ALL ISLAND GRID STUDY

STUDY OVERVIEW

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Study Overview

The All Island Grid Study is the first comprehensive assessment of the ability of the electrical power system and, as part of that, the transmission network ("the grid") on the island of Ireland to absorb large amounts of electricity produced from renewable energy sources. The objective of this five part study is to assess the technical feasibility and the relative costs and benefits associated with various scenarios for increased shares of electricity sourced from renewable energy in the all island power system.

Study Methodology

Six generation portfolios were selected for investigation comprising a range of different renewable and conventional technologies in varying compositions. The assessment considers certain elements of cost and benefit for a single year (2020). Specialist consultants with relevant expertise for each area carried out a screening study, a resource assessment, a dispatch study, and a network study, which provided information for assessment in the cost benefit study. A high-level interaction of the various studies, referred to as work streams, is outlined in the following figure.

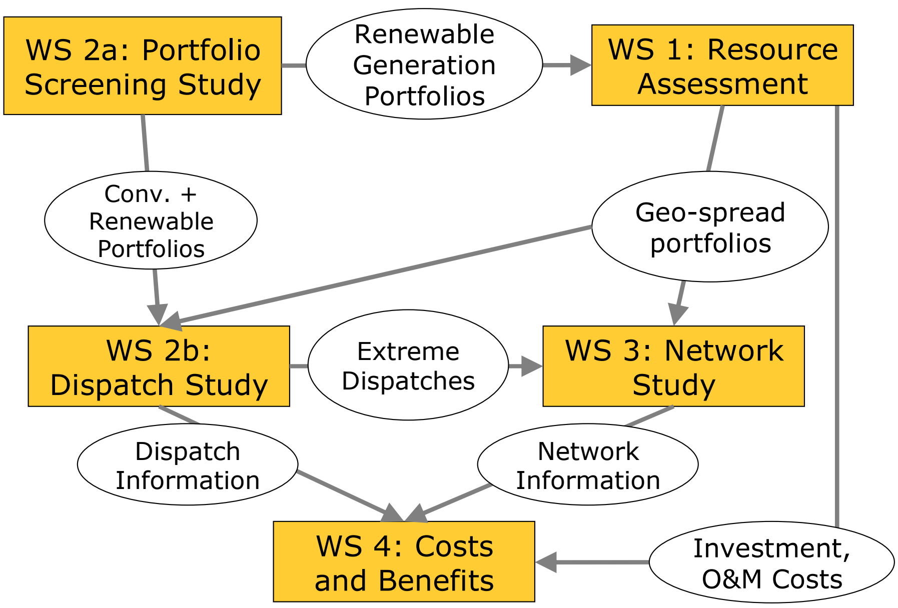


Figure E-1: Work streams of the Study and their interactions

Work stream 2A selected the portfolios of generation to be examined in the remaining work streams using a linear programming optimisation model with a simplified treatment of dispatch and network issues to produce least cost generation portfolios over a wide range of cost scenarios for fuel, carbon, renewable resource, conventional generation, and network reinforcement requirements. The portfolios selected cover a range of renewable energy penetration with renewable electricity providing from 17% to 54% of energy demand in portfolios 1 to 6 respectively. These were subsequently adjusted in work stream 2B to ensure a comparable level of system security across all portfolios.

The six portfolios were then populated by specific renewable generation projects through the resource study analysis in **work stream 1**. This study included the establishment of resource cost curves for each technology using cost assessments including investment and both fixed and variable operating costs. Investment costs included the cost of network connection to the closest connection point on the 110 kV network. The population of the renewable generation for each portfolio gave priority to those projects that had already submitted applications for grid connection or had received planning permission. The remainder of the allocation was based on least cost projects as identified on the resource cost curve. A spatial allocation of all generation plants and the costs of energy for each renewable project were provided to work stream 2b and work stream 3, and the renewable generation costs were a key input to work stream 4.

Work stream 2B used a scenario tree tool to provide continuous forecast scenarios of wind power, load, forced outages and required reserves for the year 2020. Based on the forecast scenarios a scheduling model minimised the expected operating costs across the portfolios. The model provided dispatch information on all plants for the year 2020 for each portfolio considered, including fuel consumption, volume of reserve provision, electricity imports and exports, and CO_2 emissions. A number of assumptions made in this study are important to any interpretation of the results, including: the dispatch assumed no network restrictions because iteration between the work streams was not possible; total interconnection to Great Britain was assumed to be 1000MW; 100MW of interconnection was assumed available for spinning reserve; CO_2 costs were assumed to be €30/tonne and gas costs assumed are €22/MWh thermal.

Work stream 3 used the spatial allocation of the generation portfolios provided by **work stream 1** to assess the extent and cost of the required additional network development to accommodate the renewable generation in the different portfolios. Specific dispatches representing winter peak, summer maximum and summer night valley, with high and low wind generation were used to test the load flow simulations. Some additional dispatches from work stream 2B were also considered. The network development was done initially with a DC load flow model and then refined with an AC model to address voltage and reactive power issues[1]. The study methodology incorporated a number of limitations that should be

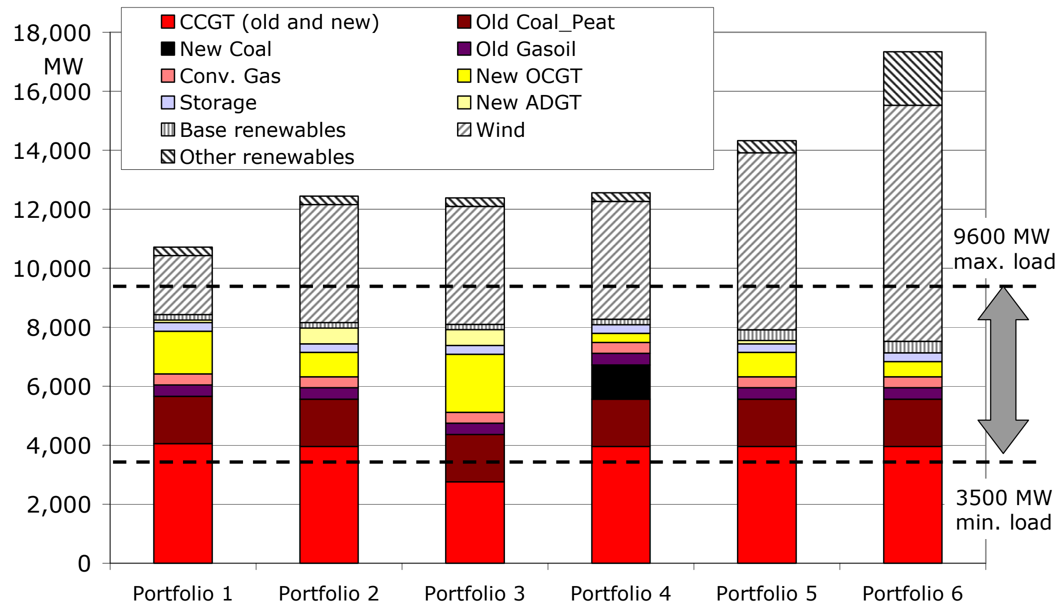
[1] "A D.C. (Direct Current) load flow model is a simplified computational model for network analysis which simulates direct current electricity flow within the modelled electricity network to initially establish the direction and magnitude of power flows and estimate the required conductor sizes. A more complex A.C. (Alternating Current) network model is then applied to simulate the actual operation of the system under steady state conditions, allowing accurate assessment of power flows and selection of the required network components."

noted by the reader, namely: the network developed allowed for the unexpected loss of a *single* transmission line at any one time but did not include provision to take lines out of service for maintenance, which may have understated the required instances of generation constraint; the studies were steady-state calculations meaning dynamic issues such as frequency stability and transient stability were not considered, which may have understated dispatch restrictions, resulting in an underestimation of operational costs, required wind curtailment, and CO_2 emissions.

Work stream 4 analysed the information provided from each of the previous work streams to present a comparison across the portfolios of the various costs and benefits identified. The work stream included a stakeholder analysis of the key stakeholder classes across the electricity sector: conventional generators, renewable generators, network operators and owners, system operation and interconnector operation. The key findings from the previous work streams in relation to each stakeholder group were discussed and quantified in cost and benefit terms where the Study scope and methodologies facilitated such quantification. The costs examined in relation to electricity generation for all stakeholder classes were then aggregated to provide a relative cost comparison across generation portfolios. It is critical to note that work stream 4, as well as work stream 2B, abstracted from real-world market designs, i.e. the study assumed market and support mechanisms without imperfections and a strictly marginal cost pricing principle.

Results and Conclusions

Portfolios selected (results of work stream 2A)



Share of renewable capacity	23 %	36 %	36 %	36 %	47 %	59 %

Figure E-2: Composition of 2020 generation portfolios, renewable share of total installed **capacity**

Work stream 2A assumed that approximately 1,800 MW of the existing generation units will be retired by 2020. The figure above shows the installed capacities of conventional generation (solid areas) and renewable generation (hatched) in the 2020 scenario. The term “base renewables” characterises all renewable technologies capable of contributing to base load such as biomass or biogas plants. “Other renewables” comprises wave and tidal energy.

Portfolios 2 to 4 vary the amounts and technologies used to satisfy the requirement for new conventional generation with the same amount of renewable generation: Portfolio 2 uses a large proportion of combined cycle gas turbines; Portfolio 3 uses a large proportion of open cycle gas turbines and aero-derivative gas turbines; Portfolio 4 uses a new large coal plant. The amount of renewable generation across the portfolios is as follows:

- Portfolio 1 – 2000MW wind energy, 182 MW base renewables, 71MW additional variable renewables
- Portfolios 2 to 4 – base and variable renewables as in Portfolio 1 but increasing to 4000MW wind energy
- Portfolio 5 – 6000MW wind energy, 360 MW base renewables, 285MW additional variable renewables
- Portfolio 6 – 8000MW wind energy, 392 MW base renewables and 1685MW variable renewables.

These portfolios are used throughout the remainder of the work streams in the All-Island Grid Study (the Study).

Portfolio 6

In the course of the analysis of the dispatch and the network implications, portfolio 6 exceeded the limitations of the methodologies applied. In the dispatch study a significant number of hours characterised by extreme system situations occurred where load and reserve requirements could not be met. The results of the network study indicated that for such extreme renewable penetration scenarios, a system re-design is required, rather than a reinforcement exercise.

At this point, the determination of costs and benefits had become extremely dependent on the assumptions made for extreme situations, which adversely affected the robustness of the results. As a consequence, throughout the Study, results of portfolio 6 were only included for illustrative purposes in selected circumstances.

Geographic distribution of generation and renewable energy investment costs (results of work stream 1)

The figure below shows the geographic spread of wind energy in key zones. At the level below this graph, wind energy projects are mapped on a grid of 200 metre spacing for analysis of outputs based on wind speed mapping, and transmission system planning as well as connection costs based on distance to the nearest 110kV connection point.

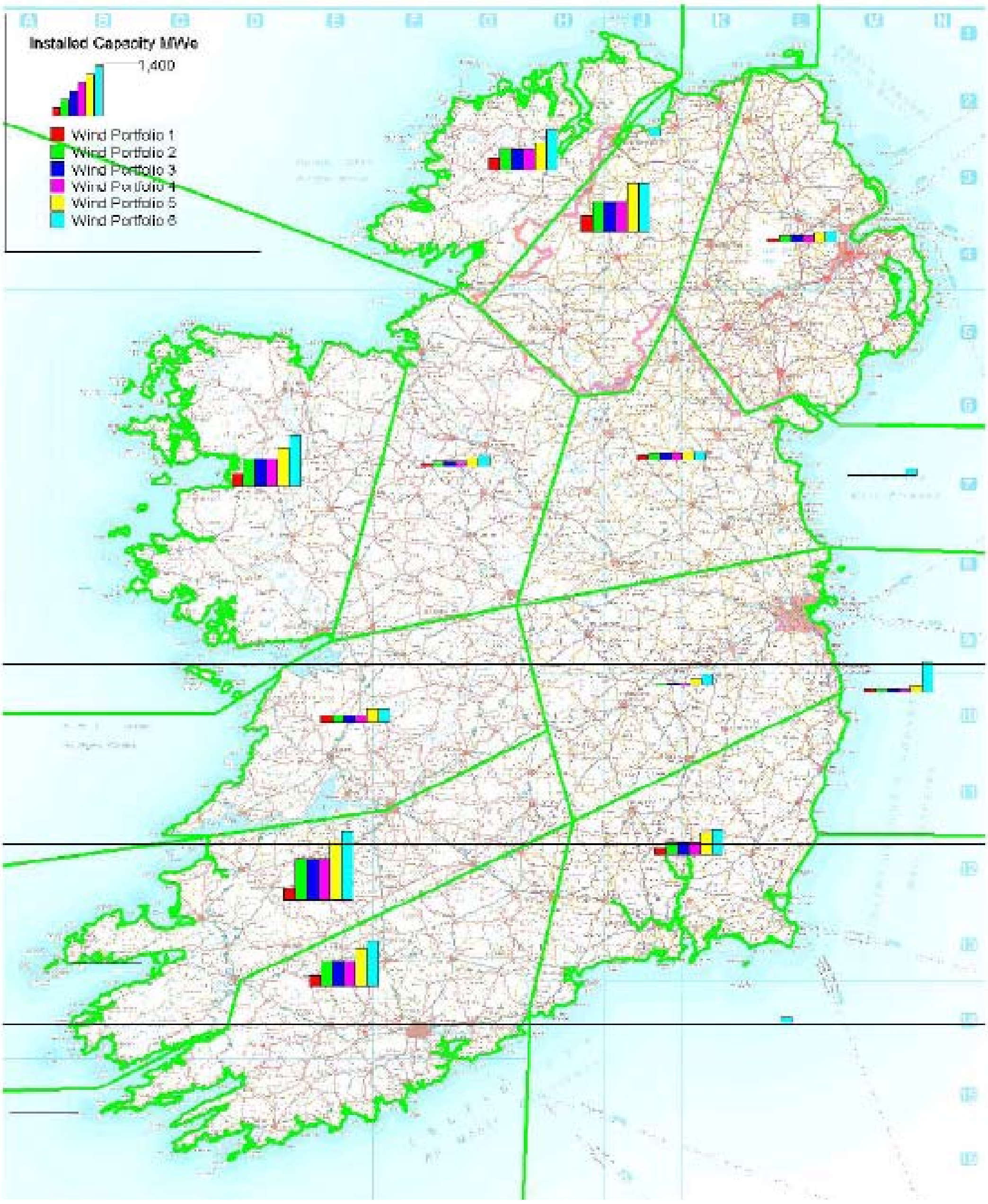


Figure E-3: Illustration of wind generation zones for installed wind capacity defined in work stream 1 and used in the study

Similar geographic distribution information was prepared for the other renewable energy technologies. This information is a key contribution to the network development study in work stream 3, and to the scenario tree tool used in work stream 2b for determining the power output from all variable renewables to feed in to the scheduling model.

Work stream 1 also generated levelised cost curves for each technology. The levelised cost represents the total discounted capital and operating cost divided by the total output in kWh over the life of a project, estimated using cost and interest rate assumptions and power output estimates derived from existing resource maps. The result represents the average price a renewable generator would have to receive, in euro per kWh, for power produced to make an assumed amount of profit[2]. The levelised cost curve ranks projects by their levelised cost. For the Study, the levelised cost curves included existing and new renewable projects. Renewable projects in each portfolio were selected on the basis of the levelised cost rankings except where preference was given to projects with planning permission and grid connection contracts regardless of their levelised cost ranking. An example of the levelised cost curves generated is shown below.

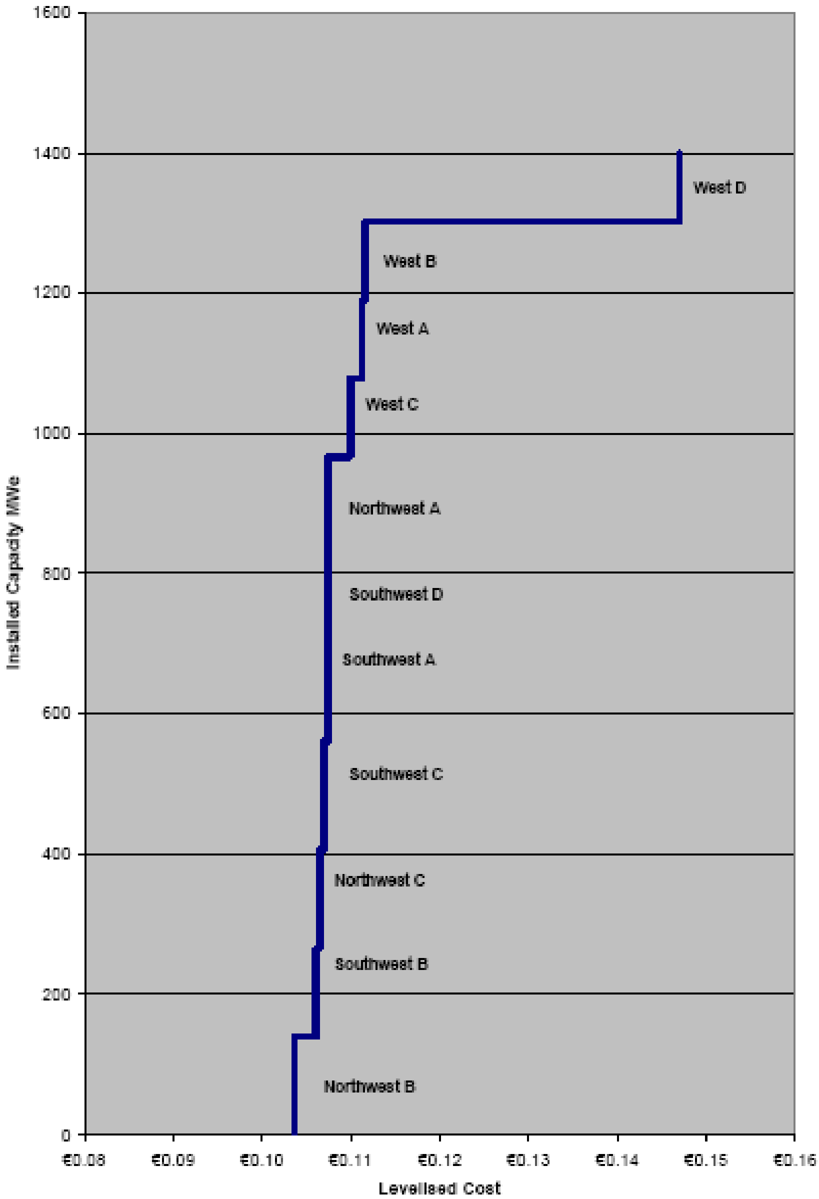


Figure E-4: Levelised cost curve (€/kWh) for wave energy projects deployed in 11 locations along the west coast

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[2] Assumed profit was based on an 8% weighted average cost of capital for the Study.

The same cost information as used in the levelised cost calculations was used to calculate the total investment cost for existing and new renewable projects included in the portfolios. This information is annualised for inclusion in the overall results of work stream 4.

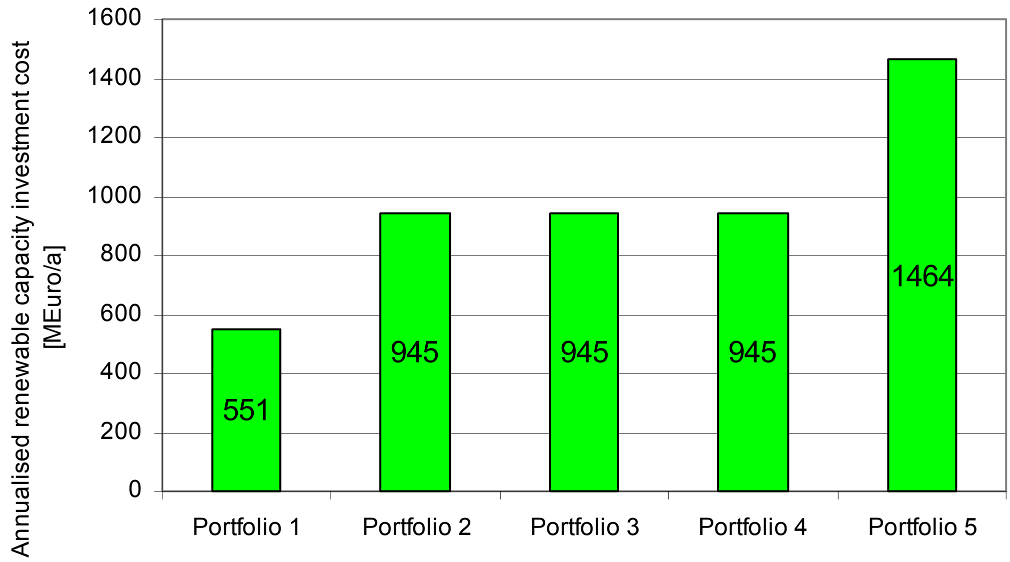

Figure E-5: Renewable energy investment cost annualised

Dispatch results: revenues and short term costs for conventional generators, and CO_2 reduction benefits (results of work stream 2b)

The dispatch model produced hourly dispatches with associated operating costs in each period. The figure below shows the total fuel cost, cost of carbon, and net import payments for the year 2020 resulting from the dispatch of conventional generators, divided by the total hours demand for the year[3]. Note that fuel costs for bio-energy projects are included in the renewable energy investment cost figures above and not in the fuel cost figures below.

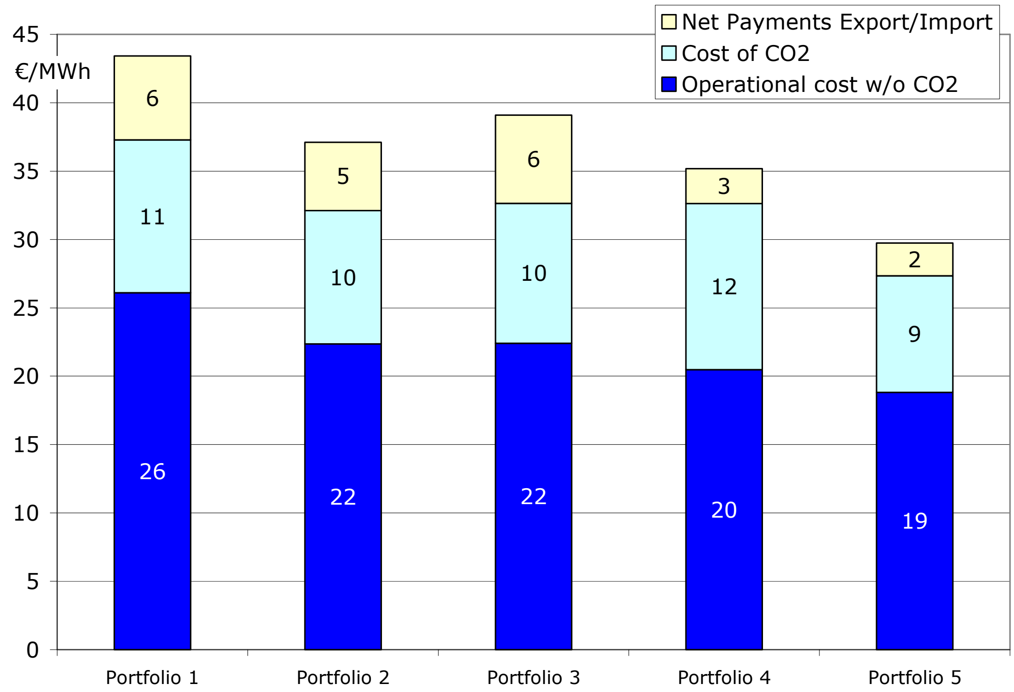

Figure E-6: Total operational costs of power production in the All Island power system, including payments related to power exchange with Great Britain[4]

At higher proportions of renewable capacity installed, less conventional capacity is required to run and thus the operational cost decreases. The difference of operating cost between the portfolio with the highest cost (portfolio 1) and the lowest cost (portfolio 5) is about 30 % or €740 million. The variance in fuel cost, carbon emissions and imports required in portfolios 2 to 4 are a result of the various new conventional generation mix technologies employed.

The dispatch model also produced hourly system marginal prices, reflecting the operating cost of the most expensive generator called on to dispatch during the period. The resulting weighted average price varied from €51/MWh to €61/MWh across portfolios 1 to 5. The dispatch results are used in work stream 4 as a proxy market price to consider the revenues possible for energy output for the different types of generators operating in the market. It is important to note that this is only a proxy and modelling a real market price would require modelling a market, which was out of the scope for this study.

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[3] Note that other variable operating costs, such as variable maintenance costs, and fixed operating costs, such as payroll costs, for conventional generators are excluded.

[4] See work stream 2B report, table 6.

Because modelling a market was out of scope for this study, inframarginal rents, representing the difference between the system marginal price and the actual operating cost of all generators dispatched, are not reflected in the figure above. Results from work stream 2A are used to reflect the investment cost of new conventional generators in work stream 4. It is recognised that market mechanisms, such as capacity payments and reserve and ancillary markets will be required to make up the difference between the annualised investment costs of both new and existing conventional generators and the market price for energy received by generators, including operating costs and any inframarginal rents received.

Network reinforcement cost annualised (work stream 3 results)

The existing all island transmission network, all reinforcements that had received internal approval within EirGrid or NIE, the assumption of some additional reinforcement to accommodate additional generation in Cork and the construction of an additional 500MW interconnector to Great Britain formed the "baseline" for the evaluation of network reinforcements in work stream 3. The study only considered transmission system costs and did not consider distribution system impacts.

Figure E-7 shows the total required capital investments in both the Republic of Ireland and Northern Ireland, and the total length of transmission network that needs to be reinforced due to the addition of renewable energy generators to the system in both jurisdictions for each portfolio. The incremental cost to incorporate 6000 MW (portfolio 5) rather than 4000 MW (portfolios 2 to 4) is roughly half the amount required to incorporate 4000 compared to 2000 (portfolio 1) MW of wind.

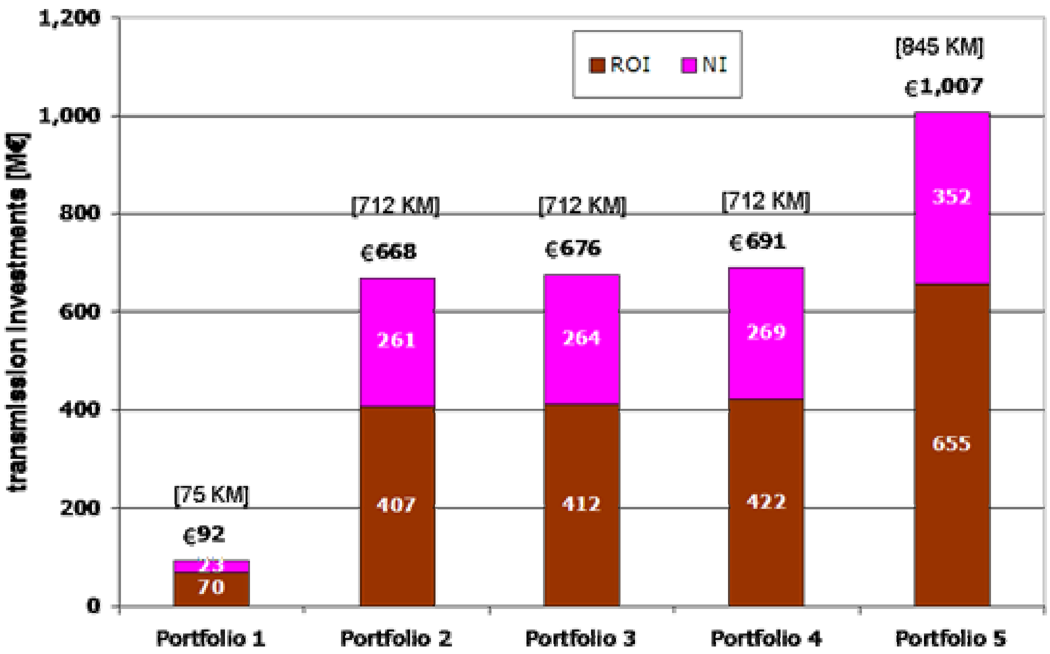


Figure E-7: Total investments in transmission line reinforcements and total length of transmission lines to be reinforced

It should be emphasised that work stream 3 assumed an integrated planning process with a predefined renewable capacity target per portfolio. Initially planning and building for 4000 MW of wind and then deciding later on to increase the network capacity to accommodate

6000 MW of wind would likely result in a requirement for more lines and higher costs than would be required if the decision at the outset was to build to accommodate 6000 MW of wind. In the former case, the costs incurred would likely be higher for the accommodation of 6000 MW than those shown above.

Planning and permitting of these new lines represents a major challenge for the network operators and the authorities. As public acceptance for overhead lines is problematic, planning procedures may be very time consuming and availability of the complete infrastructure as identified in work stream 3 by the year 2020 is questionable for the portfolios examined with high amounts of wind energy.

Total capital cost for new generation (work stream 4 analysis)

The analysis of the relative cost of generation in work stream 4 requires consideration of the investment costs for new conventional generation. Because the new conventional generation requirements are different for each portfolio, the investment costs will be different for each. The investment cost for existing conventional generators are the same across all portfolios; as their inclusion would increase costs equally across all of the portfolios, these costs are not included in the analysis of the relative cost of generation. An analysis of the total additional cost for each portfolio would increase the costs reflected in figure E-9 by the same amount on inclusion of investment costs for conventional generators.

It is important to consider the investment cost of conventional generators, both existing and new, as only the variable operating costs have been considered thus far (i.e. the cost of fuel and carbon). Conventional generators will need to recover their investment costs as well through revenue received in periods when they are not the marginal generator, and via payments for ancillary services and/or capacity payments. Because the study of a market was out of scope for work stream 4, a full analysis of the revenue available was not possible.

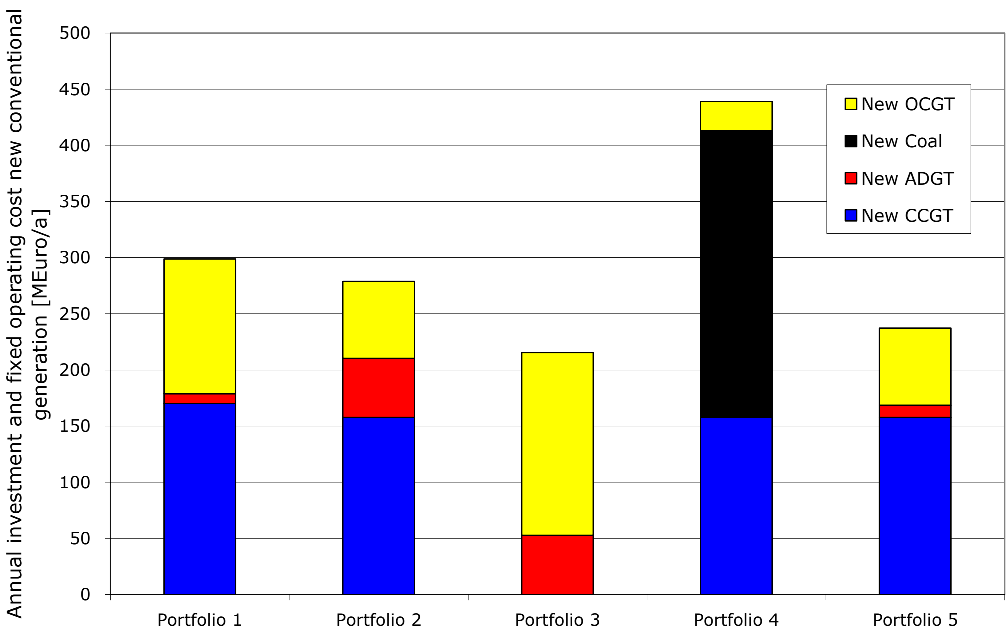


Figure E-8: Investment annuity and annual fixed operating costs for new conventional generation

Aggregate additional costs and selected benefits

The figure below provides an aggregation of the additional costs to society considered in the study in millions of euro for the year 2020 for the five portfolios. It has to be pointed out that the given cost figures do not reflect the full cost of electricity supply but rather indicate the relative relationship between the elements of the costs of generation investigated in this study in the different portfolios.

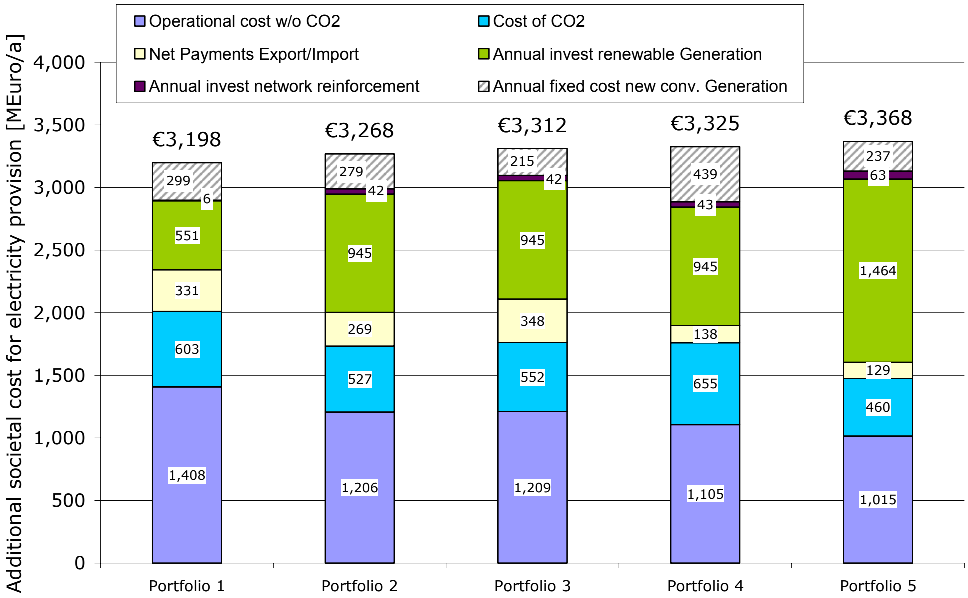
The additional cost to society is defined as the sum of the operating costs of the power system and varies with the generation portfolios. The costs are additional to the investment costs of existing conventional generators and existing and base case transmission asset costs. These costs include:

- The operational costs of generation consisting of the fuel costs and the cost of CO_2;
- The charges for the net imports over the interconnector;
- The total annual investment costs for all renewable generation, existing and new;
- The annual investment in network reinforcements;
- Investment in new conventional generation. Under market rules these costs would typically be covered by revenues from energy markets (infra marginal rents) as well as by those from ancillary services and capacity payments where in place.

The following costs were excluded from the analysis:

- o the historic investment costs of existing conventional generation as well as for the base case transmission assets and additional 500MW interconnector. As these cost components apply identically to all portfolios it does not compromise a comparison between the portfolios.
- o variable maintenance costs

These additional costs will need to be recovered within the price of electricity charged to end users.



RE share of demand	16%	27%	27%	27%	42%
CO_2 emissions [Mt/a]	20	18	18	22	15

Figure E-9: Additional societal costs for provision of electricity in M€/annum, share of renewable **demand** and CO_2 emissions

The information presented illustrates the order of magnitude of the change of the cost components examined between portfolios 1 to 5. It shows that the total cost to end users varies by at most 7% between the highest cost and lowest cost portfolios. Thus the presented results indicate that the difference in cost between the highest cost and the lowest cost portfolios are low, given the assumptions made in the Study.

The resulting relative carbon emissions from each portfolio are shown below with Portfolio 1 representing the base case. Again at higher proportions of renewable capacity installed, less carbon is emitted. Portfolio 4, with the new coal plant utilised, has the highest emissions.

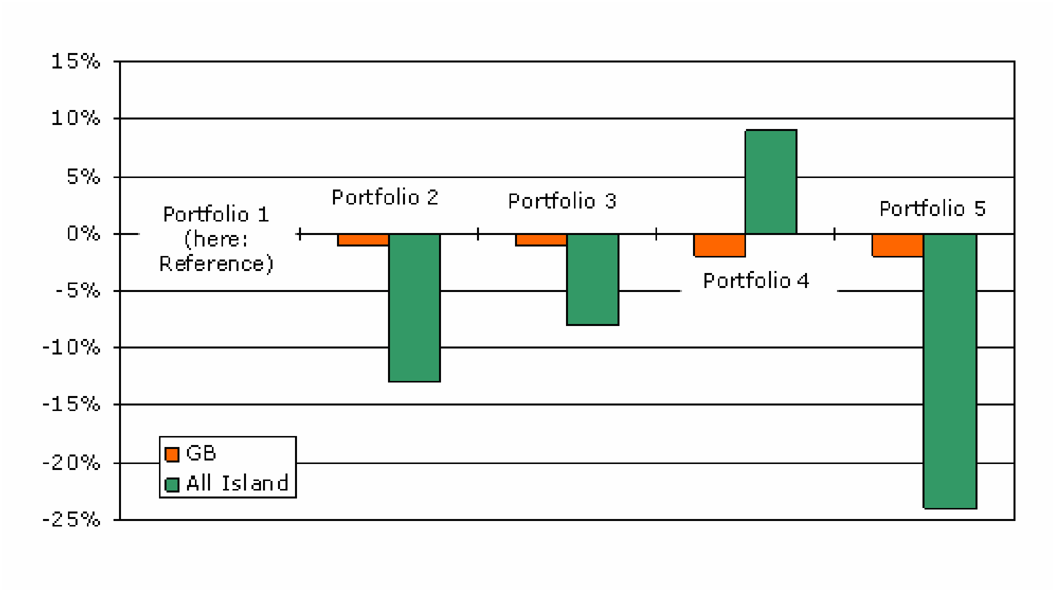
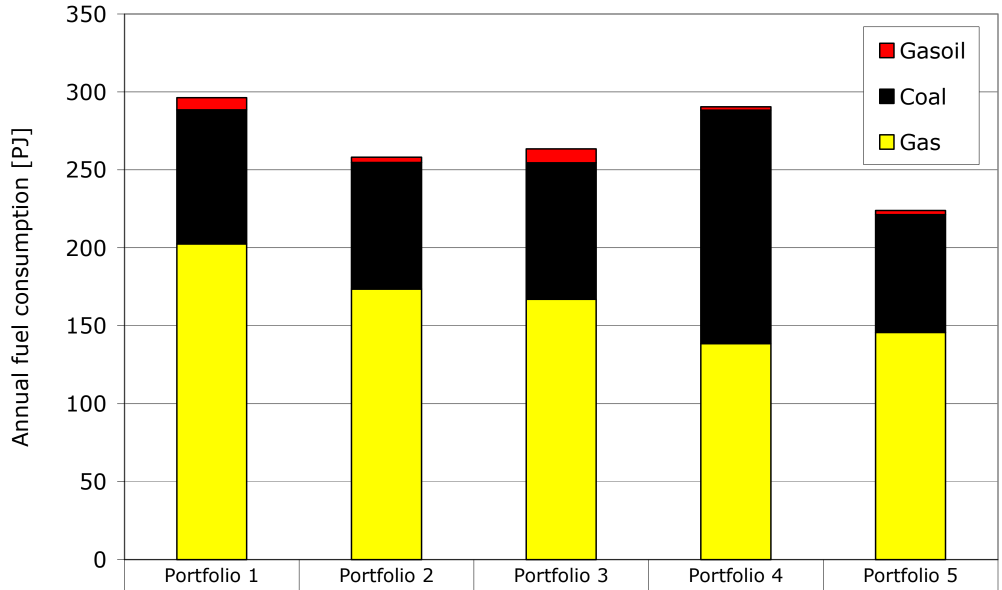


Figure E-10: Percentage change in CO_2 emissions relative to Portfolio 1

Figure E-11 shows the annual fuel consumption by the all island power system of those fuels that, for the most part, have to be imported. It can clearly be seen that the total amount of imported fuels declines with increasing shares of renewable generation.



	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Gasoil	8	3	9	2	3
Coal	86	81	88	150	75
Gas	203	174	167	139	146

Figure E-11: Structure of annual fuel consumption of fuels with high import shares[5]

All but portfolio 4, which is substantially coal based, lead to significant reductions of CO_2 emissions compared to portfolio 1. Additionally, they reduce the dependency of the all island

[5] Baseload gas and Midmerit gas are aggregated

system on fuel and electricity imports. However, the construction of a second interconnector to the GB system is a precondition for the feasibility of the portfolios.

A precondition for implementation of the portfolios, in particular in the case of high renewable shares, is a substantial reinforcement of the existing transmission networks. This is a substantial planning challenge and the typically long lead times require an immediate policy response if the study-year 2020 is accepted as target date.

More actions have to be taken in order to support the portfolios with increased renewable energy shares and to facilitate the respective transition processes. Sufficient investment in and appropriate operation of the generation plant relies on adequate framework conditions and underlying policies. Despite the snapshot character of the study, the results indicated a number of key issues likely to be relevant during this transition.

The dispatch results of work stream 2B are used in work stream 4 as a proxy market price to consider the revenues possible for energy output for the different types of generators operating in the market and to assess the required support payments for renewable generators. The analysis shows that 70% to 80% of the total investment cost for renewable generation can be recovered by these generators in the electricity market. It is important to note that this figure is only a proxy and modelling a real market price and cost of support would require modelling a market, which was out of the scope for this study. However, it was shown that the required cost of support depends not only on the renewable generation portfolio but also on the structure of conventional generation that influences the electricity price level.

Key conclusions

- The presented results indicate that the differences in cost between the highest cost and the lowest cost portfolios are low (7%), given the assumptions made and costs included in the Study.
- All but the high coal based portfolio lead to significant reductions of CO_2 emissions compared to portfolio 1
- All but the high coal based portfolio lead to reductions on the dependency of the all island system on fuel and electricity imports.
- The limitations of the study may overstate the technical feasibility of the portfolios analysed and could impact the costs and benefits resulting. Further work is required to understand the extent of such impact.
- Timely development of the transmission networks, requiring means to address the planning challenge, is a precondition for implementation of the portfolios considered.
- Market mechanisms must facilitate the installation of complementary, i.e. flexible dispatchable plant, so as to maintain adequate levels of system security.

Further work required

All efforts, within the resources of the study, were directed at developing results which are as realistic as possible using state-of-the art methodologies. However, in particular within the high penetration portfolios, a number of limitations of the study's methodologies have to be acknowledged. These limitations may affect the technical feasibility of the dispatches and consequently the economic performance of the portfolios.

The focus of technical follow up studies should be on the dynamic behaviour of the system accommodating high portions of renewable generation. These should be accompanied by detailed network planning studies assessing the challenges associated with the development of the transmission system and generator connections.

Additionally, an evaluation of the portfolios under the conditions of real markets will be required in order to specify the conditions under which sufficient returns will be available for existing and new conventional and renewable generators. Consequently these studies should sufficiently reflect risk perception and investment behaviour of stakeholders. In that way, also the potential societal cost of imperfections of market and support mechanisms can be assessed.

Finally, the study assumed "business as usual" in terms of demand side management and other energy efficiency measures. Since the study was commissioned, separate research has characterised and quantified the potential for demand side management measures in the Republic of Ireland. The impact of an aggressive programme of demand side measures should be considered.