Impact of High Levels of Wind Penetration in 2020 on the Single Electricity Market (SEM)

A Modelling Study by the Regulatory Authorities

January 2009

SEM-09-002

DISCLAIMER

CONTENTS

EXECUTIVE SUMMARY

The aim of this study is to assess the effect of increasing wind penetration on the island of Ireland on the ability of the Single Electricity Market (SEM) to operate efficiently and effectively.

The SEM is designed around a single unconstrained marginal pricing structure, i.e. the price determined within the market ignores transmission and reserve constraints but will respect generator physical abilities.[1] In commissioning this work, the Regulatory Authorities (RAs) were particularly interested in exploring the ability of the SEM, as currently designed, to adequately remunerate existing and potential new additions to capacity in 2020. To this end this study examines the impact of the five generation portfolios established in the All Island Grid Study (AIGS)[2] for the year 2020 on the unconstrained system marginal price (SMP) and on capacity payments to generators.

This study did not look at the effect of increased wind penetration on system costs (and concomitant generator revenue streams) in the SEM, i.e., for the provision of ancillary services (e.g., for additional synchronised and standing reserves) or for the relief of constraints. Equally, the costs of reinforcing the networks to accommodate increased wind penetration and of increased transmission losses have not been addressed here.

So the evaluation of the costs and benefits of increased wind on the system are limited here to:

- the additional capital costs of increased wind and other renewable generating capacity;
- fuel and carbon costs displaced by increased wind penetration; and
- the capital costs of conventional generation displaced by increased wind penetration.

Additionally, while not an economic cost or benefit, the study looked at the effect of the five portfolios on SMP and capacity payments to judge whether wholesale prices in the SEM would be higher or lower with increased wind generation in 2020; and what effect increased penetration might have on the profitability of existing and new conventional generation.[3]

OVERVIEW OF RESULTS

The results of this study suggest that the increasing penetration of wind generation in the market will have noticeable effects on the unconstrained market. The key results can be summarised according to the following 5 areas:

[1] The SEM High Level Design Decision paper is available on the All Island Project website at www.allislandproject.org

[2] The AIGS was commissioned by the Department for Communications, Energy and Natural Resources (DCENR), in Ireland, and the Department of Enterprise, Trade and Investment (DETI), in Northern Ireland. The AIGS Report was published in January 2008 and is available on the DCENR website: http://www.dcenr.gov.ie

[3] Lower (or higher) prices - at a given level of costs - represent a transfer from producers to consumers (or vice versa) and are not therefore of benefit to society as a whole.

Wholesale Energy Prices

The study shows that increased penetration of wind would be associated with significantly lower wholesale market prices (SMPs) and a concomitant transfer of income from generators to consumers. This is true irrespective of the level of fuel and carbon prices. The exception in this study is Portfolio 3, in which the annual average SMP is significantly higher, due to the fact that wind generation in that particular portfolio is accompanied by an increase in the overall penetration of Open Cycle Gas Turbines (OCGTs). The results from the other portfolios studied suggest that if new baseload Combined Cycle Gas Turbines (CCGTs) or even new coal plants are built to meet increments in demand as the penetration of wind increases, then SMP is likely to be lower.

Economic Costs and Benefits

The economic benefits of increased wind penetration are sensitive to fuel and carbon prices. In the central fuel price scenario, which assumes that the high level of fuel prices as of July 2008 will persist into the future, more wind generation has a beneficial economic effect. However, if fuel and carbon prices turn out 50% lower than in the central case, there would be economic costs associated with more wind on the (unconstrained) system in Ireland. Indeed prevailing fuel prices at the time of publication of this report are significantly lower than those used in the central scenario and are closer to the low fuel scenario.

Incentives to Enter and Exit the SEM

The picture on generator incentives to exit and enter the market appears to be mixed, since the results are portfolio-dependent. In the central fuel price scenario, existing generators would have little incentive to exit, though the existing coal stations would be vulnerable if fuel prices were low. New and existing wind generators make substantial economic rent when fuel prices are high but new wind generation would need financial support if fuel prices turn out relatively low.[4] The study suggests that incentives on OCGTs and Aero Derivative Gas Turbines (ADGTs) to enter are weak and invariant to fuel prices.[5]

Emissions

A mixed portfolio of plant, i.e. CCGTs, OCGTs and wind, has a greater positive impact on CO2 emissions than OCGTs and wind only.

SEM Design Implications

[4] Existing stations, whose capital costs are fully or partly depreciated, have a greater level of measured profits than those of the new stations which have high avoidable capital costs (as seen from the perspective of a potential new entrant) associated with them. This study adopts the economic or business decision-making assumption that all the capital costs of existing generators are sunk. The study also does not consider the costs of any capital injection which would certainly be required in existing stations to maintain their current level of operation in 2020. Therefore profits, in the conventional sense, for existing generators are overstated in this study.

[5] The RA SEM market model allows for seamless and instantaneous trading between the SEM and the BETTA market across the interconnector units. This essentially has the effect of treating the interconnectors as the most flexible generation units in the unconstrained system and thereby increasing their capacity factors, while reducing those of the more conventional flexible units such as Pumped Storage, the OCGTs and ADGTs.

The SEM design is potentially robust to significant increases in the amount of wind generation on the system, though the marginal nature of the incentives on new generation to enter the market is a potential concern, which suggests that the design will need to be kept under close review in the years to come.

THE ALL ISLAND GRID STUDY

The AIGS examined five generation portfolios. These comprised different renewable and conventional technologies in varying compositions. The configurations of generating units were chosen to produce least cost generation portfolios in 2020 over a wide range of scenarios for fuel, carbon, renewable resources, conventional generation and network reinforcement requirements.[6] The portfolios were then adjusted to ensure a comparable level of system security across all portfolios.

The five portfolios covered a range of renewable capacities in 2020, with renewable electricity providing from 16% to 42% of energy demand by then:

- Portfolio 1 included 2,000MW of wind capacity, 180MW of base renewables and 70MW of other renewables[7], and a large proportion of combined cycle gas turbines (CCGTs) and open cycle gas turbines (OCGTs).
- Portfolios 2 to 4 increased the amount of wind capacity to 4,000MW, with the same base and other renewables as in Portfolio 1, and varied the amounts and technologies of conventional generation as follows:
    - Portfolio 2 assumed a large proportion of CCGTs;
    - Portfolio 3 assumed a large proportion of open cycle gas turbines (OCGTs) and aero-derivative gas turbines (ADGTs); and
    - Portfolio 4 also assumed a new large coal plant in addition to a large proportion of CCGTs.
- Portfolio 5 included 6,000MW of wind capacity, 360MW of base renewables and 285MW of other renewable capacity, and a large amount of CCGTs.

The aim of the AIGS was to assess:

1. the technical feasibility of the electrical power system and the transmission network on the island of Ireland to absorb large amounts of electricity produced from renewable energy sources; and

[6] For the purposes of constructing the portfolios, it was assumed that approximately 1,800 MW of existing generation capacity would have been be retired by 2020.

[7] 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.

2. the relative costs and benefits associated with increased shares of electricity sourced from renewable energy in the all island electrical power system in 2020.

Assuming a gas price of €22/MWh (thermal) – equivalent to about 40p/therm at 2006 exchange rates - and a CO_2 price of €30/tonne, the AIGS estimated that the additional cost to society in 2020 of an increment of 2,000MW of wind generation would be between 2% and 4% of base case costs (Portfolio 1 costs); and little more than 5% for an additional 4,000MW of wind, where the base case costs are the costs of a portfolio that includes 2,000MW of wind (i.e. Portfolio 1).

In the AIGS increased penetration of wind and other renewables leads to benefits in the form of:

- relatively small savings on new investment in conventional generation (except in Portfolio 4);
- savings on fuel costs, ranging from 14% in Portfolios 2 and 3 to 28% in Portfolio 5;
- savings on the cost of imports of electricity across the interconnector with Great Britain, except for a small cost in Portfolio 3, which has new OCGTs and ADGTs installed in preference to CCGTs (Portfolio 2) or coal-fired stations (Portfolio 4); and
- savings on carbon emissions, except in the case of Portfolio 4, which has a large amount of coal based generation on the system.

In the AIGS, these are more than offset by increased costs in the form of:

- the annualised fixed costs of investment in new renewable capacity; and
- the additional costs of reinforcing the transmission network (which was a relatively small component of overall costs).

The AIGS, while being complete within its own scope of examining the effects of increased renewable generation, acknowledged the need for further work in a number of key areas. The AIGS did not, for instance, examine the market design implications.

OVERVIEW OF ASSUMPTIONS AND METHODOLOGY OF RA STUDY

The RAs used a market simulation software model – PLEXOS - to estimate the effect of the five different AIGS plant portfolios on prices, costs, revenues and profits. To the greatest extent possible and to allow comparisons to be made with the AIGS results, the RAs used the same assumptions as were used in the AIGS, including the five generation portfolios, generation characteristics and system demand for both the all-island market and Great Britain.

The main differences from the AIGS were in respect of what was assumed about future fuel prices and the capital costs of new generation. As the AIGS (and other studies) show, the net costs or benefits of wind generation are essentially driven by fuel and carbon costs and the capital costs of wind and conventional generating plant. Both types of costs have shown significant increases over the past two years. Fuel and carbon cost assumptions for this study were frozen in July 2008.

Low and high fuel price scenarios – with fuel prices at 50% and 150% of those in the central case respectively - were also run to look at the sensitivity of the results to relatively low and high fuel prices at the time. Given the drop in fuel prices over the past number of months the low fuel scenario in this study is more reflective of prevailing forward prices, albeit still somewhat lower.[8] This is an important point to be borne in mind by the reader when interpreting the overall results of this study.

LIMITATIONS OF RA STUDY

Modelling an electricity system is a complex task and this study sets out to examine the impact of increasing wind penetration on the SEM energy and capacity markets only, i.e. the unconstrained market schedule. The Regulatory Authorities (RAs) have employed a deterministic model using a given set of assumptions. The study assumes that there are no significant rules changes to the SEM or to the broader market by 2020. The study therefore applies the current market rules as set out in the SEM Trading and Settlement Code and assumes that the current bidding principles and the methodology for calculating the Capacity Payment Mechanism (CPM) pot and revenue streams will remain.

Underpinning the model is the assumption of perfect foresight and therefore account is not taken of system operator actions required to ensure security of supply. Therefore, the constraint costs associated with deviations between actual dispatch and our market modelled dispatch, and the costs of ancillary services are not examined in this study.[9] Network investment costs are also not taken into account. These are important omissions which require further substantial work. Indeed a number of external industry experts who were selected as peer reviewers of this report, while acknowledging that the study achieves its objectives, stressed the importance that the reader should place on these limitations.

[8] This is the case in relation to Coal, Gasoil, Fuel oil and Gas

[9] Other studies (e.g., Strbac, G, Shakoor, A, Black, M, Pudjianto, D and Bopp,T: Impact of wind generation on the operation and development of the UK electricity systems, Electric Power Systems Research 77 (2007) 1214–1227) and the AIGS itself suggest that these system costs are small by comparison with the changes in fuel, carbon and capital costs addressed here.

1 INTRODUCTION

The results of the All Island Grid Study (AIGS) were released in January 2008. The AIGS examined the impact of different scenarios of wind penetration on the electricity system of the island of Ireland in the year 2020.

In the light of the AIGS, and the proposed EU renewables targets for Ireland and the United Kingdom for 2020, the Commission for Energy Regulation and the Northern Ireland Authority for Utility Regulation (jointly the Regulatory Authorities (the RAs)) have identified the need to examine the impact of increasing penetrations of wind generation on the Single Electricity Market (the SEM).

The objective of this study is to assess the effect of increasing wind penetration on the island of Ireland in 2020 on the ability of the SEM to operate efficiently and effectively. The focus of this work has been to examine the impact that high levels of wind penetration, and more specifically the generation portfolios contemplated in the AIGS, would have on the existing design and operation of the SEM and on the ways in which generators would be remunerated in 2020, i.e., through energy and capacity payments for costs incurred in making capacity available and for generating electricity.

The work has focussed on the impact on the unconstrained system marginal price (the SMP) and schedule, and on capacity payments of the five generation portfolios established in the AIGS for the year 2020.[10]

This report sets out the result of that work.

[10] Other generator revenue streams in the SEM (for the provision of ancillary services, for the relief of constraints, for uninstructed imbalances, of make-whole payments etc.) are the subject of separate analysis and are not covered in this report.

2 BACKGROUND

The All Island Grid Study (the AIGS) was commissioned by the Department for Communications, Energy and Natural Resources, in Ireland, and the Department of Enterprise, Trade and Investment, in Northern Ireland, to evaluate the impact of high volumes of electricity generated by renewable sources on the electrical system on the island of Ireland in the year 2020. The study evaluated the technical feasibility and the total cost to society (using a cost-based approach) of five different portfolios of plant.[11]

The cost implications in the AIGS show that, relative to the base case (Portfolio 1), there is only a marginal difference in additional social costs, ranging from 2% (when wind provides a 27% share of demand requirements) to just over 5% (when wind provides a 42% share of demand requirements). The AIGS emphasises that the dispatch results only acted as a proxy of a market and that they excluded items such as infra-marginal rents, variable maintenance and fixed operating costs.

These estimates are broadly in line with those in other studies in other countries. For example, Strbac and others recently published an assessment of the costs and benefits of wind generation on the electricity system in Great Britain.[12] At a penetration level of about 20% of overall UK electricity consumption, they estimated that the net additional costs (i.e. net of benefits) of wind generation of that magnitude would amount to around £2.8/MWh (or about €4/MWh), which was 5% of the then current domestic electricity price in Great Britain.

The AIGS identified the need for further work in a number of key areas including:

- examining the interaction of generation and the network under steady state conditions, the technical feasibility of the generation portfolios, the economic impact of critical situations and an evaluation of corrective measures;
- studying the impact of the generation portfolios on the design and development of the distribution networks and the resulting costs;
- identifying the measures and investment required to address the impacts of high renewable energy penetration on reactive power, voltage rise, stability, fault level, quality of supply etc.;
- assessing the various technological concepts that may serve to optimise yield from wind power and network investments;
- examining the economic viability of demand-side measures;
- examining the operation of pumped storage in the context of increasing wind penetration;

[11] The summary of the All Island Grid Study can be found at the following link: http://www.dcenr.gov.ie/Energy/North-South+Co-operation+in+the+Energy+Sector/All+Island+Grid+Study.htm

[12] See Strbac, G, Shakoor, A, Black, M, Pudjianto, D and Bopp,T: Impact of wind generation on the operation and development of the UK electricity systems, Electric Power Systems Research 77 (2007) 1214–1227.

- examining the impacts of increased wind penetration on reserve and ancillary service provision, the need to encourage investment in appropriate plant, and the financial impact of changes to the operating regime of conventional plant; and

- researching the optimal design of any required support mechanism to facilitate the efficient growth in renewable electricity generation.

Given their responsibility for the design of the SEM, the RAs are interested in understanding whether increased penetration of wind would be compatible with the current design of the market and this is their reason for undertaking this study.

3 METHODOLOGY

This section of the Report sets out the methodology adopted to examine the impact of different levels of wind penetration in 2020 on:

- the System Marginal Price (SMP) of electricity by half hour across the year in question
- generation plant schedules by half hour across the year
- interconnector flows
- annual generator emissions of CO2
- annual generator revenues from both energy and capacity payments
- annual generator start, no load and variable costs, including the cost of fuel, carbon and variable O&M[13]
- generator gross margins
- annual generator investment and fixed costs
- generator economic returns.

The model used to derive these outputs is PLEXOS for Power Systems (PLEXOS). PLEXOS is a market simulation software system, which is used to model electricity markets in a number of jurisdictions, including Ireland. PLEXOS was designed as a general power market modelling tool. It was not built specifically to match the SEM trading and settlement rules, though certain features have been added to support SEM modelling (such as the ability to model the uplift component of the SMP and the 30 hour optimisation "look-ahead" period).

The RAs have, however, taken steps over the past two years to ensure that PLEXOS has been calibrated successfully against the scheduling and pricing algorithms used by the Market Operator in the SEM.

In January 2007 the RAs commissioned consultants KEMA to independently validate both the PLEXOS model against the SEM Trading and Settlement Code and the input data in the model for the first year of the market. The purpose of this exercise was to provide the RAs and the industry with a model that could accurately predict electricity prices in the SEM.[14]

---

[13] Assumptions have had to be made about the extent to which generators continue to have access in 2020 to a proportion of their carbon requirements free of charge in the context of a policy that will require generators to buy CO_2 allowances at annual auction. One possibility, which is assumed in this study, is that generators are assumed to anticipate with perfect foresight their annual CO_2 requirements and are successful in bidding for those exact requirements at the assumed market price of carbon in 2020.

[14] All documents and data relating to the KEMA validation project have been published on the AIP website at http://www.allislandproject.org/en/modelling-group-minutes-presentations.aspx?article=43618f97-6118-40f1-9b56-18c500592c70

In 2008 the RAs engaged NERA Economic Consulting (NERA) to validate the use of the PLEXOS model to simulate electricity prices (System Marginal Prices or SMPs) in the SEM for the period October 1 2008 to December 31 2009. As part of this exercise the simulation model's input data was re-validated to reflect developments since the previous KEMA exercise. The NERA validation project also involved the calibration of PLEXOS results against actual SEM market outcomes for the first four months of the market. NERA found that there was sufficient consistency in SMP and in generation schedules in the PLEXOS calibration exercise to have confidence in the results of PLEXOS forecasts. The RAs have used the NERA validated SEM PLEXOS model of the SEM as the basis for this study.[15]

The steps the RAs have taken in the modelling of the effects of increasing wind penetration are as follows:

1 Replicating the assumptions taken in the AIGS to relate, to the greatest extent reasonable or practical, this market modelling exercise with the results already obtained in the AIGS. This includes the generation portfolios and characteristics, system demand etc. for both the all-island electricity market and that in Great Britain for the year 2020. Where necessary assumptions are not clearly expressed in the AIGS or where more up-to-date data is available then the RAs have made the necessary changes. These are summarised in section 4.

2 Deriving the capacity payments 'pot' in 2020, for the different portfolios and other cases, on the basis of an assumed BNE peaker price in 2020 and the required amount of installed generation capacity to meet the given security standard.

3 Deriving results from PLEXOS and determining the implications for the existing SEM market design in the light of those results. Criteria against which to judge robustness include:

   a. The extent to which revenues from energy and capacity payments in 2020 cover the total costs of generators (fixed and variable, together with a market return on assets employed), which will give an indication of incentives to enter the market.

   b. The extent to which revenues from energy and capacity payments in 2020 fail to cover avoidable fixed and variable costs of generators, which will give an indication of incentives to exit the market.

   c. The proportion of revenues of conventional thermal plant accounted for by energy and capacity respectively, which will give an indication of whether a competitive wholesale market exists in a true sense – if capacity payments represent a high proportion of a baseload plant's revenues, that would tend to suggest that regulated pricing has become necessary to adequately reward generation in the SEM as currently designed.

[15] All documents and data relating to the NERA validation project have been published on the AIP website at http://www.allislandproject.org/en/modelling-group-minutes-presentations.aspx?article=b4551173-1ff4-4378-a5a1-e74f9e342dae

d. The volatility of prices in the SEM, which might be one indicator of the relative riskiness of the SEM for new entrants.

4 Conducting sensitivity analysis to see the effect of changes in some of the key assumptions on the key outputs (SMPs, generator capacity factors, generator margins etc.) These sensitivities include looking at alternative assumptions about:

- Load estimate in 2020
- Fuel and carbon prices
- Cost of capital
- Effect of increasing unit starts.

In terms of the further work required, as outlined in the AIGS and covered in section 2 of this report, it is important to note what has not been addressed in this RA market study. For example, this study:

- takes only a snapshot and deterministic view of the system in 2020. A longer timeframe or more dynamic approach over the lifetime of the additional plant added to the system may yield a better insight into the economics of various generation types in the SEM.

- takes the current SEM design and market rules without any significant changes by 2020. This study assumes all stations have firm access, ignoring any impact that non-firm access may have on prices and revenues.

- examines the impact on the SEM only of the portfolios considered in the AIGS. There may be other possible combinations of plant types which make more economic sense while maintaining the system security standard.

- examines the impact only on the unconstrained schedule and does not take into account the cost of system operation policies or issues, such as transmission and reserve constraints. These areas are likely to come more to the fore with increased intermittent generation added to the system.

- does not take account of demand side participation in the SEM and assumes inflexible system demand. Demand Side Management (DSM) is likely to become an important means of reacting to increasing fossil fuel prices and hence pool prices, and of meeting environmental and renewable targets in the future.

- does not attempt to quantify, with a great degree of accuracy, the additional costs associated with the increasing number of baseload and mid-merit gas generator unit starts which are observed in some of the portfolios studied. It does however include a sensitivity check on the results by increasing start variable operation and maintenance (VOM) costs by 50% (see section 4.12).

4 ASSUMPTIONS

A number of assumptions are required to simulate the effect of the All Island Grid Study (AIGS) portfolios on the SEM in the PLEXOS model over the 2020 horizon. The modelling assumptions used in the RA study have been primarily sourced from the AIGS.

However, as the AIGS is a compilation of different individual workstreams, a number of minor inconsistent assumptions have been used across the overall document. Where this was the case workstream 2B, which focused on the dispatch and operation of the system in 2020, was the primary source of input data, followed by workstream 2A, which focused on the development of the portfolios, and the other workstreams thereafter.

Where the RA modelling assumptions have not followed those in the AIGS these are detailed in their respective sections set out below. This is particularly the case in relation to generation capital costs and fuel prices which have been updated in this study to reflect prevailing prices. It is also worth noting that the AIGS used 2006 prices, whereas this study uses 2009 prices in relation to investment and fixed operational costs.

4.1 LOAD

The AIGS created a load profile for 2020 by assuming an annual load growth of 3% from 2003 to 2020. This resulted in a total electricity demand/consumption for the All Island system in 2020 of 54 TWh. This figure is assumed to be consistent with the definition of Total Electricity Sales (TES) used in EirGrid's generation adequacy studies.[16] The minimum load was 3,500MW and maximum load was 9,600MW.

In this study we have utilised the load profile (expressed as the Total Electricity Requirement (TER)) from the NERA-validated PLEXOS model for 2008/09 and inflated the profile such that it results in a TES of 54 TWh in 2020.[17] The implied demand growth under this method was 3.5% per annum. The table below shows the calculations establishing the All-Island total electricity requirement (TER), peak and minimum demand.

The difference in peak and minimum load compared with those in the AIGS and the table below are the result of differences in load profiles used.

Table 1: Demand Assumptions for Ireland

All-Island	2009	2020	Change	Annual Growth
TER (TWh)	40.5	59.7	0.47	~3.5 %
Transmission & Distribution Losses (9.3%)	3.8	5.5	0.47	~3.5%
TES (TWh)	37	54	0.47	~3.5%
Peak Load (MW)	7,070	10,407	0.47	~3.5%
Minimum Load (MW)	2,635	3,879	0.47	~3.5 %

16 TES is measured at the customer level as defined in EirGrid's Generation Adequacy Reports
17 TER is calculated at the generation export level as defined in EirGrid's Generation Adequacy Reports

It could be argued that this level of demand growth looks high, especially in the current economic environment. More recent projections on demand in the Republic of Ireland expect growth to be lower than 3.5%. We understand that the Grid Development Strategy, published by EirGrid, forecasts electricity demand to grow by 2.8% a year up to 2025.[18] The ESRI's 2008 Medium-Term Review projects electricity demand growth to be 3.9% up until 2010 and 1.4% from there until 2020.[19]

In the case of load in Great Britain the AIGS used the 2006 Seven Year Forecast Statement from the National Grid in the UK to compile the GB assumptions, taking the baseline forecast for 2012 of approximately 375TWh (Annual Electricity Demand).

For the purposes of this study we have also taken this assumption as the Total Electricity Requirement for Great Britain in 2020.

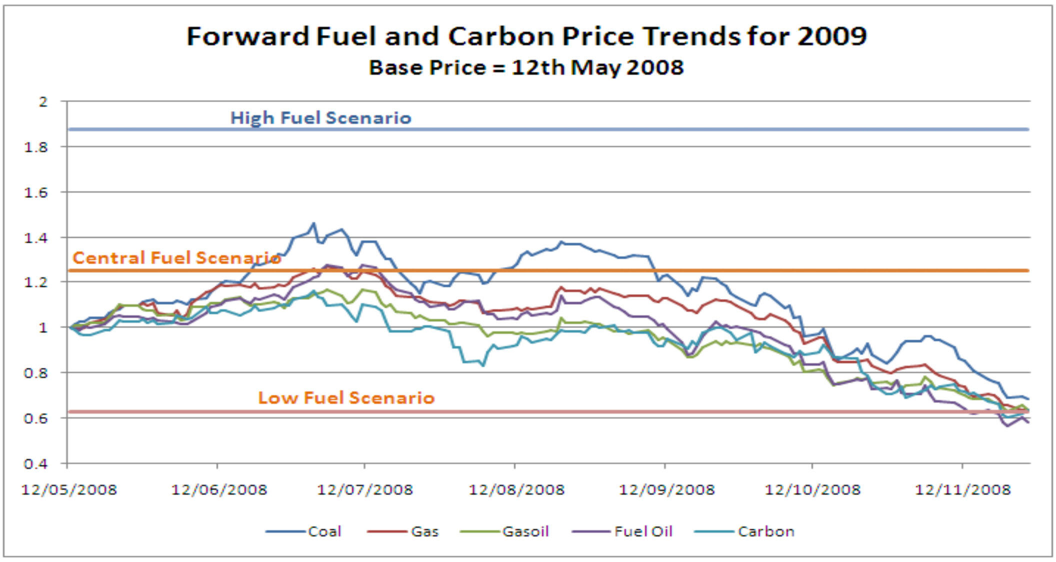
Table 2: Demand Assumptions for Great Britain

GB	2009	2020	Change	Annual Growth
TER (TWh)	336.9	375	0.11	~1%

4.2 FUEL AND CARBON PRICES

In this study the RAs have selected a set of prices in keeping with forward quarterly fuel prices for 2009 for their central fuel scenario for 2020. It should be noted however that fuel and carbon assumptions were fixed in July 2008 for the purpose of this study and since then have seen a marked decrease. This can be seen in the graph below which maps the recent trend in fuel and carbon prices using the 12th May 2008 as the base (set equal to 1).

Figure 1: Forward Fuel and Carbon Price Trends for 2009



18 EirGrid, 2008: Grid25, A Strategy for the Development of Ireland's Electricity Grid for a Sustainable and Competitive Future, pg 19 http://www.eirgrid.com/EirgridPortal/uploads/Announcements/EirGrid%20GRID25.pdf

19 ESRI: Medium-Term Review 2008-2015, Number 11, May 2008, table 5.3.

To test the sensitivity of the results to the level of fuel prices, a low and high scenario was created by a 50% reduction and a 50% increase, respectively, on all commodity prices in the central scenario.

The RAs' fuel and carbon assumptions can be seen in the second table below and can be compared with those used in the AIGS workstream 2B. The figures in the table comprise both commodity and transport elements. Estimates of transport costs were taken from the NERA-validated fuel spreadsheet.

Table 3: Average Fuel and Carbon Price Assumptions

		RA Assumptions			AIGS Assumptions		
		GB	NI	ROI	GB	NI	ROI
		€ per GJ			€ per GJ		
Coal	**Central**	5.64	5.64	5.22	1.75	2.11	1.75
	High	8.23	8.23	7.8	2.34	2.71	2.34
	Low	3.06	3.06	2.63	1.12	1.49	1.12
Gasoil	**Central**	19.77	19.77	21.22	9.64	8.33	9.64
	High	29.47	29.47	30.92	15.44	14.14	15.44
	Low	10.08	10.08	11.53	6.83	5.52	6.83
Fuel Oil	**Central**	12.32	12.32	12.68	5.22	4.83	5.22
	High	18.36	18.36	18.72	7.74	7.35	7.74
	Low	6.28	6.28	6.64	3.65	3.25	3.65
Peat	**Central**	-	-	3.71	-	3.71	3.71
	High	-	-	5.57	-	3.71	3.71
	Low	-	-	1.86	-	3.71	3.71
Baseload Gas	**Central**	13.08	13.26	13.25	5.62	5.91	5.91
(Average)	**High**	19.6	19.78	19.77	9.71	10.22	10.22
	Low	6.56	6.74	6.73	3.57	3.76	3.76
Mid-Merit Gas	**Central**	13.08	13.26	13.25	5.81	6.12	6.12
(Average)	**High**	19.6	19.78	19.77	9.91	10.43	10.43
	Low	6.56	6.74	6.73	3.76	3.96	3.96
		€ per Tonne			€ per Tonne		
Carbon	**Central**	30	30	30	30	30	30
	High	45	45	45	60	60	60
	Low	15	15	15			

The differences with the AIGS fuel price assumptions are significant and reflect the substantial increases in international fuel prices that have taken place over the last year or so. The price of coal has increased approximately threefold, those of gas and gasoil approximately twofold, and that of light oil by almost 2½ times over this period.

As the table shows, the RAs' low price scenario is more than 10% above the AIGS high price scenario in the case of coal. In the case of gas the RAs' low price assumption is about 10%

higher than the AIGS central case price. And in the case of oil, the RAs' low price scenario is almost exactly mid-way between the central and high price scenarios in the AIGS. Finally, this study uses as its central case the same carbon price in 2020 as in the AIGS.

These differences make the results of this study difficult to compare directly with those of the AIGS, since the relativity of prices in each study are quite different and because it is relative - not absolute - fuel prices that determine the pattern of dispatch, all other things being equal.

4.3 GENERATOR AVAILABILITY

The AIGS detailed the forced outage rates of the new and existing plant in workstream 2B but did not specify the stations' scheduled outages. Workstream 2A however did outline the availability of new plant.

The RAs utilised the forced outage rates used by AIGS and where they were absent (mainly hydro units) those from the NERA-validated model were used. The scheduled outages from the NERA-validated model were used for the existing plant and outage durations from similar plant were used for the new stations. Non-recurring scheduled outages in the validated model were excluded from this analysis.

Table 4: Availability Assumptions

Availability	RA Modelling	AIGS
New Coal	87%	84%
New CCGT	91%	88%
New OCGT	91%	88%
New ADGT	90%	88%

As can be seen in the table above right the RAs assume a greater availability than the AIGS for new plant. The AIGS assumptions are more in line with the availability of similar or equivalent existing plant.

4.4 WIND CAPACITIES AND OUTPUT

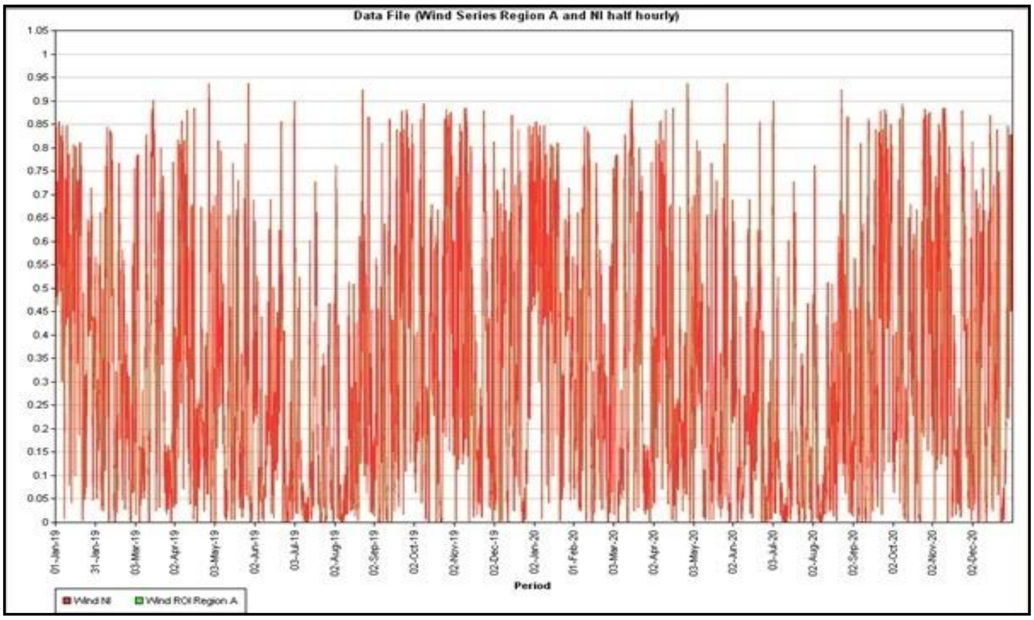
Workstream 2B of the AIGS used the Wilmar Planning Tool to analyse the increased penetration of renewable generation. This software uses a Scenario Tree Tool to generate scenario trees containing three stochastic input parameters - the demand for replacement reserves, wind power production forecasts and load forecasts - for subsequent use in its Scheduling Model.

The main input data include wind speed and/or wind power production data, historical electricity demand data, assumptions about wind production and load forecast accuracies, and data on outages and mean time to repair of different power plants. The Scheduling Model ensures that unit commitment and dispatch decisions are robust against different wind power and load prediction errors.

In the validated PLEXOS model which we use in this study, the Republic of Ireland is divided into three wind regions; A, B, and C. Northern Ireland is aligned with Region A. A time-series profile of wind rating factors is specified by the user for each region to represent wind output. As an example, the profile for Wind Region A is shown below. This half hourly profile

(365 days by 48 periods) of wind capacity factors was provided by EirGrid. This profile gives Region A, B, and C average wind capacity factors over the year of 32.0%, 32.3% and 31.4%, respectively. The additional wind capacity has been added to existing installed capacities within the existing regions on a pro-rata basis.

Figure 2: Wind Profile Example



The AIGS modelling results in a more realistic dispatch compared with the approach we utilise here, in that the PLEXOS model schedules wind with perfect foresight. In terms of wind power production data, the AIGS used 2006 wind data, which we understand resulted in a wind capacity factor of approximately 35% in all portfolios.

4.5 RESERVE MARGIN

The AIGS stated that it had a maximum load of 9,600 MW in 2020, which left the portfolios with a reserve margin, on installed capacity, ranging from over 14% in Portfolio 1 to about 50% in Portfolio 5 over peak demand.[20]

While the installed capacities of the five scenarios in this study are slightly higher than in the AIGS, for reasons explained below, the reserve margins in this study are close to those in the AIGS – at 19%, 36%, 35%, 37% and 54% for Portfolios 1, 2, 3, 4 and 5, respectively.

4.6 INTERCONNECTOR CAPACITIES

[20] The reserve margin is a commonly used measure of reliability and is the difference between the generating capacity available to serve an area and the expected peak demand, divided by the expected peak demand, expressed in percentage terms. The reserve margin in the SEM is currently about 40%. The reserve margin becomes less useful as a measure of reliability the more hydro and intermittent capacity (such as wind) is installed on the system.

In the AIGS interconnection with Great Britain was assumed to be 1,000MW, with 100MW of this assumed to be available for spinning reserve.

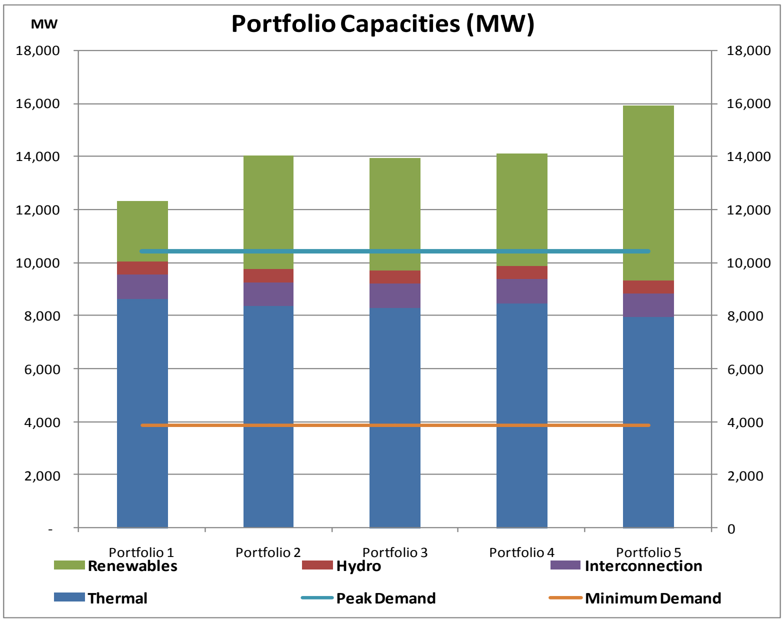
In the PLEXOS Model, the RAs used the Moyle Interconnector with an import capacity of 400MW and an export capacity of 500MW, and the East-West Interconnector with an import capacity of 500MW and an export capacity of 500MW. This study does not take into account the planned Imera interconnectors.

4.7 CANDIDATE PLANT LISTING AND CHARACTERISTICS

The plant types and their characteristics modelled by the RAs that make up each portfolio have substantially followed those established in the AIGS, particularly those set out in workstream 2B, except that the installed capacities of portfolios created by the RAs are slightly higher than those used in the AIGS, with the inclusion of the Huntstown 2 power station and an installed non-renewable fixed generation of 190MW (industrial and CHP) for 2020 (continuing the growth trend of the GAR 2008-2014). Maximum load is also higher in the RAs' model, at 10,407MW (compared with 9,600MW in the AIGS).

The chart below shows the make-up by type of plant of the portfolios in this study.

Figure 3: Portfolio Compositions (MW)



The AIGS kept the majority of current plant as operating in 2020, retiring all the oil plants and some gas plant and a number of peakers before then. The units assumed to have retired by 2020 in our study are shown in the first table below.[21] Of the existing plant that was kept for 2020, the RAs utilised the most recent set of plant characteristics as established in the

[21] While we assume for consistency with the AIGS that the Great Island and Tarbert generation stations will retire, we note Endesa's plan to refurbish them.

NERA-validated exercise[22], while we understand that the AIGS would have utilised the plant characteristics established under the AIP Loop 2 workstream. The existing plant assumed to be operating in 2020 in our study are shown in the second table below.

Table 5: Existing Thermal Generation Units Retired by 2020

Names	Capacity (MW)	PLEXOS Unit ID
Great Island unit 1	54	GI1
Great Island unit 2	49	GI2
Great Island unit 3	101	GI3
Tarbert unit 1	54	TB1
Tarbert unit 2	54	TB2
Tarbert unit 3	240.7	TB3
Tarbert unit 4	240.7	TB4
Poolbeg unit 1	109.5	PB1
Poolbeg unit 2	109.5	PB2
Poolbeg unit 3	242	PB3
Ballylumford Unit 4	170	B4
Ballylumford Unit 6	170	B6
Aghada Peaking unit	52	AP5
Aghada CT unit 1	88	AT1
Northwall Unit 4	163	NW4
Northwall Unit 5	104	NW5
Aghada CT unit 2	90	AT2
Aghada CT unit 4	90	AT4

Table 6: Existing Thermal Generation Units Included

	Capacity (MW)	PLEXOS Unit ID
Aghada Unit 1	258	AD1
Ardnacrusha Unit 1	21	AA1
Ardnacrusha Unit 2	22	AA2
Ardnacrusha Unit 3	19	AA3
Ardnacrusha Unit 4	24	AA4
Dublin Bay Power	415	DB1
Edenderry	117.6	ED1
Erne Unit 1	10	ER1
Erne Unit 2	10	ER2
Erne Unit 3	22.5	ER3
Erne Unit 4	22.5	ER4
Lee Unit 1	15	LE1
Lee Unit 2	4	LE2
Lee Unit 3	8	LE3
Liffey Unit 1	15	LI1
Liffey Unit 2	15	LI2

[22] One exception to this was the use of the AIGS's forced outage rate for existing plants.

Liffey Unit 4	4	LI4
Liffey Unit 5	4	LI5
Lough Ree	91	LR4
Huntstown	343	HNC
Marina No Steam	85	MRC No St
Moneypoint Unit 1	280	MP1
Moneypoint Unit 2	280	MP2
Moneypoint Unit 3	280	MP3
Poolbeg Combined Cycle	480	PBC
Rhode Unit 1	52	RH1
Rhode Unit 2	52	RH2
Asahi Peaking Unit	52	TP1
Sealrock 3	83	SK3
Sealrock 4	83	SK4
Tynagh	379	TY
Turlough Hill Unit 1	73	TH1
Turlough Hill Unit 2	73	TH2
Turlough Hill Unit 3	73	TH3
Turlough Hill Unit 4	73	TH4
West Offaly Power	137	WO4
Ballylumford CCGT 31	251.6	B31
Ballylumford Unit 32	251.6	B32
Ballylumford Unit 10	102	B10
Ballylumford GT1	58	BGT1
Ballylumford GT2	58	BGT2
Coolkeeragh CCGT	413	CPS CCGT
Coolkeeragh GT8	58	CGT8
Kilroot Unit 1	236.6	K1 Coal 220
Kilroot Unit 2	236.6	K2 Coal 220
Kilroot Unit GT1	29	KGT1
Kilroot Unit GT2	29	KGT2
Interconnector 1	400	
Huntstown II	412	HN2
Fixed Generation (Industrial & CHP)	190	
Subtotal Base Generation	**6,701**	

The new plant that made up the differences between the portfolios was replicated from those established in the AIGS workstream 2B. Not all the required plant characteristics were available from workstream 2B, such as duration of planned outages, variable, operation and maintenance costs etc. and in these cases the RAs utilised the data available from similar plant in the current validated model.

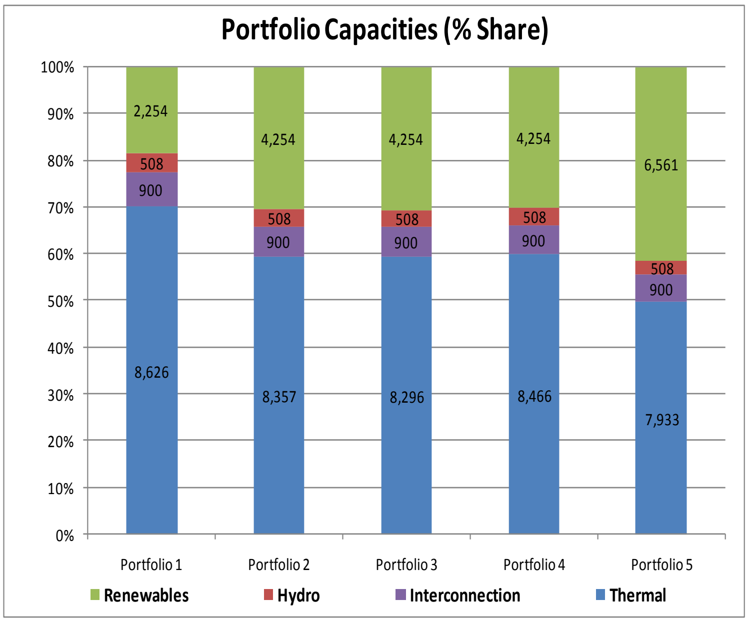
Table 7: New thermal plant additions and total wind generation

Names	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Coal 1				1,163	
CCGT	1,294	1,200		1,200	1,200

OCGT	1,450	829	1,968	311	829
ADGT	89	535	535		111
Baseload Renewables[23]	183	183	183	183	361
Variable Renewables	72	72	72	72	200
Wind	2,000	4,000	4,000	4,000	6,000
Interconnector - East-West	500	500	500	500	500
Subtotal New Generation	**5,587**	**7,318**	**7,257**	**7,427**	**9,200**
Total Installed Capacity 2020 (New and Existing)	**12,288**	**14,019**	**13,958**	**14,128**	**15,901**

The graph below shows the different categories of generation capacity that make up each portfolio in the RA study.

Figure 4: Portfolio Compositions (% Share)



The AIGS created a Great Britain portfolio for 2020 using the figures for 2012 in the 2006 Seven Year Forecast Statement from the National Grid in the UK. The only alteration made to these figures in the AIGS was the addition of 4.5GW of wind capacity bringing it to 14GW and the inclusion of 1GW of embedded generation.

The RAs utilised the GB portfolio from the latest validated model and increased the capacities of plant in line with those of the AIGS, which is summarised in the table below.

Table 8: GB Portfolio

RA GB Portfolio	MW
GB Coal	28,865
GB Distillate	1,000
GB Gas	36,389
GB Non-Fossil	24,722
GB Oil	1,990
Total	**92,966**

4.8 INVESTMENT AND FIXED COSTS

[23] Assumed to be tidal, wave and photovoltaic generation.

The RAs have updated the investment and fixed cost assumptions used in the AIGS to reflect current price levels in the industry (derived from a high level desktop analysis). For the purposes of this study prior investment or capital costs are assumed to be sunk costs for all existing plant on the system and therefore do not form part of the economic decision-making process.

Assumptions are made with regard to recurring generator fixed costs by plant type, including those that would be avoidable by exiting the market. The operation and maintenance (O&M) fixed cost component for existing thermal plant are assumed to be 50% higher than the equivalent new plant type added to the 2020 portfolio (this increase in operation and maintenance costs is not applied to existing wind and the existing interconnector). A possible limitation in our assumptions could be that no post-commissioning capital expenditures are assumed to be required for existing plant to keep them operational to current capacities and efficiencies in 2020.

For the central scenario, the RAs have used the same WACC of 8% and life expectancy for each of the additional plant as in the AIGS. The RAs have also assessed the sensitivity of the overall results of this study to alternative WACC figures of 10% and 12% (see section 5.9.3 below).

The table below shows what the RAs have assumed for initial investment and annual fixed operating costs for each plant type.

Table 9: Investment and Fixed Costs

	Investment Costs (€000 per MW)	Fixed Costs (€000 per MW)	Total (€000 per MW)	Life
Plant Additions				
New CCGT	100	90	190	15
New OCGT	59	27	86	15
New ADGT	86	43	129	15
New Coal	270	85	355	30
New Wind	183	61	244	15
Interconnector (E-W)	67	23	90	40
Existing Plant				
Coal	-	128	128	-
Peat	-	150	150	-
Gas Baseload	-	104	104	-
Gas Mid Merit	-	108	108	-
Hydro	-	70	70	-
Pumped Storage	-	35	35	-
Peakers	-	31	31	-
Wind (1000MW)	-	61	61	
Interconnector (Moyle)		23	23	

4.9 GAS CAPACITY COSTS

Gas Capacity costs are included for those stations that utilise gas in their operation. These costs are either treated as an annual fixed cost or are incorporated into short-run marginal costs of generators, depending on the optimal product for each station and assuming a liquid market in the trading of short-term gas capacity products exists.

An estimate of the typical station's gas consumption for each type of plant is used to calculate the optimal product and the resulting cost. Existing baseload and mid-merit CCGTs and the new CCGTs are accordingly assigned an annual gas capacity product, which is included in their fixed costs per MW above, while the new OCGTs and ADGTs are assigned a daily gas capacity product, which is incorporated into their start up costs.

These gas capacity costs vary for each station across Portfolios and scenarios as the station's running hours and gas consumption vary.

The cost of annual and daily gas transmission capacity is taken from the Bord Gais Networks' Gas Transmission Tariffs for 2008/09[24] and the decision paper on short-term tariffs.[25]

4.10 FIXED GENERATION / OTHER RENEWABLES

Fixed generation is the capacity of small plants and industrial units that operate outside of the SEM, and is treated in PLEXOS as negative demand.

In the AIGS baseload renewable energy is assumed to have an availability of 0.85 and a capacity credit of 0.99. Variable renewable resources (tidal, wave, photovoltaic) are treated as a form of baseload renewable generation in the analysis. Tidal and wave are assumed to have a capacity factor of 0.31, and photovoltaic a capacity factor of 0.1. The variable renewable generation category is assumed to have a capacity credit of 0.2.

Portfolios 1 to 4 envisage 182MW of baseload renewable capacity and 72MW of tidal capacity, while Portfolio 5 envisages 360MW of baseload renewable capacity and 200MW of tidal capacity. Including run-of-the-river hydro, Portfolio 1 to 4 have a renewable power production (non-wind) of 2.3 TWh and Portfolio 5 has a renewable power production (non-wind) of 4.1 TWh.

In the RAs' modelling the current capacity profile for fixed generation as per the validated model was applied to the 182MW of baseload renewables in portfolios 1 to 4 and to the 360MW of baseload renewables in Portfolio 5. This current capacity profile gives an average capacity factor of 0.85. The tidal capacities of 72MW and 200MW respectively were scaled by (31/85) and then added to the baseload renewable total. 190MW was added to fixed

---

[24] CER/08/151: Decision on BGN Allowed Revenues and Gas Transmission Tariffs for 2008/09.

[25] CER/07/115: Short Term Tariff Analysis, Response and Decision Paper.

generation in each portfolio to account for existing installed CHP and industrial units (carrying on the trend of growth from the GAR 2008-2014 to 2020).

4.11 MODELLING OF FLOWS ACROSS THE INTERCONNECTORS WITH THE GB MARKET

In the RAs' modelling it is assumed that the two interconnectors, Moyle and East West, allow for seamless and instantaneous trading between the SEM and the BETTA market in relation to price differentials. An adjustment to incorporate uplift and capacity payments is added as a wheeling charge to take account of the differences in SEM and BETTA price components.

It is important to note that the interconnectors are essentially being treated as the most flexible generation units in our unconstrained model, and that this tends to reduce the operation of the conventional flexible units such as pumped storage, ADGTs and OCGTs.

4.12 SENSITIVITY ANALYSIS ASSUMPTIONS

The assumptions set out above represent what might be thought of as a median or central case. To test the sensitivity of the results to different assumptions, analysis was made of the effect of varying the central scenario assumptions. Alternative cases considered were:

a. Load growth to 2020 – low case growth at 2.7%

b. Fuel and carbon prices – high and low cases at 50% above and below the central scenario respectively

c. Cost of capital – alternative WACCs of 10% and 12%

d. Generation Start Cost bids – increase the variable operation and maintenance (VOM) component of start costs by 50% (an arbitrary amount) for plant types which display a substantial increase in their number of starts vis-à-vis the current 2008/09 model.

5 RESULTS

This section summarises the results of the RAs' market modelling study, with a particular focus on the central scenario. The results are shown in an amalgamated form for all scenarios in the appendices of this report. The amalgamated results of our central scenario are contained in **Appendix A**. The low price variant is set out in **Appendix B**; the high price variant in **Appendix C** and the low demand growth variant in **Appendix D**.

A summarised version of the results and an outline of the key differences are also given below in the case of the low price, high price and low demand growth scenarios.

5.1 SYSTEM MARGINAL PRICE

The table below shows the annual average System Marginal Price (SMP) for Portfolios 1 to 5, in both time- and load-weighted terms. The load-weighted price is typically higher than the time-weighted price, as higher SMPs generally coincide with periods of high load, though the gap between the load- and time-weighted prices is smaller in Portfolios 2 through 5 than in Portfolio 1, suggesting that increased penetration of wind will tend to flatten the price duration curve.

Table 10: System Marginal Price

Prices (€/MWh)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Avg Time-Weighted SMP	135.0	124.8	148.0	109.2	115.5
% ∆ on Portfolio 1		-6%	12%	-18%	-13%
Avg Load-Weighted SMP	145.0	132.5	158.8	114.0	121.5
% ∆ on Portfolio 1		-9%	10%	-21%	-16%

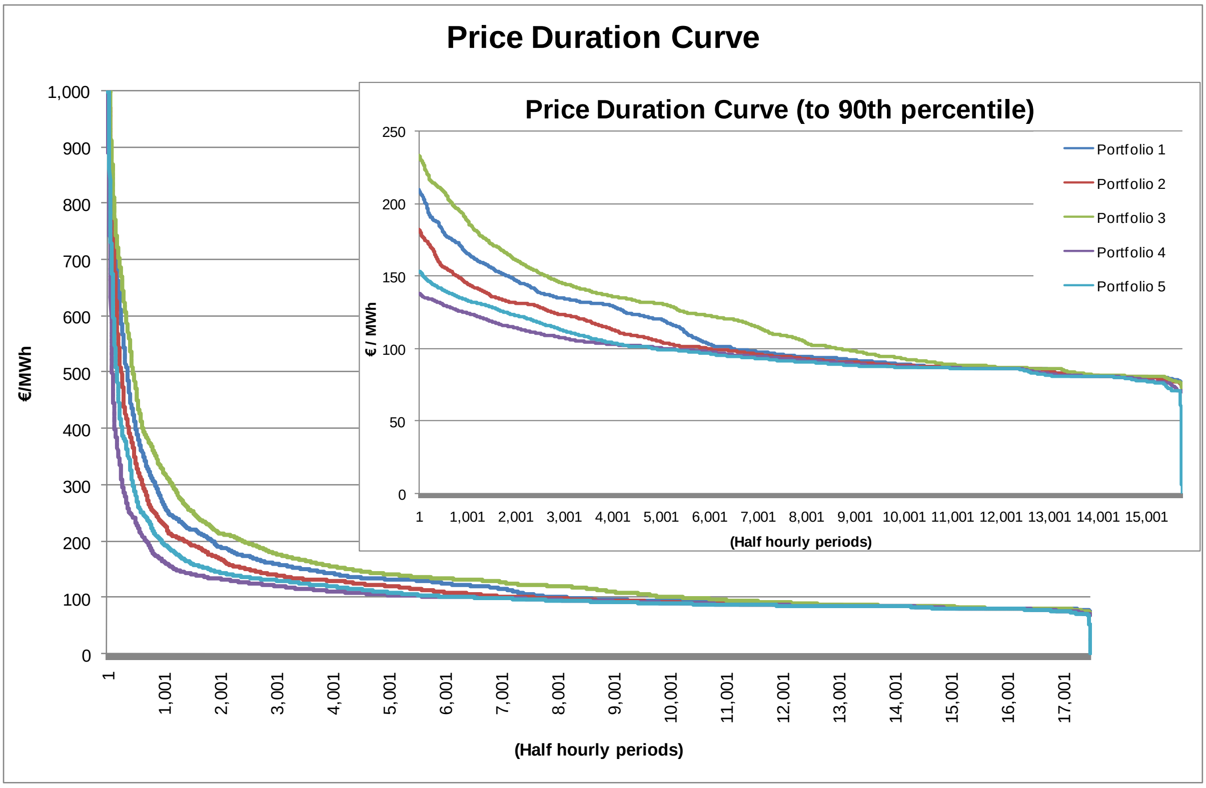
The highest absolute time- and demand-weighted prices are in Portfolio 3, which contains more Open Cycle Gas Turbines (OCGTs) and fewer Combined Cycle Gas Turbines (CCGTs) than any of the other portfolios. The lowest absolute prices are in Portfolio 4 which is the only portfolio with new coal capacity (1,163MW).

A comparison of Portfolios 1, 2 and 5, which have 2,000MW, 4,000MW and 6,000MW of wind, respectively, indicates the dampening effect of increasing price-taker generation (wind) on SMP. This is to be expected, since SMP will broadly reflect the variable costs of production; the more wind there is on the system, the lower SMP would be expected to be.

However, it should be noted that the amount of wind capacity on the system is not the only element changing between the portfolios – new generation units comprising the portfolios are also changing - and that comparisons do not hold all other elements constant. Therefore, while in general it can be seen that as the capacity of wind increases on the whole SMPs drop, a significant factor in the equation is also the type of conventional plant that make up the rest of the portfolio. Thus Portfolio 3, which includes no new CCGTs or coal stations and twice as much OCGT capacity as in Portfolio 2, has the highest SMPs of all five portfolios.

The price duration curves of the five portfolios are shown in the first graph below which illustrates the more or less uniform differences across the portfolios. The graph displays the full duration curves, and in the inset the last 10 percentiles were omitted in order to offer a clearer picture of the differences between the portfolios. As might be expected, the preponderance of OCGTs in Portfolio 3 results in the highest mid-merit and peaking prices of all the plant portfolios. And, despite Portfolio 4 having the lowest average prices, it is Portfolio 5 that has the lowest absolute prices, with a minimum of almost zero. Negative prices are not observed in any of the portfolios. Surplus generation over load in the SEM itself is exported to the GB market. This is not surprising given the very flexible treatment of the interconnectors in the SEM PLEXOS model.

Figure 5: Price Duration Curve



As the PLEXOS model uses perfect foresight of wind output (as does the actual market software) it doesn't lend itself to providing the most useful measure of the true price and cost volatility due to intermittent generation. These costs would be captured to a greater extent through system operator costs. Having said that, the figures from our unconstrained schedule suggest that while the volatility of prices tends to fall with increased capacities of wind in our unconstrained model run, the type of thermal stations that make up the rest of the portfolio can offset that tendency. Thus, Portfolio 3 exhibits the highest price volatility of all five portfolios; and Portfolio 4 (with a large amount of new coal capacity added by 2020) the lowest of all five portfolios.

The standard deviations of half hourly SMPs across all portfolios in the central scenario are shown in the table below. As a reference point, the standard deviation of SMPs in the 2009 SEM PLEXOS model is 60.1, which suggests that increased wind penetration will tend to increase price volatility over the coming years, unless new coal capacity is added to the system.

However, as alluded to above the SEM is based on an unconstrained ex post market with perfect foresight and therefore the effects of intermittent wind generation are likely to be seen to a large extent through constraints and ancillary services costs. Therefore, the relative riskiness for new entrants to the SEM is not clearly demonstrated by increases in wind generation in the unconstrained schedule.

Table 11: Standard Deviation of Half Hourly SMPs

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Standard Deviation of Half Hourly SMPs	103.4	94.0	117.6	64.0	80.0

The histograms below show the frequency of prices, up to both the 100th the 90th percentiles, for all the portfolios. The general shape of the price distribution does not change significantly across the portfolios but the range of prices does change. The flatter shape to Portfolio 3 shows the increased frequency of higher prices. Portfolios 4 and 5 have a greater frequency around lower prices.

Figure 6: SMP Histogram for Portfolio 1

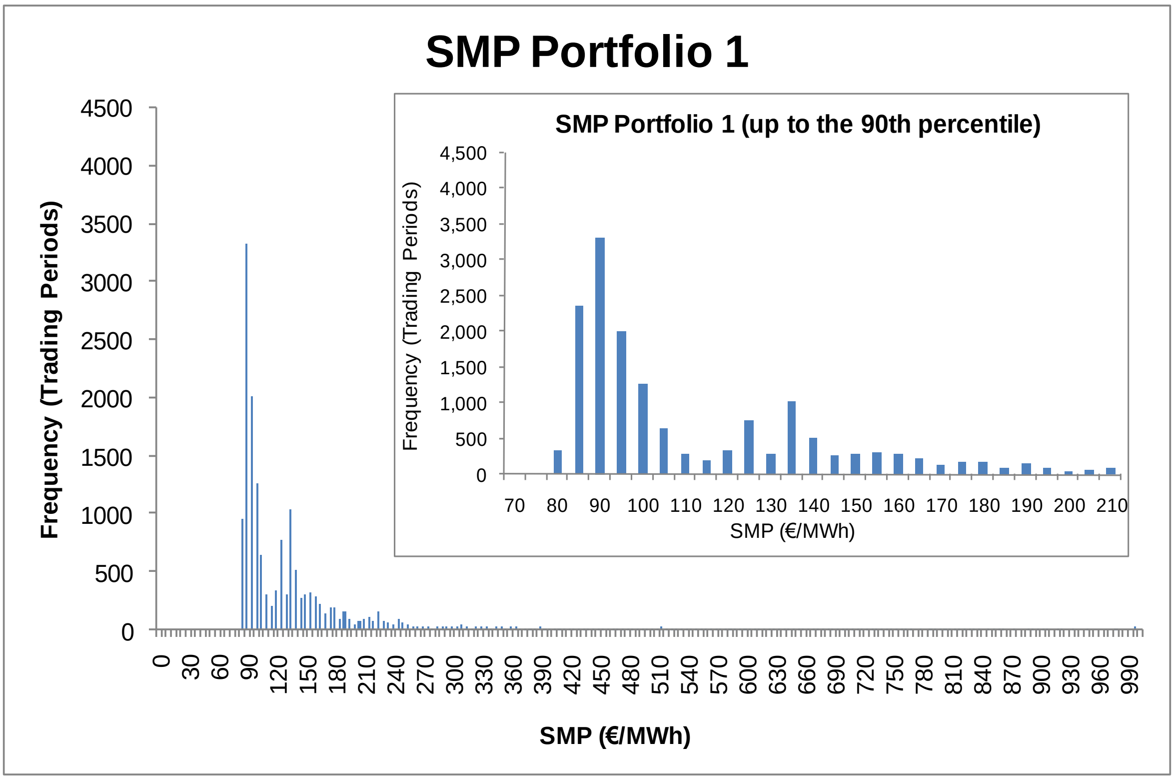


Figure 7: SMP Histogram for Portfolio 2

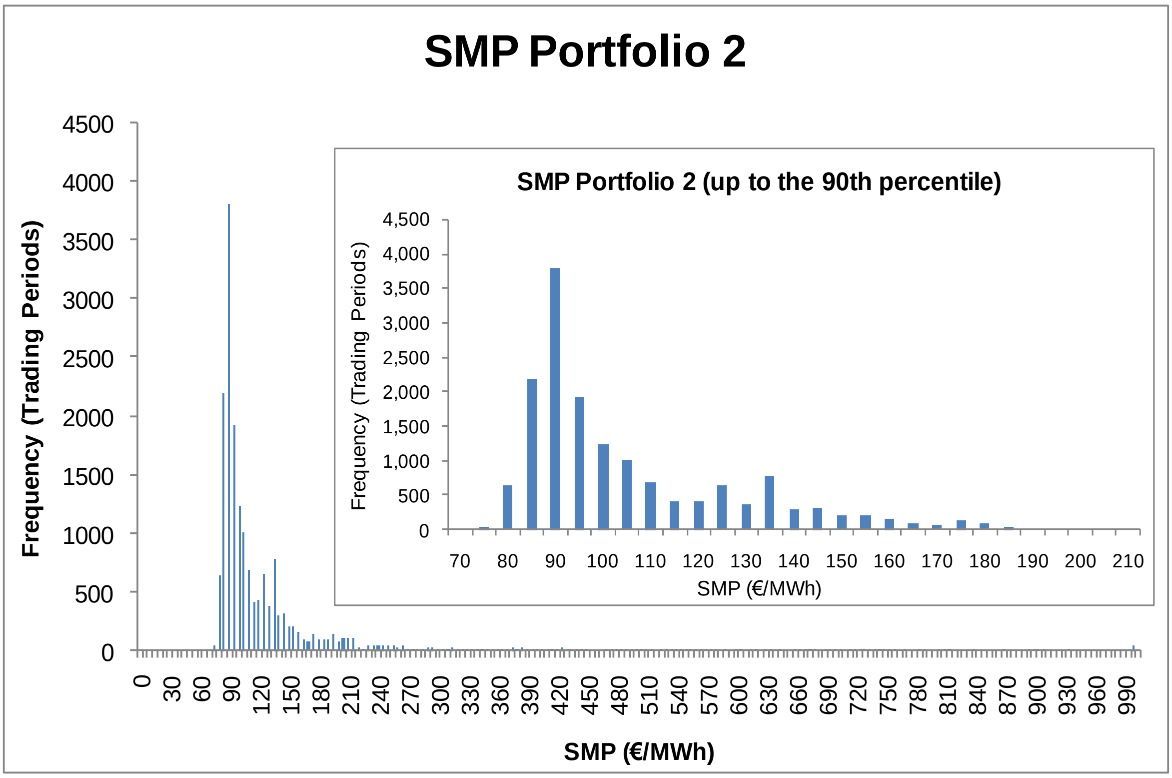


Figure 8: SMP Histogram for Portfolio 3

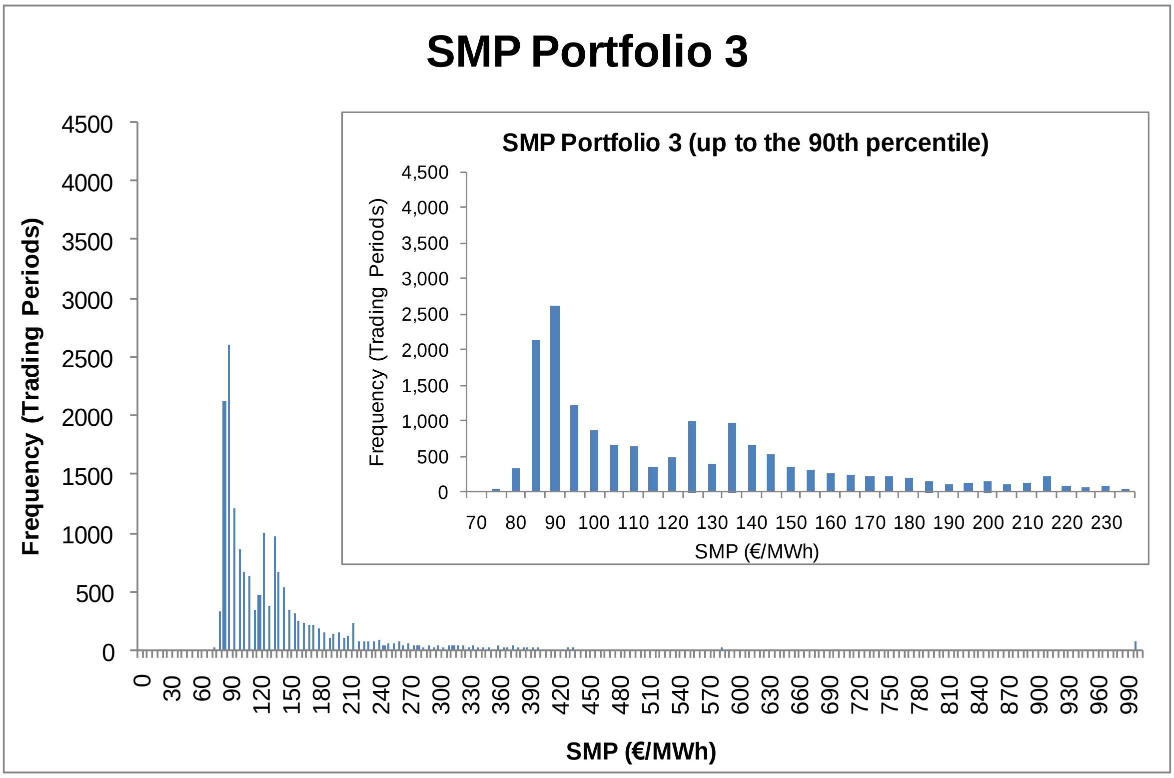


Figure 9: SMP Histogram for Portfolio 4

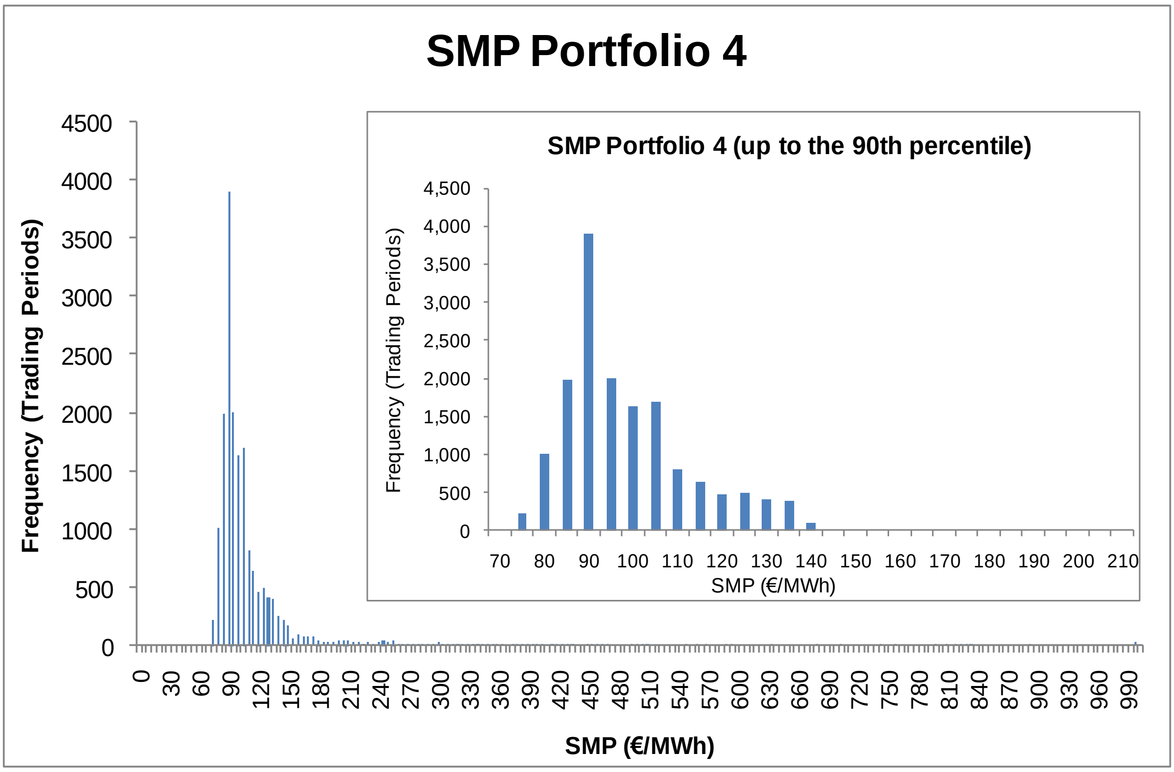
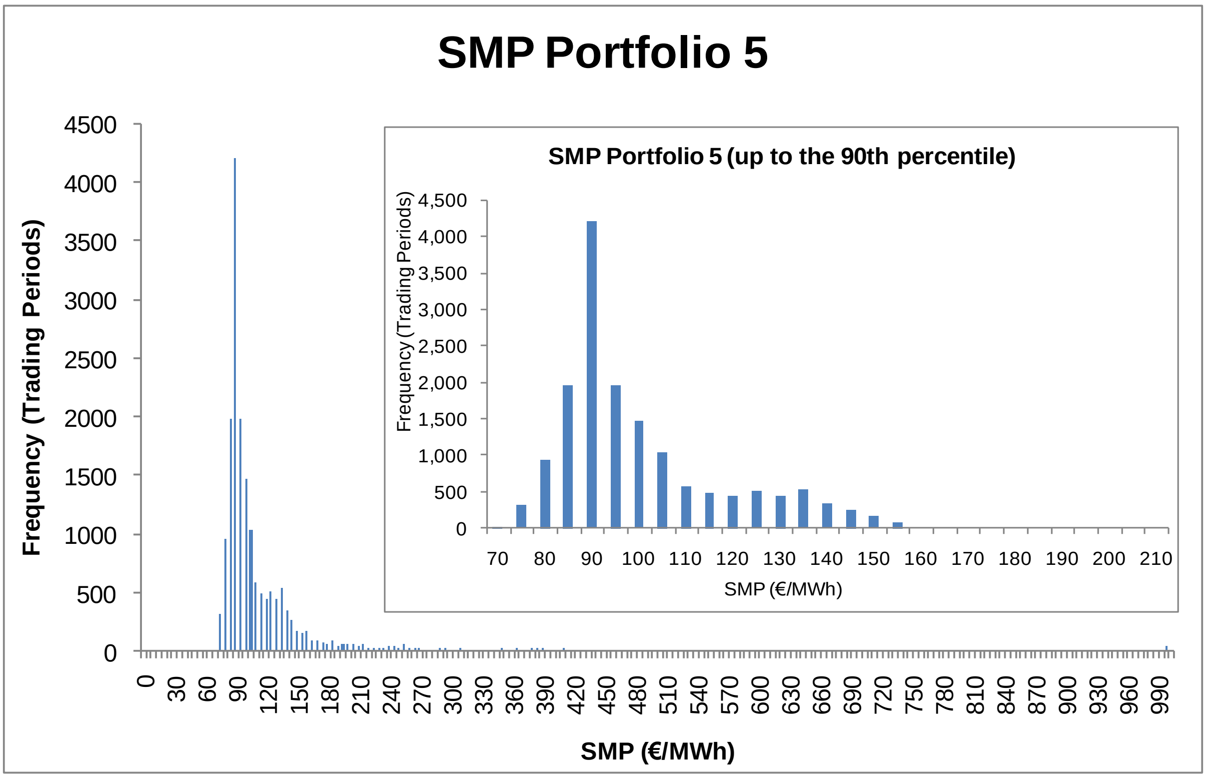


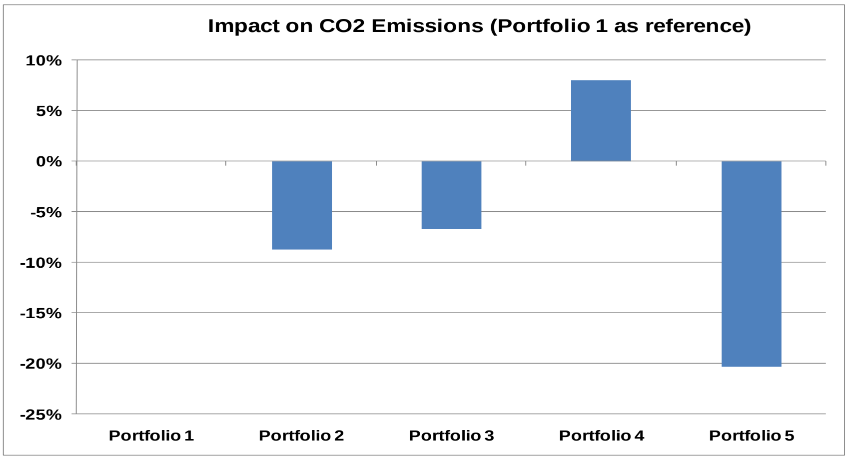
Figure 10: SMP Histogram for Portfolio 5



5.2 EMISSIONS

The European Commission's energy and climate change package, as endorsed by EU leaders, seeks to achieve a reduction in the emission of greenhouse gases of at least 21% compared with 2005 levels. A key means of achieving this target is through increased penetration of renewable generation. A mandatory EU target of 20% renewable energy by 2020 is also proposed as part of the European Commission's package.

Figure 11: CO_2 Emissions Relative to Portfolio 1



In our study we find that carbon dioxide emissions across the portfolios fall as the capacity of wind increases, with the exception of Portfolio 4 where the impact of new coal stations increases emissions compared with those in Portfolio 1.

The table below includes carbon emission figures on both an All Island and Ireland basis. The Ireland figures are shown on the basis of an allocation of 75% of carbon emissions from new thermal plant. We understand that the target level of carbon emissions for electricity generation in 2020 is approximately 12.3 million tonnes.[26] Our study indicates that the electricity generation sector will not reach this target in any of the portfolios examined.

However, a number of limitations need to be borne in mind when looking at the results of modelling emissions with PLEXOS. First, the model used is an unconstrained model that ignores the transmission system and system operation issues (such as the scheduling of reserves). Second, the PLEXOS validation exercise carried out by NERA at the beginning of 2008 noted that PLEXOS has a tendency to over commit OCGT stations in its scheduling. These two caveats might be expected to have opposing effect on the figures; the transmission system and system operation would generally tend to increase emissions and reducing over commitment would be expected to reduce them. This study does not attempt to quantify these caveats.

Table 12: CO_2 Emissions

Carbon Emissions (Mtonnes)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
All-Island	23.6	21.5	22.0	25.5	18.8
Ireland (with 75% of new thermal gen)	17.6	16.0	16.4	19.3	14.2

[26] The EU as a whole is required to reduce Industrial CO_2 emissions from the 2005 level by 21% in 2020. Applying this target to the Irish electricity sector, the 2005 emissions were approximately 15.6 million tonnes and a 21% reduction results in approximately a 12.3 million tonnes target for 2020. While no target figure is assumed here for Northern Ireland it is understood that a key goal in the NI programme for government is to reduce GHG emissions by 25% below 1990 levels by 2025.

The value of carbon emissions savings across the portfolios with reference to Portfolio 1, assuming a carbon price of €30 per tonne, is shown in the table below.

Table 13: Cost of CO_2 Emissions

Carbon (€millions)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Total value of CO_2	**707.1**	**645.4**	**659.8**	**763.9**	**563.0**
Saving relative to Portfolio 1		61.6	47.3	-56.9	144.1

5.3 GENERATION

The graphs below show the generation by fuel type and by station type for the All Island unconstrained modelled system. It is clear that gas is the fuel that is displaced the most by increased wind in Portfolios 2, 3 and 5 and by the new coal units in Portfolio 4.

The breakdown by station type shows the varying output across the portfolios and the declining output in the existing baseload gas category in particular with increased wind penetration.

Figure 12: All-Island Generation by Fuel Type

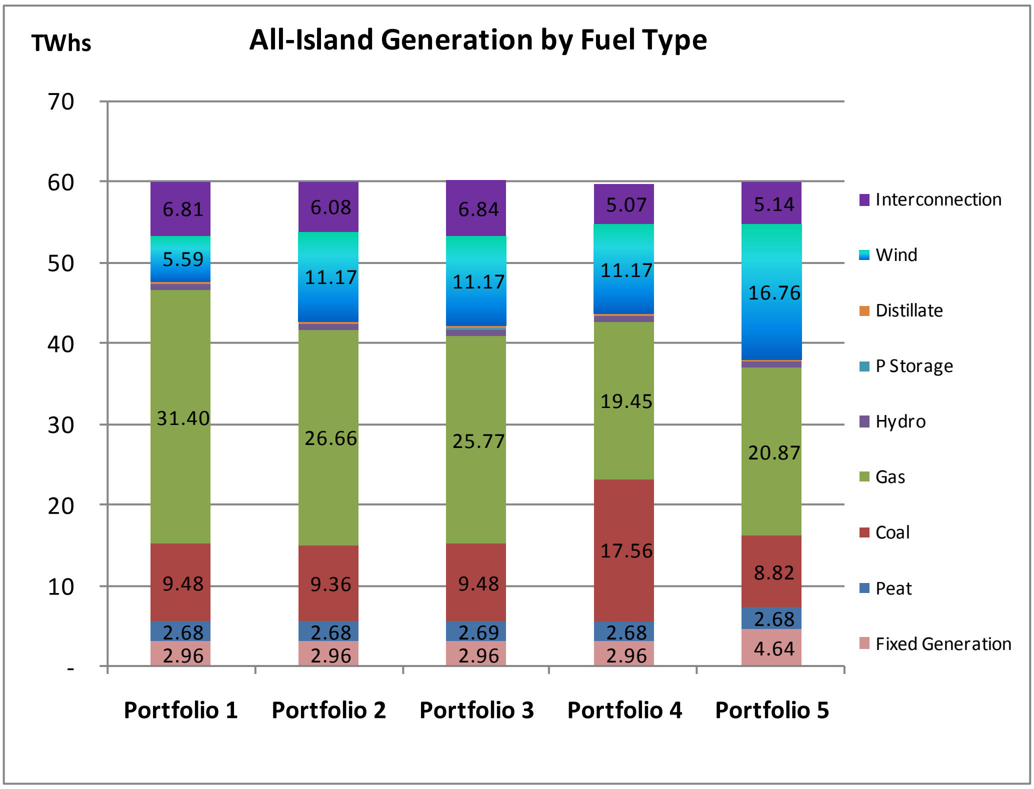
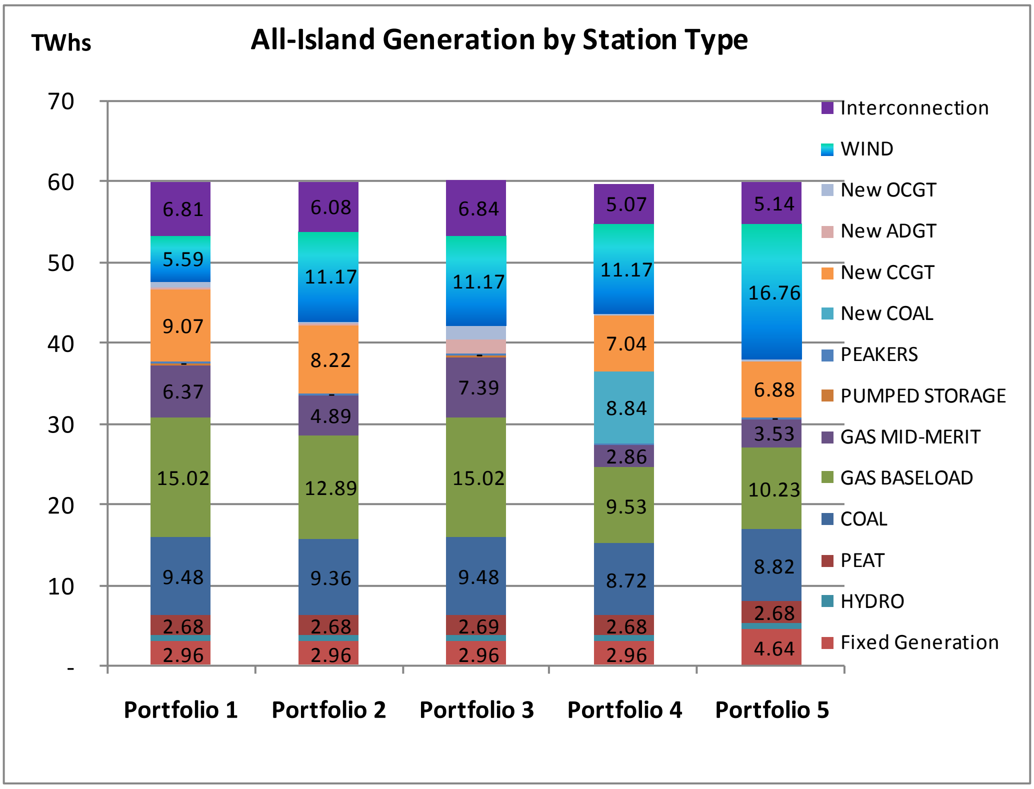


Figure 13: All-Island Generation by Station Type



The following five graphs below give a more detailed picture of the running order of the different station types across the year. The capacities of the different types of station are represented along the x-axis (in 250MW intervals) and the capacity factors are displayed along the y-axis. From these figures a crude categorisation of the different station types into baseload, mid-merit and peaking stations can be carried out, such as the following:

- Baseload - Stations with a capacity factor of 75% or above.
- Mid-Merit – Stations with a capacity factor below 75% and above 15%.
- Peaking – Stations with a capacity factor of 15% or below.

It should be noted that wind does not fall into the category assigned to it by the above criteria (mid-merit). Wind operates more like baseload, in the sense that it has zero marginal cost (and hence is almost always in merit) and the only thing that prevents it from running is the intermittent nature of its energy source, despite having a capacity factor of approximately 32%. The table below details the specific existing plant placed in each category on the basis of the unit's capacity factors in our validated 2009 SEM model run.

Table 14: Existing Gas & Peaker Units by Category

Gas Baseload (Unit Name)	Gas Mid-Merit (Unit Name)	Peakers (Unit Name)
Coolkeeragh CCGT	Aghada Unit1	Kilroot GT1
Dublin Bay Power	Ballylumford Unit 10	Kilroot GT2
Tynagh	Ballylumford Unit 31	Rhode Unit 1
Huntstown	Ballylumford Unit 32	Rhode Unit 2
Huntstown Phase II	Poolbeg CCGT	Asahi Peaking Unit
Sealrock 3	Marina (no steam)	Ballylumford GT1

Sealrock 4	Ballylumford GT2
	Coolkeeragh GT8

By taking a broad view of the graphs, looking across all portfolios, a consistent merit order of thermal stations by fuel can be seen, starting with peat, followed by coal, then gas and finally distillate. The capacity factors of wind and hydro remain unchanged across the portfolios as they have zero variable costs and a fixed output profile.

At the level of station type, we can see that in Portfolio 1 peat, coal, existing gas (labelled Gas BL) and new CCGTs fall into baseload operation. In Portfolio 2, the existing CCGTs move from baseload to mid-merit operation. With Portfolio 3, which has no new CCGTs, the existing CCGTs operate as baseload, together with peat and coal. In Portfolio 4, with the introduction of only new coal stations, only peat and the new and old coal have baseload operation and the new and existing CCGTs fall into the mid-merit category. Portfolio 5 has only peat and coal operating as baseload with new and existing CCGTs in mid-merit operation.

Figure 14: Capacity & Capacity Factors for Portfolio 1

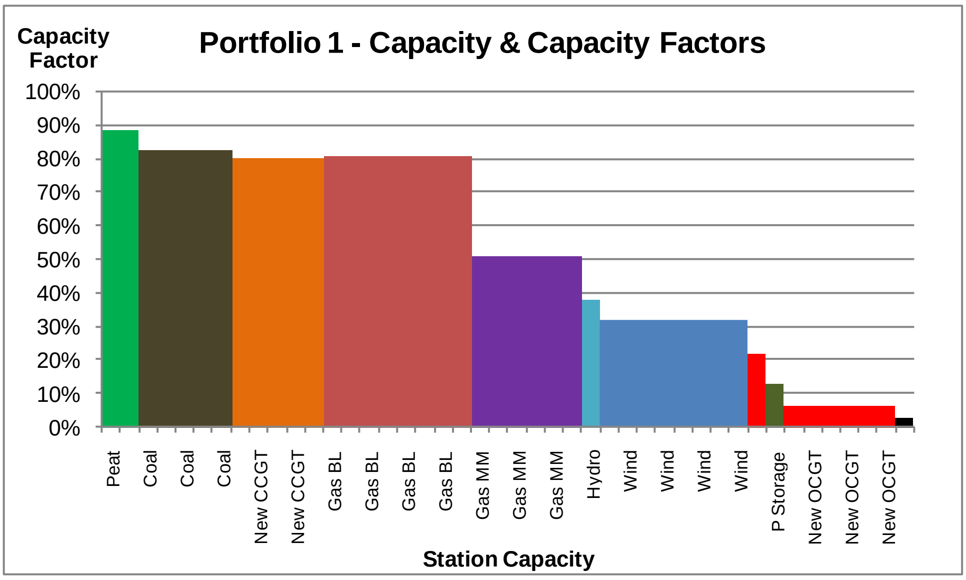


Figure 15: Capacity & Capacity Factors for Portfolio 2

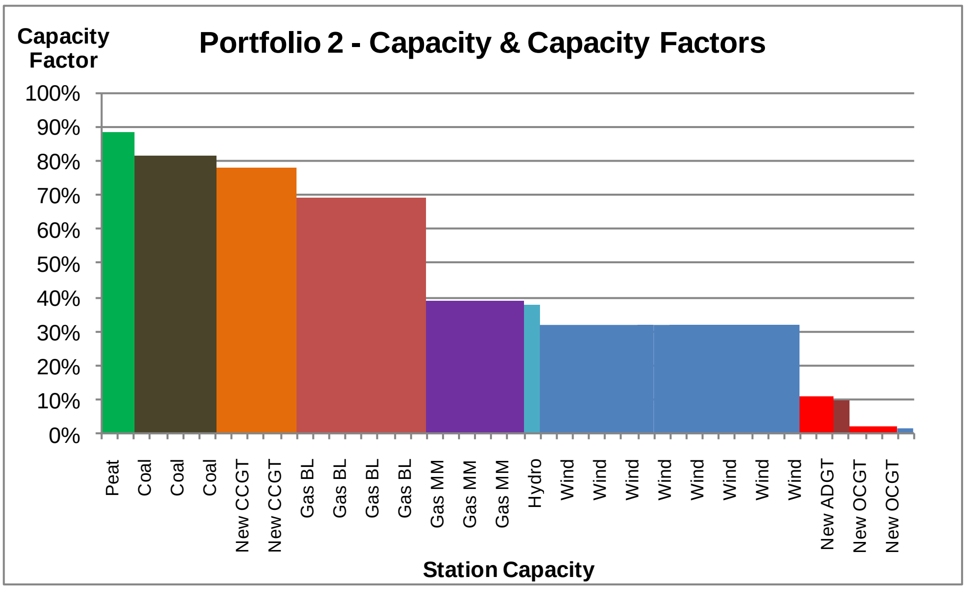


Figure 16: Capacity & Capacity Factors for Portfolio 3

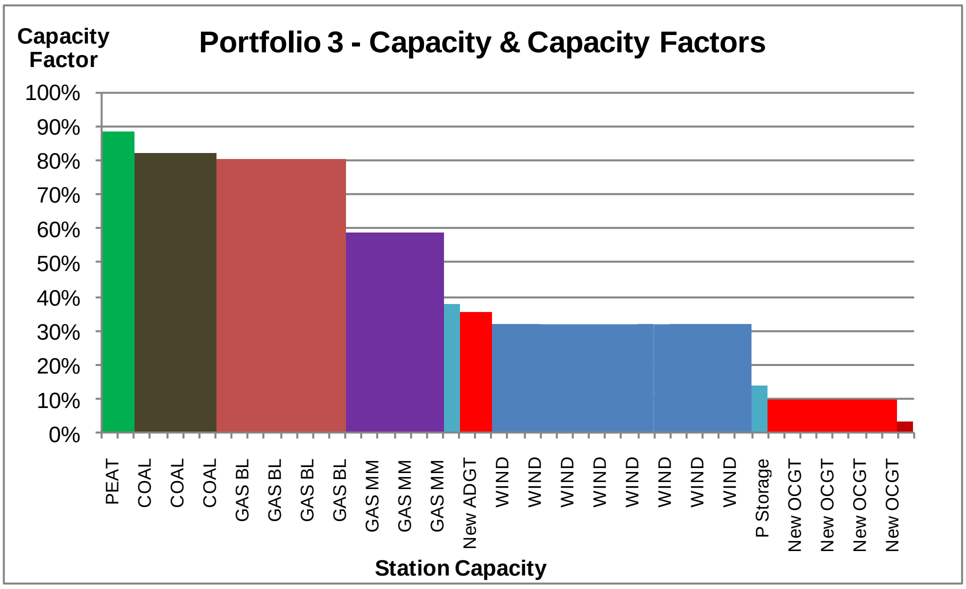


Figure 17: Capacity & Capacity Factors for Portfolio 4

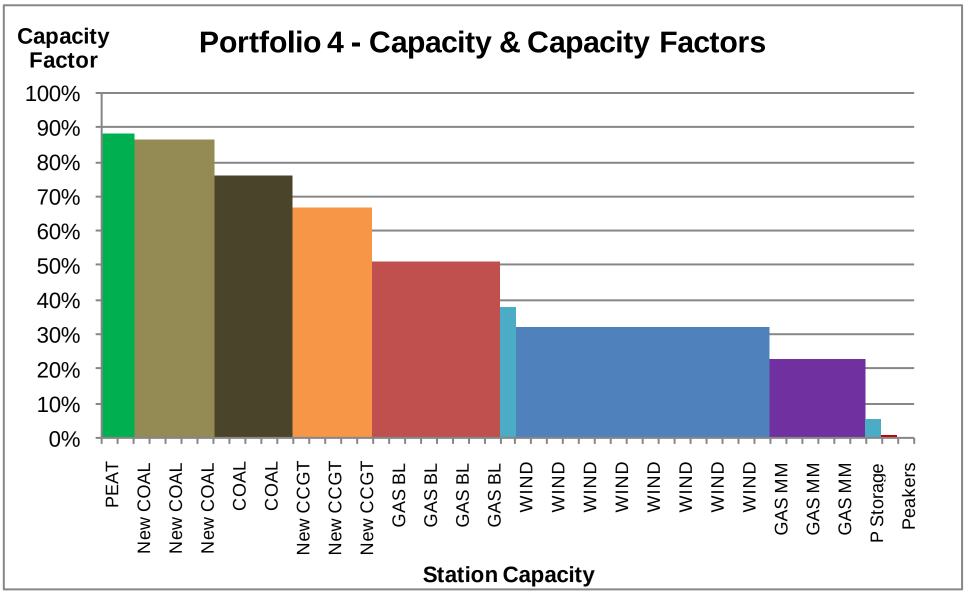
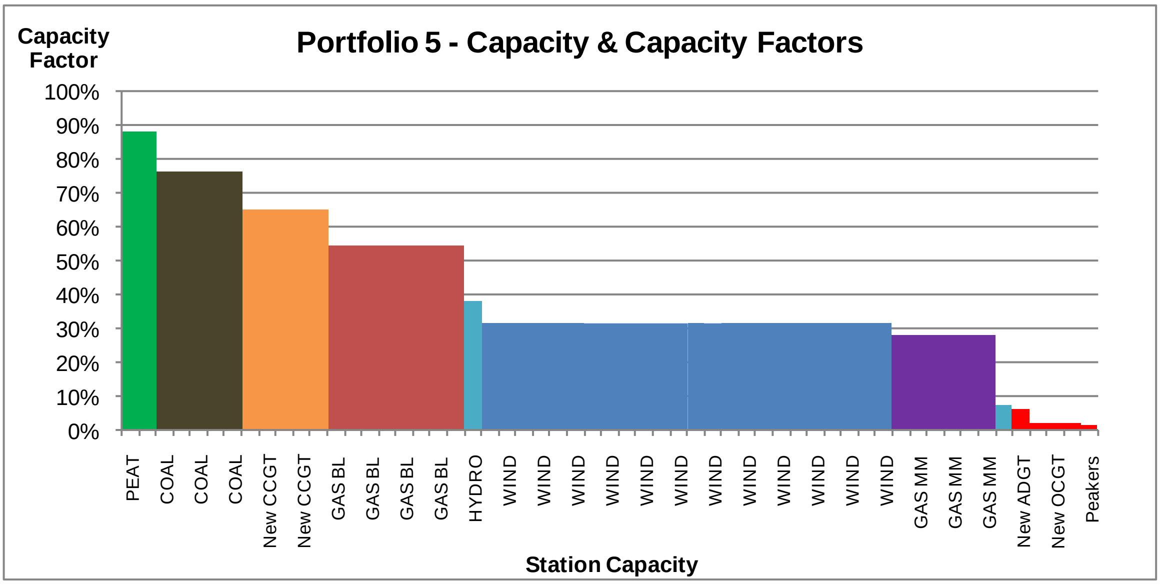


Figure 18: Capacity & Capacity Factors for Portfolio 4



The capacity factors depicted in the graphs above are also shown in the following table:

Table 15: Generation Capacity Factors

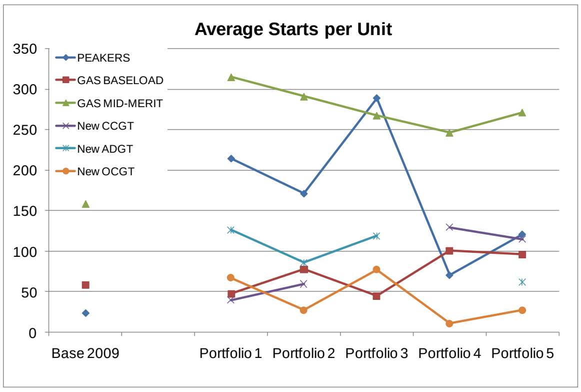
Generation Capacity Factors	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	82%	81%	82%	76%	77%
PEAT	89%	89%	89%	89%	88%
GAS BASELOAD	81%	69%	81%	51%	55%
GAS MID-MERIT	51%	39%	59%	23%	28%
HYDRO	38%	38%	38%	38%	38%
PUMPED STORAGE	13%	10%	14%	6%	8%
PEAKERS	3%	2%	4%	0%	1%
WIND	32%	32%	32%	32%	32%
New COAL				87%	0%
New CCGT	80%	78%		67%	65%
New OCGT	6%	2%	10%	1%	2%

New ADGT	22%	11%	36%		6%
INTERCONNECTION (900MW)	86%	77%	87%	64%	65%
FIXED GENERATION	85%	85%	85%	85%	85%

The charts below show the number of starts over the year that a typical station has across the portfolios. For comparative purposes the number of station starts for the year 2009 has been included to the left in the charts.

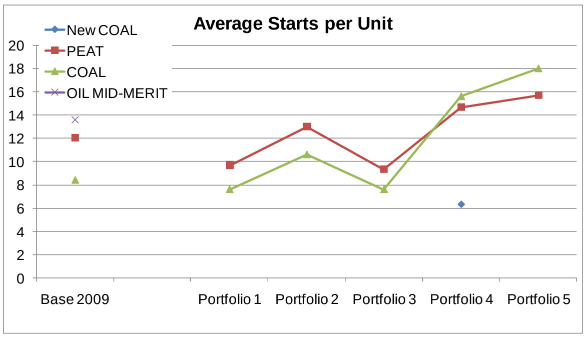
A significant caveat of this analysis is that the work undertaken during the NERA and KEMA PLEXOS validation exercises showed that the software tends to over commit units. Therefore, the usefulness of this analysis may be to indicate the relative extent of the increase in unit starts compared with the validated 2009 SEM model run, rather than the absolute level of unit starts.

Figure 19: Annual Average Starts by Unit (1)



The charts to the right show that for the typical gas baseload plant the number of starts increases in Portfolios 2, 4 and 5, from just over 50 up to approximately 100 starts. New CCGTs also show a noticeable increase in starts in Portfolios 4 and 5. The other stations types, peaker, OCGTs and ADGTs, are relatively flexible plant that typically operate with a high number of starts.

Figure 20: Annual Average Starts by Unit (2)



The second chart shows the relatively low number of starts that the coal and peat stations have over the year, compared with the more expensive and flexible gas plant.

The variable operation and maintenance (VOM) costs associated with starts included in the validated PLEXOS model do not take into account the anticipated increased number of starts of conventional units associated with increasing levels of intermittent generation. To assess the sensitivity of our central scenario results with respect to increased unit starts the RAs carried out an analysis by increasing the VOM start costs of those units most affected by an arbitrary amount of 50%. The results of this analysis are discussed in section 5.9.4.

The table below shows the share of renewable generation across the portfolios. Wind is the primary change between the portfolios, along with additional embedded renewable generation in Portfolio 5. The shares assigned to the Republic of Ireland (ROI) assume that the capacity of wind in Northern Ireland reaches 504MW in 2020 and that the ROI share of all-island demand is 75%. This shows that in our study the current Irish government's target of 40% of electricity consumption being met by renewable sources lies close to Portfolio 5.

Table 16: Renewable Share of Energy

Renewable Shares	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Renewables as percentage of Generation	**13%**	**22%**	**22%**	**22%**	**35%**
Renewables as percentage of final Demand	15%	25%	25%	25%	38%
Renewables as percentage of Irish Demand*	**13%**	**26%**	**26%**	**26%**	**41%**

*** NI wind held at 504MW * RoI demand = 45,000 GWh * 75% of Fixed Generation in RoI**

5.4 INTERCONNECTION FLOWS

In section 4.11 it was stated that the SEM PLEXOS model allows for seamless and instantaneous trading between the SEM and the BETTA market across the interconnector units. This essentially has the effect of treating the interconnectors as the most flexible generation units in the unconstrained system, and thereby increasing their capacity factor while reducing those of the more conventional flexible units such as Turlough Hill, the OCGTs and ADGTs.

The interconnector flows in our model are predominately from Great Britain, where the market price is on average lower than that in the SEM, into Ireland. It can be seen from the graph below that volumes imported from GB do generally fall as the levels of wind capacity increase, with the exception of Portfolio 3 which has the highest average SEM SMPs.

Table 17: Interconnection Utilisation Factors

Portfolio 1	86%
Portfolio 2	77%
Portfolio 3	87%
Portfolio 4	65%
Portfolio 5	68%

Portfolio 5, with the largest volume of wind capacity, does begin to register a small amount of exports. The utilisation factor of the interconnectors can be seen in the above table and shows that in Portfolios 1 and 3 they are running close to maximum capacity while Portfolios 2, 4 and 5 show a lower level of usage. The utilisation factor shows the extent to which the full import and export capacities of the two interconnectors are being used in our 2020 study.

Figure 21: All-island Interconnection Imports & Exports

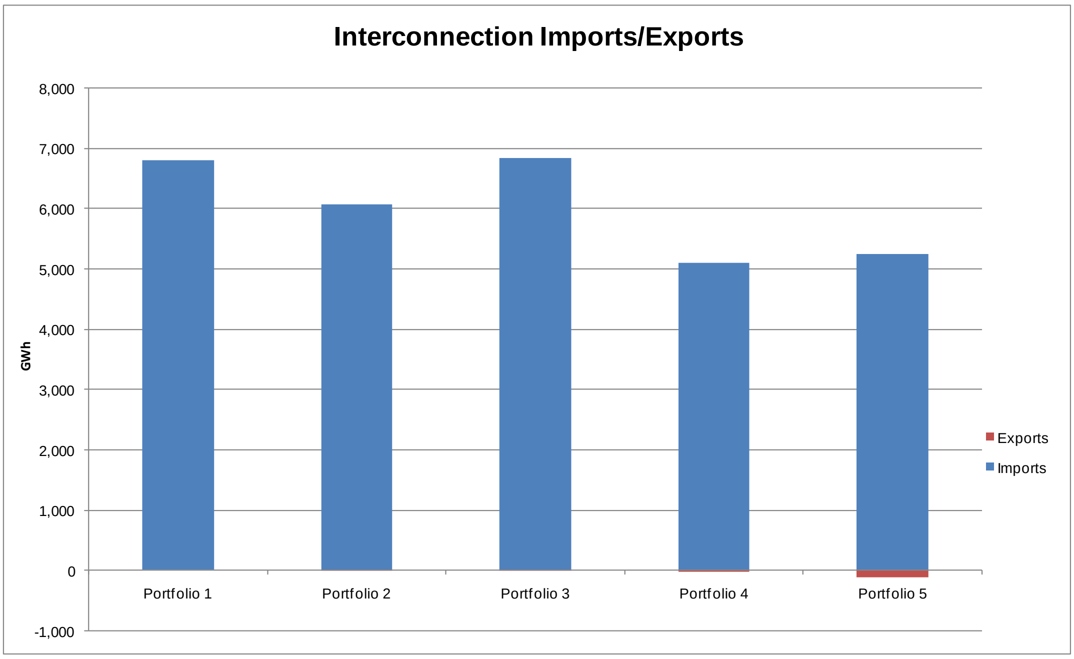


Table 18: Time Importing to and Exporting from the All-Island

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Time Importing	96%	91%	95%	84%	85%
Time Exporting	0%	0%	0%	2%	3%
Time Not Used	4%	9%	5%	14%	12%

5.5 GENERATOR REVENUES

The generator revenues that are examined in this report are those derived from the wholesale market through payments for energy (at the System Marginal Price (SMP)) and for availability (through the Capacity Payment Mechanism (CPM)). Our analysis excludes any revenues which would be earned from ancillary services and from constraint payments through out-of-merit dispatch.

5.5.1 ENERGY

The first table below outlines the revenue received by the different types of generation plant for each of the portfolios studied. Revenue is largest in Portfolio 3 which has the largest number of OCGTs and the highest average SMP. Portfolio 4 has the lowest overall revenue, which is the result of the combined effect of wind and the new coal stations on SMP.

Stations that are further up the merit order are more at financial risk to the changing SMPs, while those at the bottom have the least risk. From the first table direct comparisons can be made of the totals for existing stations whose capacities do not change across the portfolios. Those existing stations at the lower end of the merit order, such as hydro, peat and coal, suffer the least lost revenues with falling SMPs in Portfolios 2, 4 and 5.

On the other hand, those existing stations further up the merit order such as the gas and distillate stations suffer significant reductions in revenues in Portfolios 4 and 5. The interconnector falls more into the latter category as can be seen by the reduced revenues in Portfolios 4 and 5.

When examining the new stations the varying levels of installed capacities need to be borne in mind when comparing revenues across the portfolios. The second table below shows revenues on a per MW basis so that a direct comparison can be made. In the case of new CCGTs, revenues for these stations follow the same pattern as the existing baseload plant which shows significant reductions in Portfolios 4 and 5.

The capacity of installed new OCGTs varies significantly, with Portfolios 2 and 5 43% lower than Portfolio 1, Portfolio 3 36% higher and Portfolio 4 nearly 80% lower. Generally, as the new OCGTs are at the higher end of the merit order they suffer significantly with falling SMP revenue levels. A substantial drop in revenues per MW can be observed in Portfolios 2, 4 and 5 where there is a significant amount of new CCGT (1,200MW) and Coal (1,163MW in Portfolio 4) added.

The capacities of new ADGTs also vary quite substantially across the portfolios with Portfolios 2 and 3 over 5 greater times than Portfolio 1, and Portfolio 5 15% higher. These stations are just below the OCGTs in the merit order due to their superior efficiency and while following somewhat of a similar pattern in terms of revenue, fare better on a revenue per MW basis.

Table 19: Generation Annual Pool Revenue

Generation Annual Pool Revenue (€million)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	1,260	1,150	1,384	942	1,014
PEAT	357	330	393	289	305
GAS BASELOAD	2,071	1,700	2,282	1,121	1,300
GAS MID-MERIT	1,037	771	1,273	395	546
HYDRO	125	113	136	92	102
PUMPED STORAGE	94	71	115	33	51
PEAKERS	46	33	62	9	24
WIND (Existing)	355	313	371	287	286
New WIND	355	939	1,114	861	1,430
New COAL				943	
New CCGT	1,259	1,050		799	843
New OCGT	195	44	408	6	47
New ADGT	35	113	344		15
INTERCONNECTION (Existing)	485	410	537	302	333
New INTERCONNECTION	485	410	537	302	333
TOTAL POOL REVENUE	**8,158**	**7,448**	**8,957**	**6,381**	**6,628**

Table 20: Pool Revenue per MW installed

Pool Revenue per MW installed (€000)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	959	876	1,054	717	772
PEAT	1,034	955	1,136	836	883
GAS BASELOAD	973	799	1,073	527	611
GAS MID-MERIT	726	540	891	276	382

HYDRO	579	525	627	425	470
PUMPED STORAGE	322	243	395	114	174
PEAKERS	117	85	161	22	62
WIND (Existing)	355	313	371	287	286
New WIND	355	313	371	287	286
New COAL				786	
New CCGT	973	875		666	703
New OCGT	135	53	207	20	57
New ADGT	389	211	642		135
INTERCONNECTION (Existing)	970	820	1,073	605	665
New INTERCONNECTION	970	820	1,073	605	665

5.5.2 CAPACITY

The capacity payment pot has been calculated using the 2009 draft BNE peaker price of €81.24/kW/year and with the load requirements for 2020 in Table 31. [27]

One assumption made here for simplicity is that the Best New Entrant plant will not earn infra-marginal rents in 2020 for each scenario consistent with the earnings estimated for the 2009 work. In the 2009 work the infra-marginal rent was estimated at zero as the peaker was only ever scheduled to run at the margin in simulation.

The calculations for the capacity requirement in each portfolio were based on best estimates available. The Capacity Requirement was estimated heuristically using outputs from statistical exercises that have been performed to date as follows:

1. Establish the capacity margin (as a percentage) above peak demand in existing exercises;
2. In each portfolio, apply a heuristic adjustment to this margin to reflect the mean conventional set size of the portfolio compared to the mean set sizes in exercises conducted to date; and
3. Apply this margin to the peak load in each scenario to obtain the Capacity Requirement estimate.

Table 21: Capacity Requirements (MW)

Portfolio 1	11,304
Portfolio 2	11,311
Portfolio 3	10,963
Portfolio 4	11,714
Portfolio 5	11,366

As can be seen in the table above right each portfolio has a slightly different capacity requirement. The estimates of station revenues from the CPM are shown in the tables below, first in terms of overall revenues and then second in terms of capacity payments per installed MW.

Table 22: Generation Annual Capacity Revenue

Generation Annual Capacity Revenue (€million)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5

[27] The annual fixed capacity payment pot is calculated as the annualised Best New Entrant Peaking Plant fixed costs times the capacity required to meet the adequacy standard.

COAL	111	107	104	110	104
PEAT	29	28	27	28	27
GAS BASELOAD	185	177	172	182	172
GAS MID-MERIT	120	114	111	118	111
HYDRO	19	18	17	18	17
PUMPED STORAGE	25	23	23	24	23
PEAKERS	34	32	31	33	31
WIND (Existing)	33	32	31	33	31
New WIND	33	95	93	98	155
New COAL				93	
New CCGT	110	98		101	95
New OCGT	124	68	156	26	66
New ADGT	8	43	42		9
INTERCONNECTION (Existing)	44	43	41	44	41
New INTERCONNECTION	44	43	41	44	41
TOTAL CAPACITY REVENUE	**918**	**919**	**891**	**952**	**923**

Table 23: Generation Revenue per MW Installed

Capacity Revenue per MW installed (€000)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	85	81	79	84	79
PEAT	84	80	78	82	78
GAS BASELOAD	87	83	81	85	81
GAS MID-MERIT	84	80	78	82	78
HYDRO	87	83	81	86	81
PUMPED STORAGE	84	80	78	83	78
PEAKERS	87	83	81	86	81
WIND (Existing)	33	32	31	33	31
New WIND	33	32	31	33	31
New COAL				78	
New CCGT	85	81		84	79
New OCGT	85	81	79	84	79
New ADGT	85	80	78		77
INTERCONNECTION (Existing)	89	85	83	88	83
New INTERCONNECTION	89	85	83	88	83

The following tables show total revenue, energy and capacity, by generation type in absolute terms and on a per MW basis.

Table 24: Total Pool and Capacity Revenues

Total Revenues (Pool + Capacity) (€million)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	1,371	1,257	1,488	1,052	1,118
PEAT	386	358	419	317	332
GAS BASELOAD	2,256	1,876	2,455	1,303	1,472
GAS MID-MERIT	1,156	886	1,385	512	657
HYDRO	144	131	153	110	119
PUMPED STORAGE	118	95	138	57	74
PEAKERS	79	65	94	42	55
WIND (Existing)	388	345	402	320	317
New WIND	388	1,035	1,207	959	1,585
New COAL				1,036	
New CCGT	1,369	1,147		899	939
New OCGT	319	111	564	32	113

New ADGT	42	156	385		24
INTERCONNECTION (Existing)	530	452	578	346	374
New INTERCONNECTION	530	452	578	346	374
TOTAL REVENUES (POOL + CAPACITY)	**9,077**	**8,367**	**9,848**	**7,333**	**7,552**

Table 25: Total Pool and Capacity Revenues per MW Installed

Total Revenue (Pool + Capacity) per MW installed (€000)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	1,044	957	1,133	801	851
PEAT	1,118	1,035	1,214	918	960
GAS BASELOAD	1,060	882	1,153	612	692
GAS MID-MERIT	810	620	969	359	460
HYDRO	666	608	708	511	551
PUMPED STORAGE	406	324	473	197	252
PEAKERS	204	168	242	108	143
WIND (Existing)	388	345	402	320	317
New WIND	388	345	402	320	317
New COAL	0	0	0	863	0
New CCGT	1,058	956	0	749	782
New OCGT	220	134	287	104	136
New ADGT	474	292	720	0	212
INTERCONNECTION (Existing)	1,059	905	1,156	692	748
New INTERCONNECTION	1,059	905	1,156	692	748

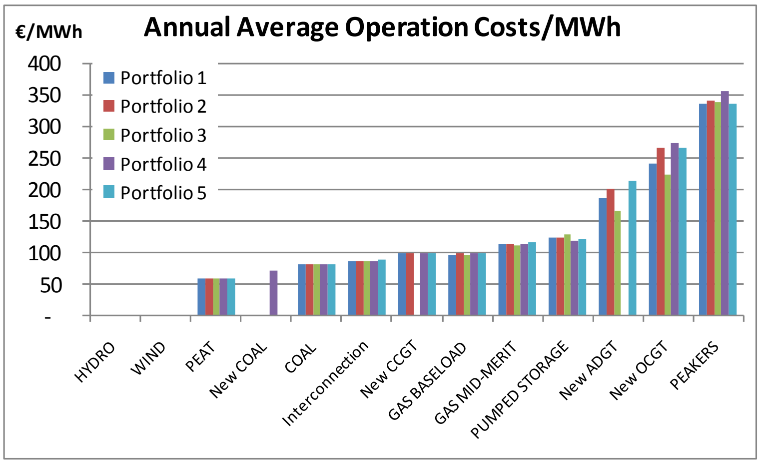
5.6 GENERATOR VARIABLE AND FIXED COSTS

Generator variable costs primarily comprise fuel and carbon costs. Thermal units also have VOM costs associated with starts and, in some cases, with their incremental bids. Wind and hydro generation have zero variable costs and are essentially treated as negative load in the SEM PLEXOS model. Costs associated with fixed generation are not taken into account in our analysis as they operate outside of the SEM.

5.6.1 VARIABLE COSTS

The total variable cost of each station is directly proportional to its generation. The graph to the right shows the annual average variable operation costs per MWh. This graph can be viewed as a proxy for the merit order of the different station types.

Figure 22: Annual Average Operating Costs by Station



Compared with Portfolio 1, total system variable costs in Portfolios 2 to 5 fall, with Portfolio 5 showing the lowest costs primarily due to the zero variable costs of 6,000MW of wind capacity. Portfolio 5 has a total variable cost savings of just under €1.4 billion in 2020 compared with Portfolio 1.

Table 26: Generation Annual Variable Cost

Generation Annual Variable Cost (€million)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	783	775	782	724	733
PEAT	161	161	161	161	161
GAS BASELOAD	1,471	1,274	1,470	952	1,019
GAS MID-MERIT	728	560	829	325	408
HYDRO					
PUMPED STORAGE	41	32	47	18	24
PEAKERS	30	22	41	6	16
WIND (Existing)					
New WIND					
New COAL				631	
New CCGT	897	808		701	683
New OCGT	187	40	378	5	41
New ADGT	32	102	278		13
INTERCONNECTION (Existing)	295	263	296	221	227
New INTERCONNECTION	295	263	296	221	227
TOTAL VARIABLE COSTS	**4,919**	**4,299**	**4,577**	**3,965**	**3,552**

5.6.2 FIXED COSTS

In terms of fixed costs there is a significant difference between the existing stations (including 1,000MW of wind and the Moyle interconnector) which have sunk capital costs, and the new stations and the new interconnector which have avoidable capital costs (when viewed from the perspective of a potential new entrant).

Fixed costs include the annualised cost of the initial capital investment (at an 8% weighted average cost of capital over the lifetime of the investment), gas capacity charges and annual recurring fixed O&M expenditures. Fixed costs increase from Portfolio 1 to 5 as the overall installed capacity increases, and as relatively expensive capacity (in the form of wind) displaces relatively cheaper capacity (OCGTs, ADGTs and CCGTs), as can be seen in the table below.

Table 27: Generation Annual Fixed Cost

Generation Annual Fixed Costs (€million)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	167	167	167	167	167
PEAT	52	52	52	52	52
GAS BASELOAD	225	226	225	227	226
GAS MID-MERIT	155	156	157	157	157
HYDRO	15	15	15	15	15
PUMPED STORAGE	10	10	10	10	10
PEAKERS	12	12	12	12	12
WIND (Existing)	61	61	61	61	61
New WIND	244	732	732	732	1,219

New COAL	0	0	0	413	0
New CCGT	246	228	0	228	228
New OCGT	125	71	169	27	71
New ADGT	11	69	69	0	14
INTERCONNECTION (Existing)	12	12	12	12	12
New INTERCONNECTION	45	45	45	45	45
TOTAL FIXED COSTS	**1,381**	**1,856**	**1,726**	**2,158**	**2,291**

The following table shows the total costs of the portfolios, the sum of the two preceding tables.

Table 28: Total Generation Costs (Fixed and Variable)

Annual Total Costs (Fixed + Variable) (€million)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	950	942	950	892	901
PEAT	213	213	213	213	213
GAS BASELOAD	1,696	1,500	1,695	1,179	1,245
GAS MID-MERIT	884	716	985	481	565
HYDRO	15	15	15	15	15
PUMPED STORAGE	51	42	57	28	34
PEAKERS	42	34	53	18	28
WIND (Existing)	61	61	61	61	61
New WIND	244	732	732	732	1,219
New COAL				1,044	
New CCGT	1,144	1,036		930	912
New OCGT	312	111	547	32	112
New ADGT	43	171	347		28
INTERCONNECTION (Existing)	306	275	307	233	239
New INTERCONNECTION	340	308	341	266	272
TOTAL COSTS (FIXED + VARIABLE)	**6,300**	**6,155**	**6,303**	**6,123**	**5,843**

5.7 GENERATOR ECONOMIC RETURNS

Having considered total revenues, variable and fixed costs, including a required return on capital (of 8%), the net results can be seen as an indication of the viability of each station type in the year 2020. Positive returns indicate value creation or economic rent which would attract entrants into the market.[28]

It is clear that the existing stations, whose capital costs are fully or partly depreciated, have a greater level of measured profits than those of the new stations which have high avoidable capital costs (as seen from the perspective of a potential new entrant) associated with them. This study of course does not consider any capital injection which would certainly be required in existing stations to maintain their current level of operation in 2020.

The table below shows total economic profit by generator category across the five portfolios. On the basis of these results, existing generation would have little incentive to exit the market however much wind is installed on the system. And the incentives to build new wind

[28] Positive economic profit is the result of earning returns that exceed the cost of capital.

generators and new interconnectors would appear to be strong, again even with 6,000MW of installed wind capacity.

Whether the incentives for new thermal plant to enter are sufficient is arguable. The results show that ADGTs and new coal and CCGTs in Portfolio 4 incur a shortfall in revenues required to meet their total costs and a rate of return on capital. In the assumptions section of this report the revenue requirement for ADGT, coal and CCGT units is assumed to be €129k, €355k and €190k[29] per MW, respectively. Therefore, when examining the second table below, which shows economic returns on a per MW basis, the shortfall in the case of coal might be interpreted as being marginal, while being more material in the case of the ADGTs, particularly in Portfolios 2 and 5, and CCGTs in Portfolios 4.

Table 29: Annual Economic Profit/Loss

Annual Economic Profit/Loss (€million)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	421	315	538	160	217
PEAT	173	145	206	104	119
GAS BASELOAD	560	376	760	124	226
GAS MID-MERIT	273	170	399	31	92
HYDRO	129	116	138	95	104
PUMPED STORAGE	68	53	81	30	40
PEAKERS	37	32	41	24	28
WIND (Existing)	327	284	341	259	256
New WIND	144	303	476	228	366
New COAL				-8	
New CCGT	226	112		-30	27
New OCGT	7	1	17	0	1
New ADGT	-1	-15	38		-4
INTERCONNECTION (Existing)	223	178	271	114	135
New INTERCONNECTION	190	144	237	80	102
TOTAL ECONOMIC PROFIT/LOSS	**2,776**	**2,212**	**3,545**	**1,210**	**1,708**

Figure 23: Total 2020 Revenues and Costs

29 CCGT AIGS fixed costs = 156k + 34k (gas capacity costs)

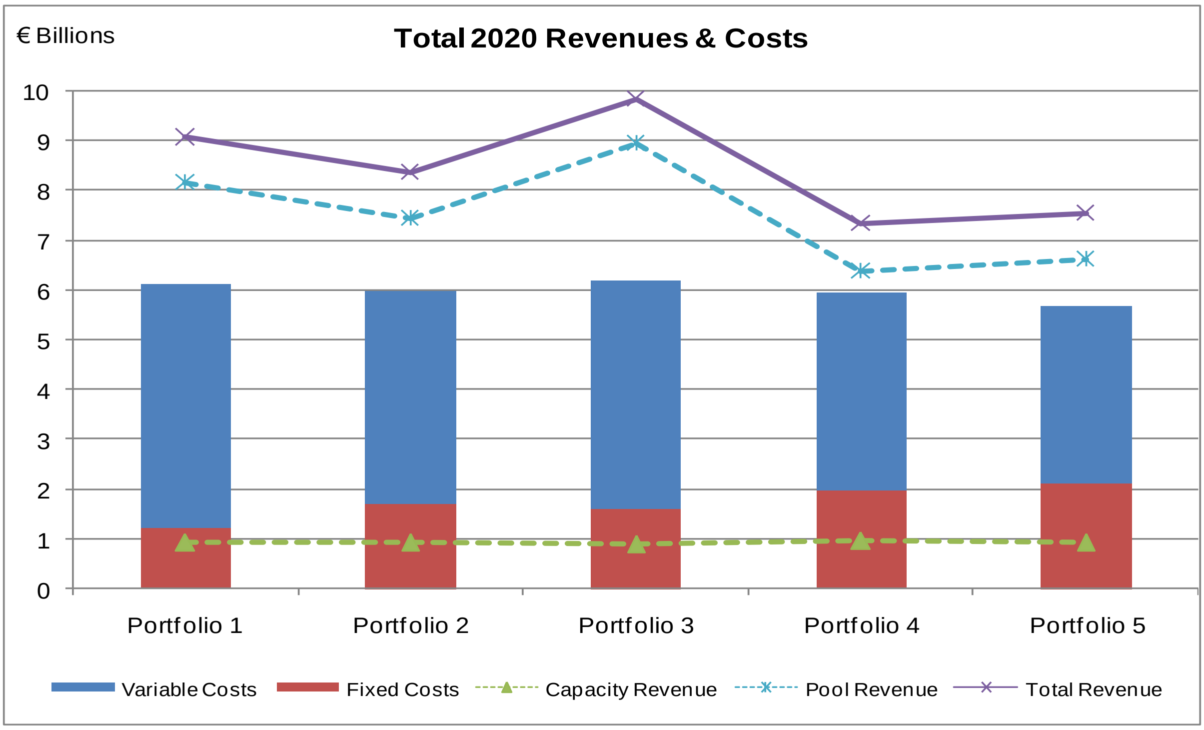
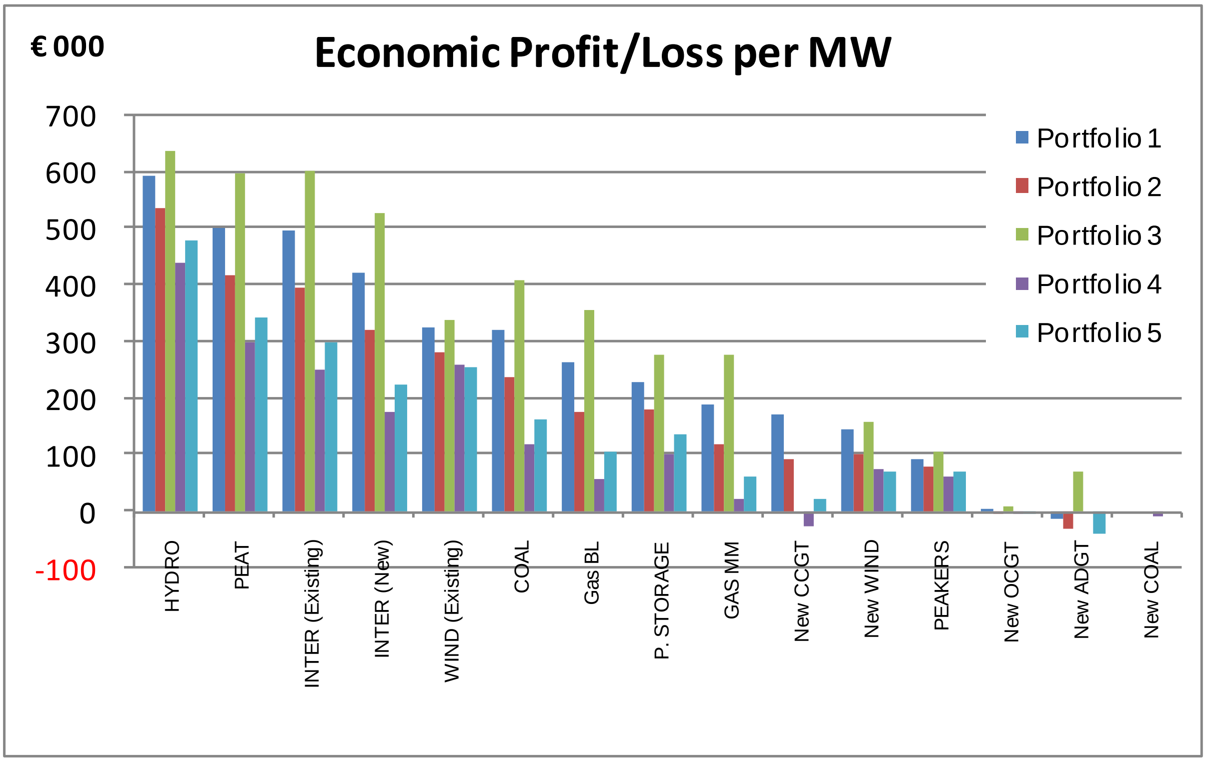


Table 30: Annual Economic Profit/Loss per MW Installed

Annual Economic Profit/Loss per MW installed (€000)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	320	240	410	122	165
PEAT	501	419	597	302	344
GAS BASELOAD	263	177	357	58	106
GAS MID-MERIT	191	119	279	22	64
HYDRO	596	538	638	441	481
PUMPED STORAGE	232	180	278	102	136
PEAKERS	95	81	106	61	72
WIND (Existing)	327	284	341	259	256
New WIND	144	101	159	76	73
New COAL				-7	
New CCGT	174	93		-25	22
New OCGT	5	1	9	1	1
New ADGT	-10	-28	71		-37
INTERCONNECTION (Existing)	496	395	602	252	301
New INTERCONNECTION	422	320	527	178	226

Figure 24: Economic Profit/Loss per MW



5.8 OVERVIEW OF KEY TRENDS IN THE CENTRAL SCENARIO

The table below provides a summary of the key differences and trends in the portfolios studied in our central fuel price and load growth scenario, using Portfolio 1 (with 2000MW of wind generation) as the reference case.

The table clearly shows that, in the central fuel price case, increased wind generation results in substantial reductions in the cost of fuel and carbon emissions, ranging from a saving of approximately €340 million in Portfolio 3 to under €1.4 billion in Portfolio 5 in 2020 compared with Portfolio 1.

However, significant amounts of capital investment in thermal generation and fixed operations costs are required across all the portfolios to support the large penetration of wind generation. At an 8% rate of return, additional annual fixed costs compared with Portfolio 1 range from about €387 million in Portfolio 3 to €910 million in Portfolio 5 in 2020.

Nonetheless, the net effect on total costs (i.e., variable and fixed) is generally beneficial, ranging from a small net increase of €3 million in Portfolio 3 compared with Portfolio 1 to a net reduction of more than €450 million in Portfolio 5.

In terms of revenues, increased wind generation tends to reduce the level of SMP in the unconstrained market schedule, resulting in significantly less revenue in the energy market by comparison with Portfolio 1. The exception is Portfolio 3.

The size of the capacity payments mechanism pot is largely unchanged across the five portfolios, with the result that the price paid per unit of available capacity falls as the amount of wind capacity increases. The price per MW of availability is 15% lower in Portfolio 3 than in Portfolio 1 and more than 20% lower in Portfolio 5.

The effect of increased penetration of wind on revenues net of costs is mixed. In three of the four portfolios, net revenues are lower than in Portfolio 1. Only in Portfolio 3 are net revenues higher, reflecting the effect of a large increase in the capacity of OCGTs on the system on SMPs. The reduction in net revenues in Portfolio 5 is greater than in Portfolio 2 but not as great as that in Portfolio 4.

Table 31: Summary of Portfolio Differences (Relative to Portfolio 1)

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
SMP ∆ (€/MWh)	-	-10.2	13.0	-25.8	-19.5
Emissions ∆ (Mtonnes)	-	-2.1	-1.6	1.9	-4.8
Fuel ∆ (TJ)	-	-35,948	-27,564	-15,339	-81,449
Revenue ∆ (€millions)	-	-710	771	-1,743	-1,525
Fixed Costs ∆ (€ millions)	-	475	345	777	910
Variable Operating Cost ∆ (€millions)	-	-621	-342	-954	-1,367
Of which:	-				
Fuel	-	-475	-364	-793	-1,043
Emissions	-	-62	-47	57	-144
Other	-	-84	70	-218	-180
Total Cost ∆ (€millions)	-	-145	3	-177	-457
Economic Profit/Loss ∆ (€millions)	-	-564.3	768.6	-1566.0	-1067.9

5.9 SENSITIVITY ANALYSIS

This section reports on the sensitivity of the key results to a number of alternative scenarios (in terms of prices, generation levels, generator revenues, generator costs, generator margins).

5.9.1 LOW AND HIGH FUEL AND CARBON PRICE SCENARIOS

a) Low fuel scenario

The detailed results of this scenario are included in **Appendix B** of this report.

This scenario reduced the fuel and carbon prices of the central scenario by 50%, resulting in a number of predictable effects. Fuel prices have experienced a significant reduction in recent months and the fuel prices in this scenario are closer to those current prices, thereby putting a greater emphasis on the results of this scenario.

The average annual time-weighted SMP and annual total pool revenue were lower by between 36% and 43% across all portfolios compared with the central scenario. Variable operating costs were also lower, by 43% to 45% across the portfolios.

A noticeable relative difference with the central scenario was the reduced capacity factors of existing and new coal stations. The capacity factors of existing coal stations drop between 29 and 57 percentage points across the portfolios and the capacity factor of the new coal station in portfolio 4 drops 15 percentage points. All gas stations, on the other hand, experience substantial increases in capacity factors, up 7 to 26 percentage points for the existing baseload and up 7 to 18 percentage points for new CCGTs.

Therefore, at low fuel and carbon prices the more efficient gas plants tend to displace less efficient and carbon-intensive coal units in the merit order as the cost of carbon comprises a larger proportion of the variable cost of coal generation. The composition of the final fuel prices in both scenarios can be seen in the graphs below.

Figure 25: Average Fuel Prices [CS]

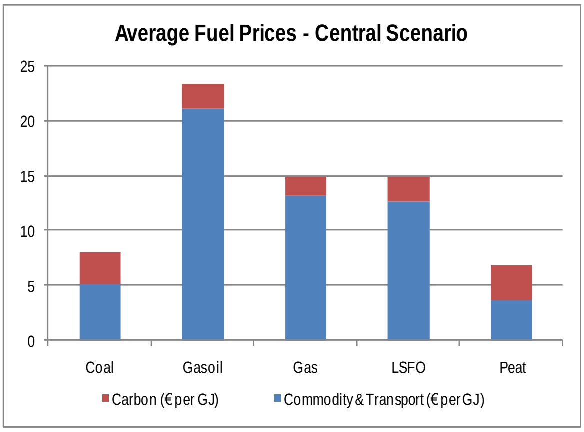
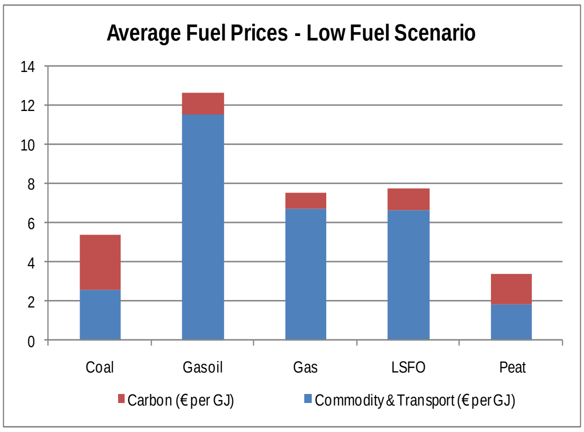


Figure 26: Average Fuel Prices [LFS]



The impact on profits follows through from the above, with the existing coal units becoming marginal in Portfolios 4 and the new coal stations' losses increasing by a factor of 20 to €139k per MW, as shown in the table below.

Table 32: Annual Economic Profit/Loss per MW Installed [LFS]

Annual Economic Profit/Loss per MW installed (€000)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	126	67	169	1	26
PEAT	324	266	364	202	222
GAS BASELOAD	238	177	279	109	130
GAS MID-MERIT	187	126	225	54	80
HYDRO	385	344	399	300	318
PUMPED STORAGE	200	160	215	113	134
PEAKERS	99	87	109	68	77
WIND (Existing)	190	161	190	148	144
New WIND	8	-22	7	-35	-39
New COAL				-139	
New CCGT	147	92		30	47
New OCGT	6	2	12	3	2
New ADGT	13	-24	65		-34
INTERCONNECTION (Existing)	377	304	422	228	239
New INTERCONNECTION	303	229	347	153	165

Moreover, new wind units are making a loss in portfolios 2, 4 and 5 in 2020 under the low fuel scenario, suggesting a continuing need for subsidy.[30] ADGT units also continue to make losses in Portfolios 2 and 5 in the market, albeit to a lesser extent compared with the central scenario.

Another impact of the substitution of gas for coal in the low fuel price scenario is reduced all-island carbon emissions, ranging from 5% to 16% compared with the central scenario and a reduced level of imports across the interconnectors from Great Britain.

The net financial benefit of increasing levels of wind penetration is less pronounced when comparing the portfolios within this scenario to Portfolio 1. For instance, Portfolio 5 shows lower variable costs of €733 million, compared with Portfolio 1. But fixed costs are higher by €910 million, resulting in a net increase in costs of €177 million. However, market revenues are lower by €934 million, providing an overall marginal financial benefit.

Table 33: Summary of Portfolio Differences (Relative to Portfolio 1) [LFS]

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
SMP ∆ (€/MWh)	-	-6.8	6.1	-15.3	-12.0
Emissions ∆ (Mtonnes)	-	-2.9	-1.3	-0.7	-6.2
Fuel ∆ (TJ)	-	-40,547	-28,845	-30,335	-88,706
Revenue ∆ (€millions)	-	-471	326	-1,006	-934
Fixed Costs ∆ (€ millions)	-	477	387	777	910
Variable Operating Cost ∆ (€millions)	-	-337	-154	-443	-733
Of which:	-				
Fuel	-	-216	-226	-326	-479
Emissions	-	-44	-20	-11	-94
Other	-	-78	92	-106	-161
Total Cost ∆ (€millions)	-	140	233	334	177
Economic Profit/Loss ∆ (€millions)	-	-608.0	135.5	-1337.0	-1108.7

30 Our analysis does not take into account the fixed tariffs of the Government's Renewable Energy Feed In Tariff (REFIT) programme in determining required subsidy levels.

b) High fuel Scenario

This trend is substantially reversed in the results of the high fuel cost scenario, as set out in **Appendix C** of this report.

Fuel and carbon prices were increased by 50% in this scenario by comparison with the central fuel price case and - as with the low fuel scenario - there were a number of predictable consequences.

When compared with the central scenario, average annual time-weighted SMPs and overall pool revenues are higher by almost 50%, and overall variable costs higher by between 41% and 44% across the portfolios.

The main relative difference with the central scenario is the increased imports from Great Britain, increasing by 11% to 32% across the portfolios. There are also some relatively small gains for coal and equivalent losses for baseload gas, while new CCGTs experience a reduction in capacity factors of up to 9%.

Overall profits increase across the portfolios and the ADGTs and OCGTs incur losses in three of the five Portfolios. The new coal stations, in Portfolio 4, move from an annual loss of €7k/MW to a profit of €197k/MW compared with the central scenario.

The level of all-island carbon emissions for this scenario are also lower than those in the central scenario, by approximately 1% to 2%, which is a result of the increased volumes imported over the interconnectors.

Higher fossil fuel and carbon prices than in the central case result in net cost savings of €1.1 billion in 2020 when comparing Portfolios 5 and 1. The average annual SMP is reduced by €25/MWh and market revenue by €2 billion in Portfolio 5 compared with Portfolio 1.

The absolute levels of system savings become apparent in this scenario, as can be seen from the table below which compares key results of all other portfolios under this scenario to Portfolio 1.

Table 34: Summary of Portfolio Differences (Relative to Portfolio 1) [HFS]

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
SMP ∆ (€/MWh)	-	-12.2	15.8	-34.4	-25.0
Emissions ∆ (Mtonnes)	-	-2.1	-1.5	2.0	-4.8
Fuel ∆ (TJ)	-	-37,627	-25,912	-16,752	-82,397
Revenue ∆ (€millions)	-	-848	938	-2,279	-1,959
Fixed Costs ∆ (€ millions)	-	477	387	777	910
Variable Operating Cost ∆ (€millions)	-	-893	-532	-1,482	-1,999
Of which:	-				
Fuel	-	-748	-521	-1,264	-1,606
Emissions	-	-96	-66	90	-214
Other	-	-49	55	-308	-179
Total Cost ∆ (€millions)	-	-416	-145	-706	-1,089
Economic Profit/Loss ∆ (€millions)	-	-430.0	1125.4	-1569.5	-871.1

5.9.2 ALTERNATIVE LOAD GROWTH SCENARIO

The detailed results of this scenario are included in **Appendix D** of this report.

The low load growth scenario assumes load growing by 2.7% between 2009 and 2020, compared with 3.5% assumed in the central scenario. This results in each of the portfolios having an increased reserve margin over the peak demand, which is 9,439 MW in this scenario.

Overall this analysis shows that some key results in the central scenario are quite sensitive to an alternative lower system demand assumption. This has an overall dampening effect on the average SMPs across the five portfolios, down between 6% to 14% relative to the central load growth scenario, in addition to this the overall capacity requirement and hence the capacity payments falls by 9%. The impact on overall pool revenues and overall variable costs is greater again with reductions of between 16% to 24% and 14% to 17%, respectively, the combination of a price and quantity effect.

The impact on capacity factors for the different station types is to generally reduce them, with the greatest impact on the gas stations. The capacity factors of existing gas baseload units fall by between 7 to 12 percentage points compared with the central scenario, and the capacity factors of existing gas mid-merit units fall by 6 to 18 percentage points, while existing peakers, new OCGTs and new ADGTs are the most affected and are not scheduled in a number of portfolios under this scenario.

Overall economic profits are down considerably, by between 34% and 50%. At the station category level both OCGTs and ADGTs are making losses in all portfolios. New CCGTs start to make losses in Portfolios 3, 4 and 5. The losses of the new coal stations are almost ten times greater than those in the central scenario. The only existing plants to face losses are the Gas Mid-Merit plants, which face marginal losses in Portfolios 4 and 5. All-island carbon emissions are down between 10% to 13% as a result of the reduced generation required to meet lower load.

It must be borne in mind that with the same portfolios of plant meeting a lower level of demand, the Loss of Load Expectation (LOLE) will be reduced. The additional costs that result from this scenario in the final energy delivered can be attributed to demand uncertainty.

The table below compares key results of all other portfolios under this scenario to Portfolio 1.

Table 35: Summary of Portfolio Differences (Relative to Portfolio 1) [LGS]

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
SMP ∆ (€/MWh)	-	-5.1	15.2	-12.6	-10.3
Emissions ∆ (Mtonnes)	-	-2.0	-1.7	1.6	-5.0
Fuel ∆ (TJ)	-	-33,884	-30,012	-13,627	-79,063
Revenue ∆ (€millions)	-	-329	888	-755	-802
Fixed Costs ∆ (€ millions)	-	477	387	777	910
Variable Operating Cost ∆ (€millions)	-	-565	-400	-812	-1,251
Of which:	-				
Fuel	-	-432	-395	-693	-952

Emissions	-	-60	-52	49	-149
Other	-	-72	47	-168	-150
Total Cost ∆ (€millions)	-	-88	-12	-35	-341
Economic Profit/Loss ∆ (€millions)	-	-237.6	944.5	-707.6	-461.0

5.9.3 ALTERNATIVE COST OF CAPITAL SCENARIOS

a) WACC of 10%

By increasing the Weighted Average Cost of Capital (WACC) from 8% in the central scenario to 10%, the fixed costs increase for all the new plants added to each of the portfolios. The overall impact on fixed costs is smallest in Portfolio 1, up 5%, which has the lowest level of additional capacity while Portfolio 4 sees the largest increase in fixed costs of 8%, owing to the impact on the new coal stations.

In terms of profits, again only the additional stations are affected with the OCGTs moving from profits to losses in all but one portfolio. ADGTs face increased losses in Portfolios 1, 2 and 5 while still earning a profit in Portfolio 3. CCGTs face increased losses, of 50%, in Portfolio 4 but maintain profits in the remaining portfolios. Coal sees a near eight-fold increase in its losses and the new wind units see a decline in profits ranging from 14% to 31%, when compared with the central scenario.

Table 36: Annual Economic Profits/Loss per MW Installed [10% WACC]

Annual Economic Profit/Loss per MW installed (€million)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	320	240	410	122	165
PEAT	501	419	597	302	344
GAS BASELOAD	263	177	357	58	106
GAS MID-MERIT	191	119	279	22	64
HYDRO	596	538	638	441	481
PUMPED STORAGE	232	180	278	102	136
PEAKERS	95	81	106	61	72
WIND (Existing)	327	284	341	259	256
New WIND	121	78	136	53	50
New COAL				-60	
New CCGT	162	80		-38	10
New OCGT	-2	-7	1	-7	-7
New ADGT	-21	-38	61		-48
INTERCONNECTION (Existing)	496	395	602	252	301
New INTERCONNECTION	405	304	511	161	210

b) WACC of 12%

A WACC of 12% results in an overall increase of fixed costs across the portfolios of between 10% to 16%, Portfolio 1 being the lowest and Portfolio 4 the highest. As in the 10% WACC scenario, the same station types face losses, with the addition of new CCGTs in Portfolio 5, only naturally greater when the WACC is 12%. The new wind stations see reductions in profits from the central scenario ranging from 30% to 62%.

Table 37: Annual Economic Profits/Loss per MW Installed [12% WACC]

Annual Economic Profit/Loss per MW installed (€000)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	320	240	410	122	165
PEAT	501	419	597	302	344
GAS BASELOAD	263	177	357	58	106
GAS MID-MERIT	191	119	279	22	64
HYDRO	596	538	638	441	481
PUMPED STORAGE	232	180	278	102	136
PEAKERS	95	81	106	61	72
WIND (Existing)	327	284	341	259	256
New WIND	97	54	112	29	26
New COAL				-115	
New CCGT	149	67		-51	-3
New OCGT	-10	-14	-6	-14	-14
New ADGT	-33	-50	49		-59
INTERCONNECTION (Existing)	496	395	602	252	301
New INTERCONNECTION	388	287	494	144	193

5.9.4 HIGH START COST SENSITIVITY ANALYSIS

This scenario applied a 50% increase to the variable Operation and Maintenance (VOM) costs associated with unit starts of existing gas baseload and mid merit stations and the new CCGTs in all portfolios studied.

The impact of these increases resulted in a marginal change in prices ranging from a reduction of 30c/MWh (Portfolio 3) to an increase of €1.50/MWh (Portfolio 5) compared with the central scenario. The capacity factors of the majority of stations remained unchanged but it was noticeable that for existing gas baseload they fell in some portfolios by between 1% and 2% and the new CCGTs were scheduled by 2% more. In addition to this the interconnector had a reduced capacity factor of 2%.

Total profits remained unchanged with the exception of Portfolio 5, which has an increase of 5%, as the price effect is the dominant factor in this scenario. For the majority of stations, changes in profits followed the changes in SMP generally; down marginally in portfolio 3; up marginally in Portfolio 5, and marginal changes up and down for different stations in Portfolios 1, 2 & 4.

Overall, this sensitivity analysis did not indicate a material change from our central scenario results.

5.10 OVERVIEW OF SENSITIVITY ANALYSIS KEY TRENDS

Some key system-wide trends from the scenario and sensitivity analysis above are depicted in the graphs in this section. The graphs highlight the effect of high fuel, low fuel, low demand and high start costs on the overall results set out in the central scenario.

Overall the graphs highlight that the central scenario results are quite sensitive to the alternative scenarios studied. The High and Low Fuel scenarios dominate the effect on key results, with the lower demand scenario also having a material effect.

The two graphs below show this effect in the case of average annual SMP and total revenues (energy + capacity). The low demand scenario shows a relatively larger change in total system revenues as both energy and total capacity revenues are reduced. In the other scenarios only the energy component of total revenues changes.

Figure 27: Scenario SMPs (time weighted)

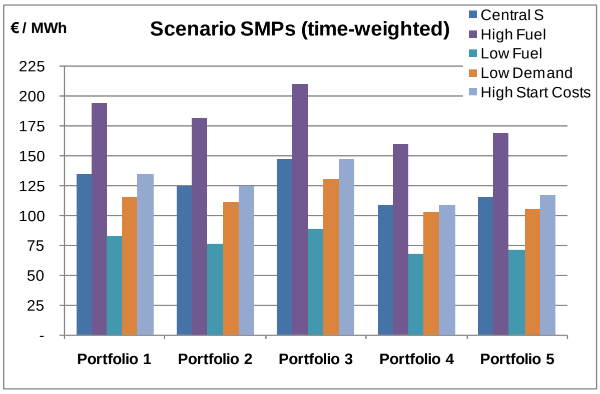
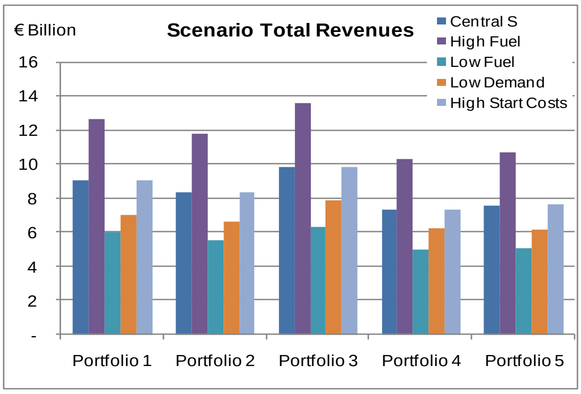
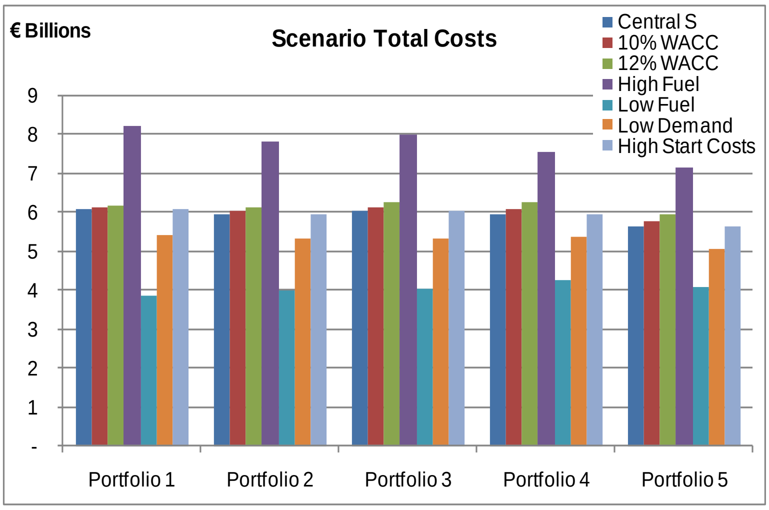


Figure 28: Scenario Total Revenues



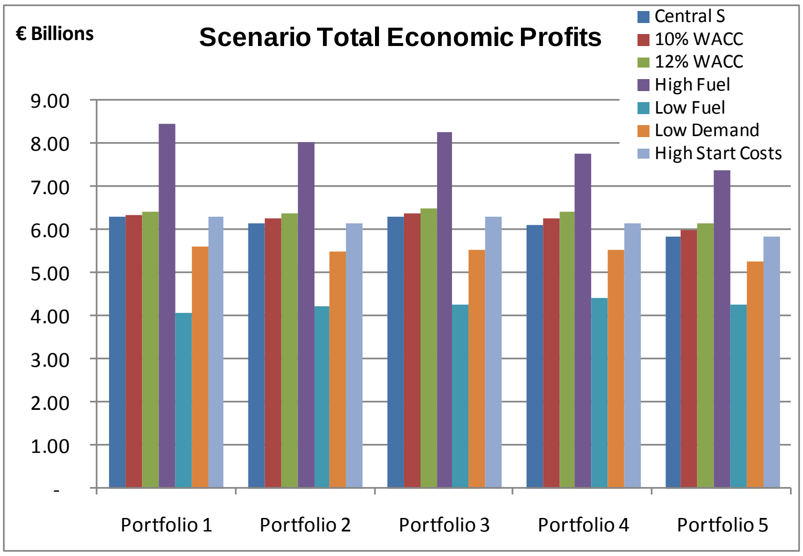
Total costs comprise mostly variable operation costs, ranging from 61% in Portfolio 5 to 78% in Portfolio 1 in our central scenario. Of total variable costs fuel makes up between 68% (in Portfolio 5) to 70% (in Portfolio 1). Again, the high and low fuel scenarios have a substantial impact on total system costs, an effect of approximately €2 billion in 2020 across all portfolios compared with the central scenario.

Figure 29: Scenario Total Costs



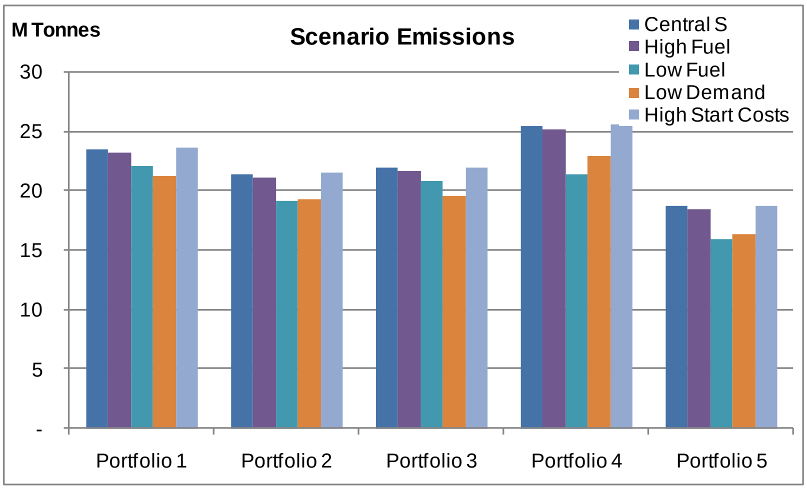
Total economic profits in the SEM across all scenarios in 2020 suggest that on the whole the market is viable for new and existing generation, both thermal and renewable. Again, the high and low fuel scenarios have a substantial impact on total system economic profits as does the low demand scenario.

Figure 30: Scenario Total Economic Profits



The low demand scenario and low fuel price scenario in our study have the largest impact on total carbon emissions. In the low demand scenario emissions are reduced by between 2.2 and 2.5 million tonnes.

Figure 31: Scenario Emissions



6 SUMMARY AND CONCLUSIONS

Modelling an electricity system is a complex process. The results of any modelling exercise will depend on how good the model is in replicating what actually happens in practice. They will also depend on the assumptions made and their coherence. For example, this study has used with little amendment the portfolios considered in the AIGS for the purposes of looking at the effect of increased wind penetration on the SEM. There may be other possible combinations of plant types and capacities which would make more economic sense, given the fuel price assumptions adopted here, while maintaining the same system security standard. Finally, the margins of error around the results are bound to be wide, particularly when the focus is on a year some way in the future (2020).

As outlined previously in this report, the study is based solely on the unconstrained schedule with perfect foresight. We therefore do not consider system operation issues which are likely to become more important as installed capacity comprises relatively more intermittent generation. Also the probabilities of the different scenarios are not examined with the deterministic modelling utilised for this study.

Dynamic studies will need to be carried out by the System Operators to examine the impact on both transmission and reserve driven constraint costs in the context of evolving system operation policies. It is also likely that the value of ancillary services and the way in which such services are remunerated requires further consideration. The effect of Demand Side Management measures also need to be explored as an effective means of meeting renewable and emissions targets.

The results of this study highlight a number of key issues for the SEM in light of increased renewable generation levels.

OPERATION OF PLANT

The results of the study suggest that increased renewable generation will have a significant impact on the operation of installed thermal generation capacity. In particular, existing baseload CCGTs will move into the mid-merit segment of the market and thereby see a sharp reduction in their capacity factors. Coal units will also see a marked reduction in their capacity factors, particularly in the low fuel price scenario. [31] The number of unit starts of thermal stations is also likely to increase significantly, with implications for recurring maintenance costs and plant life.

VARIABLE AND FIXED COSTS

The table below shows the absolute level of fixed and variable costs from the PLEXOS model across the five portfolios, using the central fuel and carbon price and load growth

[31] In the low fuel price scenario coal units become relatively more expensive than gas units as carbon comprises a greater component of the overall short-run marginal costs of the coal units.

assumptions. The absolute levels of costs (in € millions) are shown for Portfolio 1 and the change in costs relative to those Portfolio 1 absolute levels for the other four portfolios.

In common with the AIGS, this study treats the investment costs of existing plant as sunk. Only the capital costs of new plant (i.e., those units commissioned in 2009 and later years) are included as an incremental cost. Unlike the AIGS, which included the annualised cost of investment in all renewable generation, both existing and new, this study treats all generation equally. So the capital costs of existing renewable generation are treated as sunk for the purposes of this analysis.

Table 38: Effect on Costs of Increased Renewable Generation in 2020 (€ millions)

		Relative to Portfolio 1			
Cost component	**Portfolio 1**	**Portfolio 2**	**Portfolio 3**	**Portfolio 4**	**Portfolio 5**
Variable costs, including cost of carbon	4,919	-620	-342	-954	-1,367
Fixed costs, incl. annualised investment costs of new plant	1,381	475	345	777	910
Total fixed and variable costs	**6,300**	-145	3	-177	-457

Based on high fuel costs and in contrast with the AIGS, this study suggests that increased wind penetration in 2020 would broadly be beneficial from an economic point of view and increasingly so the more wind there is on the system. This is of course from the perspective of an unconstrained system only. An additional 4,000MW of wind (in addition to the 2,000MW in Portfolio 1) would reduce total costs by more than €450 million, or 7%.[32]

But this result is sensitive (as all are) to what is assumed about future fuel and carbon prices. In the low fuel price scenario, increased wind penetration has a net cost to society, of between 3% (Portfolio 2) and 8% (Portfolio 4), as shown in Table 39.

It is also the case that Scenarios 2, 4, and to a greater extent Scenario 5, shows more heavily aggressive cycling (increased number of starts per year) for the conventional plant. This is likely to result in an increase in maintenance costs and forced outage events and a reduction in plant life. These effects have not been explicitly estimated in derivation of the relative fixed and variable costs across the scenarios.

Table 39: Effect on Costs of Increased Renewable Generation in 2020 – Low Fuel Prices (€ millions)

		Relative to Portfolio 1			
Cost component	**Portfolio 1**	**Portfolio 2**	**Portfolio 3**	**Portfolio 4**	**Portfolio 5**
Variable costs, including cost of carbon	2,708	-337	-154	-443	-733

32 This ignores so-called system costs (reserves, balancing, constraints etc.) and the costs of reinforcing the networks.

Fixed costs, incl. annualised investment costs of new plant	1,380	474	345	774	908
Total fixed and variable costs	**4,088**	136	190	331	175

SYSTEM MARGINAL PRICE

The changes in the operating regime of conventional plant have a direct effect on the energy price in the SEM. The table below shows the annual average system marginal price (SMP) for Portfolios 1 to 5, in both time- and load-weighted terms, using the central fuel and carbon price assumptions.

While SMPs are generally lower the more price-taker generation (i.e., wind) there is on the system, this is not universally the case. The type of conventional plant that makes up the rest of the portfolio is also critical. Thus Portfolio 3, which includes no new CCGTs or coal stations and twice as much OCGT capacity as in Portfolio 2, has the highest SMPs of all five portfolios, including Portfolio 1. The largest falls in SMP, relative to Portfolio 1, are in Portfolios 4 and 5.

Table 40: Effect of Increased Renewable Generation on SMP in 2020 (€/MWh)

SMP (€/MWh)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Average Time-Weighted SMP	135	-6%	12%	-18%	-13%
Average Load-Weighted SMP	145	-9%	10%	-21%	-16%

Therefore the annual average System Marginal Price (SMP) will be significantly lower, unless the increase in wind penetration is accompanied by an increase in the overall penetration of Open Cycle Gas Turbine (OCGT) plant to meet demand. If new baseload CCGTs or new coal plant are built to meet increments in demand as the penetration of wind increases, then SMP is likely to be lower than would be the case with less wind on the system.

These lower prices partly reflect significantly lower variable operating costs, in the form of lower fuel and carbon costs that will accompany increased penetration of wind. The higher future fuel and carbon prices, the more pronounced these benefits will be.

CAPACITY PAYMENTS

The capacity payments to generators in 2020 have been calculated using the 2009 Best New Entrant (draft) (BNE) peaker price (of €81.24/kW/year), the forecast peak load requirements in 2020 and an index of the current methodology for calculating the capacity requirement, given the peak load requirement and the technical characteristics of the capacity installed on the system. The table below shows total installed capacity, the capacity requirement and the capacity payment 'pot' for each of the five portfolios in 2020.

Table 41: Capacity Requirement and Payments in 2020

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Total Installed Capacity (MW)	12,300	14,000	14,000	14,100	15,900
Capacity Requirement (MW)	11,300	11,300	11,000	11,700	11,400
Capacity Payments (€ millions)	918	919	891	952	923

The doubling of wind capacity by comparison with Portfolio 1 in Portfolios 2, 3 and 4 and its tripling in Portfolio 5 has little effect on the capacity requirement. This suggests that the increase in wind and other intermittent capacity displaces little conventional capacity for a given security standard.

GENERATOR REVENUES

The table below shows the net effect of the changes in operating regimes, in SMP and in capacity payments on total generator revenues in 2020 in the five portfolios; and on costs and net revenues.[33]

Table 42: Effect of Increased Renewable Generation on Generator Revenues in 2020 (€ millions)

		Relative to Portfolio 1			
	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Revenue from SMP	8,158	-710	799	-1,777	-1,530
Capacity payments	918	-1	-27	34	5
Total revenues	9,077	-709	772	-1,743	-1,525
Total fixed and variable costs	**6,300**	-145	3	-177	-457
Net revenues	**2,776**	-564	769	-1,566	-1,068

In three of the four portfolios, revenues are sharply lower as a result of increased wind penetration and by significantly more than the decline in fixed and variable costs, with the result that net revenues are also sharply lower, by more than 50% in Portfolio 4 and by

[33] Profits as defined here ignore any return on or of existing investments in generation and therefore overstate profits as conventionally defined.

almost 40% in Portfolio 5 by comparison with Portfolio 1. The exception is Portfolio 3, where the preponderance of OCGTs and ADGTs results in higher SMPs than in Portfolio 1 and correspondingly higher net revenues.

So, while increased wind penetration in the central fuel price case is broadly of economic benefit, the study suggests that increased wind penetration could be associated with a significant transfer of income from producers (i.e. generators) to consumers of electricity through its effect on the wholesale electricity price.

INCENTIVES TO EXIT AND ENTRY

Whatever the net benefits or costs of wind, the key question turns to whether the plant comprising each portfolio can be sustained in the context of the design of the SEM.

The results of this study give some cause for concern. If fuel prices stay at, or return to, the levels seen in early July (i.e., US$147/barrel), then the SEM will in all likelihood provide the majority of new stations with sufficient revenue to recover their total costs (both fixed and variable) and provide an 8% return on capital employed. However, in the case of new coal and ADGT units, the study suggests that - as a result of their relatively high capital costs - these stations could sustain losses which would be sufficient to deter entry.

But if fuel prices stay at current levels (i.e., less than half their July 2008 peak) until 2020 or if new entrants require a pre-tax rate of return on capital above 8%, then the results reported here suggest that the SEM as currently designed could present challenges incentivising the building of new thermal plant as the amount of wind on the system rises to the level required to meet renewables targets set by both the Irish and UK Governments.

This transfer from producers to consumers in three of the four portfolios could have adverse economic effects if it resulted in an insufficient incentive either to existing generation to stay in the market or to potential entrants to build new capacity.

The table below shows the rent available to the various types of generating plants in 2020, where rent is defined as revenues less costs, where the latter includes a rate of return on new investments. It can be seen as a measure of “above normal” profit. Rent is expressed in the table in per MW terms, to allow a comparison across generation types with substantial differences in installed capacities in the various portfolios.

Existing generation makes a sufficient return to incentivise it to stay in the market. The evidence on new entrant plant from the modelling is mixed. Some (i.e., new wind and new interconnections) face strong incentives to enter across all the portfolios. Expected returns for others, including new CCGTs in Portfolio 4, look marginal if not negative. OCGTs appear marginal across all the portfolios. The return on ADGTs looks to be particularly portfolio-dependent.

Table 43: Effect on Economic Rent of Increased Renewable Generation in 2020 (€000/MW)

Rent per MW of Installed capacity (€000 /MW)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Existing Coal	320	240	410	122	165
Existing Peat	501	419	597	302	344
Existing Baseload Gas	263	177	357	58	106
Existing Mid-Merit Gas	191	119	279	22	64
Existing Hydro	596	538	638	441	481
Existing Pumped Storage	232	180	278	102	136
Existing Peakers	95	81	106	61	72
Existing Wind	327	284	341	259	256
New Wind	144	101	159	76	73
New Coal				-7	
New CCGT	174	93		-25	22
New OCGT	5	1	9	1	1
New ADGT	-10	-28	71		-37
Existing Interconnection	496	395	602	252	301
New Interconnection	422	320	527	178	226

Incentives to enter and exit are sensitive to fuel prices. Table 44 shows net revenues in thousands of euro per MW of installed capacity in the low fuel price scenario.

Table 44: Effect on Economic Rent of Increased Renewable Generation in 2020 – Low Fuel Prices (€000/MW)

Rent per MW of Installed capacity (€000/MW)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Existing Coal	126	67	169	1	26
Existing Peat	324	266	364	202	222
Existing Baseload Gas	238	177	279	109	130
Existing Mid-Merit Gas	187	126	225	54	80
Existing Hydro	385	344	399	300	318
Existing Pumped Storage	200	160	215	113	134
Existing Peakers	99	87	109	68	77
Existing Wind	190	161	190	148	144
New Wind	8	-22	7	-35	-39
New Coal				-139	
New CCGT	147	92		30	47

New OCGT	6	2	12	3	2
New ADGT	13	-24	65		-34
Existing Interconnection	377	304	422	228	239
New Interconnection	303	229	347	153	165

Lower fuel prices unsurprisingly have a marked effect on the financial viability of new wind generation, suggesting that they will not enter without support. Low fuel prices also worsen significantly the position of new coal in Portfolio 4. Existing coal stations might also have a marginal incentive to exit the market in Portfolio 4. The incentives on new CCGTs to enter look stronger than in the central fuel and carbon price case.

EMISSIONS

Finally, as the table below shows, CO_2 emissions across the portfolios fall as the capacity of wind increases, with the exception of Portfolio 4 where the impact of new coal stations increases emissions relative to those in Portfolio 1.

The table below includes carbon emission figures on both an all-island and an Ireland basis. The Ireland figures are shown on the basis of an allocation of 75% of carbon emissions from new thermal plant. It is understood that the target level of carbon emissions for electricity generation in 2020 is approximately 12.3 million tonnes.[34] The modelling suggests that the electricity generation sector in Ireland will not reach this target in any of the portfolios examined. It also suggests however that a mixed portfolio of plant, i.e. CCGTs, OCGTs and wind, produces a better economic and environmental outcome when there are large amounts of wind on the system.

Table 45: Effect on Emissions of Increased Renewable Generation in 2020 (million tonnes)

		Relative to Portfolio 1			
Carbon Emissions (million tonnes)	**Portfolio 1**	**Portfolio 2**	**Portfolio 3**	**Portfolio 4**	**Portfolio 5**
All-Island	23.6	-2.1	-1.6	1.9	-4.8
Ireland (with 75% of new thermal generation)	18.6	-1.6	-1.2	1.7	-3.4

[34] Ireland is required to reduce CO2 emissions from the 2005 level by 21% in 2020. Taking this target for the electricity sector, the 2005 emissions were approximately 15.6 million tonnes and a 21% reduction results in approximately 12.3 million tonnes target for 2020.

APPENDIX A: CENTRAL SCENARIO RESULTS

	2020 RA Modelling Results			CENTRAL SCENARIO		
		Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
1)	**Prices (€/MWh)**					
	Average Time-Weighted SMP	**135.0**	**124.8**	**148.0**	**109.2**	**115.5**
	Average Demand-Weighted SMP	**145.0**	**132.5**	**158.8**	**114.0**	**121.5**
2)	**Carbon Emissions (Mtonnes)**					
	Ireland (with 75% of new thermal gen)	**17.6**	**16.0**	**16.4**	**19.3**	**14.2**
	All-Island	**23.6**	**21.5**	**22.0**	**25.5**	**18.8**
3)	**Annual Generation Volume (GWh)**					
	COAL	**9,480**	**9,360**	**9,476**	**8,724**	**8,818**
	PEAT	**2,684**	**2,681**	**2,687**	**2,680**	**2,678**
	GAS BASELOAD	**15,021**	**12,893**	**15,021**	**9,531**	**10,234**
	GAS MID-MERIT	**6,366**	**4,891**	**7,389**	**2,858**	**3,533**
	HYDRO	**720**	**720**	**720**	**720**	**720**
	PUMPED STORAGE	**325**	**255**	**363**	**146**	**193**
	PEAKERS	**90**	**64**	**120**	**17**	**46**
	WIND	**5,587**	**11,174**	**11,174**	**11,174**	**16,759**
	New COAL				**8,839**	
	New CCGT	**9,066**	**8,217**		**7,042**	**6,883**
	New OCGT	**779**	**149**	**1,697**	**19**	**154**
	New ADGT	**169**	**507**	**1,664**		**62**
	NET INTERCONNECTION IMPORTS	**6,806**	**6,075**	**6,836**	**5,072**	**5,138**
	FIXED GENERATION	**2,964**	**2,964**	**2,964**	**2,964**	**4,636**
	TOTAL GENERATION VOLUME	**60,057**	**59,950**	**60,111**	**59,785**	**59,853**
	Renewables as percentage of Generation	**13%**	**22%**	**22%**	**22%**	**35%**
	Renewables as percentage of final Demand	**15%**	**25%**	**25%**	**25%**	**38%**
4)	**Generation Load Factors**					
	COAL	**82%**	**81%**	**82%**	**76%**	**77%**
	PEAT	**89%**	**89%**	**89%**	**89%**	**88%**
	GAS BASELOAD	**81%**	**69%**	**81%**	**51%**	**55%**
	GAS MID-MERIT	**51%**	**39%**	**59%**	**23%**	**28%**
	HYDRO	**38%**	**38%**	**38%**	**38%**	**38%**
	PUMPED STORAGE	**13%**	**10%**	**14%**	**6%**	**8%**
	PEAKERS	**3%**	**2%**	**4%**	**0%**	**1%**
	WIND	**32%**	**32%**	**32%**	**32%**	**32%**
	New COAL				**87%**	**0%**
	New CCGT	**80%**	**78%**		**67%**	**65%**
	New OCGT	**6%**	**2%**	**10%**	**1%**	**2%**
	New ADGT	**22%**	**11%**	**36%**		**6%**
	INTERCONNECTION (900MW)	**86%**	**77%**	**87%**	**64%**	**65%**
	FIXED GENERATION	**85%**	**85%**	**85%**	**85%**	**85%**
5)	**Generation Annual Pool Revenue (€million)**					
	COAL	**1,260**	**1,150**	**1,384**	**942**	**1,014**
	PEAT	**357**	**330**	**393**	**289**	**305**
	GAS BASELOAD	**2,071**	**1,700**	**2,282**	**1,121**	**1,300**
	GAS MID-MERIT	**1,037**	**771**	**1,273**	**395**	**546**
	HYDRO	**125**	**113**	**136**	**92**	**102**

CENTRAL SCENARIO

			Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
		PUMPED STORAGE	94	71	115	33	51
		PEAKERS	46	33	62	9	24
		WIND (Existing)	355	313	371	287	286
		New WIND	355	939	1,114	861	1,430
		New COAL				943	
		New CCGT	1,259	1,050		799	843
		New OCGT	195	44	408	6	47
		New ADGT	35	113	344		15
		INTERCONNECTION (Existing)	485	410	537	302	333
		New INTERCONNECTION	485	410	537	302	333
		TOTAL POOL REVENUE	8,158	7,448	8,957	6,381	6,628
6	)	**Generation Annual Capacity Revenue (€million)**					
		COAL	111	107	104	110	104
		PEAT	29	28	27	28	27
		GAS BASELOAD	185	177	172	182	172
		GAS MID-MERIT	120	114	111	118	111
		HYDRO	19	18	17	18	17
		PUMPED STORAGE	25	23	23	24	23
		PEAKERS	34	32	31	33	31
		WIND (Existing)	33	32	31	33	31
		New WIND	33	95	93	98	155
		New COAL				93	
		New CCGT	110	98		101	95
		New OCGT	124	68	156	26	66
		New ADGT	8	43	42		9
		INTERCONNECTION (Existing)	44	43	41	44	41
		New INTERCONNECTION	44	43	41	44	41
		TOTAL CAPACITY REVENUE	918	919	891	952	923
7	)	**Total Revenues (Pool + Capacity) (€million)**					
		COAL	1,371	1,257	1,488	1,052	1,118
		PEAT	386	358	419	317	332
		GAS BASELOAD	2,256	1,876	2,455	1,303	1,472
		GAS MID-MERIT	1,156	886	1,385	512	657
		HYDRO	144	131	153	110	119
		PUMPED STORAGE	118	95	138	57	74
		PEAKERS	79	65	94	42	55
		WIND (Existing)	388	345	402	320	317
		New WIND	388	1,035	1,207	959	1,585
		New COAL				1,036	
		New CCGT	1,369	1,147		899	939
		New OCGT	319	111	564	32	113
		New ADGT	42	156	385		24
		INTERCONNECTION (Existing)	530	452	578	346	374
		New INTERCONNECTION	530	452	578	346	374
		TOTAL REVENUES (POOL + CAPACITY)	9,077	8,367	9,848	7,333	7,552
8	)	**Generation Annual Variable Cost (€million)**					
		COAL	783	775	782	724	733
		PEAT	161	161	161	161	161
		GAS BASELOAD	1,471	1,274	1,470	952	1,019
		GAS MID-MERIT	728	560	829	325	408

2020 RA Modelling Results — CENTRAL SCENARIO

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
HYDRO					
PUMPED STORAGE	41	32	47	18	24
PEAKERS	30	22	41	6	16
WIND (Existing)					
New WIND					
New COAL				631	
New CCGT	897	808		701	683
New OCGT	187	40	378	5	41
New ADGT	32	102	278		13
INTERCONNECTION (Existing)	295	263	296	221	227
New INTERCONNECTION	295	263	296	221	227
TOTAL VARIABLE COSTS	4,919	4,299	4,577	3,965	3,552
9) Generation Annual Fixed Costs (€million)					
COAL	167	167	167	167	167
PEAT	52	52	52	52	52
GAS BASELOAD	225	226	225	227	226
GAS MID-MERIT	155	156	157	157	157
HYDRO	15	15	15	15	15
PUMPED STORAGE	10	10	10	10	10
PEAKERS	12	12	12	12	12
WIND (Existing)	61	61	61	61	61
New WIND	244	732	732	732	1,219
New COAL				413	
New CCGT	246	228		228	228
New OCGT	125	71	169	27	71
New ADGT	11	69	69		14
INTERCONNECTION (Existing)	12	12	12	12	12
New INTERCONNECTION	45	45	45	45	45
TOTAL FIXED COSTS	1,381	1,856	1,726	2,158	2,291
10) Annual Total Costs (Fixed + Variable) (€million)					
COAL	950	942	950	892	901
PEAT	213	213	213	213	213
GAS BASELOAD	1,696	1,500	1,695	1,179	1,245
GAS MID-MERIT	884	716	985	481	565
HYDRO	15	15	15	15	15
PUMPED STORAGE	51	42	57	28	34
PEAKERS	42	34	53	18	28
WIND (Existing)	61	61	61	61	61
New WIND	244	732	732	732	1,219
New COAL				1,044	
New CCGT	1,144	1,036		930	912
New OCGT	312	111	547	32	112
New ADGT	43	171	347		28
INTERCONNECTION (Existing)	306	275	307	233	239
New INTERCONNECTION	340	308	341	266	272
TOTAL COSTS (FIXED + VARIABLE)	6,300	6,155	6,303	6,123	5,843
11) Annual Economic Profit/Loss (€million)					
COAL	421	315	538	160	217
PEAT	173	145	206	104	119
GAS BASELOAD	560	376	760	124	226

2020 RA Modelling Results

CENTRAL SCENARIO

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
GAS MID-MERIT	273	170	399	31	92
HYDRO	129	116	138	95	104
PUMPED STORAGE	68	53	81	30	40
PEAKERS	37	32	41	24	28
WIND (Existing)	327	284	341	259	256
New WIND	144	303	476	228	366
New COAL				-8	
New CCGT	226	112		-30	27
New OCGT	7	1	17	0	1
New ADGT	-1	-15	38		-4
INTERCONNECTION (Existing)	223	178	271	114	135
New INTERCONNECTION	190	144	237	80	102
TOTAL PROFIT/LOSS	2,776	2,212	3,545	1,210	1,708

12) **Annual Economic Profit/Loss per MW installed (€000)**

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	320	240	410	122	165
PEAT	501	419	597	302	344
GAS BASELOAD	263	177	357	58	106
GAS MID-MERIT	191	119	279	22	64
HYDRO	596	538	638	441	481
PUMPED STORAGE	232	180	278	102	136
PEAKERS	95	81	106	61	72
WIND (Existing)	327	284	341	259	256
New WIND	144	101	159	76	73
New COAL				-7	
New CCGT	174	93		-25	22
New OCGT	5	1	9	1	1
New ADGT	-10	-28	71		-37
INTERCONNECTION (Existing)	496	395	602	252	301
New INTERCONNECTION	422	320	527	178	226

APPENDIX B: LOW FUEL SCENARIO RESULTS

2020 RA Modelling Results | **LOW FUEL SCENARIO**

			Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
1	)	**Prices (€/MWh)**					
		Average Time-Weighted SMP	83.2	76.4	89.3	67.9	71.2
		Average Demand-Weighted SMP	90.7	82.4	96.8	72.6	76.3
2	)	**Carbon Emissions (Mtonnes)**					
		Ireland (with 75% of new thermal gen)	17.1	15.0	15.9	16.6	12.5
		All-Island	22.2	19.2	20.8	21.4	15.9
3	)	**Annual Generation Volume (GWh)**					
		COAL	6,083	4,547	6,895	2,225	2,991
		PEAT	2,685	2,683	2,687	2,672	2,669
		GAS BASELOAD	16,398	15,648	16,444	14,414	13,849
		GAS MID-MERIT	8,740	7,225	8,944	5,143	5,471
		HYDRO	720	720	720	720	720
		PUMPED STORAGE	332	259	344	152	205
		PEAKERS	117	78	144	30	60
		WIND	5,587	11,174	11,174	11,174	16,755
		New COAL				7,299	
		New CCGT	9,895	9,124		8,941	8,526
		New OCGT	790	160	1,765	19	157
		New ADGT	193	518	1,717		64
		NET INTERCONNECTION IMPORTS	5,551	4,843	6,280	4,033	3,756
		FIXED GENERATION	2,964	2,964	2,964	2,964	4,636
		TOTAL GENERATION VOLUME	60,054	59,944	60,078	59,785	59,861
		Renewables as percentage of generation	13%	22%	22%	22%	35%
		Renewables as percentage of Final Demand	15%	25%	25%	25%	38%
4	)	**Generation Load Factors**					
		COAL	53%	40%	60%	19%	26%
		PEAT	89%	89%	89%	88%	88%
		GAS BASELOAD	88%	84%	88%	77%	74%
		GAS MID-MERIT	70%	58%	71%	41%	44%
		HYDRO	38%	38%	38%	38%	38%
		PUMPED STORAGE	13%	10%	13%	6%	8%
		PEAKERS	3%	2%	4%	1%	2%
		WIND	32%	32%	32%	32%	32%
		New COAL				72%	0%
		New CCGT	87%	87%		85%	81%
		New OCGT	6%	2%	10%	1%	2%
		New ADGT	25%	11%	37%		7%
		INTERCONNECTION (900MW)	70%	61%	80%	51%	48%
		FIXED GENERATION	85%	85%	85%	85%	85%
5	)	**Generation Annual Pool Revenue (€million)**					
		COAL	600	442	702	210	298
		PEAT	220	202	236	179	187
		GAS BASELOAD	1,354	1,202	1,457	995	1,026
		GAS MID-MERIT	784	623	861	403	469
		HYDRO	80	72	84	62	66

2020 RA Modelling Results

LOW FUEL SCENARIO

			Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
		PUMPED STORAGE	67	51	76	29	40
		PEAKERS	40	29	51	12	22
		WIND (Existing)	218	190	220	177	174
		New WIND	218	570	660	530	870
		New COAL				517	
		New CCGT	822	694		608	616
		New OCGT	128	32	269	5	33
		New ADGT	26	74	215		10
		INTERCONNECTION (Existing)	273	225	313	169	176
		New INTERCONNECTION	273	225	313	169	176
		TOTAL POOL REVENUE	**5,102**	**4,631**	**5,456**	**4,063**	**4,164**
6	**)**	**Generation Annual Capacity Revenue (€million)**					
		COAL	111	107	104	110	104
		PEAT	29	28	27	28	27
		GAS BASELOAD	185	177	172	182	172
		GAS MID-MERIT	120	114	111	118	111
		HYDRO	19	18	17	18	17
		PUMPED STORAGE	25	23	23	24	23
		PEAKERS	34	32	31	33	31
		WIND (Existing)	33	32	31	33	31
		New WIND	33	95	93	98	155
		New COAL				93	
		New CCGT	110	98		101	95
		New OCGT	124	68	156	26	66
		New ADGT	8	43	42		9
		INTERCONNECTION (Existing)	44	43	41	44	41
		New INTERCONNECTION	44	43	41	44	41
		TOTAL CAPACITY REVENUE	**918**	**919**	**891**	**952**	**923**
7	**)**	**Total Revenues (Pool + Capacity) (€million)**					
		COAL	711	548	805	319	401
		PEAT	249	229	263	207	214
		GAS BASELOAD	1,539	1,379	1,629	1,177	1,198
		GAS MID-MERIT	903	738	972	521	580
		HYDRO	98	90	101	80	84
		PUMPED STORAGE	92	75	99	53	63
		PEAKERS	73	62	82	45	54
		WIND (Existing)	251	222	251	209	205
		New WIND	251	665	753	628	1,025
		New COAL				610	
		New CCGT	932	792		709	711
		New OCGT	252	99	424	31	99
		New ADGT	34	117	257		19
		INTERCONNECTION (Existing)	317	268	355	213	218
		New INTERCONNECTION	317	268	355	213	218
		TOTAL REVENUES (POOL + CAPACITY)	**6,021**	**5,550**	**6,347**	**5,015**	**5,087**
8	**)**	**Generation Annual Variable Cost (€million)**					
		COAL	378	294	416	150	200
		PEAT	86	86	86	85	85
		GAS BASELOAD	809	777	811	719	695
		GAS MID-MERIT	482	402	494	288	310

2020 RA Modelling Results

LOW FUEL SCENARIO

			Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
		HYDRO					
		PUMPED STORAGE	23	18	26	10	14
		PEAKERS	23	16	28	7	12
		WIND (Existing)					
		New WIND					
		New COAL				359	
		New CCGT	496	453		445	427
		New OCGT	118	26	232	3	26
		New ADGT	21	61	154		8
		INTERCONNECTION (Existing)	136	119	153	99	98
		New INTERCONNECTION	136	119	153	99	98
		TOTAL VARIABLE COSTS	2,708	2,371	2,554	2,265	1,975
9	)	**Generation Annual Fixed Costs (€million)**					
		COAL	167	167	167	167	167
		PEAT	52	52	52	52	52
		GAS BASELOAD	224	224	224	225	225
		GAS MID-MERIT	155	155	156	155	156
		HYDRO	15	15	15	15	15
		PUMPED STORAGE	10	10	10	10	10
		PEAKERS	12	12	12	12	12
		WIND (Existing)	61	61	61	61	61
		New WIND	244	732	732	732	1,219
		New COAL	0	0	0	413	0
		New CCGT	246	228	0	228	228
		New OCGT	125	71	169	27	71
		New ADGT	11	69	69	0	14
		INTERCONNECTION (Existing)	12	12	12	12	12
		New INTERCONNECTION	45	45	45	45	45
		TOTAL FIXED COSTS	1,380	1,854	1,725	2,154	2,288
10	)	**Annual Total Costs (Fixed + Variable) (€million)**					
		COAL	546	461	584	317	368
		PEAT	137	137	137	137	137
		GAS BASELOAD	1,033	1,001	1,035	944	920
		GAS MID-MERIT	637	557	651	444	466
		HYDRO	15	15	15	15	15
		PUMPED STORAGE	33	28	36	20	24
		PEAKERS	35	28	40	19	24
		WIND (Existing)	61	61	61	61	61
		New WIND	244	732	732	732	1,219
		New COAL				772	
		New CCGT	742	681		673	655
		New OCGT	243	97	402	30	97
		New ADGT	32	130	223		22
		INTERCONNECTION (Existing)	148	131	165	111	110
		New INTERCONNECTION	181	164	199	144	144
		TOTAL COSTS (FIXED + VARIABLE)	4,088	4,224	4,278	4,419	4,263
11	)	**Annual Economic Profit/Loss (€million)**					
		COAL	165	87	222	2	33
		PEAT	112	92	126	70	77
		GAS BASELOAD	506	378	593	233	277

2020 RA Modelling Results

LOW FUEL SCENARIO

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
GAS MID-MERIT	267	180	321	77	114
HYDRO	83	74	86	65	69
PUMPED STORAGE	58	47	63	33	39
PEAKERS	39	34	42	26	30
WIND (Existing)	190	161	190	148	144
New WIND	8	-67	21	-104	-195
New COAL				-162	
New CCGT	190	111		36	56
New OCGT	9	2	23	1	2
New ADGT	1	-13	35		-4
INTERCONNECTION (Existing)	170	137	190	102	108
New INTERCONNECTION	136	103	156	69	74
TOTAL ECONOMIC PROFIT/LOSS	1,933	1,325	2,069	596	824

12) **Annual Economic Profit/Loss per MW installed (€000)**

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
COAL	126	67	169	1	26
PEAT	324	266	364	202	222
GAS BASELOAD	238	177	279	109	130
GAS MID-MERIT	187	126	225	54	80
HYDRO	385	344	399	300	318
PUMPED STORAGE	200	160	215	113	134
PEAKERS	99	87	109	68	77
WIND (Existing)	190	161	190	148	144
New WIND	8	-22	7	-35	-39
New COAL				-139	
New CCGT	147	92		30	47
New OCGT	6	2	12	3	2
New ADGT	13	-24	65		-34
INTERCONNECTION (Existing)	377	304	422	228	239
New INTERCONNECTION	303	229	347	153	165

APPENDIX C: HIGH FUEL SCENARIO RESULTS

		2020 RA Modelling Results	HIGH FUEL SCENARIO				
			Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
1	)	**Prices (€/MWh)**					
		Average Time-Weighted SMP	194.4	182.1	210.2	160.0	169.4
		Average Demand-Weighted SMP	208.0	193.0	224.6	167.6	178.3
2	)	**Carbon Emissions (Mtonnes)**					
		Ireland (with 75% of new thermal gen)	17.3	15.6	15.5	18.7	13.7
		All-Island	23.3	21.1	21.8	25.3	18.5
3	)	**Annual Generation Volume (GWh)**					
		COAL	9,561	9,505	9,612	9,315	9,203
		PEAT	2,685	2,680	2,686	2,672	2,670
		GAS BASELOAD	14,858	12,110	14,331	8,280	9,245
		GAS MID-MERIT	6,400	4,884	7,223	2,904	3,517
		HYDRO	720	720	720	720	720
		PUMPED STORAGE	309	240	350	153	207
		PEAKERS	87	58	112	17	44
		WIND	5,587	11,174	11,174	11,174	16,759
		New COAL				8,839	
		New CCGT	8,147	7,527		6,065	6,128
		New OCGT	768	146	1,675	19	152
		New ADGT	171	504	1,656		62
		NET INTERCONNECTION IMPORTS	7,787	7,429	7,597	6,689	6,545
		FIXED GENERATION	2,964	2,964	2,964	2,964	4,636
		TOTAL GENERATION VOLUME	60,043	59,942	60,099	59,811	59,887
		Renewables as percentage of Generation	13%	22%	22%	22%	35%
		Renewables as percentage of final Demand	15%	25%	25%	25%	38%
4	)	**Generation Load Factors**					
		COAL	83%	83%	84%	81%	80%
		PEAT	89%	89%	89%	88%	88%
		GAS BASELOAD	80%	65%	77%	44%	50%
		GAS MID-MERIT	51%	39%	58%	23%	28%
		HYDRO	38%	38%	38%	38%	38%
		PUMPED STORAGE	12%	9%	14%	6%	8%
		PEAKERS	3%	2%	3%	0%	1%
		WIND	32%	32%	32%	32%	32%
		New COAL				87%	0%
		New CCGT	72%	72%		58%	58%
		New OCGT	6%	2%	10%	1%	2%
		New ADGT	22%	11%	35%		6%
		INTERCONNECTION (900MW)	99%	94%	96%	85%	83%
		FIXED GENERATION	85%	85%	85%	85%	85%
5	)	**Generation Annual Pool Revenue (€million)**					
		COAL	1,828	1,702	1,988	1,464	1,545
		PEAT	515	481	558	421	447
		GAS BASELOAD	2,959	2,374	3,157	1,483	1,772
		GAS MID-MERIT	1,481	1,110	1,773	589	793
		HYDRO	177	163	191	136	148
		PUMPED STORAGE	123	92	151	47	71

			Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
		PEAKERS	56	38	74	10	28
		WIND (Existing)	517	466	529	422	423
		New WIND	517	1,398	1,588	1,266	2,117
		New COAL				1,383	
		New CCGT	1,694	1,446		1,059	1,145
		New OCGT	265	57	557	8	60
		New ADGT	49	155	480		20
		INTERCONNECTION (Existing)	759	684	810	549	582
		New INTERCONNECTION	759	684	810	549	582
		TOTAL POOL REVENUE	**11,699**	**10,850**	**12,665**	**9,387**	**9,735**
6	)	**Generation Annual Capacity Revenue (€million)**					
		COAL	111	107	104	110	104
		PEAT	29	28	27	28	27
		GAS BASELOAD	185	177	172	182	172
		GAS MID-MERIT	120	114	111	118	111
		HYDRO	19	18	17	18	17
		PUMPED STORAGE	25	23	23	24	23
		PEAKERS	34	32	31	33	31
		WIND (Existing)	33	32	31	33	31
		New WIND	33	95	93	98	155
		New COAL				93	
		New CCGT	110	98		101	95
		New OCGT	124	68	156	26	66
		New ADGT	8	43	42		9
		INTERCONNECTION (Existing)	44	43	41	44	41
		New INTERCONNECTION	44	43	41	44	41
		TOTAL CAPACITY REVENUE	**918**	**919**	**891**	**952**	**923**
7	)	**Total Revenues (Pool + Capacity) (€million)**					
		COAL	1,939	1,808	2,092	1,573	1,649
		PEAT	544	509	585	450	474
		GAS BASELOAD	3,144	2,551	3,329	1,665	1,944
		GAS MID-MERIT	1,600	1,224	1,884	706	905
		HYDRO	196	181	208	155	166
		PUMPED STORAGE	147	115	174	71	94
		PEAKERS	89	70	106	44	59
		WIND (Existing)	550	498	560	455	454
		New WIND	550	1,493	1,681	1,364	2,271
		New COAL				1,476	
		New CCGT	1,804	1,544		1,160	1,240
		New OCGT	389	125	713	34	126
		New ADGT	57	198	521		29
		INTERCONNECTION (Existing)	804	727	851	593	623
		New INTERCONNECTION	804	727	851	593	623
		TOTAL REVENUES (POOL + CAPACITY)	**12,617**	**11,769**	**13,556**	**10,338**	**10,658**
8	)	**Generation Annual Variable Cost (€million)**					
		COAL	1,038	1,034	1,043	1,017	1,005
		PEAT	257	256	257	256	256
		GAS BASELOAD	2,178	1,805	2,111	1,262	1,394
		GAS MID-MERIT	1,089	837	1,211	499	613
		HYDRO					
		PUMPED STORAGE	56	55	65	25	35

2020 RA Modelling Results — **HIGH FUEL SCENARIO**

			Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
		PEAKERS	41	28	53	8	21
		New WIND					
		New COAL					
		New CCGT				834	
		New OCGT	1,217	1,117		919	920
		New ADGT	258	54	527	7	56
		INTERCONNECTION (Existing)	46	143	402		18
		New INTERCONNECTION	452	430	441	387	383
		New WIND	452	430	441	387	383
		TOTAL VARIABLE COSTS	7,083	6,190	6,551	5,601	5,084
9	)	**Generation Annual Fixed Costs (€million)**					
		COAL	167	167	167	167	167
		PEAT	52	52	52	52	52
		GAS BASELOAD	225	226	225	227	227
		GAS MID-MERIT	155	156	157	153	158
		HYDRO	15	15	15	15	15
		PUMPED STORAGE	10	10	10	10	10
		PEAKERS	12	12	12	12	12
		WIND (Existing)	61	61	61	61	61
		New WIND	244	732	732	732	1,219
		New COAL	0	0	0	413	0
		New CCGT	247	228	0	229	229
		New OCGT	125	71	169	27	71
		New ADGT	11	69	69	0	14
		INTERCONNECTION (Existing)	12	12	12	12	12
		New INTERCONNECTION	45	45	45	45	45
		TOTAL FIXED COSTS	1,382	1,857	1,726	2,154	2,293
10	)	**Annual Total Costs (Fixed + Variable) (€million)**					
		COAL	1,205	1,202	1,210	1,184	1,173
		PEAT	309	308	309	308	307
		GAS BASELOAD	2,403	2,031	2,336	1,489	1,620
		GAS MID-MERIT	1,244	993	1,368	651	771
		HYDRO	15	15	15	15	15
		PUMPED STORAGE	66	66	75	35	45
		PEAKERS	53	40	65	20	33
		WIND (Existing)	61	61	61	61	61
		New WIND	244	732	732	732	1,219
		New COAL				1,247	
		New CCGT	1,463	1,346		1,148	1,149
		New OCGT	383	125	696	34	128
		New ADGT	57	212	471		33
		INTERCONNECTION (Existing)	463	441	453	399	395
		New INTERCONNECTION	497	475	486	432	428
		TOTAL COSTS (FIXED + VARIABLE)	8,465	8,047	8,278	7,755	7,377
11	)	**Annual Economic Profit/Loss (€million)**					
		COAL	734	607	881	389	476
		PEAT	235	201	276	142	167
		GAS BASELOAD	741	519	994	176	324
		GAS MID-MERIT	356	231	516	55	134
		HYDRO	181	165	193	140	151
		PUMPED STORAGE	81	49	99	36	49

2020 RA Modelling Results | **HIGH FUEL SCENARIO**

		Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
	PEAKERS	36	30	40	23	27
	WIND (Existing)	489	437	499	394	393
	New WIND	306	761	949	633	1,052
	New COAL				229	
	New CCGT	341	198		12	91
	New OCGT	6	-1	16	-0	-2
	New ADGT	-0	-14	51		-4
	INTERCONNECTION (Existing)	340	286	399	194	229
	New INTERCONNECTION	307	252	365	161	195
	ECONOMIC PROFIT/LOSS	4,152	3,722	5,278	2,583	3,281
12)	**Annual Economic Profit/Loss per MW installed (€000)**					
	COAL	559	462	671	296	363
	PEAT	681	581	799	411	482
	GAS BASELOAD	348	244	467	83	152
	GAS MID-MERIT	249	162	361	39	94
	HYDRO	837	766	894	646	697
	PUMPED STORAGE	277	169	338	122	166
	PEAKERS	93	77	104	60	68
	WIND (Existing)	489	437	499	394	393
	New WIND	306	254	316	211	210
	New COAL				197	
	New CCGT	264	165		10	76
	New OCGT	4	-1	8	-0	-2
	New ADGT	-2	-26	94		-34
	INTERCONNECTION (Existing)	756	635	886	431	508
	New INTERCONNECTION	681	560	811	357	434

APPENDIX D: LOW DEMAND SCENARIO RESULTS

	2020 RA Modelling Results		LOW DEMAND SCENARIO			
		Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
1)	**Prices (€/MWh)**					
	Average Time-Weighted SMP	115.6	110.5	130.8	103.0	105.3
	Average Demand-Weighted SMP	121.7	115.2	139.1	106.5	109.2
2)	**Carbon Emissions (Mtonnes)**					
	Ireland (with 75% of new thermal gen)	15.8	14.5	14.6	18.1	12.8
	All-Island	21.3	19.3	19.6	22.9	16.4
3)	**Annual Generation Volume (GWh)**					
	COAL	9,392	9,096	9,374	7,700	8,011
	PEAT	2,682	2,679	2,685	2,679	2,672
	GAS BASELOAD	13,718	10,852	13,737	7,214	8,280
	GAS MID-MERIT	4,167	3,328	5,968	2,152	2,433
	HYDRO	719	720	720	720	720
	PUMPED STORAGE	211	162	296	88	122
	PEAKERS	27	17	70	3	8
	WIND	5,587	11,174	11,174	11,174	16,755
	New COAL				8,836	
	New CCGT	8,487	7,662		6,044	6,042
	New OCGT	76	54	450	0	14
	New ADGT	0	6	765		0
	NET INTERCONNECTION IMPORTS	6,325	5,565	6,274	4,592	4,521
	FIXED GENERATION	2,964	2,964	2,964	2,964	4,636
	TOTAL GENERATION VOLUME	54,356	54,279	54,477	54,165	54,214
	Renewables as percentage of Generation	14%	25%	25%	25%	38%
	Renewables as percentage of final Demand	15%	25%	25%	25%	38%
4)	**Generation Load Factors**					
	COAL	82%	79%	81%	67%	70%
	PEAT	89%	88%	89%	88%	88%
	GAS BASELOAD	74%	58%	74%	39%	44%
	GAS MID-MERIT	33%	27%	48%	17%	19%
	HYDRO	38%	38%	38%	38%	38%
	PUMPED STORAGE	8%	6%	12%	3%	5%
	PEAKERS	1%	0%	2%	0%	0%
	WIND	32%	32%	32%	32%	32%
	New COAL				87%	0%
	New CCGT	75%	73%		57%	57%
	New OCGT	1%	1%	3%	0%	0%
	New ADGT	0%	0%	16%		0%
	INTERCONNECTION (900MW)	80%	71%	80%	58%	57%
	FIXED GENERATION	85%	85%	85%	85%	85%
5)	**Generation Annual Pool Revenue (€million)**					
	COAL	1,063	988	1,210	786	840
	PEAT	306	292	347	272	278
	GAS BASELOAD	1,626	1,265	1,881	796	951
	GAS MID-MERIT	586	452	944	261	323
	HYDRO	100	93	119	83	86
	PUMPED STORAGE	48	35	82	16	25
	PEAKERS	13	7	35	1	4
	WIND (Existing)	311	290	326	277	273
	New WIND	311	870	978	831	1,363
	New COAL				890	
	New CCGT	1,008	865		652	676
	New OCGT	21	13	117	0	4
	New ADGT	0	1	152		0
	INTERCONNECTION (Existing)	383	329	443	255	265
	New INTERCONNECTION	383	329	443	255	265
	TOTAL POOL REVENUE	6,160	5,831	7,074	5,375	5,354
6)	**Generation Annual Capacity Revenue (€million)**					
	COAL	101	97	94	99	94
	PEAT	26	25	24	26	24
	GAS BASELOAD	168	160	156	165	156
	GAS MID-MERIT	108	104	101	107	101
	HYDRO	17	16	16	17	16
	PUMPED STORAGE	22	21	21	22	21
	PEAKERS	31	29	29	30	28
	WIND (Existing)	30	29	28	30	28
	WIND (New)	30	86	84	89	140
	New WIND				85	
	New COAL	100	89		91	86
	New CCGT	112	61	141	24	60
	New OCGT	7	39	38		8
	New ADGT	40	39	38	40	38
	INTERCONNECTION (Existing)	40	39	38	40	38
	TOTAL CAPACITY REVENUE	833	833	808	863	838
7)	**Total Revenues (Pool + Capacity) (€million)**					
	COAL	1,165	1,085	1,304	885	934
	PEAT	332	317	371	297	302
	GAS BASELOAD	1,793	1,425	2,038	961	1,107
	GAS MID-MERIT	695	556	1,045	367	424
	HYDRO	117	109	135	100	102
	PUMPED STORAGE	70	56	103	38	46
	PEAKERS	44	37	63	31	32
	WIND (Existing)	342	319	354	307	301
	New WIND	342	956	1,062	920	1,504

2020 RA Modelling Results

LOW DEMAND SCENARIO

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
New COAL				975	
New CCGT	1,108	954		743	762
New OCGT	133	74	258	24	63
New ADGT	7	40	190		8
INTERCONNECTION (Existing)	424	367	480	295	303
New INTERCONNECTION	424	367	480	295	303
TOTAL REVENUES (POOL + CAPACITY)	6,993	6,664	7,882	6,238	6,191
8) **Generation Annual Variable Cost (€million)**					
COAL	777	754	775	637	668
PEAT	161	161	161	161	161
GAS BASELOAD	1,353	1,078	1,355	718	828
GAS MID-MERIT	479	379	675	234	276
HYDRO					
PUMPED STORAGE	26	20	37	10	14
PEAKERS	10	6	24	1	3
WIND (Existing)					
New WIND					
New COAL				631	
New CCGT	844	757		606	602
New OCGT	19	13	110	0	4
New ADGT	0	2	136		0
INTERCONNECTION (Existing)	273	241	271	203	205
New INTERCONNECTION	273	241	271	203	205
TOTAL VARIABLE COSTS	4,216	3,651	3,817	3,404	2,965
9) **Generation Annual Fixed Costs (€million)**					
COAL	167	167	167	167	167
PEAT	52	52	52	52	52
GAS BASELOAD	225	226	225	227	227
GAS MID-MERIT	156	156	156	145	158
HYDRO	15	15	15	15	15
PUMPED STORAGE	10	10	10	10	10
PEAKERS	12	12	12	12	12
WIND (Existing)	61	61	61	61	61
New WIND	244	732	732	732	1,219
New COAL				413	
New CCGT	247	228		229	228
New OCGT	125	71	169	27	71
New ADGT	11	69	69		14
INTERCONNECTION (Existing)	12	12	12	12	12
New INTERCONNECTION	45	45	45	45	45
TOTAL FIXED COSTS	1,383	1,856	1,726	2,147	2,292
10) **Annual Total Costs (Fixed + Variable) (€million)**					
COAL	944	921	943	805	835
PEAT	213	213	213	213	213
GAS BASELOAD	1,579	1,304	1,580	945	1,055
GAS MID-MERIT	635	535	831	379	434
HYDRO	15	15	15	15	15
PUMPED STORAGE	36	30	47	21	24
PEAKERS	22	18	36	13	15
WIND (Existing)	61	61	61	61	61
New WIND	244	732	732	732	1,219
New COAL				1,044	
New CCGT	1,091	985		834	830
New OCGT	144	84	279	27	75
New ADGT	12	71	205		14
INTERCONNECTION (Existing)	285	252	283	215	216
New INTERCONNECTION	319	286	316	248	250
TOTAL COSTS (FIXED + VARIABLE)	5,599	5,507	5,542	5,551	5,257
11) **Annual Economic Profit/Loss (€million)**					
COAL	220	164	362	81	99
PEAT	119	104	158	85	90
GAS BASELOAD	215	121	458	15	52
GAS MID-MERIT	60	21	213	-11	-10
HYDRO	102	94	119	85	87
PUMPED STORAGE	34	26	55	18	22
PEAKERS	22	18	27	18	17
WIND (Existing)	280	258	293	245	240
New WIND	98	225	330	188	284
New COAL				-69	
New CCGT	17	-31		-92	-68
New OCGT	-11	-10	-21	-3	-12
New ADGT	-5	-30	-16		-7
INTERCONNECTION (Existing)	139	115	197	81	87
New INTERCONNECTION	105	82	164	47	53
TOTAL ECONOMIC PROFIT/LOSS	1,395	1,157	2,339	687	934
12) **Annual Economic Profit/Loss per MW installed (€000)**					
COAL	168	125	275	61	75
PEAT	344	302	456	245	259
GAS BASELOAD	101	57	215	7	24
GAS MID-MERIT	42	15	149	-8	-7
HYDRO	472	437	553	394	404
PUMPED STORAGE	116	90	189	61	75
PEAKERS	57	47	70	46	43
WIND (Existing)	280	258	293	245	240
New WIND	98	75	110	63	57
New COAL				-60	
New CCGT	13	-26		-76	-57
New OCGT	-8	-12	-11	-10	-14
New ADGT	-52	-56	-30		-59

2020 RA Modelling Results		**LOW DEMAND SCENARIO**			
	Portfolio 1	**Portfolio 2**	**Portfolio 3**	**Portfolio 4**	**Portfolio 5**
INTERCONNECTION (Existing)	**308**	**256**	**438**	**179**	**192**
New INTERCONNECTION	**234**	**181**	**364**	**104**	**118**

APPENDIX: ABBREVIATIONS

ADGT	Aero Derivative Gas Turbine
AIGS	All Island Grid Study
AIP	All Island Project
BETTA	British Electricity Trading and Transmission Arrangements
BNE	Best New Entrant
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation
CHP	Combined Heat and Power
CPM	Capacity Payment Mechanism
DSM	Demand Side Management
EU	European Union
GAR	Generation Adequacy Report
GB	Great Britain
NI	Northern Ireland
NIAUR	The Northern Ireland Authority for Utility Regulation
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
RAs	Regulatory Authorities
ROI	Republic of Ireland
SEM	Single Electricity Market
SMP	System Marginal Price
TER	Total Electricity Requirement
TES	Total Electricity Sales
VOM	Variable Operation and Maintenance
WACC	Weighted Average Cost of Capital