Establishing the Role That Wind Generation May Have in Future Generation Portfolios

Ronan Doherty, *Member, IEEE*, Hugh Outhred, *Member, IEEE*, and Mark O'Malley, *Senior Member, IEEE*

***Abstract*—Assessing the correct future mix in generation portfolios has become more difficult given the introduction of emission trading schemes, the recent fuel price rises, and the increasing competitiveness of wind energy. This paper combines analysis of generation economics, load and wind generation characteristics, generation adequacy, and plant utilization to gain insight into the role of wind generation in desirable generation portfolios. The unique characteristics of wind generation are accounted for in the analysis, and sensitivity analysis is carried out with respect to discount rates, carbon taxes, and various fuel price scenarios. Results show that for a large range of future scenarios, wind generation has a significant role to play in future generation portfolios in Ireland. Mean-variance portfolio theory is applied to examine the benefits of portfolio diversification in terms of avoiding exposure to volatile fuel prices. Analysis shows that wind generation has a further role to play in generation portfolios in this respect.**

***Index Terms*—Energy resources, environmental factors, fuel diversity, integrated resource planning, power system economics, wind energy.**

I. Introduction

LONG-TERM generation resource planning is a complex task with many unknown and uncertain factors [1]. Rather than striving to develop optimal resource plans in the strictest sense, long-term generation planning is an inexact science, which requires the assessment of various factors, often from several perspectives, to gain insight into what may be desirable generation plans. Recent technological developments and emission trading schemes have made wind generation more competitive with conventional sources of generation, and this has consequently added another dimension to the generation planning problem. The characteristics of wind generation differ fundamentally from that of conventional generation. These characteristics must be fully recognized within generation planning assessments. While many aspects of wind generation can be controlled, e.g., reactive power, there is a variable upper limit on the wind generation's active power. The variable nature of wind generation means that it cannot be thought of as providing base-load energy to serve the load shape but rather as providing energy to reduce and alter the load shape. This has cost implications for other generation in the portfolio that serve the remainder of the load. Its variable nature also means that it contributes differently to generation adequacy in systems than conventional generation.

In the past, vertically integrated utilities carried out generation resource planning and were in a position to coordinate and execute such plans. Planning methods grew increasingly sophisticated considering not just least-cost energy but multiple objectives and also the robustness of generation resource plans in relation to uncertainties [2]–[4]. With the recent onset of market liberalization in many systems, there has been a corresponding de-emphasis on central planning. However, market-driven planning may not always result in the most desirable outcomes for the economy and society that the electricity system is serving [5]. Systems that have been exposed to the adverse effects of market failures such as California, and others in the northwest of the United States have recently, again resorted to more comprehensive long-term central resource planning [6], [7]. Helm [8], commenting on the evolution of the electricity industry, states that, "the two simplistic ways forward—pure markets and planning—have given way to a mixture of both."

A popular procedure for determining the value of generation investment is discounted cash flow analysis. This results in single levelized production costs, which makes the comparison of different technologies easy. For generation resource planning, this approach has many flaws [9] and is particularly ill-suited for wind generation, which has been shown to exhibit varying benefit to systems, depending on the penetration [10]. It is also difficult to account for cost uncertainties with the levelized cost approach. For electricity generation, the most significant uncertainties surround future fuel prices. Single levelized generation costs, without sensitivity analysis, are almost meaningless in the long term, given the current volatility in international fuel prices. Diversifying generation portfolios is cited as a means to reduce the exposure to fuel price and other types of risk, and it has been suggested that wind generation may have a significant role to play in this respect. There are, however, differing opinions as to how and on what basis portfolios should diversify [9], [11], [12].

This paper combines analysis of generation economics, load and wind generation characteristics, generation adequacy, and plant utilization to gain insight into the role that wind generation and other sources of generation may have in future generation portfolios. New innovations in the methodology here mean that the unique and variable characteristics of wind generation, and its impact of the net-load shape, are accounted for in the

Manuscript received October 6, 2005; revised March 15, 2006. This work was conducted at the Electricity Research Centre, University College Dublin, Ireland, which is supported by Electricity Supply Board (ESB), ESB National Grid, Commission for Energy Regulation, Cylon, Airtricity, and Enterprise Ireland. Paper no. TPWRS-00639-2005.

R. Doherty and M. O'Malley are with the Electricity Research Centre, University College Dublin, Dublin 4, Ireland (e-mail: ronan@ee.ucd.ie; mark.omalley@ucd.ie).

H. Outhred is with the School of Electrical Engineering and Telecommunications, University of New South Wales, Sydney 2052, Australia (e-mail: h.outhred@unsw.edu.au).

Digital Object Identifier 10.1109/TPWRS.2006.879258

TABLE I
GENERATION COST AND CHARACTERISTICS

Plant Type	Notional Size of Installation (MW)	Plant Life (Years)	Build Time (Years)	Average Efficiency (%)	Capital Cost (€/MW)	Op & Main (€/MW p.a.)	CO_2 Emissions (Tons Co_2/MWh)	Availability (%)	Resource Limited (MW)
Coal PF	1000 (3 x 333 MW)	30	4	37	1,479,200	34,800	0.92	84	-
Coal IGCC	800 (2 x 400 MW)	25	5	48	1,761,321	69,000	0.71	84	-
Peat FB	150	25	4	37	1,223,807	55,200	1.15	87	1000
OCGT	110	20	1	43	518,411	36,000	0.47	92	-
CCGT	390	20	2	56	537,500	50,000	0.36	88	-
Wind 1 (On-Shore)	30 (15 x 2 MW)	20	2	-	981,475	34,800	0.00	-	1200
Wind 2 (Mix)	30 (15 x 2 MW)	20	2	-	1,028,775	54,250	0.00	-	2600
Biomass & Biogas 1	10	20	2	-	2,418,750	80,000	0.00	78	70
Biomass & Biogas 2	10	20	2	-	3,386,250	90,000	0.00	78	50
Biomass & Biogas 3	10	20	2	-	4,353,750	90,000	0.00	78	500

PF = Pulverized Fuel. IGCC = Integrated Gasification Combined Cycle. FB = Fluidized Bed.
CCGT = Combined Cycle Gas Turbine. OCGT = Open Cycle Gas Turbine.

analysis. The costs and characteristics of various generation options are fed into a constrained optimization to determine the least-cost portfolio given the set of inputs. Sensitivity analysis is then carried out on key factors to gain an understanding of desirable generation portfolios and the role of wind generation within them. Finally, mean-variance portfolio theory is applied to examine the benefits of wind generation in portfolios diversifying to avoid exposure to fuel price risk.

The analysis assumes that almost all the existing capacity in the all-Ireland system is retired by 2020, and as a result, least-cost portfolios derived in this paper can give insight into generation planning issues in other systems. Many practical system factors are included in the analysis. However, as with any high-level analysis, there are factors that are impractical to include. In this paper, unit startup and ramping issues have been excluded. Preliminary investigations were carried out into the role of new energy storage. However, this analysis is not presented here due to inconclusive results, uncertain input costs, and the lack of physically suitable sites for new pumped storage in the all-Ireland system.

Section II gives a summary of the generation costs and characteristics and other inputs used in the analysis. Section III assesses capacity credits for the various types of generation to ensure generation adequacy in portfolios. Section IV presents the formulation of the least-cost portfolio optimization. Section V contains results and discussion on least-cost portfolios and the role of wind generation. Section VI highlights the role the wind generation may play in avoiding fuel price risk in diverse portfolios. Conclusions are given in Section VII.

II. INPUTS

A. Generator Inputs

For this paper, an extensive list of generator characteristics, efficiencies, and costs were gathered from many sources [13]–[19]. Table I shows the generators, costs, efficiencies, and characteristics assumed achievable in the all-Ireland system by 2020. Costs are based on units of a notional size given in Table I. Oil fired plant, which was deemed to be prohibitively expensive, and nuclear generation, which is unlikely to be developed in Ireland, were excluded from the analysis. The category "Wind 1" represents a possible 1200 MW of onshore wind capacity that can be practically developed with a capacity factor of 0.35. It is assumed that there is a further 2600 MW of potential development, which consists of onshore wind generation with a lower capacity factor and offshore wind with a higher capacity factor and higher costs. These projects are grouped together as "Wind 2" and approximated with an average capacity factor of 0.35 and a higher capital cost. In reality, there may be a higher usable wind resource in Ireland; however, the limit of this resource remains unclear. The limit of 3800 MW was chosen here to allow a significant range of wind penetration scenarios to be assessed while still generally avoiding penetrations where it is envisaged that significant curtailment of wind generation may occur for operational reasons.

TABLE II
FUEL PRICE SCENARIOS

Fuel	Low €/GJ	High €/GJ
Gas	4.31	5.54
Coal	1.59	1.65
Peat	2.64	3.12

The various biomass and biogas technologies and the extent of their resource have been grouped together in three categories based on cost. Peat is a native Irish fuel source usually burnt in fluidized bed plant. All costs are expressed in current value, € 2005. Capital costs include the cost of interest on phased capital expenditure during construction.

B. Fuel Prices

Two fuel price scenarios are used in this paper: a low fuel price scenario, which is based on 2005 fuel prices, and a high fuel price scenario based on projected 2020 fuel prices (see Table II). The fuel price scenarios were compiled from several sources [15], [19]–[21] and are all expressed in current value, € 2005. Forecasting long-term future fuel prices is a difficult task, and the high fuel price scenario here is based on those in [21]. The most notable feature in the high fuel price scenario, compared to the low, is the relatively higher price of gas relative to the other fuels. It is assumed that on average, the fuel cost component for the biomass and biogas 1, 2, and 3 categories is 20, 31, and 43 €/MWh, respectively [17].

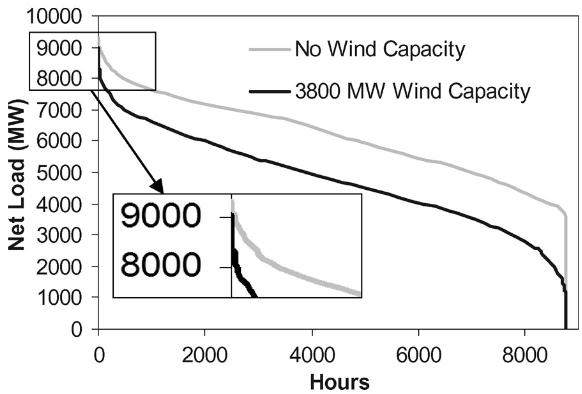


Fig. 1. Net-load duration curve with and without 3800 MW of wind capacity for the all-Ireland system in 2020.

C. Carbon Costs

Under the EU emissions trading scheme, the all-Ireland system will be part of a larger emission trading scheme across the whole of Europe [22]. From a macroeconomic perspective, the all-Ireland system is exposed to the cost of carbon, and whether the carbon credits are grandfathered or bought in the trading scheme, the cost of carbon should be included when considering the future generation portfolio. The cost of carbon is included in the analysis here in the form of a carbon tax, which is applied to the energy output of each type of generation in accordance with the emissions values given in Table I.

D. Load Growth and Profiles

The load profile for the all-Ireland system in 2020 was derived from the historic data and an assumed average annual load growth of 3%. This is roughly in line with the Republic of Ireland system operator's median load growth scenario [23]. To encapsulate the load duration characteristics of the demand in the algorithm, the load was broken up into 18 separate load bins. Each bin is 500 MW wide and records the number of hours during the year when the load fell within the range of the bin. The energy to be served in each bin is found by multiplying the number of hours in the bin by the median value of the bin. The load duration curve is illustrated in Fig. 1.

E. Hydro, Pumped Storage, and Interconnection

It is assumed here that Ireland's hydro generation is already fully exploited, and further hydro projects are not considered in this paper. The all-Ireland system has approximately 509 MW of hydro and pumped storage capacity at present. The hydro and pumped storage units are incorporated into the model by using their historic operation profile [20]. It is assumed that Ireland will have 800 MW of HVDC interconnection with Great Britain by 2020 [24]. It is assumed that these interconnectors can import energy at a price that is about 7% less than the cost of energy from CCGTs in Ireland given the lower gas price and the economies of scale achievable in Great Britain.

F. Wind Generation

Due to its variable nature, wind generation is included into the modeling in a different way to the other generation sources. Hourly wind generation profiles were used in this paper. These were developed in [25] using real wind farm output data from around Ireland and then scaled to meet the various statistical parameters for various installed capacities. These profiles include the statistical benefits of diversity derived from spreading wind farms over a large geographical area and also factor in the limit of diversity that can be achieved on a small island such as Ireland. Five separate wind profiles were used here for 77, 845, 1300, 1950, and 3900 MW of installed wind capacity. The effects of these wind profiles on the net-load profile were expressed in terms of the changes it caused to the load duration bins. These effects were then linearly interpolated to give a set of duration bin values for net-load profiles, which corresponded to wind capacities ranging from 0–3800 MW in 200-MW steps. Fig. 1 shows the net-load duration curve with no wind capacity and with 3800 MW of wind capacity. Installed wind capacity of 3800 MW is capable of serving 22% of the energy demand. The uncertain and variable nature of wind generation means that systems need to have increased amounts of installed capacity and operational reserve. The issue of uncertain wind output and adequate system capacity is dealt with in the next section. Results in [25] show that increasing wind generation does require an increase in operational reserve but that this does not result in a significant increase in cost to the system. For this reason, operational reserve costs have been excluded from the analysis here.

G. Uncertainties in Inputs

There are uncertainties surrounding many of the inputs relating to future generation costs and characteristics, and the challenging nature of generation resource planning results from these uncertainties. In high-level analysis such as this, it is impossible to account for all sources of uncertainty. However, sensitivity analysis in relation to various key inputs such as fuel prices, carbon taxes, and discount rates is carried out. The uncertainty surrounding other factors such as generator build time and operation and maintenance costs have been shown to be relatively small [11]. Diversity analysis is also applied, which may also be thought of as implicitly accounting for general uncertainty in the input data [12].

III. Generation Adequacy

It is essential that a power system has enough capacity to serve the load to the extent defined by a system reliability criterion. The provision of capacity in systems is an important issue to consider when analyzing future generation portfolios as it can have significant cost implications. Intermittent sources of generation, like wind generation, make a different contribution to the generation adequacy of a system than conventional dispatchable generation. As can be seen from Fig. 1, wind capacity can serve a significant amount of total energy without necessarily decreasing the hours of peak net-load by the same amount. This trait has been overlooked in other work [11].

The generation adequacy requirement used by the system operator in the Republic of Ireland requires sufficient capacity to maintain a loss of load expectation (LOLE) of eight hours per year [23]. This paper aims to produce generation portfolios that meet this criterion by deriving capacity credits for wind generation and conventional generation. These capacity credits are then included in the least-cost portfolio optimization.

A. Capacity Credit Calculations

There are several ways to calculate system LOLE and generation capacity credits [26]. The approach adopted here is a Monte Carlo approach similar to that used in [27]. Typical forced outage probabilities and the number of days needed each year for scheduled maintenance were used for the dispatchable generation. It was found that running each Monte Carlo simulation for 1000 years gave good outcomes in terms of convergence with the final LOLE answers having a standard deviation of just 0.1 h per year.

In order to find the capacity credit of the generation considered in this paper, the impact of the installed capacity of the generation must be related to the LOLE of the system. For the 2020 all-Ireland hourly load profile, a base portfolio of generation was created that gave a LOLE of eight hours per year. This portfolio is the basis from which the effect of the individual plant can be examined. The portfolio was made up of 10 101 MW of dispatchable generation, which approximates to 108% of the peak load. The capacity credit results were found not to be sensitive to the makeup of this base portfolio.

1) Dispatchable Generation: To find the capacity credit of a certain type of dispatchable generation, extra units of it were added to the portfolio. The portfolio of plant was then scheduled out on maintenance, and the LOLE was calculated for the 2020 all-Ireland load profile. A decrease in the system LOLE could be measured due to the increase in capacity. The load was then increased uniformly during the year until the LOLE returned to eight hours per year. The capacity credit was then found by dividing the amount of generation capacity added by the increase in load that it could serve at a LOLE of eight.

It was found that all of the dispatchable generation had a capacity credit of approximately 0.99. This implies that 1 MW of conventional generation allows almost 1 MW of extra load to be served every hour in the year without decreasing system reliability. Despite having availabilities of around 86%, the fact that the units can be scheduled out on maintenance at times of low load means that they keep a high capacity credit.

2) Wind Generation: To find the capacity credit of the wind generation, the various wind profiles were subtracted in turn from the load profile. The LOLE calculations were carried out as before, and the capacity credit was again found by dividing the corresponding installed wind capacity by the increase in load. This was done for the five different wind profiles, and Fig. 2 shows the capacity credit for the wind capacity at different penetrations. It can be seen that the capacity credit of the wind capacity is initially about 0.4 for low penetrations of wind generation. However, this decreases as the penetration of wind generation increases and is about 0.19 for a wind capacity of 3800 MW.

The wind generation's capacity credit at low penetrations exceeds its average capacity factor of 0.35. This is because there are strong seasonal and diurnal elements to the wind generation output. At times of system peak demand during winter daytime hours, the wind can in general be expected to be producing more than its average yearly output.

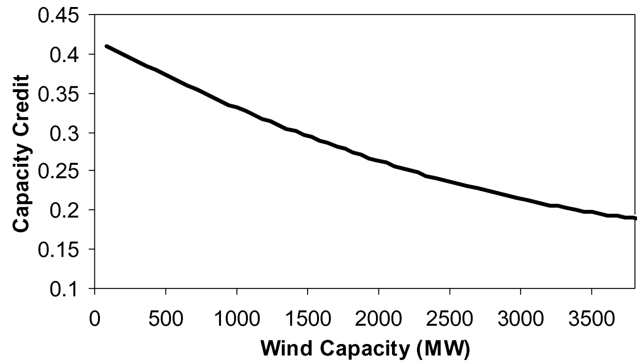


Fig. 2. Capacity credit versus installed wind capacity.

The first point on the curve in Fig. 2 was calculated for a wind penetration of 77 MW consisting of six wind farms. At this initial point, the benefits of diversity are already factored in for the six wind farms. It is likely that a single wind farm would have a much lower capacity credit than this. Even assuming a reasonably diverse range of wind farms, it can be seen that the correlation of their output still means that the capacity credit decreases when the wind capacity increases. However, assuming a reasonably diverse range means that the capacity credit will not fall as fast as it would if the increased capacity was sited close to the first six wind farms.

IV. Portfolio Optimization Algorithm

A portfolio optimization algorithm is used to find the mix of generation technologies that, for a given set of inputs, results in the load being met at least cost. Temporal system aspects and unit startup factors are not included. However, the impact of wind generation is included through the use of the load bins, as are issues of plant utilization, load duration, and generation adequacy. This approach gives insight into the relative effects of key factors on the least-cost generation portfolios.

A. Formulation

Rather than solving for the installed capacity of the various types of generations in the portfolio while trying to approximate how they may be utilized, the approach adopted here is to optimize the installed capacities and optimize how they are utilized.

Although the generation cost characteristics are based on a notional size of installation, the optimization algorithm allows the installed capacity of each technology to be a continuous variable from 0 to infinity or its resource limited amount as shown in Table I. This allows the problem to be formulated as a linear program and the complications of discrete integer optimization to be avoided. The energy served in each load bin by each technology, $E_{b,n}$, is linked to the installed capacity of that technology, I_n, with the use of constraints. The aim is to minimize the objective function in (1). This is the cost of supplying the all-Ireland load in 2020

$$min \quad \sum_{n \in N} Cc_n I_n + \sum_{n \in N} \sum_{b \in B} Cf_n E_{b,n} \tag{1}$$

where

- N set of generation technologies being considered;
- B set of load duration bins;
- Cc_n annuitized capital cost and annual operation and maintenance cost of generation n in € per MW installed/year;
- Cf_n fuel cost of generation n in €/MWh.

This is subject to the capacity constraint, which ensures every portfolio will have a LOLE of eight hours per year

$$\sum_{n \in N} CapC_n I_n \geq 10\,000 \tag{2}$$

where $CapC_n$ is the capacity credit of generation type n. The value of 10 000 in the constraint comes from 10 101 MW $\times$ 0.99 and is coincidental.

The constraint in (3) ensures that there is sufficient energy from the generation to serve the demand in each load bin

$$\sum_{n \in N} E_{b,n} = H_b M_b, \quad \forall\, b \in B \tag{3}$$

where

- H_b number of hours in each load bin;
- M_b center value of each load bin.

The energy served by each generation technology must not be greater than the installed capacity of that technology multiplied by its availability in hours per year, $Avail_n$, as shown in Table I

$$\sum_{b \in B} E_{b,n} \leq I_n Avail_n, \quad \forall\, n \in N. \tag{4}$$

The constraint in (5) is used to ensure that that one MW of installed capacity does not provide more than one MWh at a time

$$E_{b,n} \leq I_n H_b, \quad \forall\, b \in B, \quad \forall\, n \in N. \tag{5}$$

The constrained optimization algorithm shown in (1)–(5) is run several times for different wind penetrations ranging from 0 to 3800 MW in 200-MW steps. In each run, the relevant installed wind capacity, the energy served by the wind capacity in each load bin, and the related capacity credit are fixed in the optimization. This produces a series of portfolios, and the portfolio that results in the least cost can then be selected as the optimal.

V. Least-Cost Generation Portfolio Results and Discussion

A range of portfolios produced by the portfolio optimization algorithm were fed back into the maintenance scheduling and LOLE algorithms outlined in Section III to check that they resulted in an LOLE of eight hours per year. All portfolios, including those with wind generation, were found to have a LOLE in the range of 7.9–8.1 hours per year. This confirms the accuracy of the capacity credits used. A nominal discount rate of 7.5% is initially applied to the capital cost of all the generation plant [13], [15].

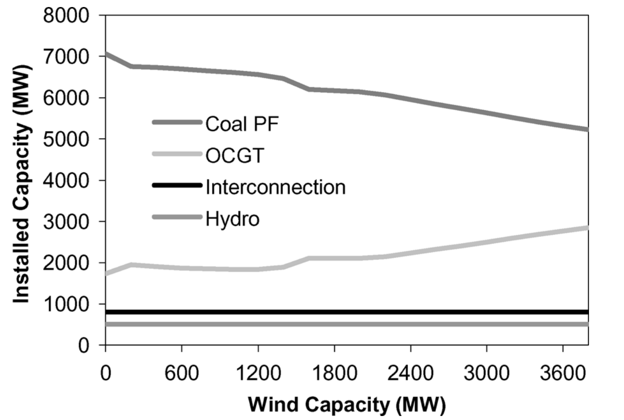


Fig. 3. Installed capacities of generation in least-cost portfolios against wind capacity for the low fuel price, no carbon tax scenario.

A. *Effect of Increasing Wind Capacity*

Analysis was carried out to examine the effect of increasing wind capacity on the remaining mix of generation in least-cost portfolios. Fig. 3 shows the installed capacities of the generation in the least-cost portfolios with increasing wind generation for the low fuel price scenario with no carbon tax.

It can be seen that the increasing wind capacity causes a decrease in the amount of base loaded plant and an increase in the amount of peaking capacity required. This is due to the changes that wind generation causes to the net-load duration curve. Similar trends were found for portfolios that had CCGTs as the base loaded plant. This behavior is in contrast to the impact wind capacity has on existing portfolios, where it normally displaces the units with higher incremental costs. To ensure efficient generation portfolios as wind capacity increases, it becomes more important that the correct long-term signals for peaking capacity are provided in the marketplace.

B. *Effect of Carbon Tax on the Least-Cost Generation Portfolio*

Tables III and IV show the generation portfolios for the all-Ireland system with various carbon taxes for the low and high fuel price scenarios, respectively. If regulatory bodies can ensure that the cost of carbon is properly reflected in the marketplace, it is reasonable to assume, given the inputs, that these are the sort of generation portfolios that the industry will be heading toward in the year 2020.

It can be seen for the low fuel price scenario that a CCGT-based system is found to be least-cost once the carbon tax is 10 €/ton of CO_2 and above. This is consistent with the industry in Ireland at present, where most proposed generation projects are for the development of new CCGTs. It also can be seen that optimal penetration of wind power increases, as expected with increasing carbon tax.

The high fuel price scenario forecasts a higher price for gas relative to that of coal. The result of this is that a coal-based system is the least cost option up to a carbon tax of 30 €/ton of CO_2. It can be seen that the increased gas price accelerates the role of wind as a means to reducing carbon emissions in a

TABLE III
PORTFOLIOS WITH INCREASING CARBON TAX FOR LOW FUEL PRICES

Plant Type	Installed Capacity (MW)					
	0 €/Ton Co_2	10 €/Ton Co_2	20 €/Ton Co_2	30 €/Ton Co_2	40 €/Ton Co_2	50 €/Ton Co_2
Coal PF	7060	0	0	0	0	0
Coal IGCC	0	0	0	0	0	0
Peat FB	0	0	0	0	0	0
OCGT	1732	2278	2572	2156	2469	2405
CCGT	0	6289	5826	6241	5805	5782
Wind 1 & 2	0	600	1200	1200	1800	2400
Biomass 1,2 &3	0	0	0	0	0	0
Interconnection	800	800	800	800	800	800
Hydro	509	509	509	509	509	509
Total	10101	10476	10907	10906	11383	11896

TABLE IV
PORTFOLIOS WITH INCREASING CARBON TAX FOR HIGH FUEL PRICES

Plant Type	Installed Capacity (MW)					
	0 €/Ton Co_2	10 €/Ton Co_2	20 €/Ton Co_2	30 €/Ton Co_2	40 €/Ton Co_2	50 €/Ton Co_2
Coal PF	7060	6560	5229	0	0	0
Coal IGCC	0	0	0	0	0	0
Peat FB	0	0	0	0	0	0
OCGT	1732	1838	2469	2381	2374	2374
CCGT	0	0	576	5765	5700	5630
Wind 1 & 2	0	1200	1800	2800	3800	3800
Biomass 1,2 &3	0	0	0	0	0	70
Interconnection	800	800	800	800	800	800
Hydro	509	509	509	509	509	509
Total	10101	10907	11383	12255	13183	13183

least-cost manner with the maximum penetration of 3800 MW of wind capacity reached with a carbon tax of 40 €/ton of CO_2.

The Republic of Ireland currently aims to serve 13.2% of electricity from renewable sources by 2010 [28]. The government has tried in the past to encourage renewable development with subsidies. However, it can be seen from Tables III and IV that allowing the all-Ireland electricity system to feel the effects of the European traded cost of carbon, something that would be correct macroeconomic practice regardless, may result in significant development of renewable energy without the need for any subsidy.

C. Role of Wind Generation in Least-Cost Portfolios

An examination of the role of wind generation in least-cost portfolios was undertaken for a large range of scenarios. Three variables that have significant uncertainty associated with them and have a large impact on the generation portfolios were altered over a large range to find the role wind generation plays in the subsequent least-cost portfolios. The three variables altered are gas price, carbon tax, and discount rate. Fig. 4 shows the optimal amount of wind generation versus the gas price and carbon tax for discount rates (DR) of 6%, 7.5%, and 10%. The prices for the other fuels in the analysis are the same as those in the high fuel price scenario.

It can be seen from the surfaces in Fig. 4 that wind generation plays a significant role in least-cost portfolios for a large range of scenarios. It can also be seen that for a considerable amount of scenarios, the optimal amount of wind capacity was found to be the maximum amount assumed available: 3800 MW. This indicates that wind generation may have an even larger role to play in future generation portfolios than has been indicated here. However, establishing the role of wind generation above this level requires analysis of other systems issues, such as the curtailment of wind generation and the potential for energy storage. This type of analysis requires the adoption of a sophisticated operational strategy that fully and fairly accounts for wind generation.

The results here may provide insight into generation planning issues on other systems. The methodology presented here, if applied with the appropriate inputs for other systems, should

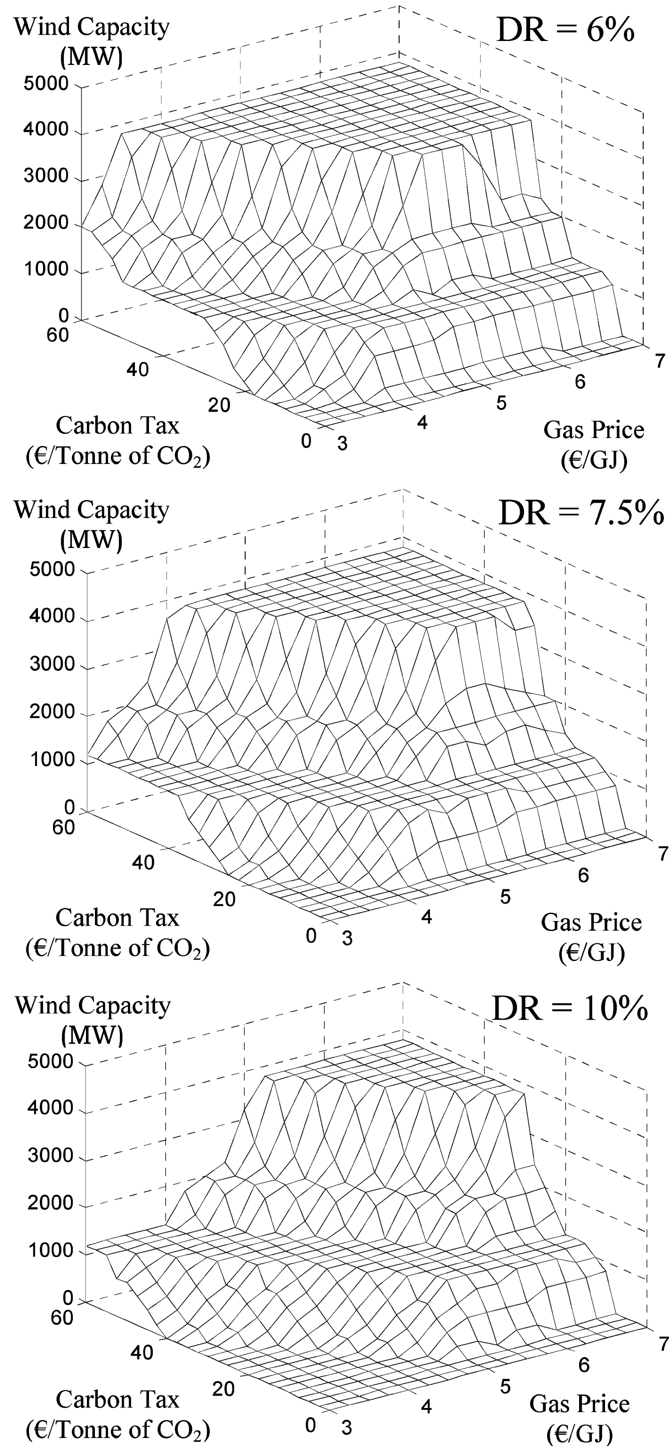


Fig. 4. Wind capacity in least-cost portfolios for various carbon taxes, gas prices, and discount rates.

establish the role of wind and other generation for these systems, just as the analysis here established the respective role of the generation sources for the all-Ireland system.

VI. Fuel Price Volatility and Portfolio Diversification

The all-Ireland system relies heavily on imported fuel for electricity production. This exposes Ireland to possible price hikes and may even be exposed to shortages in supply. This would have a detrimental effect on the economy of the island [5]. It is generally accepted that diversification of generation resources will serve to reduce the risk to which those systems are exposed. However, correctly quantifying how much to diversify and what to diversify with is a difficult task, which has yet to be successfully achieved. It was decided here to adopt mean-variance portfolio theory as a means of analyzing the diversity issue. Although this technique has some drawbacks [9], [12], it was thought to be the most practical for analyzing this issue. It is a standard technique often used in finance theory for stocks, shares, and bonds and has also been applied to generation portfolios before [11].

A. Fuel-Related Electricity Cost Volatility and Application of Mean-Variance Portfolio Theory

The standard deviation and correlation of the cost of electricity produced by gas and coal are needed here to apply mean-variance portfolio theory. These were derived from historic data of the average annual fuel prices and forecasts of future real fuel prices. The average fuel efficiency for coal and gas plant were used in the calculations, and the yearly standard deviation and correlation of the resultant annual electricity prices were found. It was found that electricity produced from gas and coal plant had a standard deviation of 8 €/MWh and 4.2 €/MWh, respectively, over the time period considered. The correlation coefficient was found to be 0.3. It was assumed that there is a zero standard deviation of the price of electricity produced from peat, biomass, and wind generation. These values and assumptions are in line with the literature [5], [11], [29].

In order to find the trade-off between electricity price and electricity price volatility, the set of all possible portfolios was searched by altering the amount of energy to be served by coal plant and gas plant between 0 and 100% in steps of 2.5%. For each step, the portfolio optimization algorithm as described in Section IV was run and the least-cost portfolio found. This process allows the full space to be searched and the efficient frontier to be found. The efficient frontier is the frontier at which the price cannot be reduced any further without accepting an increase in the volatility of the price.

B. Illustrative Results

Fig. 5 shows the results of this analysis for the high fuel price scenario and 30 €/ton of CO_2 carbon tax. The portfolios that are made up exclusively of coal and gas plant are shown in dark grey. Portfolios that include other sources of generation, i.e., wind, peat, and biomass, are shown in light grey. Table V shows the installed capacities of the different portfolios shown in Fig. 5.

Portfolio A, which consists mostly of gas plant, results in the lowest price possible from any combination of coal and gas plant but results in a high price volatility. Portfolio B has the lowest price volatility possible for any combination of coal and gas plant, and it can be seen that it consists of a significant amount of IGCC coal plant. The carbon tax means that the increased efficiency of the coal fired IGCC plant results in it being more cost effective that the traditional PF plant. Portfolio C is the least-cost portfolio, and it can be seen that 2800 MW of wind capacity results in a reduction in cost and a reduction in the volatility from portfolio A. Portfolio D, with increased quantities of wind capacity and a large amount of coal plant, shows significant decrease in the price volatility while only causing slight increase in price. Portfolio E has a diverse mix of plant and results in very low volatility but high price.

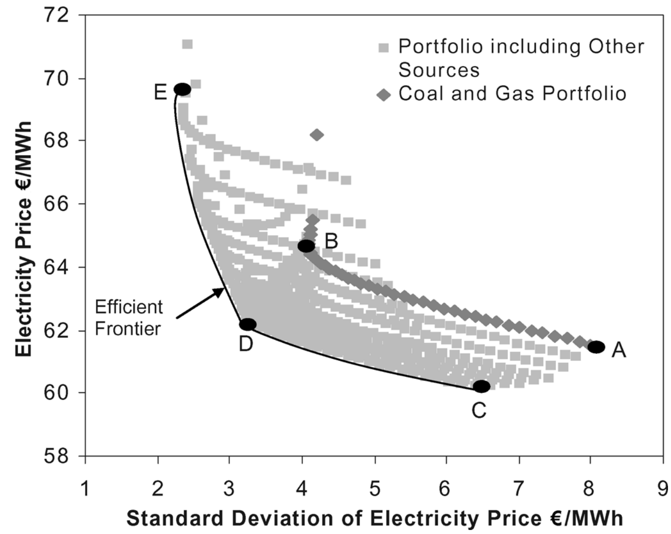


Fig. 5. Mean-variance portfolios analysis for the scenario with high fuel price and 30 €/ton of CO_2 carbon tax.

TABLE V
MEAN-VARIANCE PORTFOLIO ANALYSIS—SIGNIFICANT PORTFOLIOS

Plant Type	Installed Capacity for Portfolio (MW)				
	A	B	C	D	E
Coal PF	0	0	0	0	0
Coal IGCC	0	6136	0	4180	3506
Peat FB	0	0	0	0	1000
OCGT	2013	2013	2381	2374	2374
CCGT	6778	643	5765	1451	721
Wind 1 & 2	0	0	2800	3800	3800
Biomass 1,2 &3	0	0	0	70	473
Interconnection	800	800	800	800	800
Hydro	509	509	509	509	509
Total	10100	10101	12255	13184	13183

Similar analysis for different scenarios showed a similar trend: price volatility is reduced if increased amounts of wind generation are added to the fossil fuel portfolios. However, the extent to which wind generation can reduce exposure to price volatility is limited by the amount of wind generation assumed available. The corresponding impact on cost of increasing wind generation will depend on the fuel prices and level of carbon tax.

VII. Conclusion

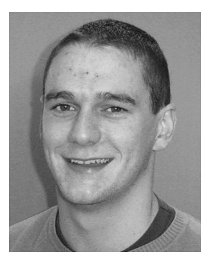
This paper combined analysis of generation economics, load and wind generation characteristics, generation adequacy, and plant utilization to gain insight into the role of wind generation in future generation portfolios. Considering these various aspects allows for a more complete determination of the role of wind generation in portfolios than may have been possible before. Results showed that for a large range of scenarios, wind generation played a significant role in desirable generation portfolios. Results found that for various scenarios, the desirable level of wind generation may exceed that maximum level considered here. Further analysis using a sophisticated operational strategy, which fully and fairly accounts for wind generation, energy storage, and wind energy curtailment, is required to explore these scenarios further. It was shown that in least-cost portfolios, wind generation displaces base-load plant. This may contrast with the impact that wind generation has on existing portfolios, where it may dispatch higher merit order units. Analysis also showed that wind generation plays an important role in generation portfolios that are diversified to reduce exposure to fuel price risk.

ACKNOWLEDGMENT

The authors would like to thank M. Bazilian of SEI and J. FitzGerald and N. McCarthy of the ESRI for their help during this work.

REFERENCES

[1] H. Khatib, *Economic Evaluation of Projects in the Electricity Supply Industry*. London, U.K.: IEE, 2003, Power Energy Series, no. 44.
[2] B. F. Hobbs and P. M. Meier, “Multicriteria methods for resource planning: An experimental comparison,” *IEEE Trans. Power Syst.*, vol. 9, no. 4, pp. 1811–1817, Nov. 1994.
[3] R. Tanabe, K. Yasuda, R. Yokoyama, and H. Sasaki, “Flexible generation mix under multi objectives and uncertainties,” *IEEE Trans. Power Syst.*, vol. 8, no. 2, pp. 581–587, May 1993.
[4] W. J. Burke, H. M. Merrill, F. C. Schweppe, B. E. Lovell, M. F. McCoy, and S. A. Monohon, “Trade off methods in system planning,” *IEEE Trans. Power Syst.*, vol. 3, no. 3, pp. 1284–1290, Aug. 1988.
[5] J. Fitz Gerld, The Macro-Economic Implications of Gas Dependence, 2002. [Online]. Available: http://www.esri.ie.
[6] California Energy Commission, Integrated Energy Policy Report, 2003. [Online]. Available: http://www.energy.ca.gov/2003_energy-policy.
[7] Northwest Power and Conservation Council, The Fifth Power Plan: A Guide for the Northwest’s Energy Future, 2005. [Online]. Available: http://www.nwcouncil.org/energy/powerplan.
[8] D. Helm, “The assessment: the new energy paradigm,” *Oxford Rev. Econ. Pol.*, vol. 21, pp. 1–18, 2005.
[9] F. Roques, D. Newbery, W. Nuttall, S. Connors, and R. de Neufville, “The diversification value of nuclear power as part of a utility technology mix when gas and carbon prices are uncertain,” in *Proc. IAEE Eur. Energy Conf.*, Bergen, Aug. 2005.
[10] S. Kennedy, “Wind power planning: Assessing long-term cost and benefits,” *Energy Pol.*, vol. 33, pp. 1661–1675, Sep. 2005.
[11] S. Awerbuch and M. Berger, Applying Portfolio Theory to EU Electricity Planning and Policy-Making, Feb. 2003. [Online]. Available: http://www.iea.org.
[12] A. Sterling, “Diversity and ignorance in electricity supply investment,” *Energy Pol.*, vol. 22, pp. 195–216, Mar. 1994.
[13] Royal Academy of Engineering, The Costs of Generating Electricity, 2004. [Online]. Available: http://www.raeng.org.uk.
[14] ESB National Grid, Impact of Wind Power Generation in Ireland on the Operation of Conventional Plant and the Economic Implications, 2004. [Online]. Available: http://www.eirgrid.com.
[15] Commission for Energy Regulation, Best New Entrant Price 2005, 2004. [Online]. Available: http://www.cer.ie.
[16] M. Junginger, A. Faaij, and W. C. Turkenburg, “Cost reduction prospects for offshore wind farms,” *Wind Eng.*, vol. 28, pp. 97–118, Jan. 2004.
[17] Sustainable Energy Ireland, Economic Analysis of RES-E Support Mechanisms, 2004. [Online]. Available: http://www.sei.ie.
[18] General Electric—Energy, New High Efficiency Simple Cycle Gas Turbine- GE’s LMS 100, 2004. [Online]. Available: http://www.gepower.com/home/index.htm.
[19] Sustainable Energy Ireland, A Study on Renewable Energy in the New Irish Electricity Market, 2004. [Online]. Available: http://www.sei.ie.
[20] ESB National Grid, Download Centre, 2003. [Online]. Available: http://www.eirgrid.com.
[21] European Commission Directorate-General for Energy and Transport, European Energy and Transport—Trends to 2030, 2003. [Online]. Available: http://europa.eu.int/.
[22] European Union, Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 Establishing a Scheme for Greenhouse Gas Emission Allowance Trading Within the Community and Amending Council Directive 96/61/EC, 2003. [Online]. Available: http://europa.eu.int.
[23] ESB National Grid, Generation Adequacy Report 2004–2010. [Online]. Available: http://www.eirgrid.com.
[24] Commission for Energy Regulation, IRELAND—WALES Electricity Interconnection, 2004. [Online]. Available: http://www.cer.ie.
[25] Sustainable Energy Ireland, Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System, 2004. [Online]. Available: http://www.sei.ie.
[26] M. Milligan and B. Parsons, A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators, 1997. [Online]. Available: http://www.nrel.gov.
[27] J. Fitz Gerld, Generation Adequacy in an Island Electricity System, 2004. [Online]. Available: http://www.esri.ie.
[28] European Union, Directive 2001/77/EC of the European Parliament and the Council of 27 September 2001 on the Promotion of Electricity Produced From Renewable Energy Sources in the Internal Electricity Market, 2001. [Online]. Available: http://europa.eu.int/.
[29] A. Bergin, J. Fitz Gerald, M. Keeney, E. O’Malley, and S. Scott, Aspects of Irish Energy Policy, 2005. [Online]. Available: http://www.esri.ie.

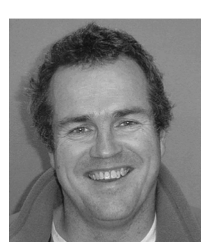


Ronan Doherty (S’03–M’06) received the B.E. and Ph.D. degrees from the University College Dublin, Dublin, Ireland, in 2001 and 2005, respectively.

He has research interests in power system operations and markets, energy policy, and the integration of renewable energy sources, specifically wind generation. He has experience in the electricity industry and markets in Ireland and has also spent time on research collaborations in the University of New South Wales, Sydney, Australia.

Hugh Outhred (M’73) received the Ph.D. degree in electrical engineering from the University of Sydney, Sydney, Australia, in 1974.

He is an Associate Professor in the School of Electrical Engineering and Telecommunications at the University of New South Wales, Sydney. His current research interests are in the areas of energy industry restructuring, energy economics, demand management, and renewable energy.



Mark O’Malley (S’86–M’87–SM’96) received B.E. and Ph.D. degrees from University College Dublin, Dublin, Ireland, in 1983 and 1987, respectively.

He is currently a Professor at University College Dublin and Director of the Electricity Research Centre, with research interests in power systems, control theory, and biomedical engineering.