victoria Harbour site. A common application for load management schemes is to apply them to residential properties within a community environment. This application may often coincide with an electrically islanded situation, where the community has renewable and sustainable energy targets, and the cost of power is much higher than would otherwise be the case. For the purpose of this research project, it is assumed that the Victoria Harbour residents will not form themselves into this type of energy community because they would find it unacceptable to have their electrical requirements managed and controlled by external factors. Moreover the site developers also want to maximise the return on their investment, so they are unlikely to develop residential housing with demand side management if this may prevent them from obtaining maximum return on the sale of the properties.

Under the regulations for competition in electricity supply, any residential customer in the UK is able to choose their supply company for electricity and gas. This feature of the electricity and gas markets precludes a direct arrangement between the on-site generators and the residential customers. There is also no driver for an electricity supply company to constrain supply in order to satisfy DNO network constraint. For the purposes of this report we have therefore assumed that any load management strategy would be transparent to residential customers. This transparency is achieved with the use of a heat network, coupled with heat stores, as described previously, so that customers have control over their heat consumption.

For this RPZ proposal, not all reinforcements are avoided, as the connection of the generation plants would cause some of the circuits to be overloaded under maximum load conditions and the fault levels to rise above the rating of the existing switchgear equipment. Reinforcement work would be required to alleviate thermal limits and fault level issues on the existing circuits.

For the thermal limits issues, the length of circuit that would require replacement needs to be confirmed by means of a full outage study. We have estimated the total length for replacement to be between 3.7km and 6.78km, as described in the previous section. For the RPZ option, we have used the estimated cost budget for 3.7km, as it is likely that overloads under 0.5MW would not require the replacement of the circuits concerned.

In practical terms the solution to the fault level issues would mean upgrading the switchgear at the primary 66kV/11kV substation and some remedial work at the existing 11kV/LV substations. Some specific ideas that we have developed with CE Electric to reduce the contribution to fault levels from the proposed levels of generation on the site are to install reactors to increase the impedance of the network, specify higher impedance for the generator transformers or to install superconducting fault current limiters of the resistive type.

The cost of these reinforcements can be spread over several years of site development, as initially only some of the generation plants would be installed and at this time not all switchgear and existing 11kV/LV substations would need upgrading.

Cost benefit analysis for Site 2

Following the results of the studies for energy mix 1, 2 and 3, we conclude that an RPZ option for the site at Victoria Harbour would be the use of a control system in association with on-site generation to support loads, as embodied in the description of energy mix 3. Table 12 summarises the cost comparisons for the electrical connections for the different options considered during this project. The costs shown are based on the replacement of all circuits that are loaded to more than half their design rating but do not take into account any potential for apportioning the costs based on the actual direct benefit of any reinforcements to the site.

Option	Estimated budget cost
Business as usual	Estimated budget cost: £3,600k (Estimated budget cost taking into account the apportionment rule: £2,100k,)
Energy mix 1	Estimated budget cost: £2,540k
Energy mix 2	Estimated budget cost: £2,354k
Energy mix 3	Estimated budget cost: £1,790k
RPZ (energy mix 3 with generation control scheme)	Estimated budget cost: £1,296k

Table 12: Cost comparison of electrical connections studied during the project

The estimated budget costs for energy mix 1 quoted in Table 12 include the cost of replacing the transformers at the primary 66kV/11kV substation. As mentioned earlier, CE Electric has advised that it may not be possible to replace these transformers and that a new 66kV/11kV substation would be required, and therefore the cost for energy mix 1 would be the same as for the “business as usual” solution.

It is worth noting that the costs provided in Table 12 are estimates based on the information available to the project team. The studies carried out as part of this project aimed to establish the feasibility of creating an RPZ at Victoria Harbour, and design studies would be required in order to confirm the estimated budget costs, particularly to establish the costs for actual lengths of new 11kV circuits required.

RPZ for Site 2

The characteristics of the potential RPZ option for Victoria Harbour are summarised below.

- Use generation to support the loads on the site
- Allow the DNO to control the generation in order to ensure that thermal and voltage limits are not exceeded
- Use the existing 11kV network capacity as a backup source of power when some of the CHP units are not available and load levels on the site are high
- Carry out reinforcements to the primary 66kV/11kV substation and to existing 11kV/LV substations in order to mitigate fault level issues created by the installation of the generation on the site
  - The fault level issues at the existing 11kV/LV substations may be mitigated using standard methods (reactors, higher impedance for generator

transformers) or innovative methods (super conducting fault current limiter techniques)

- Carry out reinforcements to some of the existing 11kV circuits. The length of circuit replacement would need to be determined by a full outage study to ensure security of supply is maintained to all customers along the circuits
- Under normal operations, there would be no control of electrical loads on the site. Heat loads would be managed via a heat network and heat storage. Under exceptional circumstances (e.g. loss of fuel gas infeed), loads could be disconnected to avoid damage to the existing 11kv network due to circuit overloads.
- The costs of upgrade to the 11kV network may be partially deferred until later phases of the development of the Victoria Harbour site

The extra revenue to the DNO to cover the risks of the innovations for the RPZ at Victoria Harbour is shown in Table 13.

Level of Generation	Unit revenue (£/kW/year)	Total revenue
RPZ (Energy mix 3): 15,550kW	3	£46,650 for 5 years = £233,250

Table 13: DNO revenue from Victoria Harbour RPZ

Under the current RPZ framework, there is no provision for any mitigation of risks to the site developer for the liability of maintaining the generation plants in order to avoid network issues. Further discussion on this topic is detailed in section 7.

RPZ benefits to the site developer

This section explores the cost benefit of the whole energy development for the Victoria Harbour site. For the site at Victoria Harbour, the increased cost of generation and the cost of the thermal storage is more than offset by the reduction in electrical connection charges and the assumed 5% reduced energy bills seen by the site. Table 14 demonstrates the benefit to the developer in terms of Net Present Value (NPV).

Option	Business as usual, £k	Energy Mix 1 £k	Energy Mix 2 £k	Energy Mix 3 £k	RPZ
Cost of generators or boilers	2,386	15,728	10,988	12,166	12,166
Cost of electrical connection	3,600	2,540	2,354	1,790	1,296
Cost of thermal stores	0	0	0	0	555
Total capital costs	5,986	18,263	13,342	13,956	14,017
Annual Energy costs	3,876	1,018	1,695	1,536	1,459
Indicative NPV @ 7.5% interest rate	-42,232	15,580	13,747	14,684	15,357

Table 14: Financial benefits to the site developer

Conclusions for Site 2

We have conducted a range of studies and cost benefit analysis for assessing the option of creating an RPZ around the Victoria Harbour site in Hartlepool. We started with the site developer's specification for the proposed loads and generation plants for the site (energy mix 1), and updated our studies in line with the changes in the developer's plans (energy mix 2).

We have considered two main types of innovations to avoid reinforcements due to power flow and voltage issues: demand side management and generation to support load. We identified that the only suitable demand side management techniques would be those where the customers were not aware of the management technique as we have assumed that the customers would not have any particular incentive to have their electrical loads managed, and the commercial drivers for them to do so would not be obvious to them. We have explored in detail the use of generation to support load, which we considered to be a practical option and we found that the site developers could be expected to respond positively to the increased levels of generation (energy mix 2 was the lowest payback option).

The results from the studies for energy mix 1 and 2 did not prove conclusive in terms of cost benefit analysis compared to the "business as usual" solution. We then devised energy mix 3, which aimed to minimise the reinforcement costs by having more generation than load on the site. We were successful in reducing the reinforcement costs very significantly, although not completely. We have not, at the time of writing this report, checked with the site developers whether energy mix 3 would be an option in terms of their development plan, but we have checked that the payback on the total generation plant capital, operation and maintenance cost, including the connection costs would be of a similar quantity to those costs for omitting all generation on the site and for utilising the "business as usual" type of connections.

Our conclusions from the work carried out to date for the Victoria Harbour are therefore:

- The use of on site generation as an innovation measure for mitigating network reinforcement has to make financial sense in its own right.
- The RPZ option is centred around the DNO controlling the generation plants when the network limits are exceeded, leaving the customer to run their generation as they find most advantageous commercially when the network is within limits.
- When developing the budget for a site like Victoria Harbour, the total capital costs should include the connection costs, so that the balance of generation plant costs and initial connection costs can be optimised as a whole. This optimisation work could be complex and extensive, as many parties may need to be involved to provide the specialist knowledge into a complex sequence of decision-making.
- In a staged development, where all properties would be not developed at the same time, then connection costs could be deferred until later phases of development if the balance of load and generation is shown to be advantageous in the earlier phases of development.
- Reductions in initial connection costs may not be visible to the customer purchasing properties in the later stages of development. These customers would be liable for the operation and maintenance costs of the generation plants, either directly or indirectly depending on the ownership of the generation plants, and would also be liable for the on-going use of system charges for the connection of these generation plants, the latter to include a proportion of RPZ surcharge.

7 DISCUSSION AND CONCLUSIONS

One of the objectives of this research project is to attempt to draw out some generic design rules / issues / useful techniques that have become apparent from the two specific studies. This section of this report contains some generic RPZ findings.

RPZ process

The first useful generic finding that we may derive from the work in this project is the means for identifying whether or not a particular network requirement may successfully lead to an RPZ and this process is summarised in the flow chart in **Figure 19** in section 9.

The first step in the formation of an RPZ is to attract an enquiry from one or more generation developers. Ideally, such enquiries are the first moves towards submitting an application for connection, but they also allow the DNO to carry out the additional evaluations for an RPZ at the earliest possible opportunity. The DNO then needs to determine the nature of the network issues that will trigger the site for consideration as an RPZ. An analysis of the network performance on a "business as usual" basis is required as an initial overview or as a full study involving network modelling.

The second step is to examine the use of potential innovations that may solve one or more of the network issues identified in step 1. We have identified those innovations considered in this research project in Table 3, but DNOs will want to include their own ideas at this stage. The third step is to compare the cost of the "business as usual" solution with the cost of the innovative solutions. In our experience, this is the key stage of the project in view of our difficulties in justifying the establishment of an RPZ on the sites covered in this report.

At this point, the DNO will decide that it is possible or not possible to establish an RPZ. The type of RPZ will be defined according to its use for accommodating one generation site (asset light), several generation sites for one or more developers (DG reception), or a range of new loads and generations on a site (green park). The DNO will then want to determine that the levels of risk are adequately covered by the potential RPZ income. If the risk cannot be covered by income then it may be possible to carry out an IFI project in order to better understand the nature and level of the risks.

If DNOs would like to proactively look for RPZ sites on their network instead of evaluating individual generation site enquiries for potential RPZ application, then the key steps are to evaluate the network for the issues shown in Table 3, probably by running "what if " scenarios involving attempts to connect generic amounts of generation. The results of this work then needs to be matched with the results of a cost benefit analysis for each area identified. The DNO may thus build a map of network areas where a certain level of generation for connection may trigger the establishment of an RPZ. Such an approach would again entail a considerable amount of work for the DNO staff.

Energy storage systems as an innovative solution for connection

The second useful generic finding that we derive from the work on this project is related to our experience in trying to create an RPZ using energy storage systems as an innovative solution for connection.

There two main points to consider when attempting to use energy storage systems as an alternative to network reinforcements, as follows:

- The reinforcements costs must be at least of the same order of magnitude as the cost for the generation plants, on a per MW basis. This balance may result from the use of reasonably long route lengths of new circuits, or from the use of relatively expensive circuit constructions.
- The time for storage of energy from the generation plants must be estimated as accurately as possible. This requirement is driven by the cost of an energy storage system, which is dominated by the cost associated with the storage capacity element of that system. For generation from wind energy, the method used in this report can be used to work out how much storage capacity is required to capture near 100% of the energy so generated, provided that the raw wind data is available for a representative length of time, typically over several months.

In addition, the following points need to be considered before an application for an energy storage RPZ is made.

- There are regulation issues to be resolved with Ofgem, and these could incur significant delays to the process. Such delays would result from the process required for Ofgem to indicate whether or not a DNO can own an energy storage system and if the losses associated with such a system can be accounted as network losses.
- If the best economical solution is to install the energy storage system in association with generating plants, but not on a DNO network, then at present such an arrangement is unlikely to qualify for RPZ. In this case, the economical drivers must be such that the cost benefit analysis must be favourable when considering the total cost of the site, including the connection costs, all being outside the RPZ framework. This comparison means that the cost benefit analysis will compare the total costs for the generation plants and their connection in a routine manner to the total costs for the generation plants, the energy storage system and their connection.
- There is no reward for the developer who takes risks in using an energy storage system in order to reduce connection costs, and if indeed such a connection is proposed for an RPZ then there may be additional use of system charges for the connection being part of the RPZ.

Generation plants to support load as an innovative solution for connection

The third useful generic finding that we derive from the work in this project is related to our experience in trying to create a green park RPZ.

The main points to consider when attempting to develop a green park into an RPZ are given below.

- Where on-site generation is an objective for the site development, without reference to any potential for RPZ, then it can be advantageous to include the requirements for connection to a local 11kV network as part of the payback calculations for the capital costs of the generation plants. The amount of on-site generation can be optimised in terms of payback (in years) for the generation plant capital and running costs, together with costs allocated to CO_2 emissions (if this is an objective) and connection costs.
- It is worth checking the practicalities of installing particular types of generating plants on the site at an early stage, as such checks can reduce the scope of work necessary for meeting the required levels of on-site generation. Similarly, it is worth checking the planned electrical capacity for non-heat load against standard values,

as some property developers may be overly conservative in their estimates and ask for an electrical connection capacity larger, and more expensive, than may be eventually needed

- For an urban regeneration site that is located near a number of existing 11kV/LV (or equivalent voltage) substations, one option for connection is to divide the site into plots, with groups of plots connected to the same 11kV/LV substation. This arrangement may lead to many connection points for the site (10 or more).
- A rule of thumb for the feasibility stage of a site development is to take the total size of loads (in MW), divide it by a percentage factor to obtain the minimum amount of generation that would be required to ensure that the site as a whole does not increase the loading on the existing 11kV network to which it may be connected. For CHP plants, the percentage factor can be 80%, for other types of plants the percentage factor can be calculated from Engineering Recommendation P2/6 [20]. In addition, if an early indication of the existing capacity of the 11kV network can be obtained from the DNO, then the calculations should allow for the possibility of at least two large generation plants being out of service, and for the existing network capacity to supply the load which would otherwise be supplied by this lost generation. Any spare network capacity then remaining can be offset against the requirement for on-site generation, thus reducing the amount of generation required for the purpose of minimising the cost of connection.
- Where the site is to be developed in stages, then installation of generation plant in the earlier phases of development may defer some or all of the connection costs for the site as a whole.
- Where the site includes domestic customers, who do not form a community with green objectives, then the most practical form of demand side management is one that is transparent to the user. This concept of transparency means avoiding the concept of controlling the electricity supply to domestic dwellings (whether houses or a apartments). The heat for the dwelling is, however, a potential candidate for demand side management, particularly if a heat network, coupled with heat stores, is installed on part or the whole of the site. Heat energy is not regulated in the same way as electrical energy, so it is possible to have a compulsory buy in to the heat network for all customers on the site. Any form of demand side management on its own does not qualify for RPZ. It must be applied in conjunction with another innovation (such as on-site generation) to qualify for RPZ.
- It can be difficult to understand the implications of the planned loads and generation plants to the connection of a particular site, and if a mapping system (Geographical Information System) is being developed by the architect for the site, then the inclusion of layers to show the distribution of loads, generation plants and existing network can make the task easier.

In addition, the following points need to be considered before establishing if an RPZ is possible for a green park.

- The connection of a new urban generation site of significant size is likely to require the connection of loads in the multi MW range. Such connection is likely to trigger network issues, which include thermal limits on the existing circuits and voltage levels outside limits. Including on-site generation to reduce or eliminate these problems, and thus reducing the cost of connection, is likely to give rise to fault levels exceeding limits. It is therefore expected that there may be some reinforcements of the existing network required before the site is connected but the use of on site generation could minimise the connection costs.

- Where the amount of on-site generation approximately matches the amount of loads on the site, then it is likely that network issues would arise when the loads on the site are at or towards their minimum value. If this is the case, then a method to reduce these network issues is to control the on-site generation. The owners of the generation plants would want to operate them to their maximum financial advantage, with DNO initiated control only taking place where the operation of site generation would cause the existing network to go outside limits.
- The connection studies need to evaluate the feasibility of connecting the site as a whole, and also the feasibility of connecting each phase of the development, in the order in which they will be developed. This process will require a large number of feasibility studies, with associated engineering costs.
- When carrying out feasibility studies for the connection of the site, it is worth checking the design policy of the DNO, particularly the method used for maintaining security of supply to all customers.
- Any feasibility study for the connection of the site will need to be confirmed by a detailed design for the connection. This detailed design must take into account any existing electrical infrastructure located within the boundaries of the site and any electrical infrastructure that may need replacing as a result of site construction activity and any communication system costs, the latter being required for the DNO to control the on-site generation.
- The site developer needs to be aware of the costs for operation and maintenance, which would be incurred after the generation plants are commissioned. It is likely that an ESCo (Energy Supply Company) would be created for the site, which would belong to either the customers who have bought the properties, to a private company or to the original site developers. The costs of operation and maintenance will therefore fall onto the buyers of the properties, either directly if all property owners on the site own the ESCo collectively or indirectly if the ESCo belongs to a private company or to the original site developers. These operation and maintenance costs need to make economical sense in their own right, regardless of any initial saving on connection costs. This requirement stems from the absence of any clear mechanism by which savings on the connection cost initially made by the site developer would be passed onto the ESCo, as these savings are likely to be retained as profit by the site developers. In addition, the ESCo will also be liable for a higher use of system charges for the generating plants than if these plants did not form part of an RPZ.

Other generic RPZ findings

The fourth and final useful generic finding that we derive from the work in this project is related to our overall experience with this project.

- We expended a significant amount of time trying to find a way forward for the two sites that we have chosen and to create the specification for an RPZ for each site. The sites were selected in association with the DNO and actual developers in the Tees Valley area, and many possible sites were examined before the most promising sites were selected. The sites selected appeared as practical propositions at the start of the project. DNOs may not find it possible to expend similar efforts on attempting to create an RPZ for a given site, given the time constraints for DNOs to process connection applications. It is possible that DNOs will seek additional funding through the IFI scheme in order to provide resources for the required studies.

- We have found that for the two sites that we have studied, introduction of innovative solutions would be technically possible but the economical case either cannot be made or is not very clear-cut.
- There are different types of innovations that could be trialled in an RPZ: some are pieces of equipment that are installed on the network, others are related to the operation of the network. It is easier to identify an RPZ site where the innovation involved is a piece of equipment, as the studies required are much reduced compared to innovations related to network operations.
- There is only one official RPZ at the time of writing this report. We believe that this singularity exists partly because of the time taken to establish the site requirements and the difficulty in finding the right combination of generation site, network issue and innovation that will solve that network issue. The fact that the normal rules of network operation apply in an RPZ in the same way as they do outside an RPZ may increase the difficulty of this task.
- The aim of the RPZ framework is to promote innovation in connection, and this aim is being fulfilled in so far as DNOs are proactively looking for potential RPZs, becoming aware of what innovation may be available to trial and generally broadening their vision. We are not sure how the benefits of the RPZ framework may be measured in terms of actual material advantages to generation customers and customers in general, as potential RPZs are proving difficult to establish.
- For the two sites that we have studied, we have found that the developer may be better placed than the DNO to apply innovation to their electrical connection schemes. We would like the opportunity of examining the RPZ framework conditions in terms of how they could be amended to account for innovation on the developer's side.
- Similarly, when a generator is constrained for some of the time (e.g. by voltage rise), applying innovation to an existing connection could increase the amount of energy produced by the generation plant (more MWh) but this would not qualify for RPZ status, as no extra generation plant capacity (MW) would be connected.
- When an innovative solution is being applied for the first time in a real life situation, usually there are several units trialled in a range of situations, in order to prove the innovation before it becomes commercially acceptable. The current RPZ framework allows for the trial of an innovation just once in the UK in a given situation, so that two DNOs can trial the same innovation only if it is applied in a different situation. We would like to challenge the RPZ framework in terms of whether a DNO should be able to trial a given innovation several times on their network in different situations to enable them to build their knowledge and confidence before using the innovation more extensively. Another DNO may need to do the same, but in this case, to their own network, thus it could appear logical that the RPZ framework should allow each DNO to trial the same innovation in the same situation, but on their own, different networks.
- It is not clear at the time of writing this report how the DNO will levy the RPZ revenue (the £3/kw/year). The mechanism for collecting these extra charges is defined as being the distribution use of system charges but it is not clear whether the extra RPZ payments will be collected from the use of system charges for the generation sites connecting only in RPZs only, or whether the charges will be collected from all the new generation sites that connect to the DNO network from April 2005.
- The RPZ framework provides a mechanism for the demonstration of innovations that help the connection of generation plants. There is no framework at present for

demonstrating other types of network innovations on the network, either network innovations not involving the connection of generation plants and those that have to be researched via the IFI framework.

- The type of RPZ defined in this report as “DG reception” may be incompatible with the requirement for DNOs to avoid installing assets that would be eventually unused (“stranded assets”), thus making this type of RPZ difficult to develop in reality. The avoidance of stranded assets would restrict the ability of DNO to advertise otherwise suitable areas for connecting prospective generation site developers.

<u>Report conclusions</u>

We have investigated two potential RPZ sites in the CE Electric distribution network. For the Site 1 we attempted to connect a 38MW wind farm using an “asset light” type of RPZ. For the site at Victoria Harbour, Hartlepool, we attempted to connect a new urban regeneration site using a “green park” type of RPZ. In both cases we investigated the use of innovative methods to overcome primarily an issue of thermal limits on the existing network.

The innovation for Site 1 was that we considered the use of an energy storage system to remedy network power flow issues resulting from connection of the wind farm. This innovation proved to be economically not viable. We then extended the studies in an attempt to find a generic situation where the economical case for an energy storage system could be made. The conclusion from these studies is that there is unlikely to be a scenario where the cost benefit analysis of using an energy storage system compared to installing “business as usual” reinforcements would be favourable when working within the limits of the RPZ framework. We therefore concluded that energy storage systems would not in the foreseeable future be an innovation that would fit within the RPZ framework.

The innovation considered for the site at Victoria Harbour was the use of on-site generation to support loads, coupled with demand side management of the customer’s heat loads and the control of the on-site generation by the DNO in order to significantly reduce the costs of network reinforcements. The mix of generation plants and loads originally specified by the site developer, and subsequently updated as the site developer’s architect refined the site design, eventually proved to be an inconclusive basis for our cost benefit analysis. The RPZ solution was cheaper than the business as usual solution but required extensive replacement of existing underground cables in an urban environment, which is not a practical option. We then designed a third mix of generation plants and loads which was specifically aimed at minimising the costs of network reinforcements and succeeded in proving that this latter RPZ solution was indeed an option for consideration. Whilst we have not communicated this option directly to the site developer at the time of writing this report, it represents a realistic scenario in terms of payback on the capital and on-going costs and in terms of feasibility of installation.

We disseminated the results of this research project at a seminar open to all interested parties, as well as consulting directly with the stakeholders including the DNO CE Electric, Ofgem who issued the RPZ framework strategy, and the site developers and their representative.

From the results of the research and consultation activities, we have derived a number of generic rules, techniques and issues related to the specific RPZ sites that we have studied, as well as more general issues that have been raised during the course of the project.

In conclusion, we have found it difficult to justify the innovations that we considered on a cost benefit basis, even though from a technical point of view the introduction of such innovations would be practical. We have expended a significant amount of resources in attempting to create an RPZ on both sites, with mixed results. It may not be acceptable for DNOs to commit the same level of resource to establishing a site as an RPZ and we are uncertain that the RPZ framework is achieving its objectives in terms of demonstrating innovation, although it is a fact that DNOs are actively looking for RPZ sites and this activity in itself raises the profile of innovation within the electricity distribution industry.

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9 FIGURES

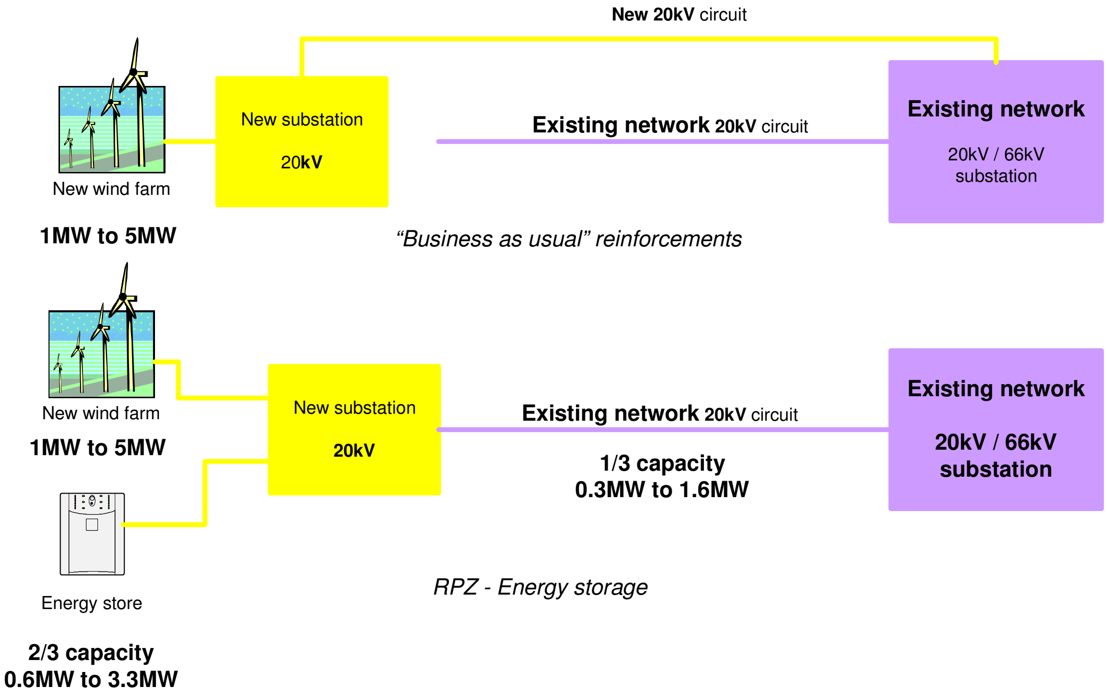

Figure 2: 20kV scenarios

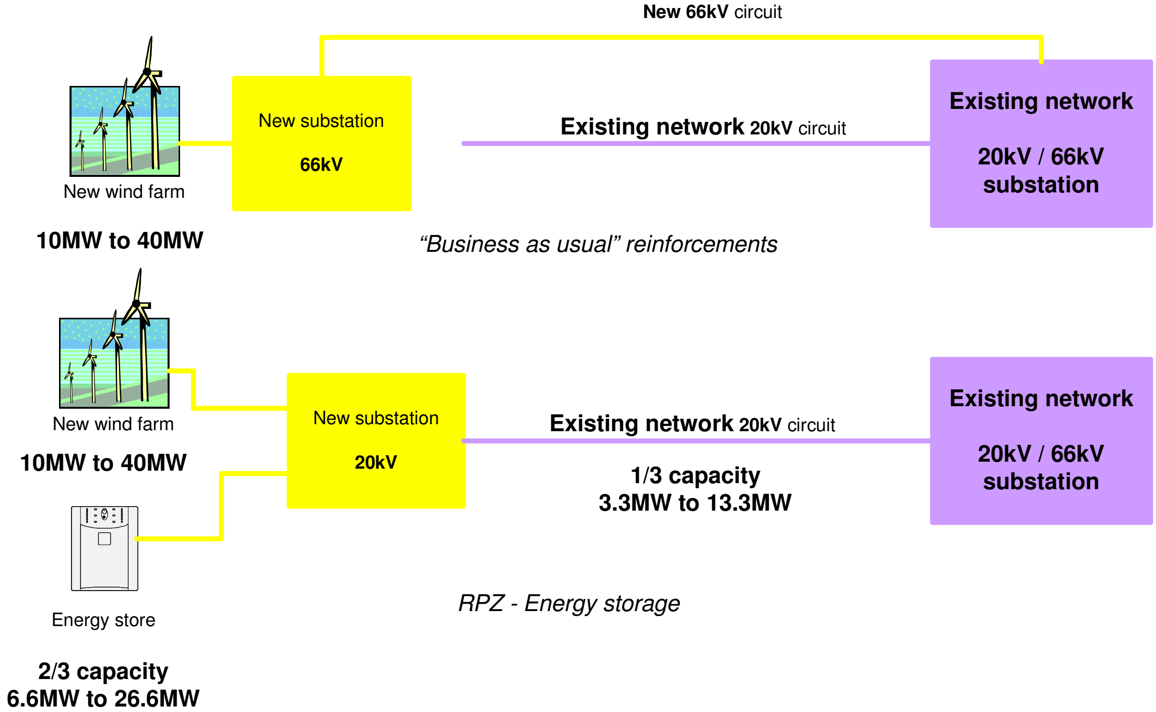

Figure 3: 66kV scenarios

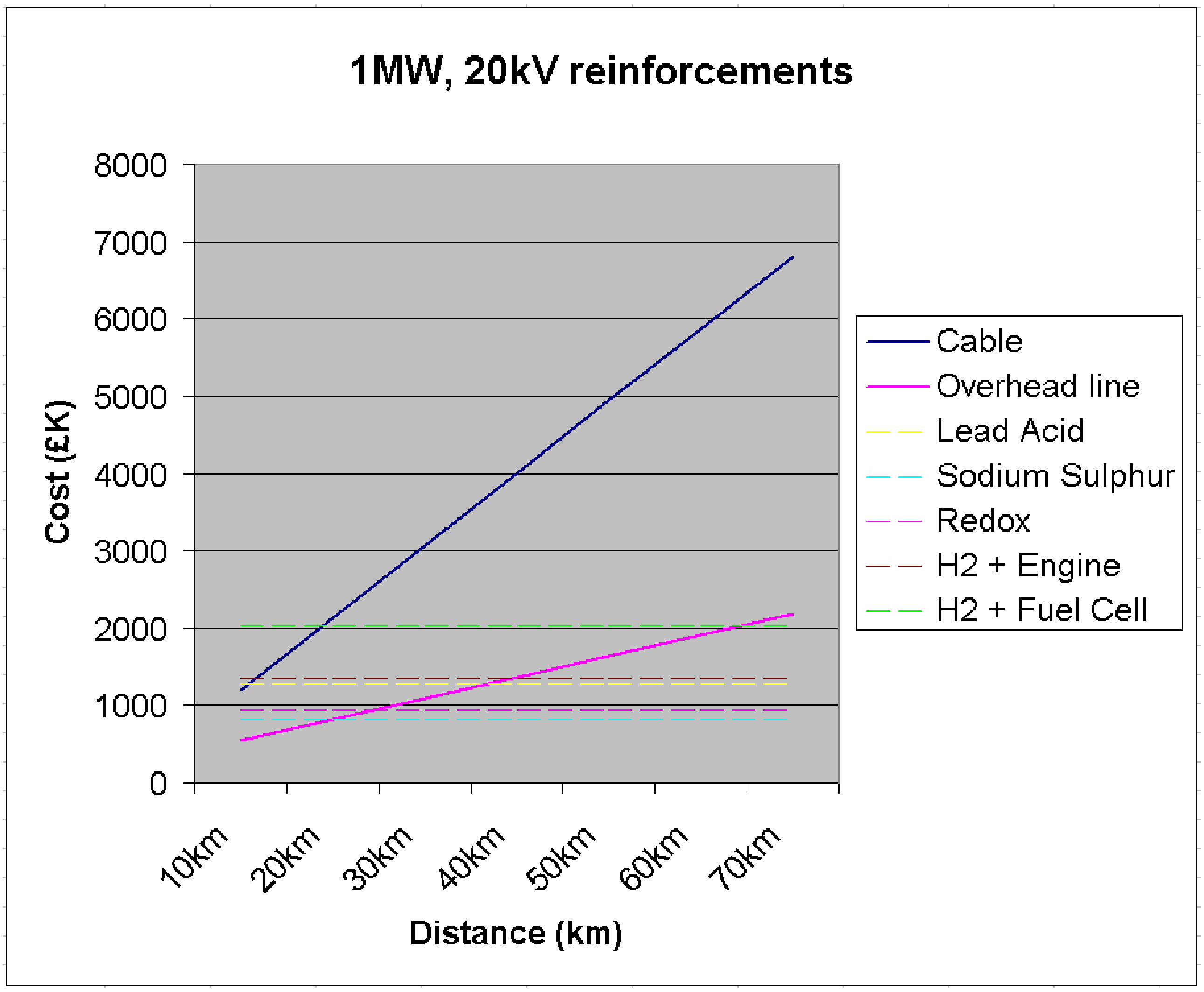

Figure 4: 1MW, 20kV, 8h storage vs. “business as usual” cost comparison

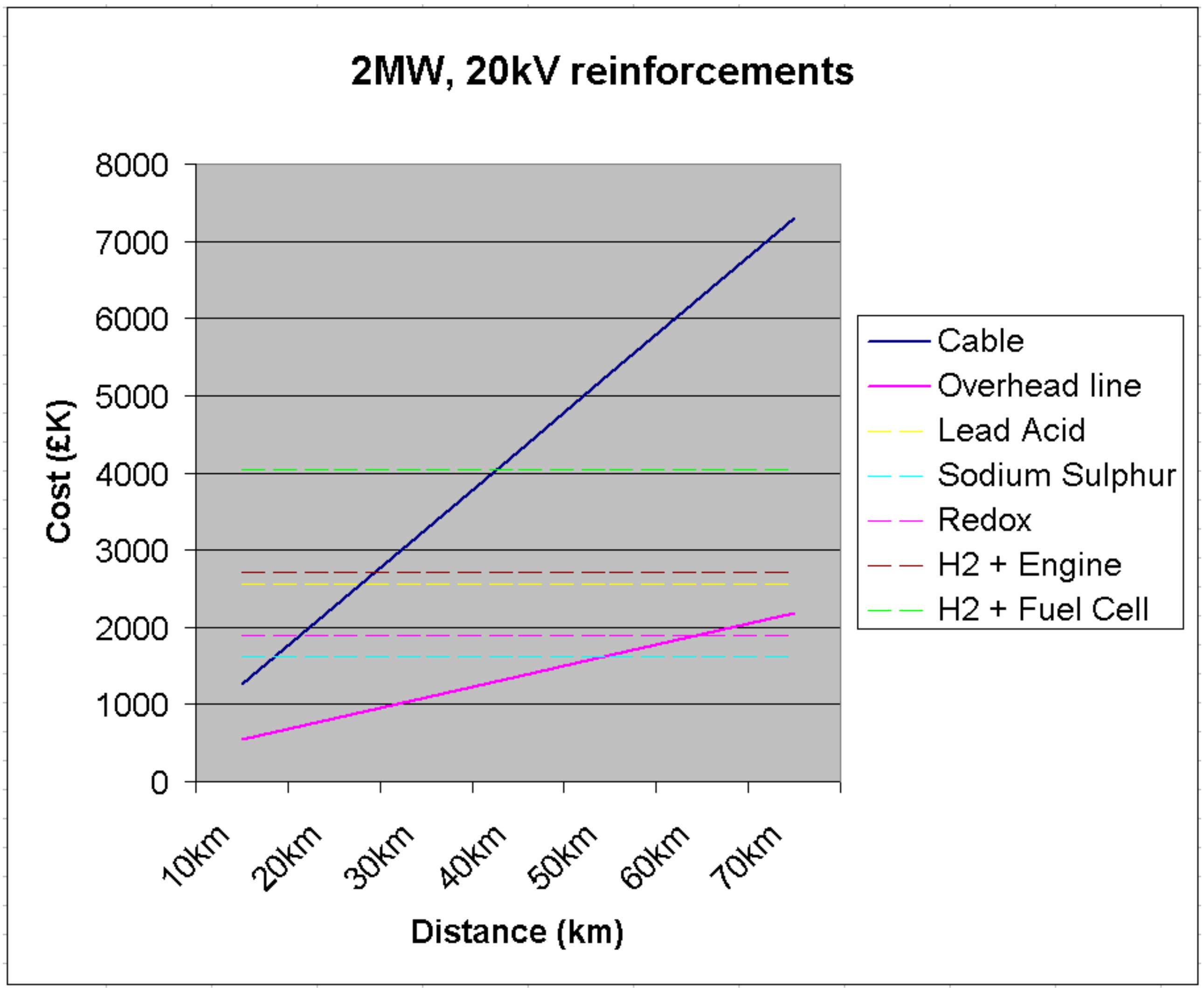

Figure 5: 2MW, 20kV, 8h storage vs. “business as usual” cost comparison

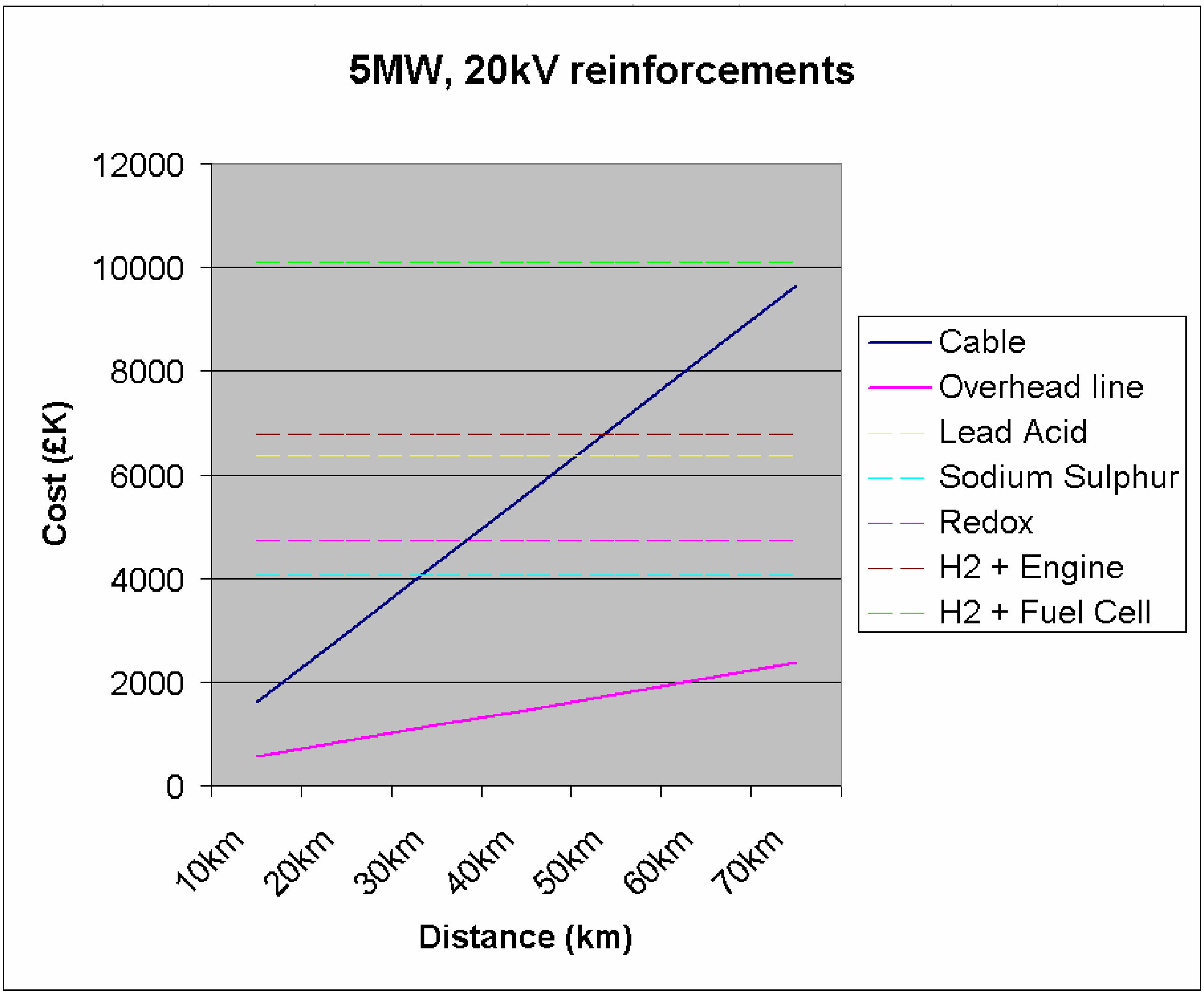

Figure 6: 5MW, 20kV, 8h storage vs. “business as usual” cost comparison

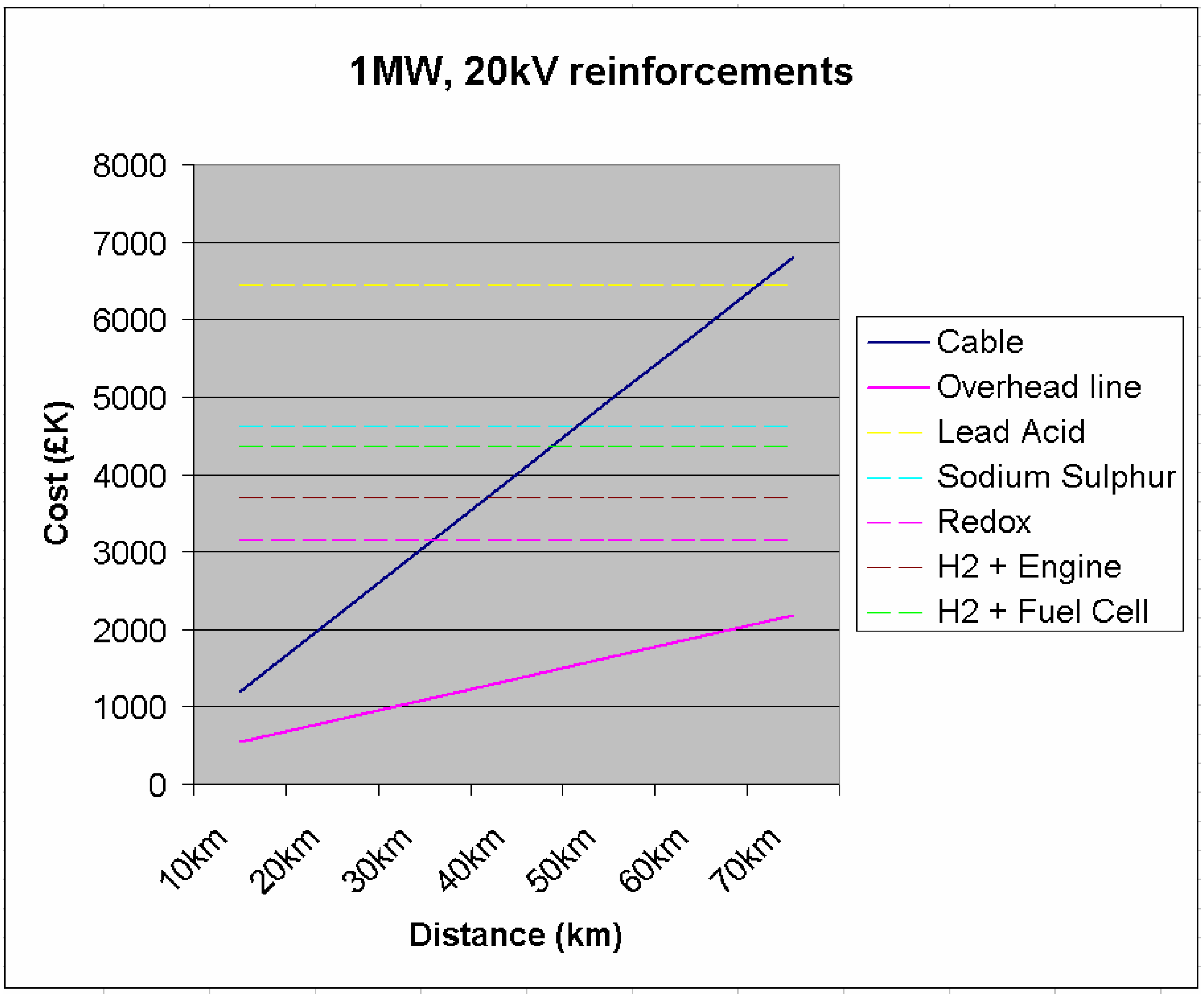

Figure 7: 1MW, 20kV, 2 days storage vs. “business as usual” cost comparison

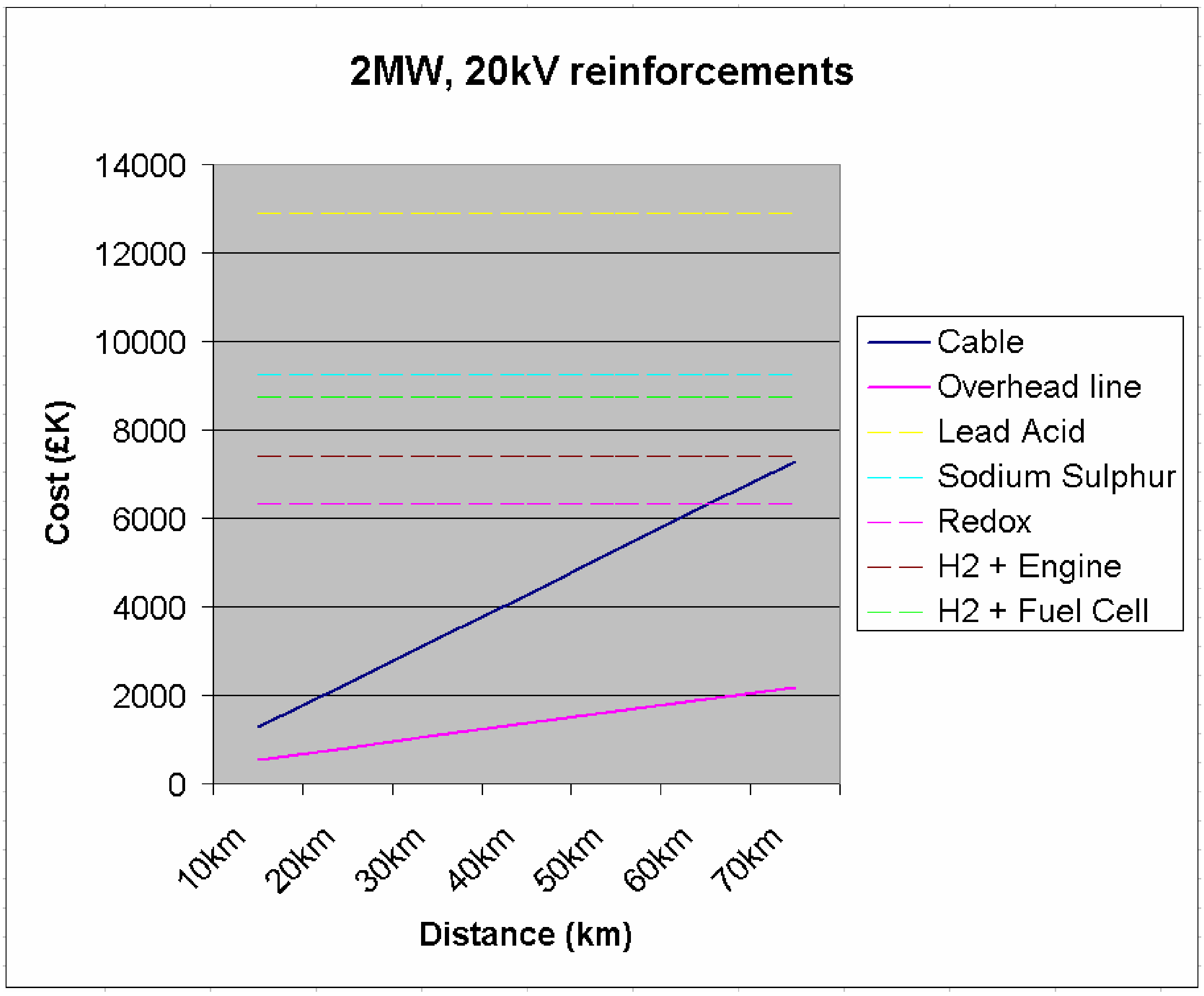

Figure 8: 2MW, 20kV, 2 days storage vs. “business as usual” cost comparison

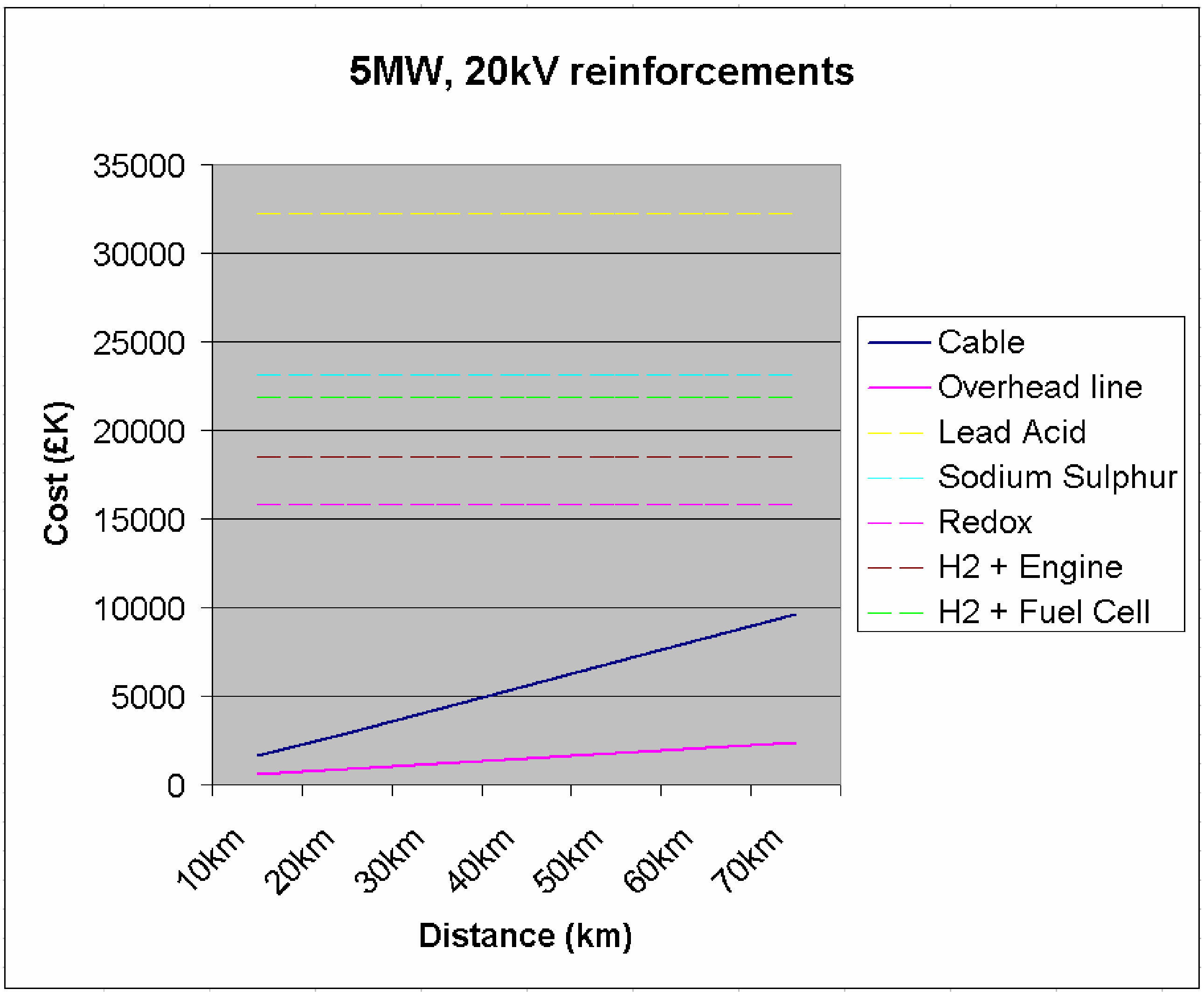

Figure 9: 5MW, 20kV, 2 days storage vs. “business as usual” cost comparison

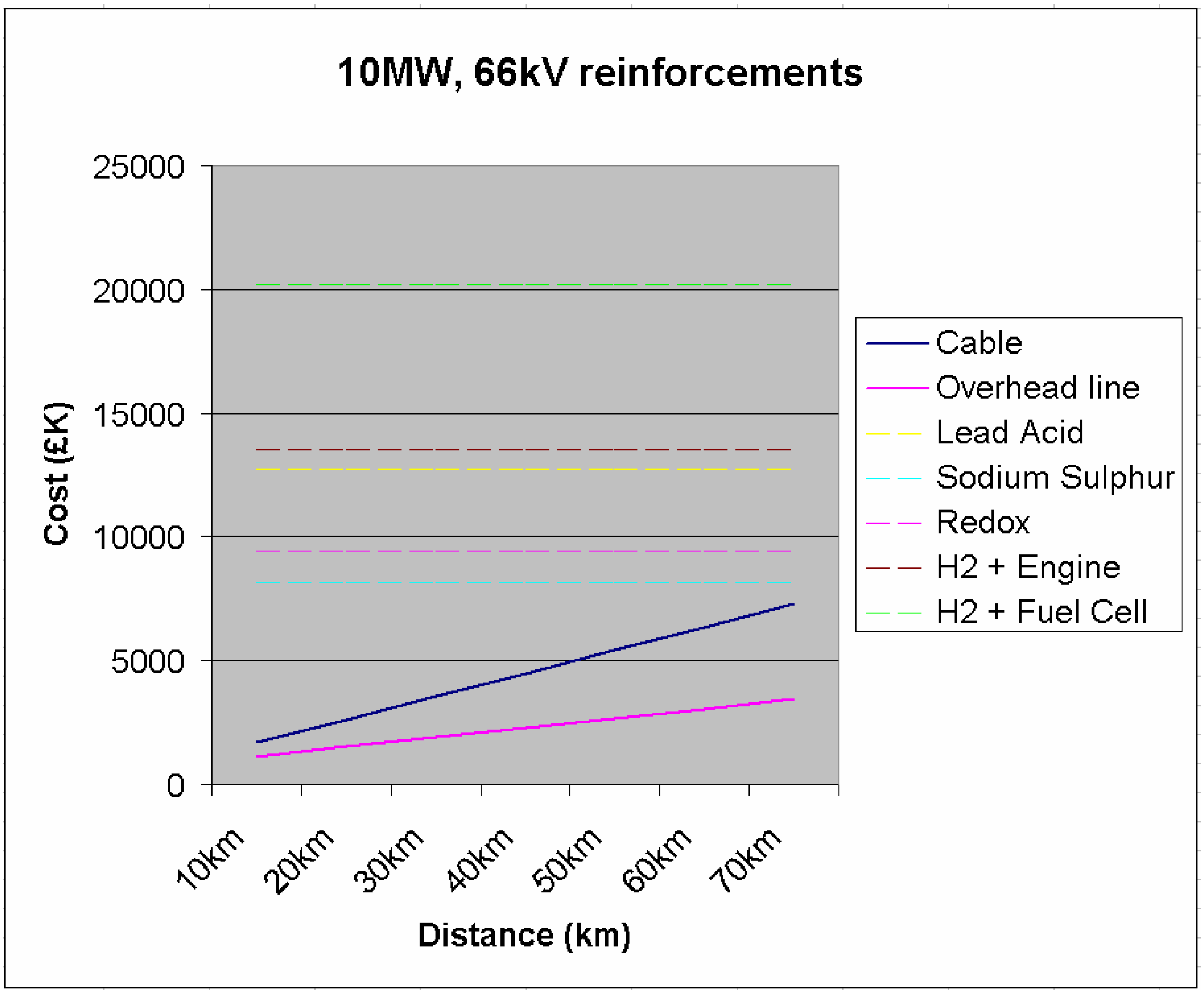

Figure 10: 10MW, 66kV, 8h storage vs. “business as usual” cost comparison

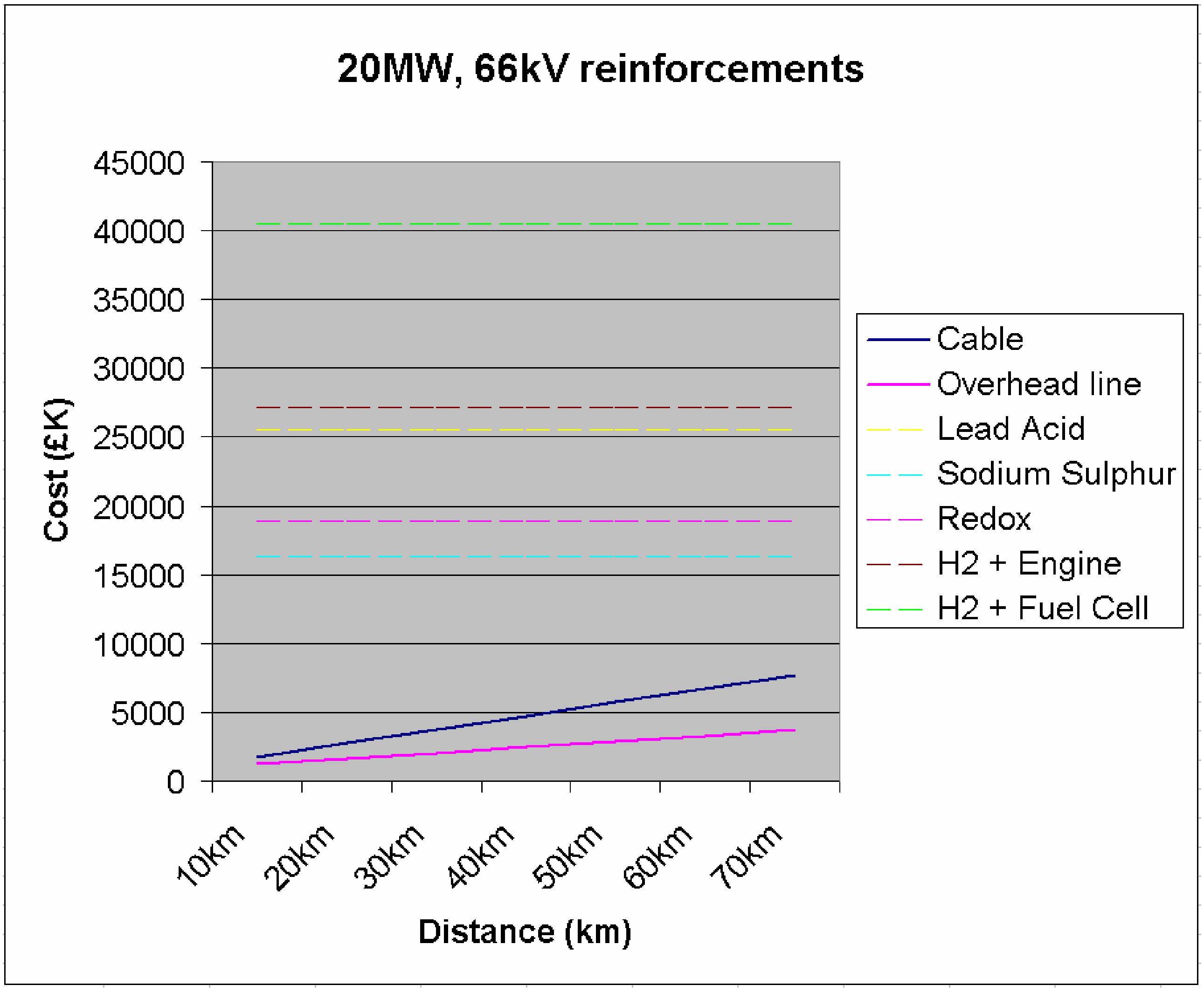

Figure 11: 20MW, 66kV, 8h storage vs. “business as usual” cost comparison

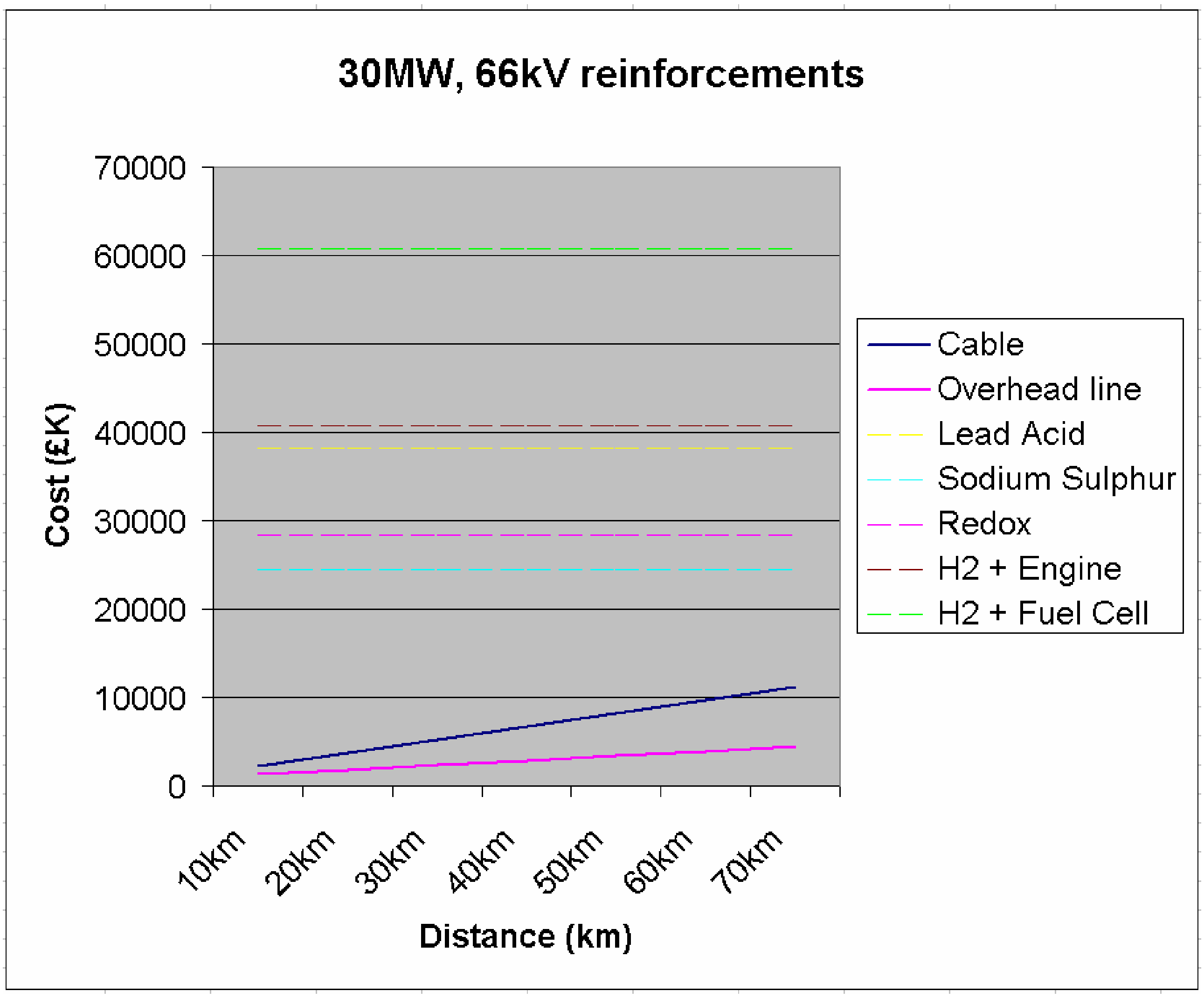

Figure 12: 30MW, 66kV, 8h storage vs. “business as usual” cost comparison

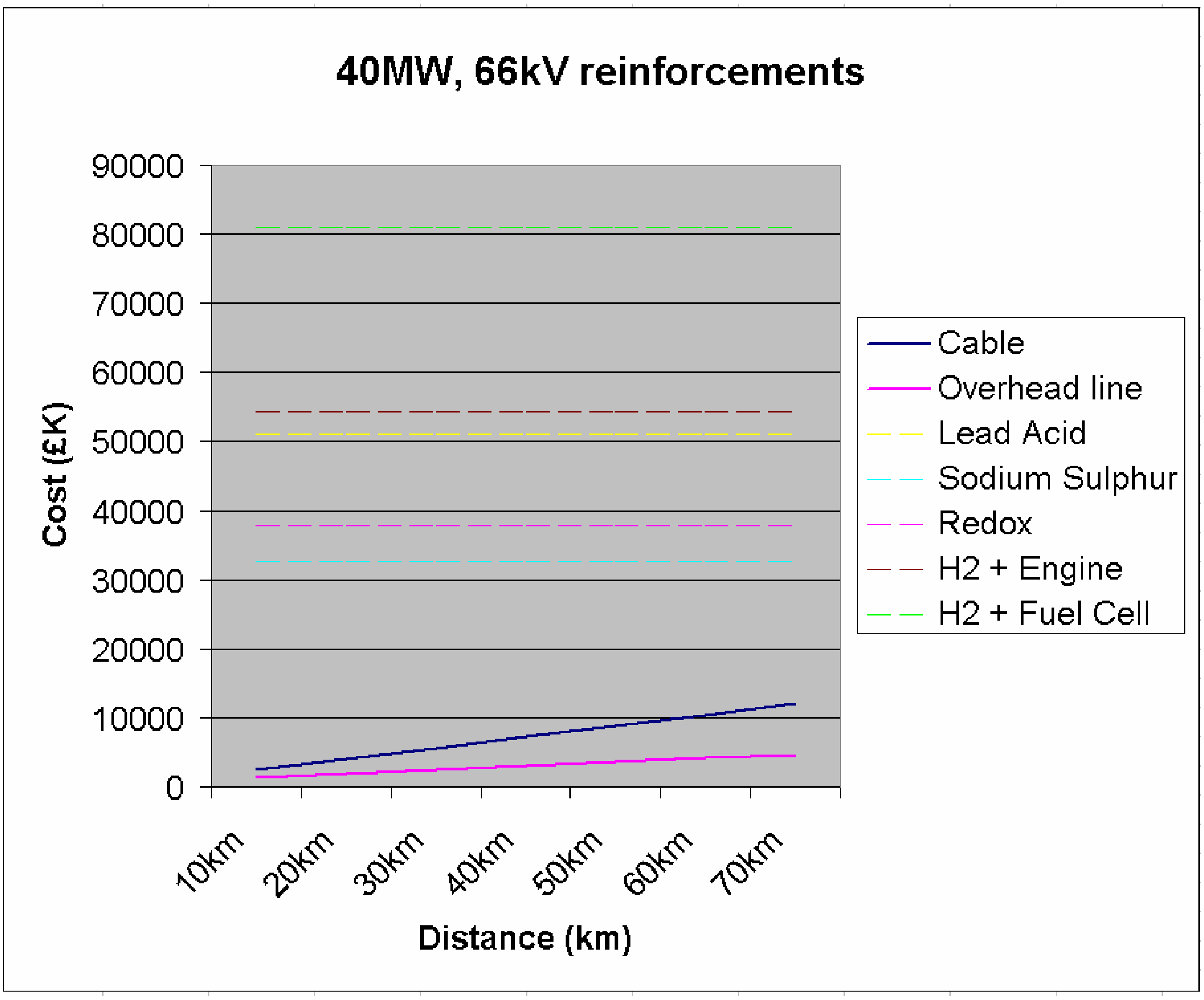

Figure 13: 40MW, 66kV, 8h storage vs. “business as usual” cost comparison

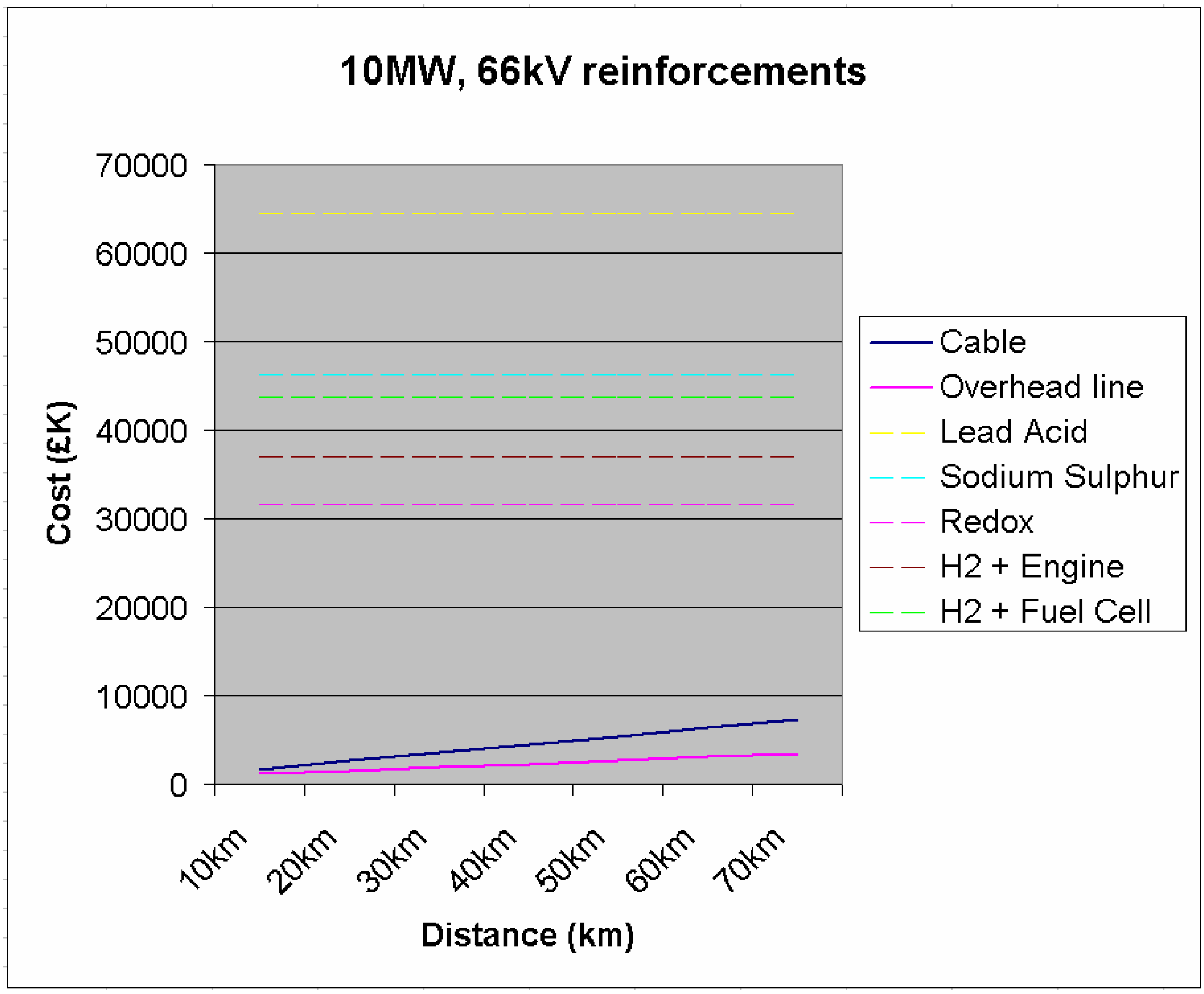

Figure 14: 10MW, 66kV, 2 days storage vs. “business as usual” cost comparison

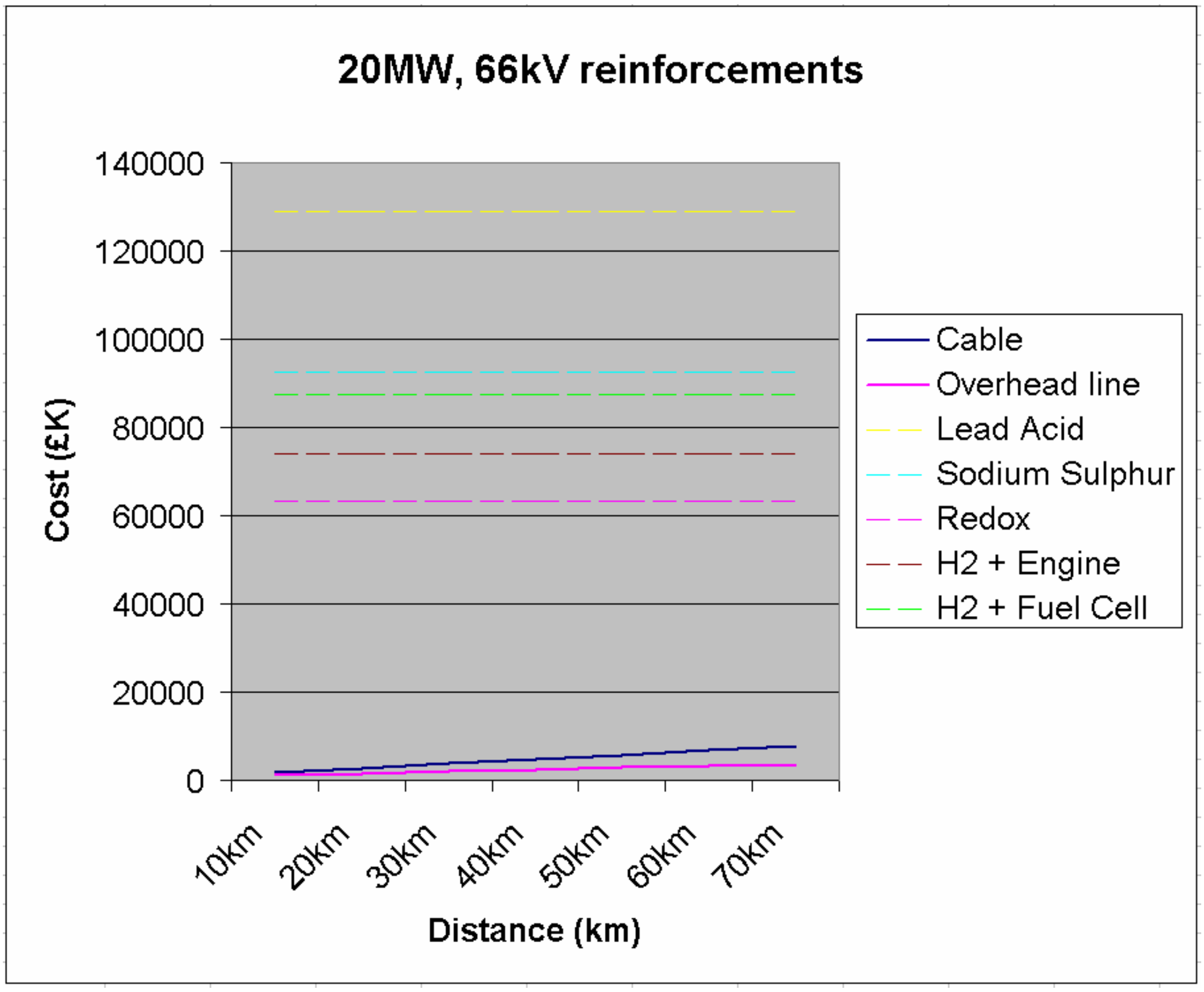

Figure 15: 20MW, 66kV, 2 days storage vs. “business as usual” cost comparison

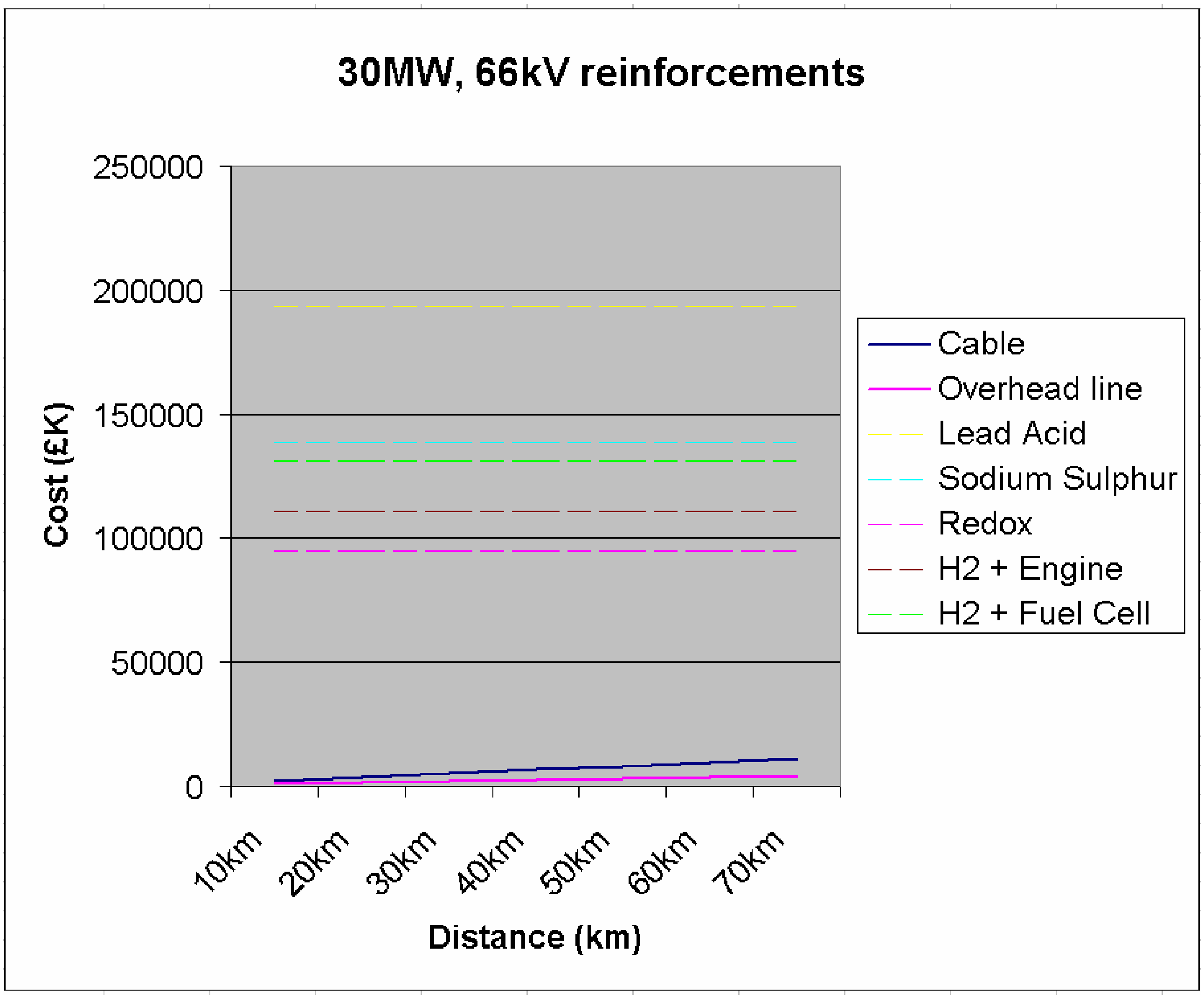

Figure 16: 30MW, 66kV, 2 days storage vs. “business as usual” cost comparison

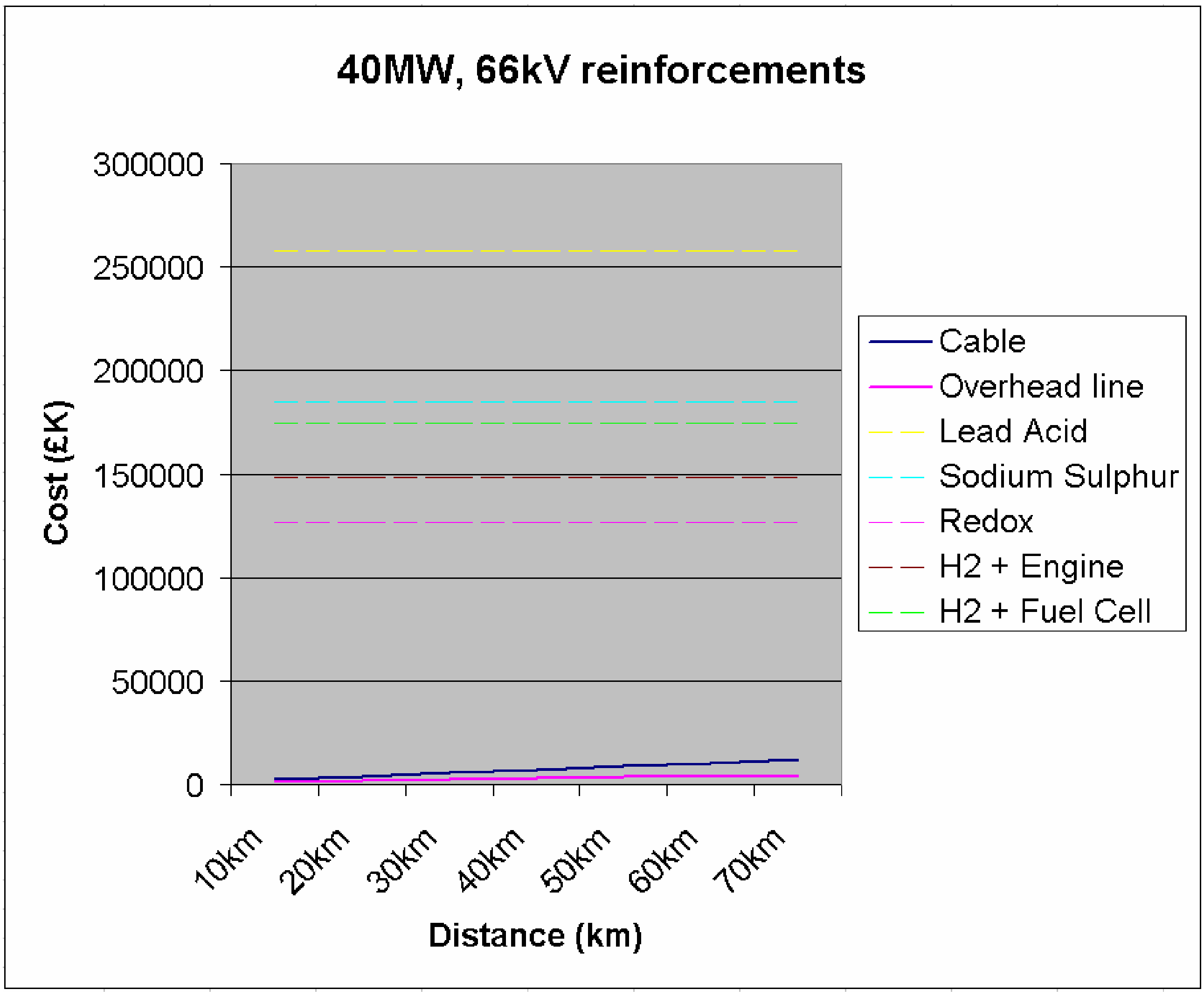

Figure 17: 40MW, 66kV, 2 days storage vs. “business as usual” cost comparison

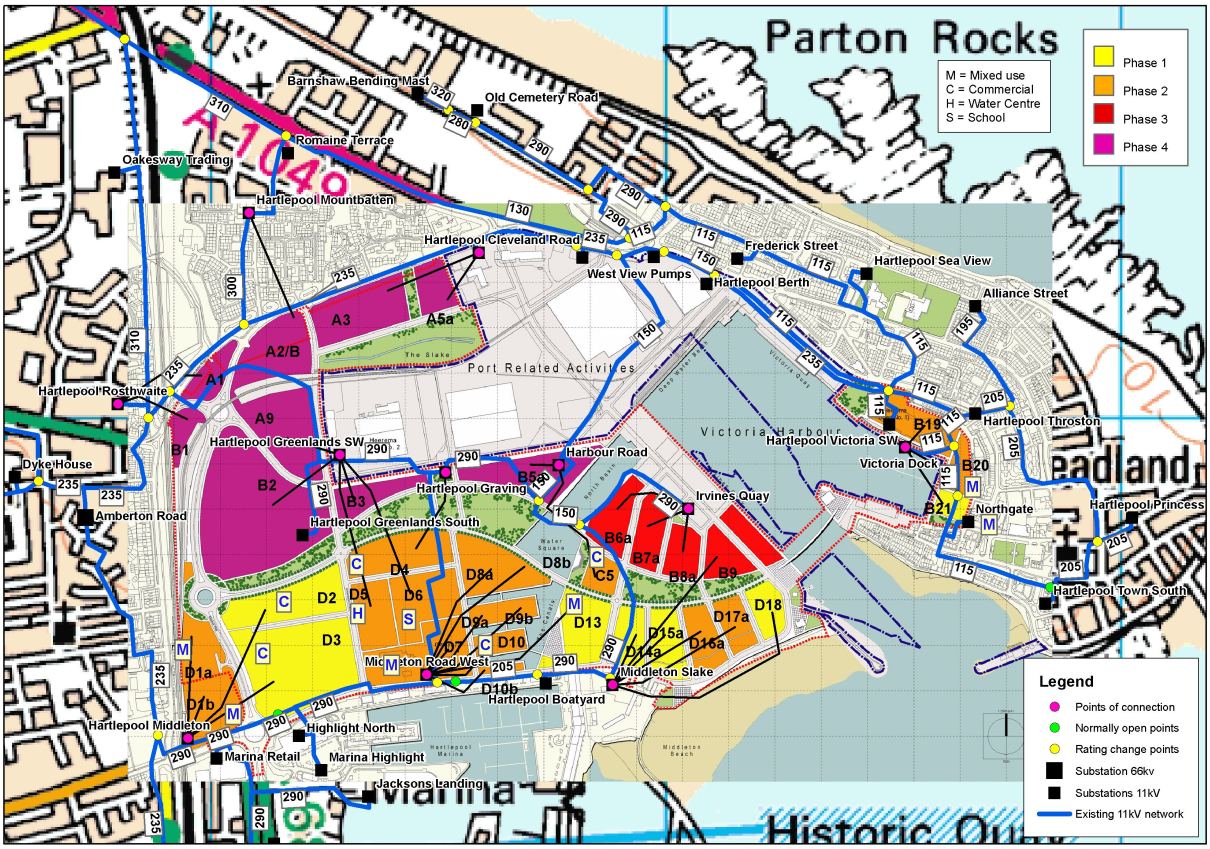

Figure 18: Victoria Harbour site, with existing 11kV network and connection points (energy mix 3)

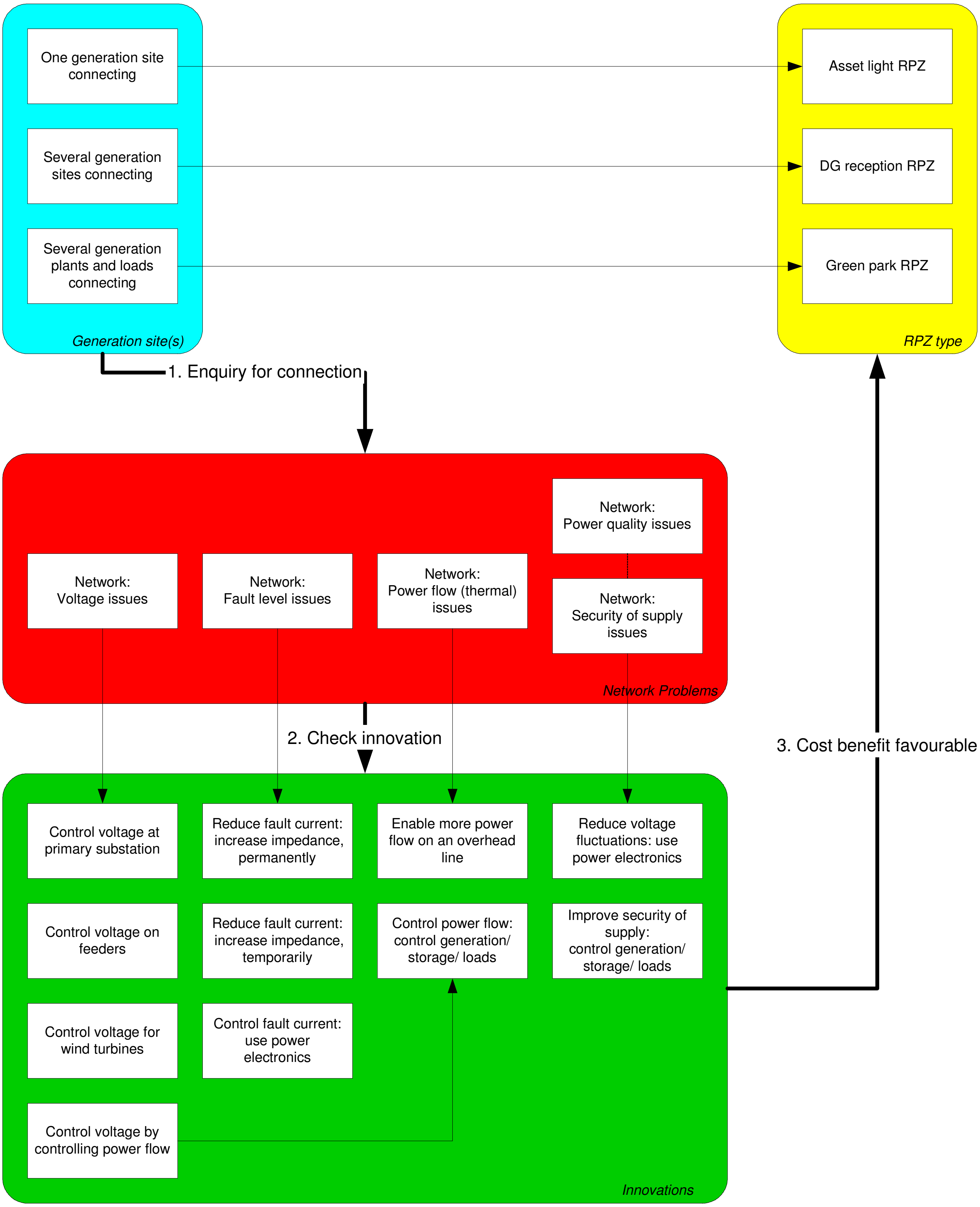

Figure 19: RPZ flow chart

10 GLOSSARY

AC	Alternating current
Active network	A type of electricity network where the operation of the assets on the network are managed after their installation
Asset Light	A type of RPZ where there is reduced/zero assets for connecting embedded generation.
AVC	Automatic Voltage Control.
Business as usual solution	The solution that is currently used by network operators to connect distributed generation to their network.
Capacitor	Two conductors in parallel separated a dielectric (insulator). It is used in AC power network as generator of reactive power. This reactive power provides a boost to the voltage, the magnitude being dependent on the amount of capacitance, the network impedance and the network frequency.
Capacity	The amount of energy (MW) that can be exported to or imported from the electrical network whilst staying within statutory and safety limits of that network.
CE Electric	New owning company of NEDL and YEDL distribution network operators.
CHP	Combined Heat and Power.
Circuit	The conductors and equipment transmitting current in an electrical network. These may be overhead lines, underground cables, transformers, switchgear etc.
Constraint	A generator is constrained in the amount of power it is allowed to export to the electrical network when transmitting more electricity to the network would cause that network to operate outside statutory and safety limits.
Customer	A customer of the electricity network. This can be a demand customer (load) or a generation customer.
DC	Direct current
Demand side management	See load management.
DG	Distributed generation.
Direct connection onto busbar	A connection where a dedicated circuit is constructed between the new generation plant and an existing substation on the distribution network.
Distributed generation	Generation plants that are connected to the distribution network.
Distribution network	The part of the electrical network of a country or region, which carries current at medium and low voltage. In England the voltage for the distribution system range from 132kV to 230V. In other parts of the UK and abroad the definition of the voltage range may be different.
Distribution Price Control Review	The review of the electricity charges made by Distribution Network Operator. Ofgem carries this out every five years.
District CHP	A system where a Combined Heat and Power generation plant produces heat that is distributed via water pipe to a number of properties on a site.

DNO	Distribution Network Operator in England, Scotland and Wales.
DNO settlement meter	The electricity meter that is installed by the DNO and is located at the last point on the network belonging to the DNO near the connection point for a customer (load or generation)
DTI	Department of Trade and Industry.
Electrolysis	A piece of equipment that uses electricity and water to produce hydrogen.
ENA	Energy Network Association.
Energy storage system	A system whose aim is to store energy that comes from an electrical source and to restore that energy in the form of electricity
Energy transformation	The process of transforming electricity into another form that is suitable for storage over a period of time.
ESCo	Energy Services Company.
ESQCR	Electricity, Safety, Quality and Continuity Regulation.
Export	The process of transmitting electricity from a generator to the electrical network.
FCL	Fault current limiters
Fault level issues	Electrical faults on electrical networks may be caused by for example an overhead line breaking, or the accidental excavation and damage to an underground cable. When this happens, very high currents can occur (fault current). To protect the network and its users, protection (switchgear) equipment is fitted at strategic points on the network. When connecting a new generation plant to the network, the fault currents increase and the existing protection equipment may not be adequately rated to perform its protection duties and may need replacing.
Feeder	A circuit connected to a primary substation that serves a number of customers.
Firm capacity/ connection	The capacity remaining when one circuit or transformer (the highest rated) is out of service.
Fit and forget connection	Standard method of connecting generators to the distribution/transmission network, in which the network is reinforced using mature technologies to accept the generation.
Flow battery	A battery where the electrolyte is separate from the electrode. The electrolyte is pumped to the electrode, the reaction takes place and the electrolyte is pumped away.
Fuel cell	A piece of equipment that transforms hydrogen into electricity. It operates like a battery, but does not run down or requires recharging so long as hydrogen is supplied.
GIS	Geographic Information System.
GPG	Good Practice Guide.
Green Business Park	A type of RPZ where there is active control and integration of generation and demand.
Heat pumps	A pump system that compresses air or gas in order to provide heating to a dwelling. This can be an air source heat pump installed above ground level, or a ground source heat pump buried in the ground.
HV	High voltage, usually referring to voltages at 11kV or 20kV.
IFI	Innovation Funding Incentive.
Impedance	Impedance is made up of two components: resistance and

	reactance. Resistance is a measure of a circuit's power dissipation (related to real power) and reactance is a measure of a circuit's reactance (related to reactive power).
Import	The process of transmitting electricity from the electrical network to a load or a generator connected to that network.
Induction generator	A type of rotating electrical generator, which operates at a speed that is not directly related to the network frequency. The machine is generally excited by reactive power drawn from the network.
LDC	Line Drop Compensation.
Load management	The process of switching the electricity supply to some loads on and off in order to match the amount of electricity available to the network at any point in time to the amount of electricity consumed by the loads on that network.
LTDS	Long Term Development Statement.
LV	Low Voltage, usually referring to voltages of 1000V and below
Micro CHP	Small CHP generators with capacity of approximately 1-10kW.
Micro wind	Small wind generators with capacity of approximately 1-10kW.
MicroTAPP	A type of transformer control system.
NaREC	New and Renewable Energy Centre.
Network operator	A company responsible for operating a part of the electrical network.
NPV	Net present value
Ofgem	The Office of Gas and Electricity Markets.
Outage	De-energisation of a section of network, which may result in the loss of electrical supply to some customers.
P & D Ports	The owners of the land at the Victoria Harbour site studied in this project.
Passive network	A type of electricity network where the operation of the assets on the network after their installation in predetermined and not managed.
Power flow issues	An electrical network is designed to carry electrical currents, which results in electrical power being transmitted around the network. When connecting a new generation plant to the network, the amount of power that is transmitted around the network changes, potentially leading to thermal and voltage issues.
Power quality issues	Power quality on an electrical network is related to issues with voltage fluctuations, which may be visible to customers through flickering on their lighting system. When connecting a new generation plant to the network, the voltage fluctuations may worsen, and remedial work may be required.
Primary sub-station	The points in the network where the voltage is transformed from higher voltages to lower voltages. This is a physical building, containing transformation, protection and other equipment.
RD&D	Research, Development and Demonstration.
Reactive power	Power that flows through AC network is made up of two components: real power and reactive power. Reactive power is not used or dissipated in a circuit, but its effect can be observed on voltage and current on the network, and it is measured in vars. This type of power only exists in AC networks.
Real power	Power that flows through AC network is made up of two components: real power and reactive power. Real power is the actual amount of power being used or dissipated in a circuit and it is measured in

	watts. It manifests itself in a tangible form (radiation, dissipation, and/or mechanical motion).
Reinforcement	The process of replacing one or more existing plant items on an electrical network, either because the plant has reached the end of its operational life or because the plant rating is not sufficient enough due to new generation or load to be connected to the network.
Renew Tees Valley	Energy & environmental development company operating in the Tees Valley area, in the North of England.
RPZ	Registered Power Zone.
Security of supply	A term referring to the number and length of disconnections from the DNO network, measured annually in Customer Minutes Lost and number of incidents per 100 customers.
Stranded assets	Assets that have been installed on an electrical network but which are not been used and become obsolete. Ofgem does not allow “prospective” network development that may lead to stranded assets.
Substation	See primary substation
Synchronous generator	A type of rotating electrical generator which operates at a speed that is directly related to the network frequency.
Tee connection	A connection where a dedicated circuit is constructed between the new generation plant and an existing circuit on the distribution network.
Tees Valley Regeneration	Urban regeneration company operating in the Tees Valley area, in the North of England.
Thermal capacity	See thermal issues
Thermal issues	Each element of the distribution network, circuits, transformers etc has a limited current-carrying capacity. If it is loaded above this limit for an extended period of time, it will overheat, which may lead to permanent damage, including fire or explosion. When connecting a new generation plant to the network, the amount of current that flows through the network changes, which may cause existing network asset to be loaded above their thermal limit, in which case they would need replacing with assets capable of withstanding the new thermal loading.
Transmission network	The part of the electrical network of a country or region, which carries current at high voltage. In England the voltages for the transmission system range from 400kV to 275kV. In other parts of the UK and abroad the definition of the voltage range may be different.
Voltage issues	Voltage levels in distribution networks must be maintained within statutory limits in order to provide consistent electrical supply to customer. The actual voltage varies around the network and with time as the load on the network changes. Voltages tend to fall when people are using a lot of electricity and they are often lower at the ends of long distribution circuits. Conversely, power export from distributed generators tends to increase local voltage levels, which may rise beyond operational limits. In this case, remedial work would be required on the network.