A STUDY INTO THE ECONOMIC RENEWABLE ENERGY RESOURCE IN NORTHERN IRELAND AND THE ABILITY OF THE ELECTRICITY NETWORK TO ACCOMMODATE RENEWABLE GENERATION UP TO 2010

A REPORT PREPARED BY PB POWER

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LIST OF ABBREVIATIONS

ac	alternating current
AGL	above ground level
AONB	area of outstanding natural beauty
ASSI	area of special scientific interest
BWEA	British Wind Energy Association
CC	countryside centre
CHP	combined heat and power
CP	country park
DARD	Department of Agriculture and Rural Development
dc	direct current
DETI	Department of Enterprise, Trade and Investment
DFIG	Double-fed induction-generator
DNC	declared net capacity
DTI	Department of Trade and Industry
EC	European Commission
EfW	Energy from waste
EHSNI	Environment and Heritage Service Northern Ireland
EIA	environmental impact assessment
ETSU	an operating division of AEA Technology Environment
GWh	gigawatt-hour
IENICA	Interactive European Network for Industrial Crops and their Applications
IPPC	integrated pollution and prevention control
kWe	kilowatt (electric)
kWh	kilowatt-hour
LFG	landfill gas
MDF	medium density fibreboard
MNR	marine nature reserve
MSW	municipal solid waste
MW	megawatt
MWe	megawatt (electric)
MWth	megawatt (thermal)
N&RE	new and renewable energy
NFFO	non-fossil fuel obligation
NI	Northern Ireland
NOABL	numerical objective analysis of boundary layer
NR	nature reserve
OS	Ordnance Survey
RoI	Republic of Ireland
SAC	special area of conservation
SPA	special protection area
SRC	short rotation coppice
tpa	tonnes per annum
UK	United Kingdom

EXECUTIVE SUMMARY

The purpose of this study is to assess the realistic contribution that renewable energy sourced electricity, produced at an acceptable additional price to the end consumer, can make to the likely demand in Northern Ireland in 2010. The “acceptable price” for the purpose of this study has been taken as 7p/kWh. This figure is calculated on the basis of a current average price of electricity in Northern Ireland of 4p/kWh plus a renewable “premium” of 3p/kWh. This latter figure is based on the level of the “buy-out” price set under the Renewables Obligation in Great Britain.

The potential contributors to renewable-resourced electricity have been identified as:

- onshore and offshore wind.
- biomass.
- hydro-electricity.
- municipal and agricultural wastes.
- landfill and sewage gas.

Other technologies, such as photo-voltaic and solar power, were considered. However, it is considered that significant contribution can only be achieved if they are incorporated into new build schemes. This would require a mind set change in NI and amendment to building regulations. An in-depth assessment of the potential of energy to be extracted from marine currents is beyond the scope of this review and will be assessed separately.

Detailed evaluation of the wind resource across the whole of Northern Ireland indicated a total onshore potential of between 588 - 684 MW of capacity distributed over 30 - 40 sites. This includes existing or committed schemes which amount to 120 MW of capacity.

The feasibility of developing a further 150 - 250 MW of offshore wind capacity is currently being investigated at a site off the north coast of Northern Ireland. The developer’s current programme indicates that if the project does proceed the electricity which it will generate will be available well in advance of 2010.

The remaining resources and technologies listed above add about a further 50 MW of capacity to that identified from wind resources but have the advantage that they are less intermittent and unpredictable and thus will have greatly increased capacity factors. They will, therefore, contribute more than twice the energy per unit of capacity installed than that of the wind farms.

The locations of the identified renewable resources (and therefore the projects themselves) are distributed across the region within reasonable connection distance of the 33 kV or 110 kV networks of NIE. During periods of time when transmission plant is out of service for repair or maintenance, constraints on generation (either conventional or renewable-sourced) may be necessary. These constraints can be eased significantly if the 110 kV system is selectively reinforced and modified control and protection procedures are adopted.

It should be noted that, because of non-availability of data on the dynamic performance of individual wind generators, no dynamic modelling of the impact of wind generation on the operational performance of the transmission and distribution system was undertaken during the work. It is recommended that this work be undertaken when suitable wind generator models become available.

The effects of a potentially large portion of relatively unconventional renewable generation, particularly wind, were examined in considerable detail in the study to determine the extent of renewable generation that could be accepted onto the NI system under varying load conditions. The “system costs” i.e. costs associated with running conventional thermal plant part-loaded, or the costs of having fast-start plant available to cover unexpected loss of wind generation, were evaluated and have been included in the calculation of total costs of renewable generation. The beneficial effects of the availability of the Moyle interconnector and the transmission system interconnections with the Republic of Ireland, were included in the analysis also.

The findings of the study are presented in the form of price-quantity relationships at two discount rates. These show that, as the available capacity of renewable generation increases and, therefore, the potential energy resource recoverable from that capacity increases, the cost of making that energy available to the electricity consumer increases also. At higher levels of installed capacity of intermittent generation (i.e. wind power) the study determined that system operational costs may need to rise by approximately 0.5 p/kWh to maintain system security and reliability standards.

At the price which has been deemed acceptable to the end consumer, i.e. 7 p/kWh, the energy recoverable amounts to 1589 - 2664 GWh/yr at 8 per cent discount rate and 656 - 922 GWh/yr at 15 per cent discount rate, depending on the particular way the Moyle Interconnector is operated. These energy values, the associated capacities and attendant increases in total annual energy cost by 2010 are presented in 2002 prices in the following table. The rate of growth in costs to the level presented will be dictated by the rate at which renewable power projects are developed in Northern Ireland. However, the full utilisation of Northern Ireland’s renewable energy resources is likely to be dependent upon a change in legislation which would encourage the trading of Renewable Obligation Certificates (ROCs) with suppliers in Great Britain.

INCREASE IN TOTAL ANNUAL COST OF ELECTRICITY FOR NORTHERN IRELAND

		First Despatch Scenario		Second Despatch Scenario	
		Discount Rate		Discount Rate	
	Units	8%	15%	8%	15%
Annual Energy from Renewable Sources	GWh	1589	656	2664	922
Installed Capacity	MW	391	220	631	340
Green Premium	p/kWh	3	3	3	3
Total Annual Cost	**£million**	**47.67**	**19.68**	**79.92**	**27.66**

The next table shows the generation capacity in service which contributes to the energy production level. This generation mix is based on a strict "merit order" despatch of plant. Commercial arrangements currently in place in Northern Ireland, in relation to the availability of either conventional generation or the Moyle Interconnector, may affect the outcome in practice.

RENEWABLE CAPACITY (MW) PROVIDING ELECTRICAL ENERGY AT A PRICE OF ≤ 7 P/KWH

	Discount Rate	
Generation type	**8%**	**15%**
Wind	360-600	200-320
Landfill gas	9.1	9.1
Energy from waste	8.3	8.3
SRC	Marginal	Marginal
Wood residue	Marginal	Marginal
Poultry litter	5.8	Marginal
Agricultural wastes	5.0	Marginal
Sewage gas	2.6	2.6
Total Renewable Capacity (MW)	**390.8-630.8**	**220-340**

1. INTRODUCTION

This report was prepared by PB Power Ltd for Department of Enterprise, Trade and Investment, Department of Trade and Industry and Northern Ireland Electricity. The completion of this assignment was controlled by a project board chaired by Professor Nick Jenkins and including senior representatives of NIE, DETI and OFREG. Its purpose is to advise and inform on the renewable energy (RE) resources in Northern Ireland (NI) and to estimate the contribution that these resources can make, at an acceptable price, towards total electricity production in 2010. The focus of the study was the opportunity to generate electricity for grid supply.

There may be significant opportunity for some technologies (particularly biomass) to generate at a small scale for local/self consumption but this opportunity was not evaluated within this study.

2. RESOURCE AVAILABILITY AND CONVERSION TECHNOLOGIES

Renewable energy resources which may exist can only be utilised if technologies to convert the resources into electrical energy are available in a reliable and cost-effective form. Certain technologies which hold promise for the future may still not be available in commercial quantities by 2010. Investigations into all existing and prospective renewable technologies have been made during the course of the study. Where such technologies have yet to enter into mass production, even though prototypes may exist, they have been disregarded for the purpose of the study because of the extended periods likely for development and commercial proving. These future technologies are discussed further in Section 2.8.

Those resources and technologies which are likely to be realisable by 2010 include:

- Onshore wind.
- Offshore wind.
- Biomass.
- Hydro-electricity.
- Photo-voltaic and solar power.
- Municipal and agricultural wastes.
- Landfill and sewage gas.

Each of these is dealt with separately in the sections which follow.

2.1 Onshore wind

The assessment of onshore wind was made on the basis of wind resource data available in the public domain, supported by long-term meteorological data.

The evaluation of wind energy resource was made by applying a series of increasingly restrictive criteria to the identified resources. The process is shown as a series of discrete activities in Figure 2.1. The stages in the process are:

a. gross (‘technical’) potential

b. development potential

c. interference constraints

d. clustering effects

e. practical potential

FIGURE 2.1: PROCESS ADOPTED IN IDENTIFYING POTENTIAL ONSHORE WIND ENERGY RESOURCE

Stage (i)	Stage (ii)	Stage (iii)	Stage (iv)	Stage (v)
Unconstrained review of the gross resource potential	Removal of clearly unsuitable sites	Consideration of wind flow interference effects / site inter-relationships	Consideration of clustering issues/inter-relationships	Appraisal of practical onshore wind power potential
378 sites, 4547 MW	254 sites, 3201 MW	235 sites, 2955 MW	High bound: 103 sites (1546 MW) Low bound:81 sites (1209 MW)	Approx. 30-40 sites 468 - 564 MW

The detailed considerations in each stage of the evaluation are described below.

a. **Gross (‘Technical’) potential**: Suitable sites were identified for wind farms based on appropriate topography and long-term average wind speed data. Potential sites were excluded which were located in places where planning consent was likely to be difficult or impossible to obtain, such as:

   - Areas of outstanding beauty.
   - Country parks and countryside centres.
   - Areas of special scientific interest.
   - Nature reserves.
   - Marine nature reserves.
   - Special areas of conservation.
   - Special protection areas.
   - Ramsar sites.
   - Built heritage sites and archaeological and historic monument sites.

   A range of turbine sizes and rated outputs were then considered for application on each of the sites and a capacity assigned to each site. Standard power curves for the turbines and long-term average wind speed data allowed an estimate to be made of the annual average energy yield. Sites were then graded according to a subjective assessment of the planning approval potential of each site. A total of 378 sites were identified in this way, having a total installed capacity in excess of 4500 MW.

b. **Development potential**: Once this initial assessment had been completed, the list of sites was refined to identify those projects with more definite development potential. Sites were discounted which had a relatively poor wind resource i.e. the long-term wind speed was not likely to be sufficient to support a commercially-viable wind farm and/or the characteristics of the sites were such that they were unlikely to be acceptable when considered against some or all of the fundamental planning issues, such as visual impact. This refinement led to the reduction in the number of potential sites to 254, having a total capacity of about 3200 MW.

c. **Interference constraints**: The potential sites then remaining under consideration were subject to a further review to eliminate any sites which might have had an effect on those which were already existing, or which were committed to development. Information on these latter sites was provided by NIE. This review reduced the number of sites to 235 having a total aggregate capacity of 2955 MW.

d. **Clustering effects**: This stage addressed the issue of ‘clustering’ of sites and its impact on the probability of securing planning approval. This is an important criteria. Each additional new development will increase impact on the environment, and upon local acceptance of that and further development. Within a given region, the development of sites will have a cumulative impact on the acceptability of further developments until an acceptable level of development (seen against the overall need) is reached. This assessment reduced the number of sites to between 81-103 and the total capacity to 1209-1546 MW.

e. **Practical potential**: The final stage of assessment applied development probability factors to the individually identified sites according to one of three categorisations, ranging from highly likely, through probable to possible. The scaling factors applied to these three categories were 0.75, 0.50 and 0.25 respectively. This resulted in a total aggregate capacity of 468-564 MW. When existing and committed wind farms are included, the total capacity figure increases to 588-684 MW.

The resources identified in the above analysis represent wind farms which have the potential to contribute energy to the NI system unconstrained by cost. The costs of connecting each individual wind farm to the system will vary according to the state of development of the electricity distribution system in the vicinity of the development. In more remote areas, the cost will be high and, conversely, in more developed areas, the cost is likely to be comparatively low. Estimates of these costs on a district-by-district basis have been made in order to assess the production costs of energy from the individual wind farms. In some cases connection costs may discourage development, however if a move towards shallow charges was implemented this would tend to overcome such barriers to connection.

In addition, costs (described in more detail in Section 4.2.3) will be incurred by the System Operator Northern Ireland (SONI) to allow for the intermittency and unpredictability of wind energy. These costs are identified in Sections 4 and 5.

The above two categories of cost, when summated with capital and operating expenditure, have allowed the relationship between price and quantity to be assessed for wind energy as depicted in Figures 5.4 and 5.5.

2.2 Offshore wind

A private sector consortium is assessing the feasibility of developing a wind farm off the North Coast. Should it proceed the installed capacity of this wind farm is expected to be between 150 and 250 MW.

2.3 Biomass

Biomass resources available in NI which could be utilised for electricity production include:

- Straw.
- Poultry litter and spent mushroom compost.
- Short rotational willow and miscanthus coppice.
- Forest products and forest residues.
- Other biofuels.

The potential for electricity generation by 2010 from all resources in the above categories is relatively small, both in terms of existing electricity production in NI and in relation to the energy potential of wind farms. There may of course be considerable potential for very small scale biomass plant generating modest quantities of power and heat for self/local consumption but this is outside the scope of this report. Whatever electrical energy is produced, however, it is likely to be more predictable and less intermittent, given the relatively high availability of the feedstock for the projects and the maturity of the technology employed.

2.3.1 Straw

The technology for burning straw to produce electricity is well established in Denmark and there is a 36 MWe plant now in operation in East Anglia which consumes approximately 5% of the unused straw resource in England. In NI, the straw resource is much in demand, being mainly used either for equine or agriculture purposes or ploughed back into the soil. Some of the straw resource could be diverted for use in straw-fired boilers for on-site heat requirements (again this is outside the scope of this report).

Given that straw production in NI is relatively small, and it is sought after resource, we consider that no significant contribution to renewable electricity production is likely to arise from this resource by 2010.

2.3.2 Poultry litter and spent mushroom compost

There are three plants currently operating in England and Scotland which use poultry (chicken) litter as a fuel. Their capacities range from 8 MWe to 38 MWe. In NI at the present time, about 70 per cent of poultry litter produced is used in the production of mushroom compost and the remainder is spread on farmland as a fertiliser. Any electricity generation project, therefore, would compete with these applications for the resource although moving further down the chain and utilising spent mushroom compost as a fuel source may have potential in the future. This analysis has assumed that 30 per cent of the available resource could be used to supply a single 5.8 MW generating plant near to the existing chicken farming areas in Counties Armagh, Antrim and Tyrone.

2.3.3 Short rotational willow coppice and miscanthus

Based on the soil classification by Cruickshank et al approx 58% of the land area of NI could sustain the growing of short rotational coppice (SRC). Indeed SRC is currently grown successfully in NI at a small scale. The case for miscanthus is much less clear and is not considered further in this report.

An integrated gasification combined-cycle power plant partly fuelled by SRC willow has operated in North Yorkshire (the ‘ARBRE’ project). The plant is a demonstration project funded by the EC, has a capacity of 8 MWe and operates under a NFFO-3 contract. SRC willow is grown for the project on set-aside arable land and reclaimed land within a 60 km radius. However at the time of the review the project is in liquidation and its future is uncertain. This indicates the level of complexity surrounding issues of viability for SRC energy projects at the larger scale.

Additionally, despite enhanced grant rates for the establishment of energy coppice under the England Rural Development Plan, only 55 growers have planted a total of 447 hectares of energy coppice up to August 2002. This level of planting would only be sufficient to fuel a 0.9 MWe SRC plant.

There are currently two 100 kWe CHP plants fuelled by biomass operating under NI-NFFO contracts at Blackwater Museum and at Brook Hall.

The transportation costs of SRC willow are high due to its low bulk density and hence schemes are only viable when the SRC plantations are close to the generating plant. It is feasible that, by 2010, a number of small-scale plants could be built in NI of the order of hundreds of kWe each. This could provide local substitution for grid electricity which would enable farmers to add value to their crops and use the waste heat for space heating of buildings or drying of crops.

Encouraging diversification into SRC growing at a level which would sustain a sizeable plant generating electricity for the grid, depends heavily on the levels of grant aid or other growing incentives available. These are currently lower in NI than those available for energy coppice schemes in England developed under the England Rural Development Regulation Plan and it is by no means clear that the level of support provided in NI would encourage significant uptake.

Perhaps more importantly, the infrastructure necessary to support significant diversification into SRC growing is not in place in NI and there is some uncertainty that the agricultural community could access sufficiently affordable capital to fund the necessary investment programme. Equally important is the lack of skill base in commercial wood growing and it is clear that significant retraining would be necessary to enable large scale diversification from traditional farming in NI into the growing of energy crops.

In summary, the low incentives available for SRC in NI, the logistical requirement to have sufficient grassland or arable land within economic transport distance of a biomass power plant and the lack of infrastructure/skills suggest that any contribution to renewable energy from this resource at an acceptable price by 2010 is likely to be modest in nature. There is, however, scope to develop small/micro applications for local energy consumption and the completion of a biomass sub-strategy with a small scale focus should be considered a priority.

2.3.4 Forest products and forest residues

Approximately 5 per cent of the area farmed in NI is forest managed by the Forest Service, of which half is located in Counties Fermanagh and Tyrone.

Technology used to generate electricity from wood and forest residues is well established. There are several projects in Sweden and Finland fuelled in part by forest residues ranging from one to many hundreds of MWe. A 38 MWe chicken litter plant in Thetford, UK, is supplemented by 8 per cent forest residues and wood chips.

Forest residues are the part of the tree left in the forest after harvesting and include branches, bark, and tree tops. These can account for half of the forest yield, but at present, forest residues are not recovered in NI for commercial purposes.

Wood co-products include sawmill residues, excess small wood, and the residues and off-cuts from the manufactured wood products industries (such as particleboard or MDF). It is estimated that in NI these are currently in excess of the market requirement, and so could potentially be used as a fuel. It is common practice in the wood products industry to use wood waste as a fuel for on-site heat demands.

The proportion of wood and wood waste which can be used for electricity generation depends on a number of factors including the price of the wood and wood waste, the demand for wood-based products manufactured from them, as well as the price of electricity and heat. The viability of using even a small proportion of merchantable timber in NI for electricity generation would depend on market factors and is therefore beyond the scope of this study.

If, however, a project was to proceed it is likely to be located at Enniskillen, due to the significant forest resource located in counties Tyrone and Fermanagh, and the existing infrastructure located there which serves a large user of timber (Balcas Timber).

The Forest Service also appears committed to increase the level of forested area in NI annually. The NI resource, supplemented by forest residues from the Republic of Ireland, could, we estimate, support a total installed capacity of 7.1 MWe.

2.3.5 Biofuels

Biofuels are produced from energy crops grown specifically for fuel production. Arable crops such as rapeseed can be used to produce bio-diesel, and grasses, cereals and sugar beet can be used to produce bio-ethanol.

Energy crops for biofuels would be grown on arable land, which makes up 6 per cent of the total land farmed in NI. This is an insufficient land area to make biofuel production viable at the scale necessary to make a meaningful contribution to electricity generation.

2.4 Hydro-electricity

Hydro power is generated from the energy available in water flowing down through a pipe or open channel.

In NI, attempts have been made over the past 50 years to build large-scale hydro projects. These, however, did not go ahead because of environmental constraints. This study, therefore, has considered only small-scale installations, and has used as a source of data the Study carried out in 1989[1]. The scope of that report included sites with installed capacities of 25 kWe to 5 MWe.

The total technical resource in NI was given in that report as being capable of supporting hydro-electric plants totalling 2.89 MWe of which 2.4 MW is existing installations, leaving a further 0.49 MW to be developed. It would seem reasonable to assume that all of these sites could be exploited by 2010 as they are the best and most economically viable of the 57 sites evaluated in the report.

2.5 Wave energy and tidal power

2.5.1 Wave energy

There are a number of devices in use as prototype machines to generate electricity from wave power. The only operating wave power station in the UK is located on the Scottish island of Islay, and has an installed capacity of 500 kW. It was commissioned in 2000, and operates under an SRO-3 contract.

The NI coast, however, is sheltered from the North Atlantic swell. A re-worked analysis of wave energy potential was influenced by the opinion of an industry expert (Professor Trevor Whittaker of Queens University Belfast). He confirmed that wave power resource in NI is negligible. His assessment supports the conclusions of earlier studies[2].

2.5.2 Tidal power

There is a significant tidal stream energy resource in Northern Ireland. Harnessing this energy is dependent upon the availability of suitable technology. This is considered in a separate report prepared for DTI.

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[1] Small scale hydroelectric generation potential in the UK, 1989, Vols 1 & 2 (ETSU SSH 4063).

[2] ETSU for NIE and DED, ‘Renewable Energy in the Millennium, the NI Potential’, June 1999

2.6 Photovoltaic and solar power

2.6.1 Photovoltaics

Photovoltaic (PV) materials generate an electric potential when exposed to light. The dc current from the PV cells can be used directly or fed through an inverter in order to provide ac power.

In NI, the most likely application for PV panels is mounted on existing buildings or on new buildings as a substitute for materials such as glass façade, roof materials or shading films. In this case there is an avoided cost of new building materials. The capital cost of a PV installation however remains the major obstacle to the widespread adoption of this technology.

PV integrated into an average glazed office block is likely to become commercially viable towards 2020, and in domestic buildings towards 2025. The contribution by 2010 is considered negligible on cost grounds.

2.6.2 Solar power

Solar energy can be derived in two ways:

- **Passive solar design**: The objective of passive solar design in buildings is to utilise the solar gain of the building and air currents generated by this to regulate the temperature in the building. This minimises the consumption of power for heating, cooling, and lighting. It does not contribute directly to the generation of electricity although it does impact on demand management. It has not, therefore, been considered in this study.

- **Solar thermal power stations**: Solar thermal power stations use a simple principal – solar collectors concentrate heat, which is used to generate electricity from a conventional thermal power plant. For the operation of these plants to be economically viable, however, they are best located in the Earth's hot, dry, zones south of the 40th latitude. They are not applicable to NI and have not been considered in this study.

2.7 Municipal and agricultural wastes

The resource in NI for generating electricity from waste includes the thermal conversion of municipal solid waste and commercial/industrial waste; gas from landfill sites; and generation of biogas from sewage sludge.

2.7.1 Municipal solid waste

Technology for energy from waste by incineration is well established and fully proven. The Waste Management Strategy for NI[3] supports energy from waste (EfW) and states that 'development of energy from waste facilities will be necessary to meet the targets set in the Landfill Directive'.

In England, Wales and Scotland, the electricity from EfW schemes is neither eligible for Renewable Obligation Certificates (ROCs) nor does it count towards achievement of renewable energy targets unless it is produced from EfW plants employing advanced technologies such as anaerobic digestion, gasification or pyrolysis. Such technologies are not yet available in a fully-proven commercial form in the UK although it is possible that they might be by 2010. Where mixed wastes, e.g. MSW without pre-sorting, are used as a feedstock for such plant, only the non-fossil element (typically about 50 per cent) is classified as a renewable.

2.7.2 Sewage sludge digestion

Sewage biogas is generated by the anaerobic digestion of sewage sludge. Some of the gas is needed as a fuel to maintain the temperature in the digester, and the remainder can be used in a reciprocating engine to generate electricity.

It is worthy of note that, should NI adopt a policy of treating sewage sludge as a renewable resource for use in digester energy recovery schemes, some 19 GWh of electricity could be recovered.

Contracts granted under NI-NFFO 1 for sewage gas were cancelled due to lack of progress with planned sewage plants. They were for 560 kW in total and are not significant in the context of the total aggregated renewable resources considered in this study. This is an area worthy of further encouragement by the NI administration.

2.7.3 Agricultural wastes

Wet agricultural wastes include slurry from pig and cattle farming, which accumulates when the animals are kept indoors over the winter and chicken slurry from commercial egg layers. Slurry would usually be stored for a period of several months before being applied to agricultural land. It can, however, undergo biological treatment, such as anaerobic digestion, to produce biogas. This contains methane (up to 65 per cent) which can be used as a fuel for heating or for power generation.

In order to improve the viability of a biogas project, a proportion of food waste can also be processed, with the slurry. This improves the calorific value of the biogas, and a gate-fee can be charged for disposing of the waste.

The technology for anaerobic digestion is commercially proven. In the UK, there is an anaerobic digestion scheme in Holsworthy, Devon, operating under a NFFO-4 contract. The plant was commissioned in 2002, and treats 400 tonnes a day of farm slurry mixed with 20 per cent food waste.

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[3] 'Waste Management Strategy, Northern Ireland'. (not dated)

There is a gate-fee charged for food waste, whilst the slurry is treated and returned to the farms as a bio-fertiliser, with no charge to either party. The biogas is stored on site and combusted in spark ignition engines. A similar plant at Fivemiletown in NI is in the preliminary stages of project development. This will treat a mix of 50 per cent slurry and 50 per cent food waste.

The extent of the resource used in the future would depend, amongst other factors, on future environmental legislation relating to the management of farm slurry. In addition, the availability of the food waste resource would depend on future legislation relating to the management of biodegradable waste. Much of the technical resource, were it to be used, would be in installations in the sub-1 MWth range, and may use the heat energy only, without generating electricity.

In order to estimate the maximum contribution by 2010, it was assumed that 20 per cent of the current agricultural wastes technical resource could be used for electricity generation, which includes both the farm slurry and food waste resource. We recognise that this level of yield from farmers is ambitious but it would appear to be consistent with industry predictions[4]. It is likely that possible developments would comprise several plants of the order of 1 to 2 MWe.

Further it was assumed for the purposes of system modelling that all of the resource by 2010 would be concentrated in County Fermanagh, near Enniskillen. In reality, however, the farm slurry resource is scattered throughout NI, with food waste concentrated in the towns. The critical element which would determine the location of the plant is the market for the waste heat. In this regard, municipal projects may have the greatest potential.

2.7.4 Landfill gas

Power generation from landfill gas has been employed in the UK since 1984 and is a commercially proven process. Landfill gas is a methane-rich biogas which is formed from the decomposition of organic material in landfill. The gas is drawn from the landfill site through a network of pipes, and is cleaned before being supplied to a spark ignition engine or a gas turbine to generate electricity. It can also be used directly in kilns or boilers.

Data on landfill sites, necessary to calculate the resource available in NI, is not held centrally by a government department as each Local Authority is responsible for its own waste management. Fifteen of the 26 councils were contacted during the course of this Study, but insufficient data was available to assess the overall technical resource with any reliability. There are likely to be several plants in the range of 1 to 2 MWe at each landfill site, scattered throughout NI, with the most significant resource being in Greater Belfast.

2.8 Potential capacity and location of renewable technologies in Northern Ireland in 2010

The potential new capacity of each of the technologies described above, and their locations on a county-by-county basis, to renewable resource potential in NI, is illustrated in Figure 2.2.

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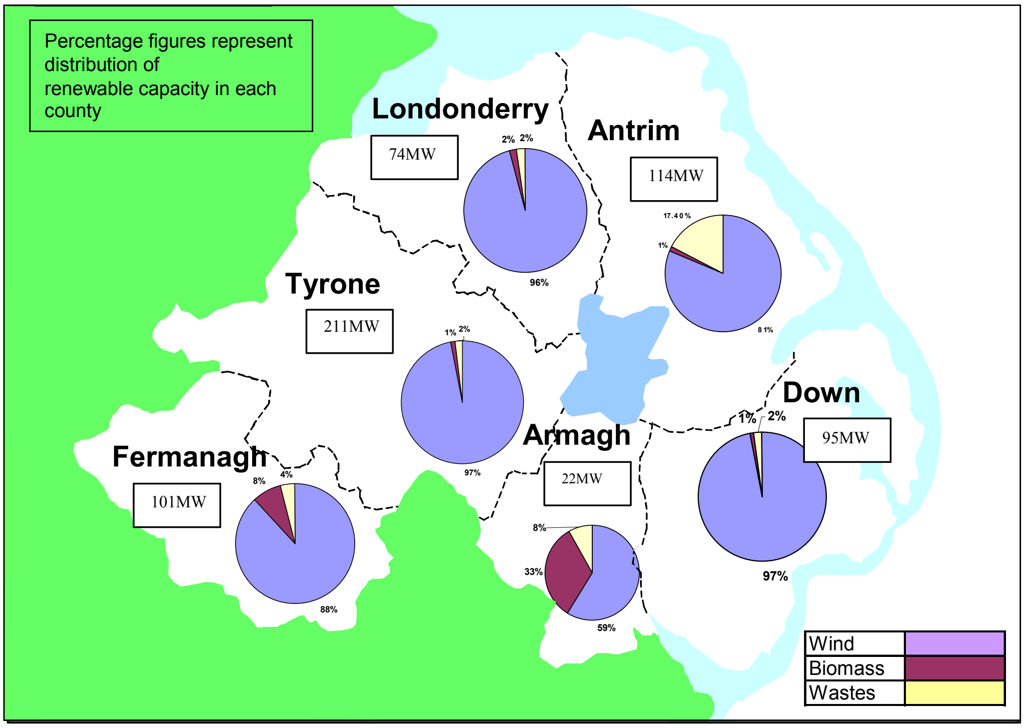
[4] Discussion with Clare Luckhurst, Consultant for the Holsworthy biogas project.

FIGURE 2.2: POTENTIAL CAPACITY AND LOCATION OF RENEWABLE NEW TECHNOLOGIES IN NORTHERN IRELAND IN 2010



2.9 Beyond 2010

The tidal power technical resource around the coast of NI is very large. There are companies in the UK who are due to commission demonstration projects during 2002. Trials are underway on several prototype generating machines. It is difficult to form a judgement on the contribution that tidal stream generators can make by 2010 and beyond because of the prototype nature of current developments.

Marine Current Turbines have an aggressive business plan which envisages installing several hundred MW of generators by 2010. The Engineering Business envisage installing 3 to 5 MW of generators by 2004, and quote a generation cost of between 4 and 14 p/kWh.

The widespread use of PV panels in NI depends principally on the economics of the installation. In addition, however, PV is a highly visible form of electricity generation with a ‘green image’ and has zero CO_2 emissions at the point of use. This may be a driving factor for consumers who wish to be associated with this image.

Currently generation costs are around 30p/kWh[5] for PV and so would need to reduce by a factor of six or more to become competitive with other renewable technologies. Projections of capital cost reductions depend on the market growth to achieve the required economies of scale. Based on the growth over the past 5 years, the costs of PV electricity when installed as a part of the original

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[5] Discussion with Dr Nicola Pearsall of the Newcastle Photovoltaic Application Centre, March 2002

structure of new buildings will close-in significantly on conventional electricity prices towards 2015 – 2020[6].

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[6] Photovoltaic (PV) Government –Industry Group Final Report (for DTI), 26 Mar 2001

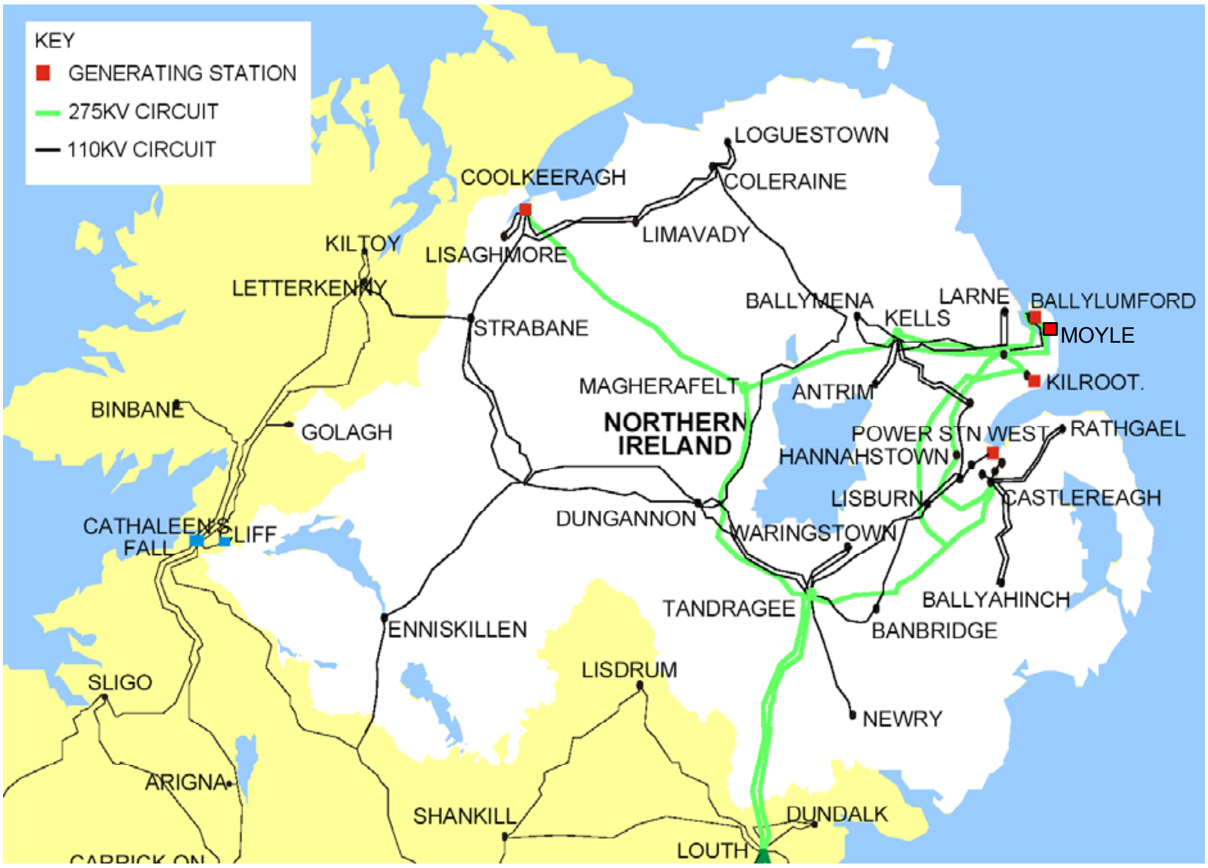
3. RESTRICTIONS ON RECOVERY OF RESOURCE

3.1 Connections to the transmission and distribution systems

3.1.1 Transmission system

The existing transmission system in NI comprises an interconnected network of 275 kV and 110 kV circuits owned and operated by NIE. The system is depicted in Figure 3-1 below.

FIGURE 3.1: NIE TRANSMISSION SYSTEM



Detailed analysis has been undertaken to assess the ability of the network to accommodate the power flows associated with increasing levels of renewable generation.

Analysis of the system was based on best available information regarding the likely system configuration, demand level and (conventional) generation make-up corresponding to the Year 2010 forecast condition. The work was based on computer models of the complete system, including all existing and expected conventional generating stations.

The analysis was undertaken in two parts:

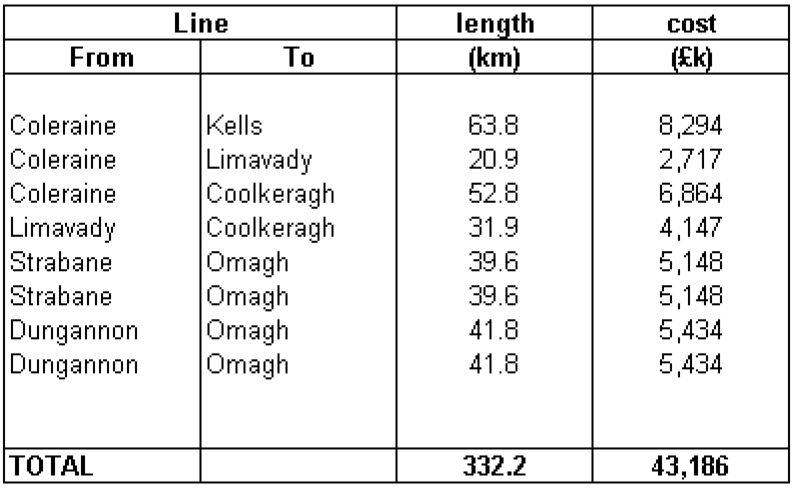
- assessment of potential generating capacity that could be accommodated at each of the 110 kV substations on the NIE system, without the need for system reinforcement.

- assessment of the effect on transmission system power flows with increasing levels of renewable generation.

Potential capacity for new generating capacity at 110 kV nodes: The analysis indicated that between 150-200 MW of new capacity in Winter and between 50-200 MW of new capacity in Summer could be connected to the 110 kV system, under the worst-case transmission outage conditions and without any reinforcement of the system. To remove this constraint in the Coleraine/Loguestown/Limavady area, the up rating of approximately 150 km of 110 kV overhead lines would be required at a cost of about £20-25m to accommodate significant new generating capacity.

Effect on transmission system power flows: Under certain (worst-case) 275 kV transmission circuit outage conditions, there is a constraint on the amount of power that may be exported from the Omagh/Coolkeeragh/ Coleraine area. This would apply to the thermal generating plant (460 MW) at Coolkeeragh also. At its most severe, and subject to dynamic analysis of the transmission system including wind generation, this could limit the amount of running generation in the area to about 550 MW under transmission circuit outage conditions. This constraint could be removed by up rating most of the 110 kV circuits in the area at a capital cost of about £40 – 45 m. The breakdown of these costs is presented in Table 3.1.

TABLE 3.1: ESTIMATED COSTS OF UPRATING 110KV LINES



Line		length	cost
From	To	(km)	(£k)
Coleraine	Kells	63.8	8,294
Coleraine	Limavady	20.9	2,717
Coleraine	Coolkeragh	52.8	6,864
Limavady	Coolkeragh	31.9	4,147
Strabane	Omagh	39.6	5,148
Strabane	Omagh	39.6	5,148
Dungannon	Omagh	41.8	5,434
Dungannon	Omagh	41.8	5,434
TOTAL		**332.2**	**43,186**

Summary: Analysis of the impact on system power flows of significant new renewable resources (up to 600 MW of distributed generation) indicates that transmission constraints may be experienced in the North and West of NI. To remove the constraints altogether would be costly, estimated at £40 - 45 M to up rate about 300 km of 110 kV transmission lines. These transmission costs have been included in the renewable energy cost curves as shown in Figures 5.4 to 5.5 although the alternative approach, subject to detailed investigation, could be to accept certain generation constraints in the North and West for certain specific transmission outage conditions.

Note

Systems reinforcement requirements have been reviewed by Northern Ireland Electricity since the completion of this work. It is now considered that with certain control and protection procedures, the envisaged level of renewables could be accommodated with the addition of an additional line between Coleraine and Kells at a cost of approx £10m.

3.1.2 Distribution system

The distribution system in NI has been designed to distribute power from the transmission grid supply points, at either 275 kV or 110 kV, medium voltage (MV) and low voltage (LV) customers. The change in use of the distribution system arising from generation connecting at MV or LV can cause equipment ratings and network operating limits to be exceeded. Operational restrictions and protective system modifications may be required. Such problems as will arise are surmountable, at a cost, by replacing and upgrading parts of the distribution system, by requiring the use of double-fed induction machines on wind generators and by using higher connection voltages for wind farms.

The likely costs of connecting renewable generation have been estimated, by reference to the generation location and proximity to the existing distribution infrastructure, and incorporated within individual renewable generation project costs.

3.2 Security and quality of supply

The effects of renewable sourced generation on security and quality of supply were reviewed in terms of spinning reserve requirements and the variability of wind generating capacity. From these the additional system costs associated with maintaining acceptable supply arrangements were determined.

3.2.1 Spinning reserve

Spinning reserve generation i.e. operational but only partly loaded generating plant is provided on most electrical power systems in order to avoid the need to shed demand in the event of a forced outage of an operating generator, the ‘spinning reserve’ plant being automatically instructed to increase its own output at such times. Typically, systems will be operated with sufficient spinning reserve to accommodate the loss of the largest single generator. Provision of specific reserve generation, to maintain system frequency between statutory limits and the need to respond to the sudden loss of a large generation unit, is generally a system-wide consideration. This is evident in Ireland by the bi-lateral arrangement between NIE and ESB to share ‘system reserve’, thereby reducing total system costs.

The connection of wind powered generation, with the consequential displacement of ‘conventional’ generation, impacts on the system frequency issues in two ways: Firstly, wind generators tend to be much lighter items of plant than ‘conventional’ generators, hence their displacement of conventional generation will result in a significant reduction in the total ‘system inertia’, thereby making the system more sensitive to any sudden plant loss. Secondly, in contrast to conventional generation, as the power output of wind generation is essentially determined by the available wind it is not able to increase its output in response to a sudden plant loss. As a consequence the ability of the system to respond to a sudden loss of plant will also be reduced.

Analysis was undertaken to determine the spinning reserve capability required to limit falls in system frequency to within acceptable levels under present conditions and with increased levels of wind generation. It was found that if wind generation simply displaced conventional plant, it was necessary to carry additional reserve equivalent to about 25 percent of the connected wind generation. This requirement applied under both maximum and minimum system demand conditions.

The finding outlined above is significant with respect to the amount of wind generation that can be safely accommodated on the system at certain times, particularly at times of low system demand, with the implication that at such times it may be necessary to constrain the levels of connected wind generation and/or carry additional part loaded conventional generation with associated implications on system operational costs.

3.2.2 Wind variability

Wind power was introduced to NI in the 1980s. Initially, the level of wind power generation in NI was small with only a few units connected to the grid. At that time the power production was viewed as ‘negative load’ and was essentially ‘lost’ in the normal uncertainty of short-term energy demand. As such, no additional operational control was required beyond the ‘normal’ balancing of demand with available generation. However, any significant increase in wind generation, due to its variability will add to the complex task of the system operator in balancing demand and supply.

As well as being dependent upon the wind itself, the intermittency and unpredictability of the wind resource is also a function of the number of turbines and the number and geographic location of wind farms. Analysis based upon Met Office wind records for NI indicate that if about 600 MW of wind generation were installed, variations in wind speed would cause changes in wind generation output of up to 100 MW over a one hour time period on a number of occasions each year.

3.2.3 System operating costs with intermittent wind power generation

The operating cost issues associated with the integration of wind essentially centre around the question as to what level of wind generation output should be assumed by the system operator and what are the resultant impacts on system costs and overall system security when the system is subject to out-turn levels of wind generation which will invariably differ from the original assumptions. The basic ‘system cost’ concern underlying this issue is that if the operator underestimates the actual out-turn wind generation then, in practice, more thermal generation plant may have been despatched than was necessary and as a consequence such plant will generally be operating at reduced output with a consequential loss of efficiency. Alternatively, if the operator overestimates the actual out-turn then, at times, additional higher cost open cycle gas turbine (OCGT) plant may need to be run in order to make up the shortfall.

In order to investigate the impact of intermittent generation on system operating costs we have undertaken an investigation of the practical operation and despatch of the NIE system under increasing levels of wind generation. This analysis has been informed by a generation ‘despatch optimisation' algorithm extended to take into account the uncertainties associated with integrating wind generation into the 'day ahead' and 'week-ahead' despatch planning.

This analysis has been undertaken for two operational scenarios, essentially relating to the determination of spinning reserve requirements and also operation of the 400 MW, Moyle HVDC link with Scotland.

a) In the first, and more conservative scenario it is assumed that:

    - the HVDC link is despatched on a 24 hour ahead basis, with its subsequent availability being determined by that despatch within the link's practical operating range, and

    - the NIE spinning reserve requirements, nominally 100 MW, applies irrespective of the levels of power import over the HVDC link. Under this scenario the allowable level of wind generation will be constrained by the availability of NIE spinning reserve capacity in line with the requirements outlined in 3.2.1 above, i.e. for 100 MW of wind generation to be operating, a total of 125 MW of spinning reserve capacity must be available to the system.

b) In the second 'Improved Moyle' scenario, it is assumed that

    - the HVDC link is operated essentially as a complement to the wind generation, with any variability in wind generation being accommodated by varying the level of HVDC link power[7] within the link's practical operating range, and

    - the nominal NIE spinning reserve requirement, nominally 100 MW recognises the inherent "zero inertia" nature of the HVDC link and hence, additional spinning reserve is only required when the sum of the HVDC link and wind generation output exceeds a nominal HVDC link capacity of 400 MW.

Under both scenarios, the analysis showed that, in the absence of accurate forecasting of wind generation output, the most prudent assumption the system operator can make is that day-ahead wind generation output will be zero. In essence, the down-side associated with having to despatch higher cost plant, due to being overly-optimistic with respect to the level of wind generation, dominates any complementary downsides associated with being unduly pessimistic and thereby despatching more than required higher merit, albeit thereafter only part loaded, plant.

The consequences of over-estimating the out-turn level of wind generation are quite significant, with total system despatch costs[8] more than doubling in extreme circumstances, due to a five-fold increase

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[7] This implies a transfer of some of the costs of accommodating wind variability onto the GB system.

[8] Despatch costs include fuel costs, operation and maintenance costs and costs associated with the installation of fast-response plant, e.g. open cycle gas turbines.

in the costs for open-cycle gas turbines (OCGT) burning high cost distillate fuel in comparison with combined cycle gas turbine (CCGT) units running on lower cost natural gas. The conclusion from this analysis is that when faced with any significant uncertainty with respect to the likely actual outturn levels of wind generation, the operator should always “day-ahead despatch” on the basis of zero expected wind. Such an approach also ensures that sufficient plant will always be available to meet the forecast demand, thereby ensuring security of supply.

The analysis demonstrated that with increasing installed wind generation, total system despatch costs will reduce. In essence, less fossil fuel will be consumed by thermal power stations partially displaced by the wind capacity. At certain times wind capacity causes thermal plants to operate less efficiently, as they are forced to operate at part load, whilst at other times the overall efficiency of the system is improved as wind energy displaces the less efficient plant that may have been scheduled simply to meet shorter term peaks in demand. However, due to the limited ability of the NIE system to accept wind generation within its demand profile and to maintain the requirements for the provision of spinning reserve which requires part loaded conventional generation to remain connected, the savings per-unit of wind generation capacity decrease as more wind generation is installed. The impact of additional wind generation capacity on operational costs has been determined by quantifying the operational costs associated with specific levels of wind generation and then combining these costs with the likelihood of that level of power output from the installed wind capacity.

Under the first operational scenario outlined above (a), the savings with 100 MW of installed wind capacity corresponds to about £4 million pa and with 450 MW to about £10 million pa. The incremental annual saving per kW of installed wind capacity therefore reduces from about £40/kW with 100 MW of capacity, down to about £5/kW with 450 MW of installed capacity. Under the second scenario (b), the wind generation is somewhat less constrained and the benefits of increased wind generation (in terms of reduced despatch cost) continue up to about 450 MW. This is because the assumed greater flexibility of operation of the HVDC link results in increased “headroom” with respect to system demand and also less restrictive spinning reserve requirements.

Expressed another way, the operational costs associated with accommodating wind generation increase significantly with increasing wind capacity such that they may eventually start to outweigh the benefits of the “free” energy associated with the wind generation. Also, as savings in operational costs are essentially an indication of the decrease in fossil fuel burn, it is also clear that the environmental benefits themselves are reducing with increasing wind capacity. Under the two modelled scenarios it is evident that at an installed wind capacity of approximately 150 MW, each incremental kilowatt hour of wind energy displaces approximately 1 kWh of conventional generation. As more and more wind capacity is added to the system the displacement of conventional generation reduces to below 0.5 kWh for each kilowatt hour of wind energy. This indicates that the incremental benefit to the environment at 600 MW of wind capacity can be less than half of that experienced at 150 MW. From this it can be concluded that at a certain (high) level of wind capacity there would be significantly less environmental benefit in adding any more capacity as there would be only limited displacement of conventional fossil fuel generation.

One way in which the environmental benefits, and hence the cost savings, can be increased is through improved wind generation forecasting accuracy. However, owing to the longer timescales associated with optimising despatch of the NI generation and the inherent variability of wind generation over these same timescales achievable benefits will be limited.

Summary: Extensive analysis of optimum plant despatch with significant wind generation penetration has been undertaken as part of the study. This has allowed broad conclusions on operating limits and system performance to be reached. It is recommended, however, that further work be undertaken in this area to confirm the results already obtained and to more carefully define the acceptable levels of wind generation that can be connected to the system.

Additionally, operation of the Moyle Interconnector is currently constrained by commercial agreements covering the allocation of capacity, particularly that portion of capacity that is dedicated to renewable generation. These commercial constraints, which apply in 2002, were not taken into account in the study, which was concerned with a situation likely to exist in 2010. Accordingly, the operating strategy discussed and described in this report may need to be adjusted in accordance with the commercial agreements relating to the use of the interconnector likely to be in place in 2010.

4. SUMMARY OF RESOURCE AVAILABILITY BY 2010

The potential capacity of renewable energy generation schemes in NI is 841 - 938 MW, made up as shown in Table 4.1.

TABLE 4.1
SUMMARY OF POTENTIAL RENEWABLE RESOURCES IN NORTHERN IRELAND

Resource	**Installed capacity MWe**
Onshore wind power	587 - 684
Offshore wind power	200
Total Wind Capacity	**787 – 884**
Landfill gas	9.1
Municipal and commercial waste	16.6
SRC willow	7.5
Wood and forestry residues	7.1
Poultry litter	5.8
Agricultural wastes	5.0
Sewage gas	2.6
Straw	0.0
Biofuels	0.0
Wave power	0.0
Tidal barrage	0.0
Tidal stream	To be separately studied0
Total Non-Wind Capacity	**53.7**
Total Renewable Capacity	**841 – 938**

5. EVALUATION OF RESOURCES AND PRESENTATION OF RESULTS

Previous studies into RE resources in NI, including those performed by ETSU and others[9],[10],[11] have investigated resources and identified technologies which could be utilised to exploit those resources. None of this earlier work, however, made forward projections for energy production likely to be realised in 2010 from renewable sources. Nor did it give any indication of the price/quantity relationship in respect of renewable energy production.

This study commenced with an evaluation of the gross (or 'technical') resource available from all renewables for electricity production; assessed how much of that resource, in terms of generating capacity, was capable of being connected to the existing electricity infrastructure in Northern Ireland and then calculated the fraction of that 'connectable' resource which could be assimilated in the supply system without adversely affecting existing security or quality of supply standards.

In order to present this information in a meaningful way, resources were identified on an individual site-by-site basis. Costs of energy production were calculated for each site taking into account:

- Fuel or feedstock costs.
- Capital cost of facility.
- Cost of operating and maintaining facility.
- Cost of connecting the facility to the grid, together with any network reinforcement costs.
- System operational costs (or savings).

The process adopted is illustrated diagrammatically in Figure 5.1.

5.1 Renewable energy costs

A key objective of this study has been to determine what price customers are prepared to pay for energy from renewable sources. The proposed value for the "acceptable price" for this study was 7 p/kWh. This figure is calculated on the basis of a current average price of electricity in Northern Ireland of 4p/kWh plus a renewable "premium" of 3 p/kWh. This latter figure is based on the level of the "buy-out" price set under the Renewables Obligation in Great Britain.

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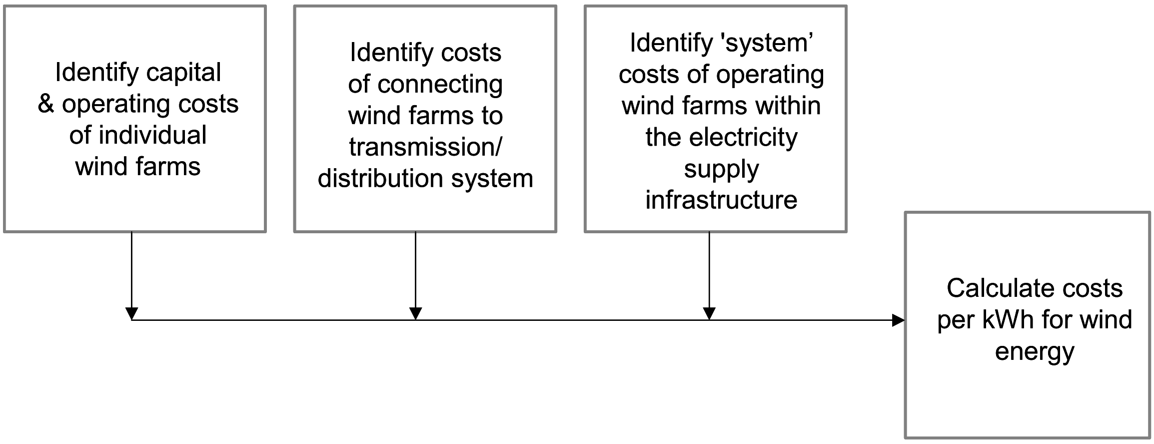
[9] 'New and Renewable Energy: Prospects in the UK for the 21st Century: Supporting Analysis', ETSU for DTI, March 1999.

[10] 'Renewable Energy in the Millennium, the NI Potential', ETSU for NIE and DED, June 1999.

[11] Prospects for Renewable Energy in NI, DED and NIE, July 1993.

FIGURE 5.1: PROCESS FOR CALCULATING COST OF ENERGY OUTPUT FROM WIND FARMS

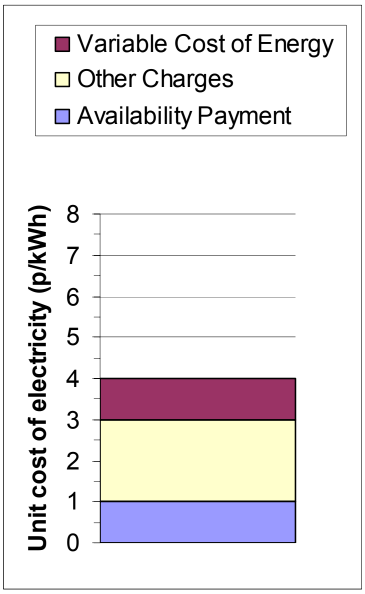


The current average price of 4 p/kWh is built-up from the following components:

- Existing availability payments to the incumbent thermal generators.
- The variable cost of despatch.
- Other supply charges including transmission and distribution charges and taxes etc.

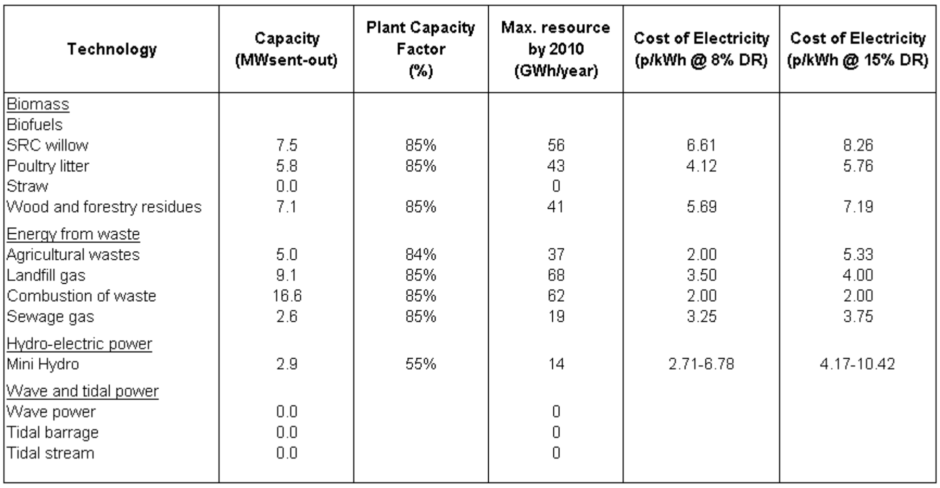
Estimates of these costs are presented in Figure 5.2. Until such time as the existing power purchase contracts expire (or are renegotiated) the costs of keeping thermal generation available will remain with the customer and will not be influenced by the degree of renewable generation development.

FIGURE 5.2: BREAKDOWN OF THE AVERAGE COST OF CONVENTIONAL GENERATION



The operating pattern of the various sources of RE generation were determined according to primary resource availability and technology and system operational constrains over a typical annual cycle to determine the cost per kWh of the electricity produced from each site. The results for non-wind renewable technologies are presented in Table 5.1.

TABLE 5.1: LIFETIME COST OF ELECTRICITY FROM NON-WIND RENEWABLE TECHNOLOGIES



Technology	Capacity (MWsent-out)	Plant Capacity Factor (%)	Max. resource by 2010 (GWh/year)	Cost of Electricity (p/kWh @ 8% DR)	Cost of Electricity (p/kWh @ 15% DR)
Biomass					
Biofuels					
SRC willow	7.5	85%	56	6.61	8.26
Poultry litter	5.8	85%	43	4.12	5.76
Straw	0.0		0		
Wood and forestry residues	7.1	85%	41	5.69	7.19
Energy from waste					
Agricultural wastes	5.0	84%	37	2.00	5.33
Landfill gas	9.1	85%	68	3.50	4.00
Combustion of waste	16.6	85%	62	2.00	2.00
Sewage gas	2.6	85%	19	3.25	3.75
Hydro-electric power					
Mini Hydro	2.9	55%	14	2.71-6.78	4.17-10.42
Wave and tidal power					
Wave power	0.0		0		
Tidal barrage	0.0		0		
Tidal stream	0.0		0		

The non-firm nature of the wind energy means that it needs special consideration in light of its impact on system operation. The non-firm capacity of wind is unlikely to generate any availability payments to wind developers. To remain successful in the market place therefore wind power will have to compete with the marginal cost of generation from the conventional thermal plant. From our extensive generation despatch exercise the average marginal cost in NI was found to be approximately 0.9 p/kWh with no wind capacity. This reflects the significant role of the Moyle Interconnector, the cost of energy transmitted across which is valued at 1 p/kWh.

It is assumed therefore that the average marginal market value for wind energy in NI will only be 1 p/kWh. From the revenue received for this energy and any green premium received, the developer and/or NI customer will have to cover the costs of capital investment, connection, operation and maintenance, plus any deep transmission reinforcement costs associated with that project[12]. Assuming that, over the long term, competition in the renewables market maintains an average green premium at 3 p/kWh[13] the average revenue from wind energy would be capped at around 4 p/kWh.

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[12] From Section 3.1 the main transmission constraint was identified in the North and North West of Northern Ireland. Under N-1 outage conditions the existing, committed wind developments plus 200 MW of new wind development could be accommodated without any deep reinforcement of the transmission system. Above this level of development the reinforcement costs are assumed to be shared equally amongst further capacity additions.

[13] Although trading of ROCs in the UK is forecast to range between 4 to 6 p/kWh in the medium term it was assumed that the potential for wind development in NI would keep the long term value at around the 3 p/kWh buy-out price.

The analysis of system operating costs with intermittent wind power generation, presented in Section 3.2.3, concluded that the incremental saving in generation despatch costs reduces from approximately 1p/kWh with lower levels of wind (circa 150 MW) to approximately 0.5 p/kWh at capacities up to 600 MW, as presented in Table 5.2. In essence the effective value (recognising the value of the green premium) of the wind energy has reduced from 4 p/kWh to 3.5 p/kWh. This indicates that the incremental benefit to the environment at 600 MW of wind capacity can be less than half of that experienced at 150 MW of wind capacity. In addition generation capacities much in excess of 400 MW could expect to be constrained at times of low system demand, with the level of constraint increasing with connected capacity.

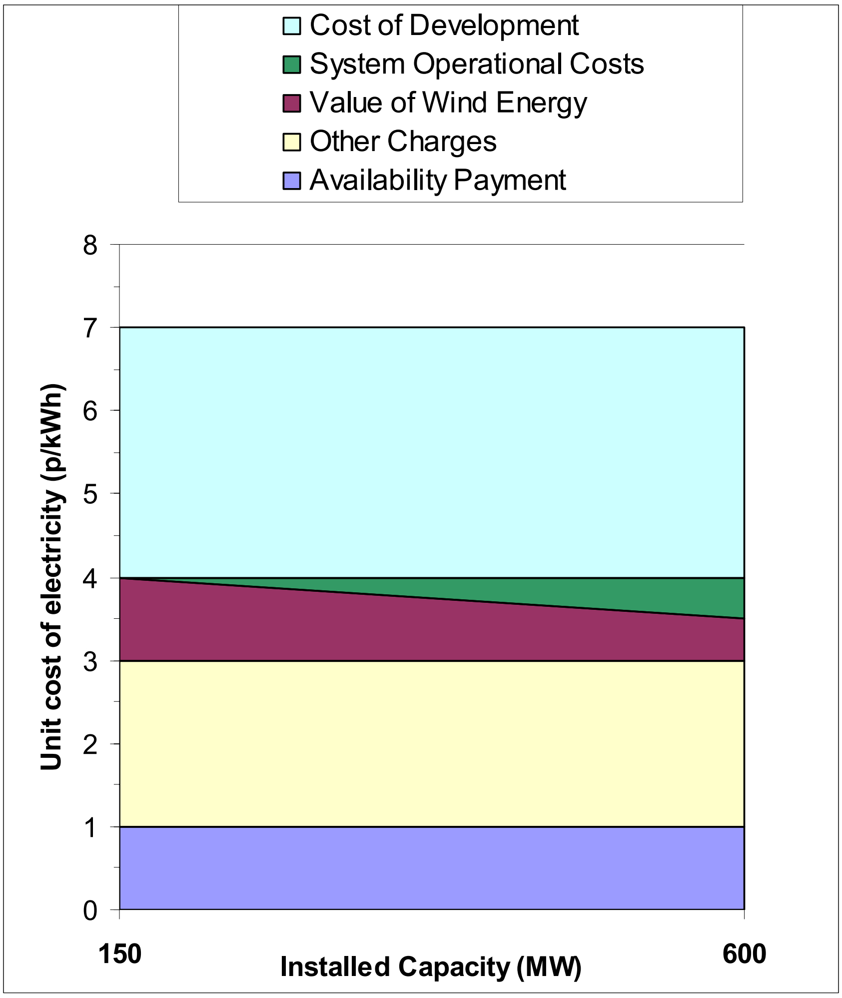
TABLE 5.2: INCREMENTAL GENERATION DESPATCH SAVINGS FROM WIND INSTALLED CAPACITY

Installed Wind Capacity (MW)	Specific generation cost savings (p/kWh)	
	Scenario (a)	Scenario (b)
100	1.36	1.70
150	0.73	1.40
200	0.43	1.10
250	0.34	1.05
300	0.41	0.96
350	0.25	1.02
400	0.18	0.91
450	0.16	0.99
500	0.13	0.97
550	0.11	0.86
600	0.10	0.73

In response to the question of what amount of renewable energy (in this case wind) can be supplied at an acceptable cost to the customer (i.e. 7 p/kWh) the answer is determined by those projects which have development costs below 4 p/kWh for initial tranches of wind power development falling to 3.5 p/kWh at higher capacity levels. The reduction in value is caused by the present mix of thermal generation plant and the requirement to schedule such generation several hours ahead of need, coupled with the variability and uncertainty associated with wind generation output levels.

This conclusion is illustrated in Figure 5.3. Of the 7 p/kWh maximum cost to the consumer the first three pence represent the availability payments to conventional generation plus other supply charges. Regardless of the source of electricity supplied to the customer these costs will still be paid for each unit of energy. The next penny represents the combined value of wind energy and the additional system costs associated with increased wind capacity. On average the sum of these should remain below 1 p/kWh, otherwise conventional generation would be despatched in preference to wind power. Sitting above these costs is the 3 p/kWh green premium from which all development costs for the project will need to be recovered.

FIGURE 5.3: AVERAGE COST OF GENERATION WITH INCREASED INTERMITTENT CAPACITY



Figures 5.4 and 5.5 present the estimated cost of wind energy for various increments of onshore wind capacity development at discount rates of 8 per cent and 15 per cent. These rates represent the limits of typical discount rates assumed for renewable energy power projects. The data presented includes the costs of capital investment, connection, operation and maintenance, any deep transmission reinforcement cost associated with that project plus the incremental cost saving from the displacement of conventional generation. The charts are based upon calculations, an example of which is presented in Table 5.3. Recognising that the system operational savings are built into the charts, and hence that they reflect the energy value assigned to the wind energy, the magnitude of wind capacity acceptable in NI is set by the green premium of 3 p/kWh. From the charts it is clear that depending upon the discount rate assumed the range in possible capacities is large. At an 8 per cent discount rate between 360 MW and 600 MW of installed capacity may be developed. At the higher discount rate of 15 per cent, values drop significantly to between approximately 200 MW to 320W.

FIGURE 5.4: INCREMENTAL COST OF ONSHORE WIND ENERGY AT 8 PER CENT DISCOUNT RATE

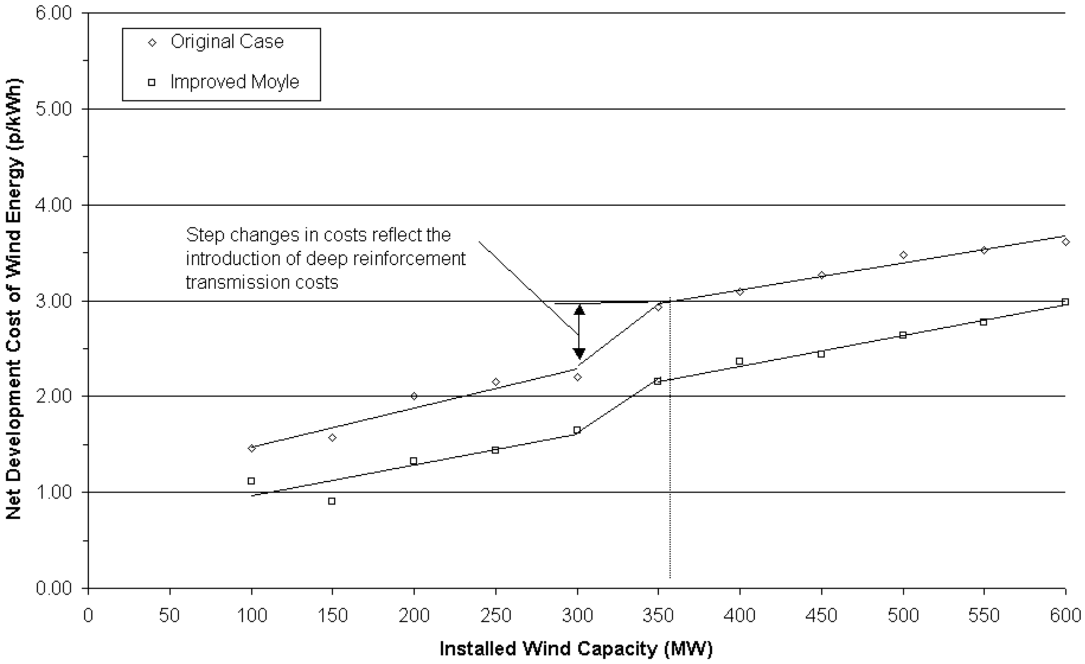


FIGURE 5.5: INCREMENTAL COST OF ONSHORE WIND ENERGY AT 15 PER CENT DISCOUNT RATE

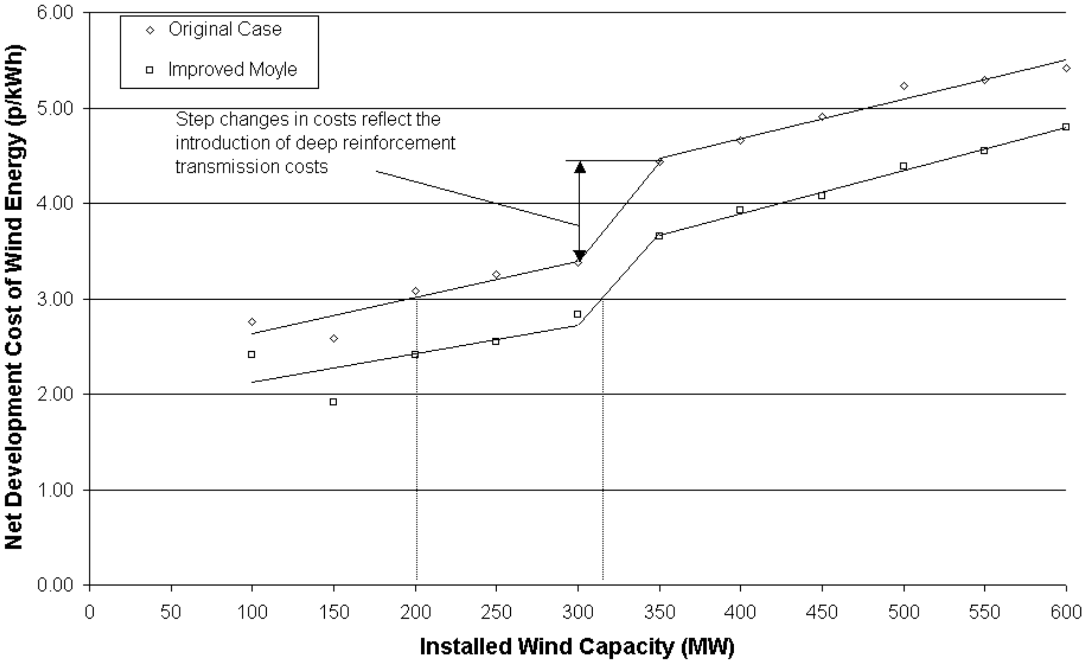


TABLE 5.3: TOTAL SPECIFIC COSTS FOR INSTALLED WIND CAPACITY (8 PER CENT DISCOUNT RATE AND MODELLING SCENARIO A)

Capacity (MW)	Energy (GWh/yr)	Incremental Energy (GWh/yr)	Average Capacity Factor (%)	Specific Capital Costs (p/kWh)	Deep Transmission Reinforcement Costs (£m)	Capitalised Transmission Costs (£m/yr)	Specific Transmission Costs (p/kWH)	Incremental Cost Saving (£m/yr)	Incremental Generation Cost Saving (p/kWh)	Total Costs (p/kWh)
100	337	337.24	38%	2.82	0.00	0.00	0.00	4.57	1.36	1.46
150	507	170.05	39%	2.30	0.00	0.00	0.00	1.24	0.73	1.57
200	709	201.40	40%	2.43	0.00	0.00	0.00	0.86	0.43	2.00
250	913	204.55	42%	2.49	0.00	0.00	0.00	0.70	0.34	2.15
300	1096	182.50	42%	2.61	0.00	0.00	0.00	0.75	0.41	2.20
350	1260	164.66	41%	2.73	7.17	0.73	0.44	0.40	0.25	2.93
400	1440	179.68	41%	2.86	7.17	0.73	0.41	0.32	0.18	3.09
450	1604	163.74	41%	2.98	7.17	0.73	0.45	0.26	0.16	3.26
500	1751	146.76	40%	3.11	7.17	0.73	0.50	0.20	0.13	3.48
550	1903	151.96	39%	3.16	7.17	0.73	0.48	0.17	0.11	3.53
600	2042	139.49	39%	3.19	7.17	0.73	0.52	0.15	0.10	3.61
Total					43.00	4.38				

The information obtained in this way can also be presented in the form of histograms (Figures 5.6 to 5.9) showing the total amount of energy available (GWh) at a particular cost (p/kWh) from the available resources at discount rates of 8 per cent and 15 per cent.

In relation to the charts the following should be noted:

a. The costs shown represent the costs of production at the point on the existing grid system where the resource is connected. No allowance for 'use of system charges', which would include the cost of delivering the energy to the end consumer, have been included in their calculation.

b. Figures 5.6 and 5.7 are compiled assuming the potential cost savings from the first and more conservative generation despatch scenario described in Section 3.2.3. Figures 5.8 and 5.9 are compiled assuming the potential cost savings from the 'Improved Moyle' generation despatch scenario, which can be seen as the upper limit, or most optimistic of the modelling.

c. Cost savings of 2 p/kWh were applied to the lifetime costs presented in Table 5.1 for the non-wind renewable technologies. This comprises 1 p/kWh saving in despatch cost as assigned to the initial tranches of wind generation plus an additional 1 p/kWh to represent the availability payments such reliable technologies may expect to receive.

d. Offshore wind power is assumed to be the first significant tranche of wind generation to be developed.

The results of this part of the analysis indicate that energy from renewable sources in Northern Ireland may range from approximately 6.7 to 9.5 per cent of the forecast electrical demand by 2010 at an 8 per cent discount rate and from 16.3 to 27.4 per cent of this forecast at a discount rate of 15 per cent. The results under the 'Improved Moyle' scenario are deemed to represent the most optimistic scenario whereby near perfect wind output forecasting and fully flexible short term despatch is possible. In reality actual workable values may be somewhat lower than the values presented as the effective cost per kWh of wind generation in excess of 400 MW (equivalent to approximately 1400 GWh) will tend to increase due to constraints on wind generation at times of reduced system demand. This effect is not fully reflected in Figures 5.6 to 5.9 below, hence the actual out-turn energy which can be generated at a cost of 3 p/kWh or less (and delivered to the customer at 7 p/kWh or less) would be somewhat reduced.

FIGURE 5.6
ENERGY PRICE QUANTITY RELATIONSHIP 8 PER CENT DISCOUNT RATE WITH FIRST GENERATION DESPATCH SCENARIO

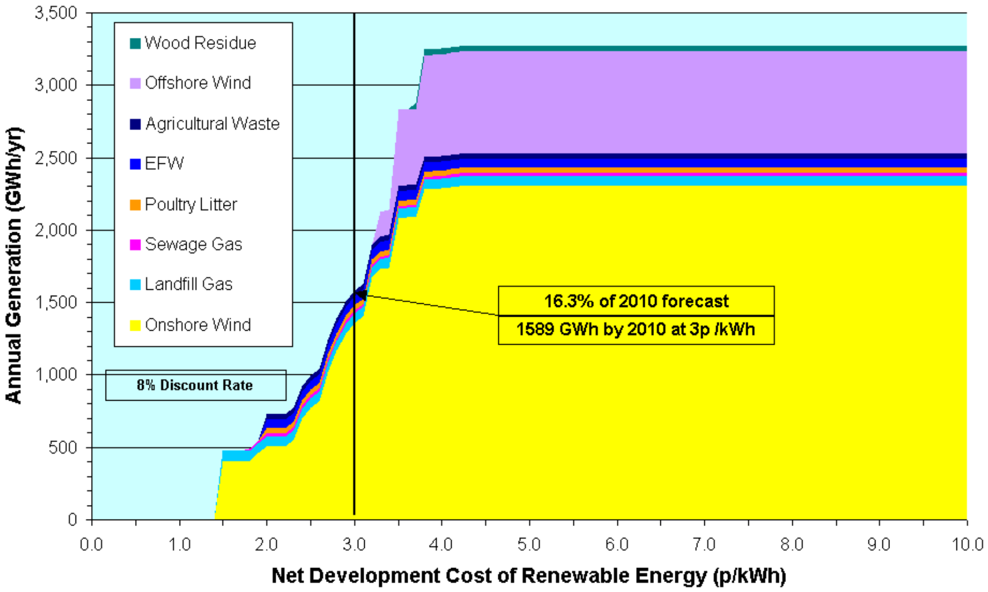


FIGURE 5.7
ENERGY PRICE QUANTITY RELATIONSHIP 15 PER CENT DISCOUNT RATE WITH FIRST GENERATION DESPATCH SCENARIO

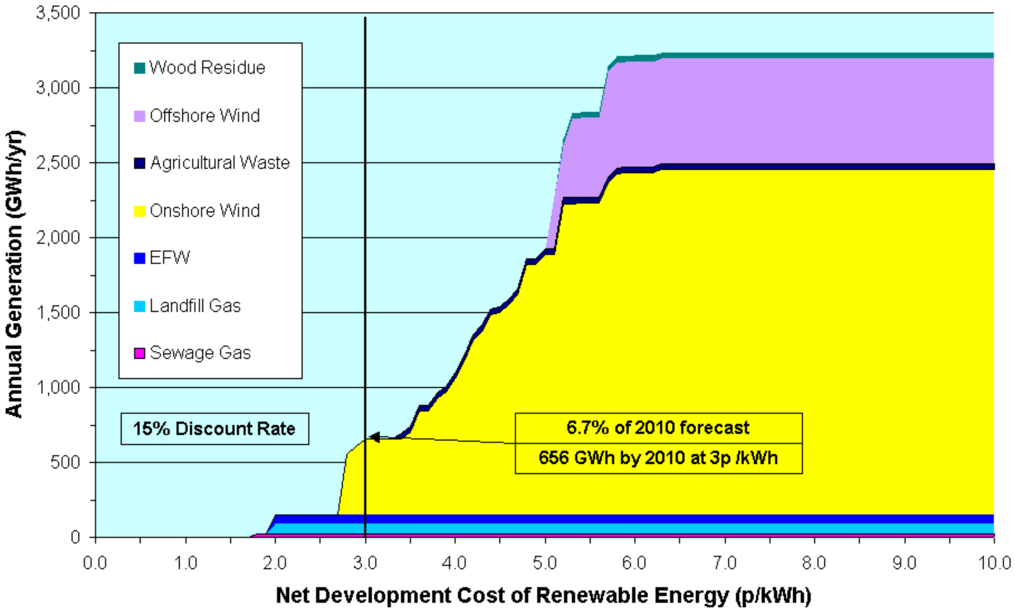


FIGURE 5.8
ENERGY PRICE QUANTITY RELATIONSHIP 8 PER CENT DISCOUNT RATE WITH 'IMPROVED MOYLE' GENERATION DESPATCH SCENARIO

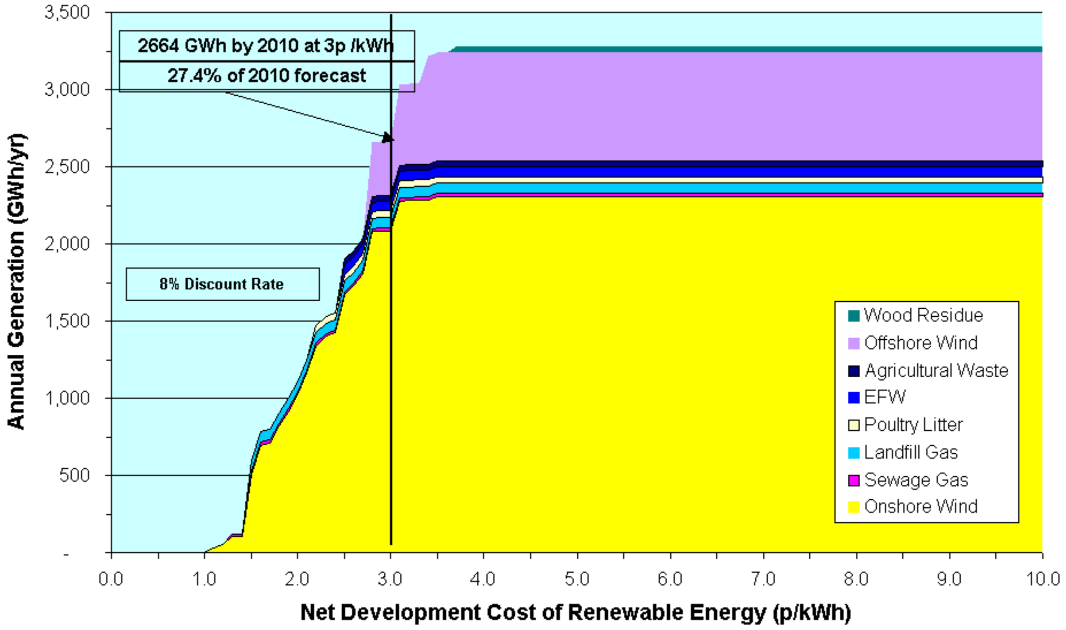
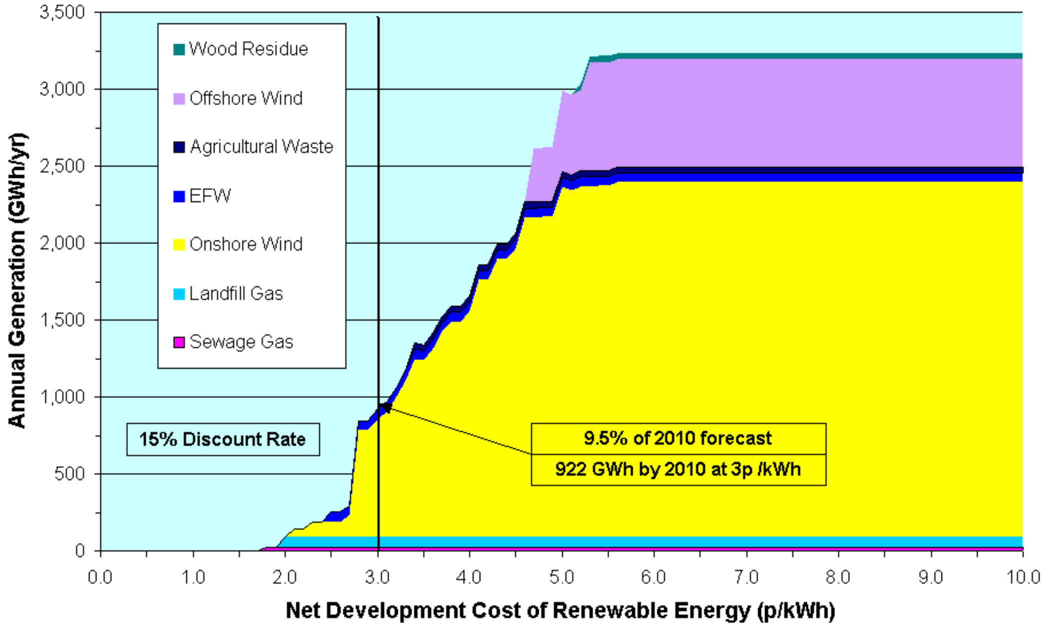


FIGURE 5.9
ENERGY PRICE QUANTITY RELATIONSHIP 15 PER CENT DISCOUNT RATE WITH 'IMPROVED MOYLE' GENERATION DESPATCH SCENARIO



It is important to recognise that our analysis suggests that only at the lowest discount rate of 8 per cent, and assuming an 'Improved Moyle' despatch scenario, can any of the energy from the proposed offshore wind farm be developed at a price of less than 3 p/kWh at the point of connection to the system. This is because of the assumed higher capital costs of offshore wind generation compared to onshore sites. If in reality the whole of the offshore wind farm can not be developed at an acceptable price then alternative schemes may need to be considered. However, this analysis doesn't recognise the social benefits which offshore wind farms offer in terms of visual impact on the environment. On the other hand, were the offshore wind farm not to be developed, alternative onshore wind farms may replace this capacity and supply energy at a cost of less than 3p/kWh.

The study has demonstrated how contributions to energy production in NI from the different renewable technologies could vary according to their cost which will be influenced by the discount rate assumed in the cost calculations and the actual generation despatch. These effects are illustrated in Table 5.4 below which illustrates how different technologies will make different contributions.

TABLE 5.4
RENEWABLE CAPACITY (MW) PROVIDING ENERGY
AT A PRICE OF ≤ 7 p/kWh

	First Despatch Scenario		**Second Despatch Scenario**	
	Discount Rate		**Discount Rate**	
Generation type	**8%**	**15%**	**8%**	**15%**
Wind	360	200	600	320
Landfill gas	9.1	9.1	9.1	9.1
Energy from waste	8.3	8.3	8.3	8.3
SRC	Marginal	Marginal	Marginal	Marginal
Wood residue	Marginal	Marginal	Marginal	Marginal
Poultry litter	5.8	Marginal	5.8	Marginal
Agricultural wastes	5.0	Marginal	5.0	Marginal
Sewage gas	2.6	2.6	2.6	2.6
Total Renewable Capacity (MW)	**390.8**	**220**	**630.8**	**340**

5.2 Total annual cost of renewable energy

The added unit cost of providing electrical energy from renewable sources is effectively the cost of the green premium, which for this study was assumed as 3p/kWh in 2002. The total annual cost to the NI customers is simply the product of the total energy from renewable sources and the unit cost of the green premium. Table 5.5 presents an estimate of the increase in total annual costs by 2010 at the two discount rates of 8 and 15 per cent. The rate of growth in costs to the level presented will be dictated by the rate at which renewable power projects are developed in Northern Ireland.

One of the key objectives of this study was to assess what contribution NI could make to the overall UK target of 10.4% of electricity generation from renewable sources by 2010. So far in this report the end consumer is assumed to be the NI customer. However, it is clear from the magnitude of costs presented above that if the full resources for renewable energy were developed it would place an unreasonable burden on the Northern Ireland consumer[1]. The introduction of a Renewable Obligation which would allow trading of Renewable Obligation Certificates (ROCs) within the UK as a whole would provide the necessary platform for the realistic and successful development of renewable power projects in NI through the sharing of costs with GB customers. This approach is promoted in the DETI's Consultation Document on the Draft Energy Bill (June 2002).

At present the Renewables Obligation Order 2002 in England and Wales only permits ROCs to be issued to NI generators if the renewable energy actually flows into the GB system (via the Moyle Interconnector) to serve GB customers. This policy seems likely to stifle renewable energy development in NI as competition in conventional generation from GB will ensure that the net energy flow over the Moyle is from GB into Northern Ireland. Therefore, without a change in the existing legislation to essentially allow for energy flow superposition, the contribution of NI renewable generators to the UK target is likely to be capped at the level of demand for renewable energy in NI, which will ultimately be dictated by the increase in annual electricity bills Northern Ireland's customers are prepared to pay.

TABLE 5.5: INCREASE IN TOTAL ANNUAL COST OF ELECTRICITY FOR NORTHERN IRELAND

		First Despatch Scenario		**Second Despatch Scenario**	
		Discount Rate		**Discount Rate**	
	Units	**8%**	**15%**	**8%**	**15%**
Annual Energy from Renewable Sources	GWh	1589	656	2664	922
Installed Capacity	MW	391	220	631	340
Green Premium	p/kWh	3	3	3	3
Total Annual Cost	**£million**	**47.67**	**19.68**	**79.92**	**27.66**

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[1] For example if 25% of NI energy was delivered at 7p/KWh this would increase average electricity bills by 16% by 2010.

6. CONCLUSIONS

The study has considered the available resources in NI for renewable energy production in considerable detail. Reference to earlier work carried out for DETI has been made during the course of the work and no major disagreements between that study and the outcome of this study have arisen.

The major resource available for electricity production is wind energy, mainly onshore but with a significant offshore potential also. Simulations of normal system operation of the NI electricity system over the course of a typical day at different times of the year have shown that a major contribution to electrical energy supply in Northern Ireland can be expected from wind farms.

A much smaller contribution arises from other renewable resources.

Assuming that the normal consent processes for electricity generation schemes are followed, and that no significant delays occur in the planning process, the most optimistic estimate of the contribution of energy from renewable sources to electricity supply in Northern Ireland, at a price to the end customer of 7 p/kWh or less, is 922 to 2664 GWh/yr by 2010. This represents between 9.5 and 27 per cent of forecast electricity demand at that time (9 700 GWh/yr). The annual cost of providing this amount of renewable energy will rise to between £28m and £80m by 2010 (2002 prices) with the rate of growth dictated by the rate at which renewable power projects are developed in Northern Ireland. It is also dependent on the implementation of appropriate legislation which would allow the costs of harnessing energy from renewable sources in NI to be shared with GB customers through the trading of ROCs.