Demand side resource operation on the Irish power system with high wind power penetration ☆

A. Keane[*,a], A. Tuohy[a], P. Meibom[c], E. Denny[b], D. Flynn[a], A. Mullane[d], M. O'Malley[a]

[a] *University College Dublin, Ireland*
[b] *Trinity College Dublin, Ireland*
[c] *RISØ DTU, Technical University of Denmark, Denmark*
[d] *ECAR Energy Ltd., Ireland*

Abstract

The utilisation of demand side resources is set to increase over the coming years with the advent of advanced metering infrastructure, home area networks and the promotion of increased energy efficiency. Demand side resources are proposed as an energy resource that, through aggregation, can form part of the power system plant mix and contribute to the flexible operation of a power system. A model for demand side resources is proposed here that captures its key characteristics for commitment and dispatch calculations. The model is tested on the all island Irish power system, and the operation of the model is simulated over one year in both a stochastic and deterministic mode, to illustrate the impact of wind and load uncertainty. The results illustrate that demand side resources can contribute to the efficient, flexible operation of systems with high penetrations of wind by replacing some of the functions of conventional peaking plant. Demand side resources are also shown to be capable of improving the reliability of the system, with reserve capability identified as a key requirement in this respect.

Key words: Demand Side Resources, Wind Power, Power System Operation

☆This work was carried out as part of Ireland's contribution to the International Energy Agency Wind Annex Task 25, and is supported by Sustainable Energy Authority Ireland.

*The corresponding author is with the School of Electrical, Electronic and Mechanical Engineering, Dublin 4, Ireland, and can be contacted at andrew.keane@ucd.ie, tel: +353 1 7161856.

Nomenclature

Indices:

i, I^{PC}, I^{PS}	Unit, set of load clipping units, set of load shifting units
I	Set of units
t, t^{End} , T	Time step, end time step in optimisation period, set of time steps

Variables:

$K_{i,t}$	Storage level [MWh]
$P_{i,t}$	Power generation [MW]
$P_{i,t}^{Onl,RP}$	Replacement reserve by online unit [MW]
$P_{i,t}^{Off,RP}$	Replacement reserve by offline unit [MW]
$P_{i,t}^{Sp}$	Positive spinning reserve by unit [MW]
$V_{i,t}^{Onl}$	Unit online (binary variable)
$W_{i,t}$	Loading of load shifting units [MW]

Parameter:

cap_i^{Energy}	Maximum reduction of load within optimisation period for load clipping units [MWh]
cap_i^{Max}	Maximum capacity [MW]
cap_i^{Sp}	Maximum spinning reserve capability [MW]
d_t	Electricity demand [MW]
K_i^0	Fixed storage level at the end of the optimisation period [MWh]
p_t^W	Wind power production [MW]

1. Introduction

The traditional view of demand side resources (DSR) has been to place them in a different category to generation in the scheduling of power system operation (Gellings and Smith, 1989). However, if DSR is to be fully and successfully utilised then these traditional divisions should be broken down. The situation is fast approaching when utilities will be presented with domestic customers who can participate in DSR schemes within a market framework, who have access to time of use tariffs through smart meters, are capable of meeting their own electricity demand, and who can actually export power onto the network (Strbac, 2008). There are a number of questions surrounding each of these capabilities, with each providing its own challenges to the planning and operation of a power system. Recent work has focused on the optimal demand response to pricing within a market (Su and Kirschen, 2008). In Walawalkar et al. (2008), the economics of demand response in the PJM market are analysed with the social welfare accrued from subsidies quantified. In Chen et al. (1995), a method of integrating direct load control into system operation with the objective of minimising system cost is proposed. Load control is coordinated with unit commitment by an iterative method. An assessment of real-time pricing, employing a unit commitment model, as a means of smoothing out the daily load profile and responding to high levels of wind output is given in Sioshansi and Short (2009).

Currently, it is mainly commercial and industrial customers that participate in demand side management schemes. As a result, the main types of demand which currently constitute DSR are on-site generation (diesel), refrigeration and deferral of production (Papagiannis et al., 2008). Domestic customers can also lower their demand by reducing their discretionary loads, air conditioning or electric heating or deferring the usage of appliances until a later time or date (Kirby et al., 2008). Ireland does not have significant air conditioning load but refrigeration offers an opportunity in this regard, whereby the load is not optional for the user but the timing of the usage is flexible to an extent Any micro-generation connected within the home also offers itself as a means to reduce net consumption when required. The residential sector has been underutilised to date and offers a potentially large resource to be exploited. In combination with DSR, many systems are increasing the installed levels of wind energy. However, due to the variable nature of this resource, balancing the supply and demand of the system will become more difficult. DSR has been proposed as a source of flexibility to compensate for the increased variability and uncertainty which results from increasing wind power penetration.

The aim of the paper is to assess how DSR can aid power system operation. To achieve this a unit commitment model, employing stochastic programming to model wind power and load forecasts uncertainty, is proposed to capture three key aspects of demand side resources; increased energy efficiency, load clipping and load shifting. Each aspect is modelled separately. It is assumed that demand side aggregation is permitted under market rules. It is also assumed that the required communications and operational infrastructure to enable demand side aggregation has been put in place. The demand resource is modelled as discrete virtual units within the plant mix in order to reflect these assumptions. Positive spinning and replacement reserve capability are both assigned to the demand side units. Replacement reserve is identified as up regulation reserve with an activation time of 5-10 minutes. The all island Irish power system in 2020, with a high penetration of wind power, is considered as a test system for the application of the DSR models within a stochastic unit commitment and dispatch algorithm. Stochastic (which includes the uncertainty of wind) and deterministic (in which forecasts of wind are assumed to be perfect) runs are carried out as a means of illustrating the increased flexibility requirements of the system when the uncertainty of wind output is taken into account, highlighting the role DSR units can play in meeting these flexibility requirements. In Section 2 the proposed model for demand side resources is described. Results and discussion are given in Section 3, illustrating the application of the demand side model to the unit commitment and dispatch of a test power system over a one year period. Conclusions are presented in Section 4.

2. Demand Side Resource Model

There is potential for DSR to contribute to the efficient planning and operation of electricity systems. The vision for DSR presented here assumes time of day pricing to incentivise reduction and shifting of demand in a passive manner. This is represented by an altered demand profile. Further steps are assumed whereby demand side aggregation options are available to customers (industrial, commercial and residential) which will enable them to be operated as a single unit via direct load control. It is assumed that the individual customer will be paid up front, with the aggregated unit then operated like any other in the wholesale market.

Here, a model is proposed for DSR that captures the pertinent characteristics of demand response for unit commitment calculations, in terms of passive and active aggregation measures. Demand response will manifest itself on the system in three ways: an altered demand profile, load shifting demand side units and load clipping demand side units. The altered demand profile captures general improvements in energy efficiency and general decreases and shifts in energy consumption. This demand is non-dispatchable and represents a general change in behaviour from both residential and commercial customers. For example, the replacement of incandescent light bulbs with CFL bulbs, or improved housing insulation. Another feature of the altered demand profile is the timing of demand, whereby residential, commercial and industrial customers will passively change their behaviour. It is not anticipated that all customers will wish to take part in a direct load control scheme. The load shifting units model demand that can be reduced, but which will be reclaimed at a later time, which includes heating along with refrigeration loads and newer loads such as electric vehicles or heat pumps. The load clipping units model discretionary load that may be reduced, such as lighting or a portion of the heating load. Other potential sources of DSR include compressed air supply, municipal water pumping systems, water desalination and purification, and aluminium smelting. The definition of three categories of DSR minimises the number of demand responses to be considered and allows the key aspects of DSR to be captured. For example, heating and air conditioning are included in two categories as they have the characteristics of both. The alternative approach would be to model each load category separately, considerably increasing the complexity of the modelling process with little or no gain achieved.

2.1. Altered Demand Profile

Initiatives to promote energy efficiency and the installation of smart meter infrastructure are expected to change people's energy consumption patterns. This passive effect can be modelled by altering the current demand shape of the system. It is expected that with the introduction of time of day pricing, the daily peak will be shaved. A portion of the demand will also be deferred, which will manifest itself by increased usage at night and into the early hours of the morning. The exact timing of this will be dependent on the particular tariff structure. An important point is that seasonal variation in demand may result in a seasonal variation of demand resource, since some DSR loads will be seasonal. It can be expected that there will be greater scope for reduction during winter months rather than summer months. For regions with a summer peak the reverse may be true. The types of load included in this demand change are general improvements in efficiency coupled with deferral/reduction of demand in the form of dishwashers, dryers and commercial demand elements (refrigeration). In CER and Utility Regulator (2010) the vision for demand side resources in Ireland for 2020 is laid out, it is expected that static time of use tariffs will be employed which should cause a greater reduction in demand at the peak and also increase demand at off peak times. In terms of inputs to a unit commitment model, the demand profile will be altered according to this new pattern of behaviour in proportion to the expected change in demand response. Since the demand profile will be altered based on the time of day and the season, each day is divided into three periods, while the year is divided into two seasons, winter and summer.

2.2. Demand Side Units

The integration of demand response into a market offers the prospect of delivering greater benefits than just an altered demand shape. Rather than each individual consumer participating in the market as a single entity, the aggregation of multiple consumers into a demand side virtual unit will allow DSR to contribute more meaningfully to the operation of a system (Pudjianto et al., 2007). These aggregated units can operate in a similar fashion to generating units, with an associated capacity. The direct load control envisaged here enables these virtual units to operate in the wholesale market as any other unit would. The regulations of the Irish market already permit this and it is expected that demand side aggregators will enter the market in the coming years (CER and Utility Regulator, 2010). It is proposed here to model their characteristics through two types of unit, load clipping and load shifting. Although this paper uses stochastic and deterministic programming models, for simplicity of exposition the restrictions on the demand side units are given in their deterministic form.

2.2.1. Load Shifting Units

The load shifting units operate on the same principle as conventional electricity storage units, i.e. they 'produce' energy when the price is high by reducing demand and consume energy when the price is low by increasing demand. The load shifting unit has a constraint imposed such that there is an energy balance within a certain time period. This is equivalent to the energy balance equation of an energy storage unit (1),

$$K_{i,t} = K_{i,t-1} + W_{i,t} - P_{i,t} \quad \forall i \in I^{PS}; t \in T \tag{1}$$

where $K_{i,t}$ is the storage level, $W_{i,t}$ is the loading of the load shifting units and $P_{i,t}$ is the power generation. The storage level must return to a certain level at a specific time step, here chosen as the end of each optimisation period, as shown in (2). This captures the fact that while demand may be deferred the energy demand will still be required to be met over a certain timeframe.

$$K_{i,t^{End}} = K_i^0 \quad \forall i \in I^{PS} \tag{2}$$

Common examples of energy shifting load are large refrigeration plants or some heating loads. By adjusting a thermostat, or switching off the thermal load, the effective load is (immediately) reduced, but the lost heat load will be completely or partially paid back depending on the initial control action and the particular application. The ability of DSR schemes to provide reserve is potentially a valuable resource for system operation. For example, in the Long Island Power Authority in the US, air conditioning demand response is a source of spinning reserve. During periods of high demand it is estimated that 25 MW of demand reduction and 75 MW of 10 minute emergency reserve are available. The reserve is achieved by switching out predefined discretionary demand (Kirby, 2003). Provision of positive spinning and replacement reserve from load shifting units are included in the online capacity restriction, as given in (3),

$$P_{i,t} + P_{i,t}^{Sp} + P_{i,t}^{Onl,RP} \ \leq \ V_{i,t}^{Onl} \cdot cap_i^{Max} \forall i \in I^{PS}; t \in T \tag{3}$$

where the binary variable, $V_{i,t}^{Onl}$, denotes the status of the ith unit at time step t. cap_i^{Max} is the maximum capacity of the ith unit. $P_{i,t}^{Sp}$ and $P_{i,t}^{Onl,RP}$ are the spinning and replacement reserve of the ith unit. Likewise, the provision of replacement reserve when offline is restricted by the amount of capacity offline, (4).

$$P_{i,t}^{Off,RP} \ \leq \ \left(1 - V_{i,t}^{Onl}\right) \cdot cap_i^{Max} \forall i \in I^{PS}; t \in T \tag{4}$$

The spinning reserve capability is restricted, as given in (5). It is assumed that load shifting units are unable to provide reserve when they are reclaiming their deferred energy.

$$P_{i,t}^{Sp} \ \leq \ V_{i,t}^{Onl} \cdot cap_i^{SP} \forall i \in I^{PS}; t \in T \tag{5}$$

Each individual source of reserve is finite in terms of its capacity and timing of delivery, but by switching loads in turn, the duration of the reserve response can be extended. The revenue required by the load shifting units, i.e. the price difference between low price periods and high price periods multiplied by the amount of energy shifted is modelled as the variable cost of the units, similar to an operation and maintenance cost of a conventional generating unit and included in the objective function of the model. Hence, the load shifting units have no start-up costs and fuel costs, and no ”storage losses”. The power balance equation in the model is extended to include the reduced demand and increased demand of the load shifting units as given in (6),

$$\sum_{i \in I} P_{i,t} + p_t^W = \sum_{i \in I^{PS}} W_{i,t} + d_t \quad \forall \in t \tag{6}$$

where d_t is the demand at time step t and p_t^W is the wind power production at time step t.

2.2.2. Load Clipping Units

Load clipping units represent demand response that is a net reduction in demand rather than a deferral of demand, as with load shifting units. The load clipping units are energy limited, i.e. they can only reduce consumption by a certain amount of energy demand each day. A common example is discretionary lighting load or reduced net heating demand. A similar principle applies to other industrial processes. This type of unit also includes industrial or commercial premises which have on-site generation, which can be scheduled on and off as required, for example combined heat and power plant. Hence, load clipping units are modelled as flexible production units having a restriction on the total 'production' within each optimisation period (7). In accordance with load shifting units the revenue required for load clipping units to reduce demand is expressed solely as the variable cost of each unit, hence the units have no start-up costs and fuel costs. The reserve capabilities of load clipping units are governed by the same restrictions (3, 4 and 5) as used for load shifting units. The 'production' (reduced demand) of the units is included in the power balance, as given above in (6),

$$\sum_{t=1}^{T} P_{i,t} \leq cap_i^{Energy} \quad \forall i \in I^{PC} \tag{7}$$

where cap_i^{Energy} is the maximal reduction of load within an optimisation period for the ith load clipping unit.

3. DSR Unit Parameters and Modelling Framework

The DSR models proposed above are implemented and tested within the WILMAR planning tool (Tuohy et al., 2009). The WILMAR model was originally used to study wind variability in the Nordic system, as described in

Meibom et al. (2006). This was then adapted to examine the Irish system as part of the All Island Grid Study (AIGS) (AIGS, 2006). The Irish system is used again here as the test system. The main functionality of the WILMAR model is in two parts - a scenario tree tool (STT) and a scheduling model. The scheduling model is a mixed integer, stochastic, optimisation model with the demand for replacement reserves, wind power production forecasts and load forecasts as the stochastic input parameters, operating at an hourly time-resolution. The model minimises the expected value of the system operation cost consisting of fuel costs, start-up costs, costs of consuming CO_2 emission permits (which is assumed to be 30 €/tonne), and variable operation and maintenance costs. The unit commitment model can be run in a deterministic or stochastic mode. The stochastic mode takes account of the uncertainty surrounding wind and load forecasts through the STT, while the deterministic mode assumes perfect wind and load forecasting, i.e. there is only one scenario. The difference between stochastic and deterministic methods is the way they deal with wind and load uncertainty. Both carry reserves to cater for forecast error and outages - however stochastic methods plan to reduce the total expected cost, each with a probability of occurrence. Therefore, unit commitment is carried out to ensure units can meet multiple future scenarios; this implies keeping more units online and additional reserve. A realized value of wind and load is then used to calculate the actual economic dispatch. In contrast, the deterministic method assumes wind and load can be perfectly forecasted, which is obviously unrealistic, but is consistent with many current wind integration studies and operating policies. This commits units day ahead as if wind was perfectly known. The realized value of wind and load is the same in the economic dispatch as was assumed in the day ahead commitment; this underestimates actual costs and additionally, underestimates usage of flexible units which are used to respond to wind uncertainty. Stochastic methods therefore give a more realistic result, and should show the benefits of DSR for integrating wind in a more realistic way.

A key element of the stochastic mode is that sufficient spinning and replacement reserve are maintained to cover each scenario of wind and load, whereas in the perfect foresight mode reserve is only carried for unit outages. The results shown in Section 5, are by default, for stochastic runs as this better represents the reality of operating a system with a high penetration of wind power. The model uses rolling planning, i.e. it loops through all time periods by solving the unit commitment and dispatch problem for a certain time period, shifts the optimisation period ahead in time and solves again when updated forecasts are available. The optimisation procedure is carried out for every 36 hour period over the year. Due to the rolling nature of the calculation, the commitment is updated before the 36 hour mark is reached with the result that constraint (6) may not be strictly obeyed at each step. This implementation reflects a realistic situation, whereby the energy is ultimately reclaimed at a later stage but perhaps not completely within a given 36 hour period. The rolling calculation ensures that up to date wind and load forecasts are used when planning the system operation. It is assumed here that the operation of DSR units can be replanned intra day to account for changes in wind and load forecasts.

The STT generates wind power and load forecasts and the associated demand for replacement reserves, represented by scenario trees that are used as inputs in the scheduling model. The demand for replacement reserve is a function of the total forecast error of the power system considered which is defined according to the hourly distribution of wind power and load forecast errors and forced outages. Thereby it is assumed that a predefined percentile of the total forecast error has to be covered by replacement reserve. The STT also produces time series for the forced unit outages. More detailed information on the STT can be found in Barth et al. (2006a) and Barth et al. (2006b). Here, the altered demand profile is calculated through manipulation of the original 2020 demand curve employed in the AIGS for Ireland. The demand profile consists of three main constituent parts; industrial, commercial and residential. The reduction applied here lead to an overall reduction in electricity demand of 4% over the year. The reduction is applied to the output demand profile of the STT. The methodology results in an adjusted scenario tree demand profile, in line with the values shown in Table 3.

Table 1: Demand Reduction Percentages

	Night (11 pm - 6 am)	Day (6 am - 4 pm) (7 pm - 11 pm)	Peak (4 pm - 7 pm)
Summer	2.2%	4.0%	5.5%
Winter	2.5%	4.5%	6.5%

The ratio of reduction to deferral has been estimated previously as being between 50:50 and 70:30 (KEMA, 2005). A split of 70:30 in favour of the clipping units is chosen with a total of 600 MW of DSR capacity based on KEMA (2005, 2008). This is the split between the classification of units. It specifies how much demand side is net reduction or deferral. It is made up of two 90 MW load shifting units and four 105 MW load clipping units as shown in Table 2. In KEMA (2008) the prospects for DSR in the Republic of Ireland are broken down according to residential, commercial and industrial, with the economic potential for peak demand reduction from each estimated as 269 MW, 676 MW and 287 MW respectively. For reference the peak demand in the Republic of Ireland is currently approximately 5500 MW. These figures do not include Northern Ireland, which is now part of the All Island electricity market (AIP, 2005). The 600 MW figure is more conservative than that quoted in KEMA (2008) but given the active aggregated response being modelled and the passive element modelled by the altered demand profile, this is prudent. The WILMAR planning tool can model replacement and spinning reserve. The clipping and shifting unit spinning reserves are limited to 17.5 MW and 15 MW respectively, recognising that it may not be realistic to assume that the full rated reserve response capability can be called upon in the timeframe required for spinning reserve. It is likely that spinning reserve will be provided from large commercial and industrial loads, such as those currently participating in the short term active response scheme and the winter peak demand reduction scheme run by the transmission system operator in Ireland (EirGrid, 2011a,b). The replacement reserve which operates over a longer time will come from other potentially smaller loads from each category. The price chosen for the load shifting units is 40 €/MWh, while the price for the clipping unit is 80 €/MWh. These prices are selected based on a recent report into demand side management in Ireland (Ecofys, 2009). This work conducted a price sensitivity analysis and found the prices quoted to be sufficient for DSR to operate viably on the Irish system. In Walawalkar et al. (2008) the socially optimal range for the incentive trigger point of DSR is priced at between 66-77 $/MWh. This value is system dependent but does indicate the price range DSR should aim for and is in line with the prices chosen here. The costs of implementing wide scale direct load control are still unclear and cannot be simply assigned an assumed capital cost as a gas plant would be. Rather it is endeavoured here to indicate for the Irish system the marginal price required for the demand side units to become active. Ecofys (2009) shows the response from a range of different prices for load curtailing and load shifting aggregated units. The prices used here are based on those prices which saw operation closest to the likely operation of aggregated DSR in that report. These would be representative of prices bid into a wholesale market by an aggregator; the actual rate paid to consumers would be assumed to be somewhat lower than this to allow for aggregator costs and profit. The parameters of the DSR units are shown in Table 2.

Table 2: Demand Side unit Characteristics

Type	No.	Capacity (MW)	Spinning Reserve (MW)	Replacement Reserve (MW)	Variable O&M cost (€)	Startup Cost (€)
Load shifting	2	90	15	90	40	0
Load clipping	4	105	17.5	105	80	0

A range of parameters have been assumed for the DSR modelled in this paper. These parameters are based on the available literature, current practice and the characteristics of the Irish system. Some have also been chosen to indicate the characteristics and cost of DSR to enable it to compete with conventional generation technologies and to contribute to secure system operation.

4. Test System and Conventional Unit Parameters

In order to analyse the impact of demand side resources on different aspects of unit commitment, the Irish system was employed as a test system and a simulation for a single year was carried out. The plant mix is based on one of the portfolios (portfolio 5) of the AIGS (All Island Grid Study - Workstream 2A, 2006), derived using the portfolio optimization method described in Doherty et al. (2006). Within the All Island Grid Study multiple possible portfolios were produced, with varying levels of installed wind power and conventional technologies. This particular portfolio has 6000 MW of installed wind power capacity, producing 18.4 TWh of wind energy over the year (which corresponds to approximately 34.3% of total energy demand - renewable energy makes up 42% of total energy demand in the portfolio chosen, due to additional tidal, hydro and base renewables, such as biomass and landfill gas). The total installed conventional capacity on the system is approximately 8300 MW, including hydro units and base loaded renewables. This is comprised of the units described in Table 3, which groups multiple units according to fuel type. Note that two types of gas plant are included - mid merit gas, i.e. open cycle gas turbines (OCGT) and aeroderivative gas turbines (ADGT), and base-loaded gas, i.e. combined cycle gas turbines (CCGT). Inflexible mid merit plant here refers to the peat plant on the system - these use an indigenous fuel source classified as a type of brown coal (IEA, 2007). Peaking units, which use distillate/gas-oil, are shown here with mid merit gas due to the fact that both are similarly flexible, when considered on an hourly time resolution. Table 3 also shows the fuel prices used for the various conventional plants, in order to provide an indication of where that type of unit is positioned in the merit order of the system. The price indicated for the gas units is an average of the different prices used in the model for each month of the year, as given in AIGS (2006). The capacity of DSR units is summarised in Table 2.

Table 3: Types of Unit in Plant Portfolio

Type of Unit	No.	Capacity (MW)	Fuel (€/GJ)
Base Load Gas	12	4114	5.91
Mid Merit Gas	19	1646	6.45
Coal	5	1257	1.75
Inflexible Mid Merit	3	345	3.71
Biomass, Biogas	1	306	2.78
Hydro	1	216	-
Pumped Storage	4	292	-
Tidal	-	200	-
Wind	-	6000	-

5. Results and Discussion

Two DSR cases and a base case are analysed here over a sample year on the test system. DSR Case 1 includes only the flexible DSR units, as described in Table 2. DSR Case 2 includes the same DSR units as case 1 but also includes the 4% general reduction in demand, implemented according to

Table 1. In the following results, both cases are compared with a base case consisting of the likely plant mix for the 2020 system, as per (All Island Grid Study - Workstream 2A, 2006).

5.1. DSR Unit Operation

Fig. 1 shows the annual operation of load clipping unit 1 and indicates that it is utilised most frequently during the winter months (left hand and right hand side of the figure). It is also utilised sporadically throughout the year. The operation of only one of the clipping units is shown here as an illustration. The other load clipping units possess identical characteristics and hence operate in a similar manner. The maximum output of the clipping unit is found to be 87.5 MW, with the remaining 17.5 MW of capacity utilised for spinning and replacement reserve. The DSR units have a zero start-up cost, and their efficiency does not increase over their operating range, unlike conventional plant, and as a result they offer a cheap source of spinning reserve for the system, explaining why they are always utilised for this purpose when online.

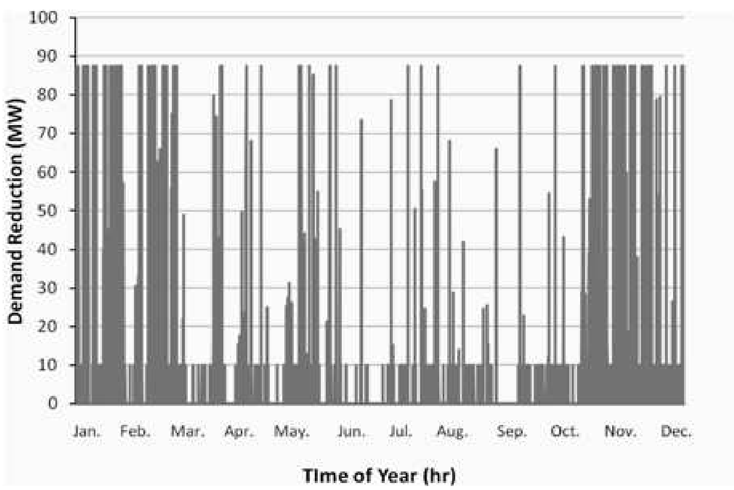

Figure 1: Annual operation of DSR load clipping unit 1 (DSR Case 2)

Fig. 2 shows the average output of clipping unit 1 throughout the day in Case 2. It can be seen that the majority of its demand reduction is during the peak hours between 4 pm and 8 pm. There is also significant operation around the smaller midday peak in demand, which occurs because at times of high midday demand the price is high enough that the DSR units are committed and dispatched ahead of the more expensive peaking plant.

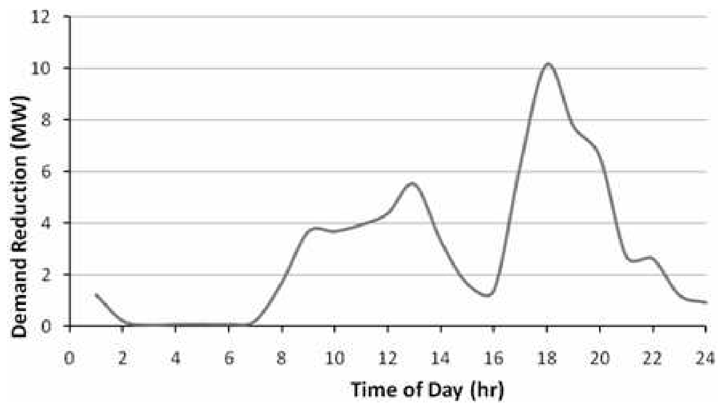

Figure 2: Average daily output of DSR clipping unit 1(DSR Case 2)

Fig. 3 shows the average daily output of load shifting unit 2 for Case 2. It can be seen that the unit operates at peak times to reduce the demand, while reclamation of this energy generally occurs in the early hours of the morning when the demand and price are low. The profile of the reduction of demand by these types of unit is similar to the output of the clipping unit, as would be expected, as both will be used to reduce peak demand. The two modes of operation of the load shifting unit are denoted by 'Load Reduction' and 'Load Increase' in Fig. 3.

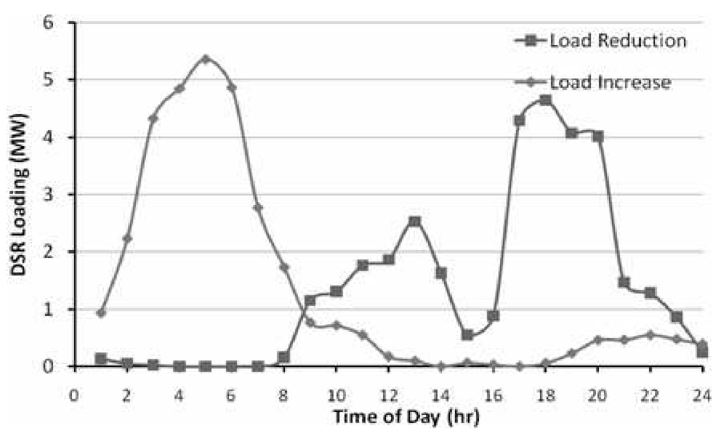

Figure 3: Average daily output of DSR shifting unit 2 (DSR Case 2)

5.2. Generation Adequacy

The generation adequacy of a system is one of the key measures of system reliability. It is important to assess the impact that any new plant will have on generation adequacy. The assessment of reliability given here is only based on one year of simulation data. A single year is quite a small dataset for such assessments. Generally reliability calculations, such as effective load carrying capability, would use multiple years of data where possible (Billinton and Allan, 1996). However, the significant differences observed in Fig. 4 between the base case and DSR cases 1 and 2 illustrate that there is considerable impact from DSR on system reliability.

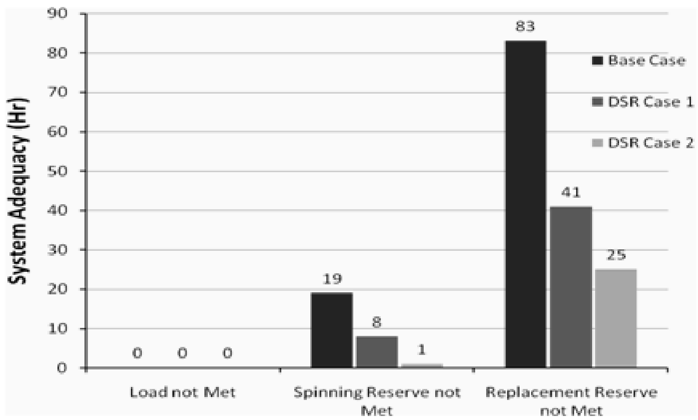

Figure 4: System adequacy statistics

It can be seen in Fig. 4 that generation adequacy and hence the reliability of the system improve as a result of introducing DSR units capable of providing reserve, and also with the general reduction in demand through the altered demand curve. This illustrates that the provision of spinning and replacement reserve from these DSR units is an important resource to the system. In DSR Case 1, where the demand profile is unchanged, the additional spinning reserve capabilities of the DSR units reduces the period when the spinning reserve target is not met to 8 hours, a reduction of 58% relative to the base case. The replacement reserve target paints a similar picture with a reduction to 41 hours when the replacement reserve target is not met, a reduction of 51%. The ability of DSR to provide replacement and also spinning reserve has been shown to deliver a significant improvement in the generation adequacy of the system for the year simulated. In Ecofys (2009), the DSR units were assumed not to be able to provide reserve - this showed that replacing conventional peaking plant with DSR units would increase the amount of hours reserve targets could not be met, unlike the results shown here, which indicate an improvement in reliability.

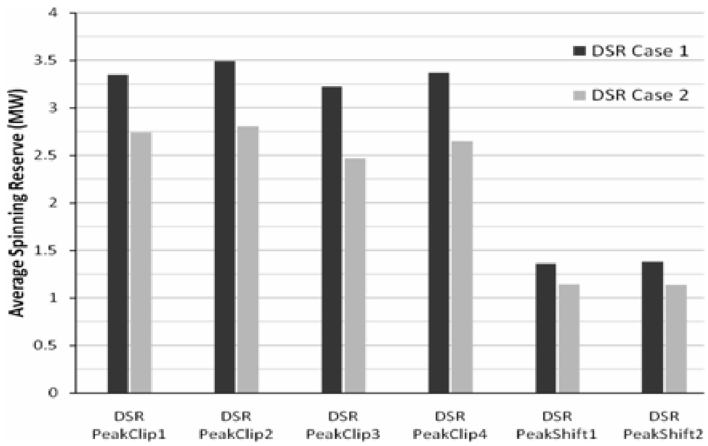

Figure 5: Spinning reserve from DSR units

The average spinning reserve available from the DSR units is shown in Fig. 5. It can be seen that, on average, they make a small but positive contribution of reserve to the system. The difference between the two cases is a consequence of the reduced demand, arising from the energy efficiency measures, in DSR Case 2 and hence there are fewer times when DSR is online and available to provide spinning reserve.

5.3. Electrical Production by Fuel

Fig. 6 shows the electrical production according to each fuel type. The impact of reduced demand for DSR Case 2 can be seen with reduced electricity production from units throughout the merit order, most notably base-load gas and coal. DSR Case 1 shows the impact of the DSR units and the flexibility they provide. In particular, it is evident that the DSR units cause a decrease in the production of base load gas units and an increase in production from coal units. This impact is due to the load shifting units, whereby demand is reduced at peak times and increased at a later time when demand is naturally lower. The operation of the peaking units, such as gas-oil units, cannot easily be discerned from Fig. 6. More detailed results for gas-oil and mid merit gas are given below in Figs. 7 and 8.

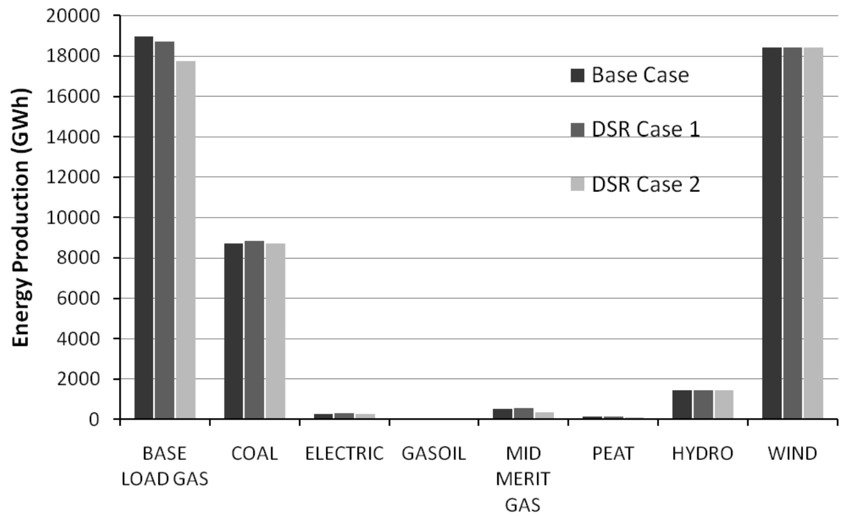

Figure 6: Electrical energy production by fuel

Fig. 7 shows the reduction in output from the gas-oil peaking units. With the introduction of both the load clipping and load shifting units, the utilisation of and energy produced from these units decreases significantly. Indeed, in DSR Case 2 they are not utilised at any stage throughout the year. These gas-oil units are already installed, but the results above indicate that there is scope to assess the need for additional OCGTs if DSR resources on the scale of those proposed here are realised in the manner that they are modelled here. Also shown is a comparison between the stochastic mode and deterministic mode. The uncertainty in wind output, that is taken account of in the stochastic mode, clearly leads to greater utilisation of the gas-oil plant. This indicates that when analysing systems with high penetrations of wind proper account should be taken of the uncertainty of wind power output and its subsequent impact upon the commitment and dispatch of other units.

Fig. 8 shows the variation in total mid merit gas production between the three cases for both stochastic and deterministic modes. It illustrates that the load shifting units and the flattening of the demand curve (smaller peak, higher night demand) that they cause leads to a slight increase in mid merit gas production. A similar contrast to Fig. 7 is seen here between the stochastic and deterministic modes. A comparison of the capacity factors of these units is given below, illustrating this effect in more detail.

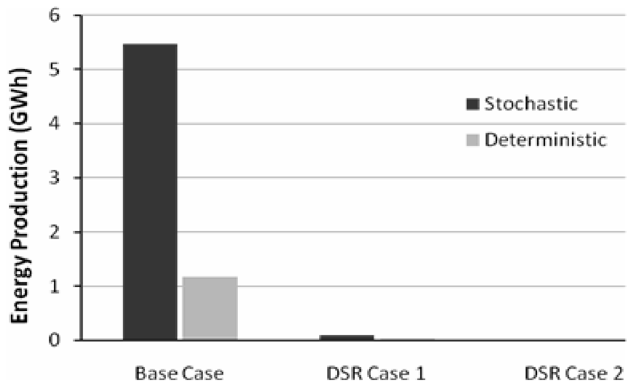

Figure 7: Annual electrical energy production of gas-oil plant for stochastic and deterministic runs

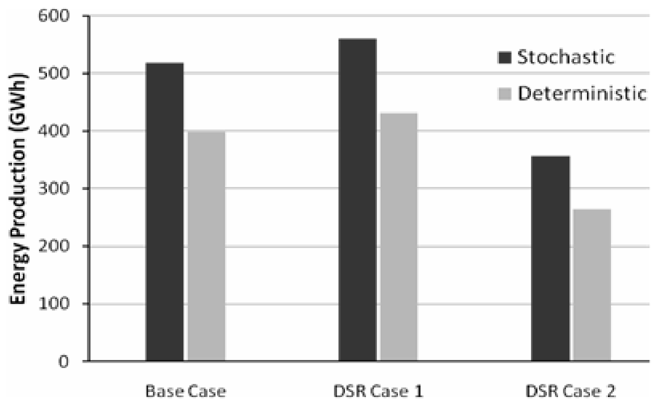

Figure 8: Electrical energy production from mid merit gas plant for stochastic and deterministic runs

5.4. Capacity Factors of Peaking Units

An analysis of the capacity factors of each of the peaking units allows a more detailed assessment of the DSR measures proposed. It can be seen from Fig. 7 that the introduction of DSR units, combined with a general reduction in the demand in DSR case 2, leads to no production from any of the peaking gas-oil units. Fig. 9 shows that there is also a reduction in the capacity factors of all units classed as 'peaking'. The impact of the reduced demand is evident in DSR Case 2 as the production from all peaking units, including the DSR units is decreased. The output of the new OCGTs (NOCGT), NOCGT 7 and NOCGT 8 is also reduced significantly, indicating that the construction of these particular units may not be necessary. These peaking units were originally required to ensure that the variability of wind could be covered by the rest of the generation plant mix. These results demonstrate that DSR, if it has the ability to provide reserve, has to some extent the capability to replace conventional peaking units in the power system. However, it should be remembered that units such as OCGTs and gas-oil generation can provide inertial and voltage support to the system as well as a short circuit level contribution, which DSR cannot.

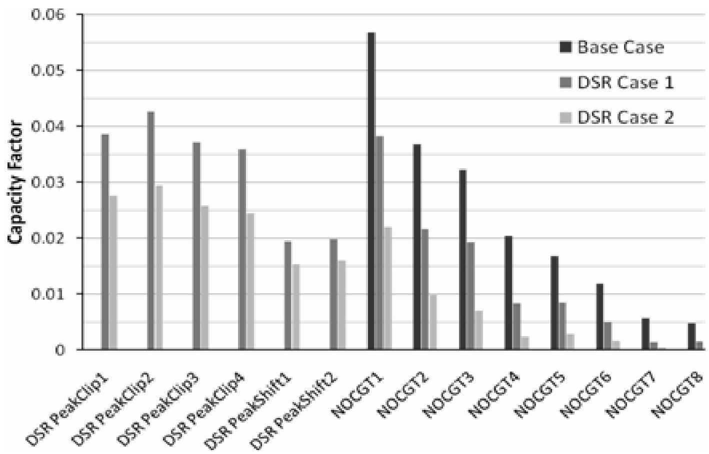

Figure 9: Capacity factor of peaking units (stochastic mode)

Fig. 10 shows the capacity factors of the peaking units for a deterministic run. NOCGTs 1 - 8 have decreasing efficiencies (in the order of their numbers), hence the decreasing capacity factor trend from 1 - 8. It is evident that the utilisation of all the peaking units, including the DSR units, is reduced considerably when compared to the stochastic run results in Fig. 9, e.g. in DSR case 1 NOCGT 1 has a capacity factor of 0.042 for the deterministic mode compared to 0.057 for the stochastic mode. This 36% increase in capacity factor in the stochastic mode illustrates the importance of capturing the uncertainty of wind and load in any calculation method. In the deterministic mode, the assumed certainty in wind production lessens the requirement for flexibility on the system. It can be seen that based on a deterministic run it could be concluded that NOCGT 4, NOCGT 6, NOCGT 7 and NOCGT 8 are no longer required. However, when a stochastic run is carried out it can be seen that the peaking capability is called upon, albeit infrequently. This demonstrates again the relevance of a stochastic calculation and the requirement for flexibility in systems with high penetrations of wind.

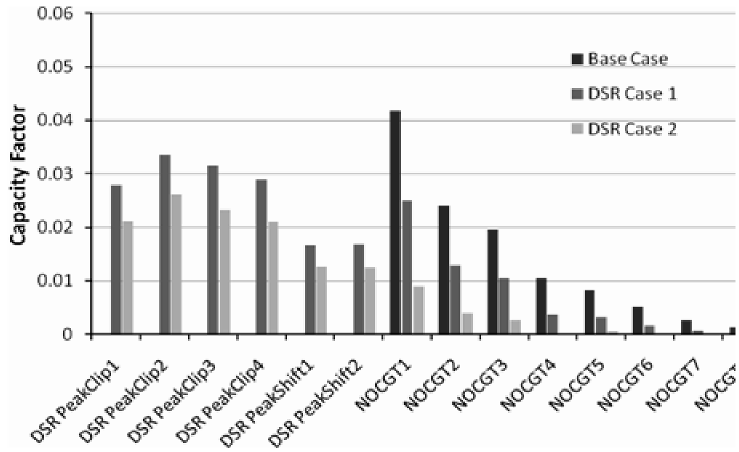

Figure 10: Capacity factor of peaking units (deterministic mode)

These combined results illustrate that utilising an energy limited resource such as demand side can aid in system operation, in particular as an effective peaking unit. In order to enable this function, refinement of market rules is required to further enable the participation of demand side resources. The aggregation of the demand side resources enables them to be employed as a coherent block, thus enhancing their contribution to the system. The prices used here are assumed but they indicate an approximate price, in the Irish system, at which demand side resource should bid. It is also evident that the provision of ancillary services such as reserve from demand side is a key function. The continued development of ancillary services markets, which place a value on such system services, will only serve to increase the viability of demand side resources. The continued promotion of energy efficiency is positive but it is evident from the results presented here that the active control of elements of demand can significantly enhance the benefits of such activities.

6. Conclusions

This paper has proposed a unit commitment model for DSR, in the form of virtual load clipping and load shifting units. A stochastic programming model (WILMAR) has been used for unit commitment calculation and the developed DSR models have been tested on the Irish system. The operation of the units is greatest during the high load months and at times of high demand. In terms of system reliability it is seen that generation system adequacy is improved, with it being important to note the high level of wind power assumed in the cases studied here. The results also show that, subject to correct pricing, such flexible virtual units can substitute for the energy function of peaking units. In addition, DSR can be a valuable source of reserve, potentially enabling conventional units to be displaced. The provision of reserve from DSR is potentially very valuable as they can then replace other conventional units. The scheduling uncertainty resulting from load variations and, in particular, wind forecasts has been shown to be a key factor when operating systems with high penetrations of wind power. In the context of this paper, DSR has been shown to be a potentially valuable resource, which can contribute to the required increased flexibility.

References

AIGS, 2006. AIGS - All Island Grid Study. A report conducted for the Department of Communications, Energy and Natural Resources, Ireland, and Department of Enterprise, Trade and Investment, Northern Ireland. Available: http://www.dcenr.gov.ie.

AIP, 2005. All Island Project (AIP). All-island modelling project. Available: http://www.allislandproject.org.

All Island Grid Study - Workstream 2A, 2006. High level assessment of suitable generation portfolios for the all-island system in 2020. Available: http://www.dcenr.gov.ie.

Barth, R., Brand, H., Meibom, P., Weber, C., 2006a. A stochastic unit commitment model for the evaluation of the impacts of the integration of large amounts of wind power. In: 9th Int. Conf. Probabilistic Methods Applied to Power Systems. Stockholm, Sweden.

Barth, R., Soder, L., Weber, C., Brand, H., Swider, D., 2006b. Deliverable d6.2 (b) documentation methodology of the scenario tree tool. Institute of Energy Economics and the Rational Use of Energy (IER), Univ. Stuttgart. Stuttgart, Germany, [Online]. Available: www.wilmar.risoe.dk.

Billinton, R., Allan, R., 1996. Reliability evaluation of power systems. Plenum 2nd Edition.

CER and Utility Regulator, 2010. Single electricity market demand side vision for 2020. Available: http://www.allislandproject.org (SEM-10-052).

Chen, J.and Lee, F., Breipohl, A., Adapa, R., 1995. Scheduling direct load control to minimize system operation cost. IEEE Trans. Power Syst. 10 (4), 1994–2001.

Doherty, R., Outhred, H., O'Malley, M., 2006. Establishing the role that wind may have in future generation portfolios. IEEE Trans. on Power Syst. 21 (3), 1415–1422.

Ecofys, 2009. All island renewable grid study updated to include demand side management. http://www.dcenr.gov.ie/Energy/.

EirGrid, 2011a. Short term active response. Available: http://www.eirgrid.com/operations/ancillaryservices/demandsidemanagementdsm/shorttermactiveresponsestar/.

EirGrid, 2011b. Winter peak demand reduction scheme. Available: http://www.eirgrid.com/operations/ancillaryservices/demandsidemanagementdsm/winterpeakdemandreductionschemewpdrs/.

Gellings, C., Smith, W., 1989. Integration demand-side management into utility planning. Proc. of IEEE 77 (6), 1908–1918.

IEA, 2007. IEA 2007 coal information,. Available: www.iea.org.

KEMA, 2005. A scoping study: demand side measures for small business and residential customers on Ireland's electrical system.

KEMA, 2008. Demand side management in Ireland, evaluating the energy efficiency opportunities, http://www.sei.ie/.

Kirby, B., 2003. Spinning reserve from responsive loads. Oak Ridge National Laboratory ORNL/TM-2003/19.

Kirby, B., Kueck, J., Laughner, T., Morris, K., 2008. Spinning reserve from hotel load response. The Electricity Journal 21 (10), 59–66.

Meibom, P., Barth, R., Brand, H., Larsen, H., Voll, O., Weber, C., 2006. Wilmar scheduling model documentation. EU contract ENK5-CT-2002-00663, www.wilmar.risoe.dk.

Papagiannis, G., Dagoumas, A., Lettas, N., Dokopoulos, P., 2008. Economic and environmental impacts from the implementation of an intelligent demand side management system at the European level. Energy Policy 36 (1), 163–180.

Pudjianto, D., Ramsay, C., Strbac, G., 2007. Virtual power plant and system integration of distributed energy resources. IET Renewable Power Generation 1 (1), 10–16.

Sioshansi, R., Short, W., 2009. Evaluating the impacts of real-time pricing on the usage of wind generation. IEEE Trans. Power Syst. 24 (2), 516–524.

Strbac, G., 2008. Demand side management: benefits and challenges. Energy Policy 36 (12), 4419–4426.

Su, C.-L., Kirschen, D., 2008. Long run optimal response to real time pricing rates. Power Systems Computation Conference.

Tuohy, A., Meibom, P., Denny, E., O'Malley, M., 2009. Unit commitment for systems with significant wind penetration. IEEE Trans. Power Syst. 24 (2), 592 – 601.

Walawalkar, R., Blumsack, S., Apt, J., Fernands, S., 2008. An economic welfare analysis of demand response in the PJM electricity market. Energy Policy 36 (10), 3692–3702.