Base-load cycling on a system with significant wind penetration

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***Abstract*—Certain developments in the electricity sector may result in suboptimal operation of base-load generating units in countries worldwide. Despite the fact they were not designed to operate in a flexible manner, increasing penetration of variable power sources coupled with the deregulation of the electricity sector could lead to these base-load units being shut down or operated at part-load levels more often. This cycling operation would have onerous effects on the components of these units and potentially lead to increased outages and significant costs. This paper shows the serious impact increasing levels of wind power will have on the operation of base-load units. Those base-load units which are not large contributors of primary reserve to the system and have relatively shorter start-up times were found to be the most impacted as wind penetration increases. A sensitivity analysis shows the presence of storage or interconnection on a power system actually exacerbates base-load cycling until very high levels of wind power are reached. Finally, it is shown that if the total cycling costs of the individual base-load units are taken into consideration in the scheduling model, subsequent cycling operation can be reduced.**

***Index Terms*—Thermal Power Generation, Wind Power Generation, Pumped Storage Power Generation, Interconnected Power Systems, Power System Modeling, Costs**

I. Introduction

As higher penetrations of wind power are achieved, system operation becomes increasingly complex, as variations in the net load (load minus wind) curve increase [1]. Wind is a variable energy source and fluctuations in output must be offset to maintain the supply/demand balance, thus resulting in a greater demand for operational flexibility from the thermal units on the system [2]. These units must also carry additional reserves to maintain system reliability should an unexpected drop in wind occur, as the power output from wind farms is also relatively difficult to predict [3]. However, even when state-of-the-art methods of forecasting are employed, the next day hourly predicted wind output can vary by 10-15% of the total wind capacity as reported in [4], which can result in thermal units being over- and under-committed [2]. Furthermore, in certain systems wind is allowed to self-dispatch, so forecast output is not included in the day-ahead schedule. This can lead to increased transmission constraints which will further intensify plant cycling and has been shown to displace energy from Combined Cycle Gas Turbines (CCGTs) in particular [5]. The culmination of adding more variability and unpredictability to a power system is that thermal units will undergo increased start-ups, ramping and periods of operation at low load levels collectively termed "cycling" [6]–[9].

In addition to wind, the competitive markets in which these units operate are also a significant driver of plant cycling; increased levels of competition brought about by widespread deregulation results in all types of generators being forced into more market-orientated, flexible operation to increase profits [10]. The severity of plant cycling, will be dependent on the generation mix and the physical characteristics of the power system. It is widely reported that the availability of interconnection and storage can assist the integration of wind on a power system [11], [12]. Interconnection can allow imbalances from predicted wind power output to be compensated via imports/exports whereas some form of energy storage can enable excess wind to be moderated in time to correlate with demand. This should relieve cycling duty on thermal units as the onus on them to balance fluctuations is relieved.

Although all conventional units will be impacted to some degree by wind integration, it is cycling of base-load units that is particularly concerning for system operators and plant owners alike. As these units are designed with minimal operational flexibility, cycling these units will result in accelerated deterioration of the units' components through various degeneration mechanisms such as fatigue, erosion, corrosion, etc, leading to more frequent forced outages and loss of income. The start/stop operation and varying load levels result in thermal transients being set up in thick-walled components placing them under stress and causing them to crack. The interruptions to operation caused by cycling disrupts the plant chemistry and results in higher amounts of oxygen and other ionic species being present, leading to corrosion and fouling issues. A multitude of other cycling related issues have been documented in the literature [13]–[19]. Excessive cycling of base-load units could potentially leave them permanently out of operation prior to their expected lifetimes.

Hence cycling of base-load units will impose additional costs on the unit, the most apparent being increased operations and maintenance (O&M) and capital costs resulting from deterioration of the components. However, fuel costs will also increase with cycling operation as the unit will be starting up more frequently, and also because the overall efficiency of the unit will deteriorate. Environmental penalties will arise as a result of increased fuel usage, while income losses arise

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as the unit will undergo longer and more frequent outages [17], [19], [20]. Quantifying these costs is particularly difficult given the vast array of components affected. Also, cycling related damage may not be immediately apparent. Studies have suggested it can take up to 7 years for an increase in the failure rate to become apparent after switching from base-load to cycling [21]. The uncertainty surrounding cycling costs can lead to these costs being under-valued by generators, which in turn can lead to increased cycling.

This paper examines the effect that increasing penetration of wind power will have on the operation of base-load units. The role that interconnection and storage play in alleviating or aggravating the cycling of base-load units is investigated across different wind penetration scenarios. Finally, the effect of increasing start-up costs (to represent increasing depreciation) on the operation of base-load units is examined. Section II details the methodology used in the study. Section III reports the results and discusses the impact of modeling assumptions on these results. Section IV provides some discussion surrounding how wind and plant cycling is treated in electricity markets. Section V concludes the paper.

II. Methodology

A. Modeling Tool

Simulations were carried out using a scheduling model called the Wilmar Planning Tool, which is described extensively in [22], [23]. The Wilmar Planning Tool was originally developed to model the Nordic electricity system and was later adapted to the Irish system as part of the All Island Grid Study [23]. It is currently employed in the European Wind Integration Study [24]. The Wilmar Planning Tool was the tool of choice for this study as it combined the benefits of mixed integer optimization with stochastic modeling. The main functionality of the Wilmar Planning Tool is embedded in the Scenario Tree Tool and the Scheduling Model.

The Scenario Tree Tool generates scenario trees containing three inputs to the scheduling model: wind, load and demand for replacement reserve. Realistic possible wind forecast errors are generated using an Auto Regressive Moving Average (ARMA) approach which considers the historical statistical behavior of wind at individual sites. Historical wind speed series taken from the various sites are then added to the wind speed forecast error scenarios to generate wind speed forecast scenarios. These are then transformed to wind power forecast scenarios. Load forecast scenarios are generated in a similar manner. A multi dimensional ARMA model, as in [25], is used to simulate the wind correlation between sites. A scenario reduction technique similar to that in [26] is employed to reduce the large number of possible scenarios generated.

In the modeling tool reserve is categorized as primary or replacement. Primary reserve, which is needed in short time scales (less than five minutes), is supplied only by synchronized units. The system should have enough primary reserve to cover an outage of the largest online unit occurring at the same time as a fast decrease in wind power production. Positive primary reserve is provided by increased production from online units or pumped storage, whilst negative primary reserve is provided by decreased production from online units or by pumped storage when in pumping mode. The demand for replacement reserve, which is reserve with an activation time greater than 5 minutes, is determined by the total forecast error which is defined according to the hourly distribution of wind power and load forecast errors and the possibilities of forced outages. A forced outage time series for each unit is also generated by the scenario tree tool using a Semi-Markov process based on given data of forced outage rates, mean time to repair and scheduled outages is produced. Any unit that is offline and can come online in under one hour can provide replacement reserve.

The Scheduling Model minimizes the expected cost of the system over the optimization period covering all scenarios generated by the scenario tree tool and subject to the generating units' operational constraints, such as minimum down times (the minimum time a unit must remain offline following shut-down), synchronization times (time taken to come online), minimum operating times (minimum time a unit must spend online once synchronized) and ramp rates. In order to maintain adequate system inertia and dynamic reactive support at times of high wind, a minimum number of large base-load units must be online at all times. Details of the objective function which contains fuel, carbon and start-up costs are given in Appendix A and further details are included in [22]. The Generic Algebraic Modeling System (GAMS) was used to solve the unit commitment problem using the mixed integer feature of the Cplex solver. For all the simulations in this study the model was run with a duality gap of 0.01%.

Rolling planning is used to re-optimize the system as new wind and load information becomes available. Starting at noon the system is scheduled over 36 hours until the end of the next day. The model steps forward with a three hour time step with new forecasts used in each step. In each planning period a three stage stochastic optimization model is solved having a deterministic first stage, a stochastic second stage with three scenarios covering three hours and a stochastic third stage with six scenarios covering a variable number of hours according to the planning period in question. The state of the units at the start of any time step must be the same as the state of the units at the end of the previous time step.

B. Test System

The 2020 Irish system was chosen as a test case for this study because its unique features make it suitable for investigating base-load cycling. It is a small island system, with limited interconnection to Great Britain, a large portion of base-load plant and significant wind penetration. Thus, potential issues with cycling of base-load units may arise on this system at a lower wind penetration.

Various portfolios were developed in the Wilmar Planning Tool for the All Island Grid Study [27] to investigate the effects of different penetrations of renewables on the Irish system for the year 2020. Portfolios 1, 2 and 5 from [27] were used in this study and are outlined in Table I as the "moderate wind", "high wind" and "very high wind" cases. A "no wind" case has also been added. As seen in Table I, the test system is

a thermal system, with a small portion of inflexible hydro capacity and the base-load is composed of coal and combined cycle gas turbine (CCGT) generation. The three wind cases examined have 2000 MW, 4000 MW and 6000 MW wind installed on the system, which supply 11%, 23% and 34% of the total energy demand and represent 19%, 32% and 42% of the total installed capacity on the system respectively.

TABLE I
INSTALLED CAPACITY (MW) BY FUEL TYPE

Fuel	No Wind	Moderate Wind	High Wind	Very High Wind
Coal	1324	1324	1324	1324
Base-load Gas	4447	4047	3953	3953
CHP	166	166	166	166
Peat	343	343	343	343
Mid-Merit Gas	1858	1754	1579	1155
Gasoil	388	388	388	388
Pumped Storage	292	292	292	292
Base Renewables	155	155	155	306
Hydro	216	216	216	216
Tidal	72	72	72	72
Wind Power	0	1999	4003	6000

The 2020 winter peak forecast is 9.6 GW and the summer night valley is 3.5 GW. Losses on the transmission system are included in the load. The test system includes four 73 MW pumped storage units with a round-trip efficiency of 75% and a maximum pumping capacity of 70 MW each and two 83 MW CHP units with "must-run" status as they provide heat for industrial purposes. The 2020 fuel prices used are shown in Table II and a carbon price of €30/ton was assumed. The gas prices shown in Table II are the averages over the year and the other fuel prices remain constant throughout. As this study is primarily concerned with the operation of base-load units, the characteristics of those units are shown in Table III.

A simplified model of the British power system is included in which units are aggregated by fuel type. Wind and load is assumed to be perfectly forecast on the British system. The model includes 1000 MW of HVDC interconnection between Ireland and Great Britain and it is scheduled on an intra-day basis i.e. it is rescheduled in every rolling planning period. Flows on the interconnector to Britain are optimized such that the total costs of both systems are minimized. A maximum of 873 MW can be imported as 100 MW is used as primary reserve at all times and there are 3% losses on the remainder.

C. Scenarios Examined

Different wind cases, as described in the previous section, were used in this study to allow various penetrations of wind power to be examined. The model was run stochastically, for one year, for the "no wind" case and each of the three wind cases to examine the effect that increasing wind power penetration will have on the operation of base-load units, as these are the units with the most limited operational flexibility and as such, will suffer the greatest deterioration from increased cycling.

TABLE II
FUEL PRICES (€/GJ) BY FUEL TYPE

Fuel	Fuel Price
Coal - Republic of Ireland	1.75
Coal - Northern Ireland	2.11
Base-load Gas	5.91
Mid-merit Gas	6.12
Peat	3.71
Gasoil - Republic of Ireland	9.64
Gasoil - Northern Ireland	8.33
Base Renewables	0

TABLE III
CHARACTERISTICS OF A TYPICAL CCGT AND COAL UNIT ON THE TEST SYSTEM

Characteristic	CCGT	Coal
Max Power (MW)	400	260
Min Power (MW)	217	103
Max Efficiency (%)	56	37
Hot Start-up Cost (€)	12,440	5,080
Full Load Cost (€/hour)	8,500	1,780
Min Load Heat Rate (GJ/hour)	1585	1140
Max Primary Reserve Contribution (% of Max Power)	9	13
Minimum Down Time (Hours)	2	5
Synchronization Time (Hours)	2	5
Ramp Rate (MW/min)	10	4

To conduct a sensitivity analysis investigating the role that storage and interconnection play in altering the impact of increasing wind penetration on base-load operation, the model was run stochastically, for one year, for the "no wind" case and each of the three wind cases, first, without any pumped storage on the system and second, without any interconnection on the system. In order to fairly compare systems without storage/interconnection to the systems with storage/interconnection, the systems must maintain the same reliability. Thus it was necessary to replace the pumped storage units and interconnector with conventional plant. The 292 MW of pumped storage was replaced with three 97.5 MW open cycle gas turbine (OCGT) units and the 1000 MW of interconnection was replaced with nine 100 MW OCGT units (as 100 MW is always used as primary reserve, the maximum import capacity is 900 MW). The characteristics of these units were set such that they could deliver the same capacity over the same time period as the interconnection/storage units they replaced. Thus, in terms of flexibility the systems with storage/interconnection were no more or less flexible than the systems without storage/interconnection. The OCGT units which replaced the storage units were capable of delivering the same amount to primary reserve (132 MW in total). The OCGT units that replaced the interconnection did not contribute to primary reserve but instead 100 MW was subtracted from the demand for primary reserve in each hour. This is the assumption used when the interconnector is in place.

The cost of running these units is generally greater than the cost of imports or production from a storage unit thus

production from storage/interconnection is not shifted directly to these units. This is advantageous in this type of study, as the operation of other units on the system without storage/interconnection can be observed whilst the system adequacy is not undermined by reduced capacity, thus facilitating sensitivity analysis. For example, had a CCGT unit been used to replace the interconnector, it would likely provide the energy that had been previously delivered by the interconnector but this would not allow examination of how the existing units on the system would be affected in the absence of interconnection. The results from the systems without storage and interconnection were compared to the base case (i.e. with storage and interconnection).

The final part of the study examined the effect that increasing the start-up costs of the base-load units will have on their operation. It was assumed the cost of starting these units would increase, as they experienced more wear and tear, from increased cycling. Given the uncertainty surrounding what this increase in costs might be [17], [19], the operation of the base-load units was examined over a range of start-up costs. The start-up cost of each of the base-load units on the system was increased by a multiple of its original value and the model was run for one year. The process was repeated with the start-up costs incremented by a greater multiple of the original amount each time. This was carried out for the "moderate" (19% installed wind capacity) and "very high" (42% installed wind capacity) wind cases.

To examine the results, the base-load units were categorized as coal or CCGT. As the total capacity of the coal and CCGT units varied across the portfolios, the results for the individual units in each group were normalized by their capacity to obtain the result per MW for each unit. The average result per MW was then obtained and this was multiplied by the capacity of a typical coal or CCGT unit (chosen to be 260 MW and 400 MW respectively) to give the result for a typical coal or CCGT unit as shown below:

$$\frac{\sum_{i=1}^{n}(x_i/c_i)}{n} * Typical\ Unit\ Size \tag{1}$$

where x_i is the result for the i^{th} unit, c_i is the capacity of the i^{th} unit and n is the number of units

III. Results

A. Effect of Increasing Wind Penetration on the Operation of Base-load Units

As the wind penetration on a power system is increased, large fluctuations in the wind power output will become more frequent, as seen in Table IV. In addition, generation from thermal units is increasingly displaced, thus the number of units online will decrease. This is shown in Table V.

TABLE IV
Fluctuations in Wind Power Output with Increasing Wind

Installed Wind Capacity (%)	0	19	32	42
No. Hours when Wind Power Output changes by >500 MW from Previous Hour	0	20	116	423

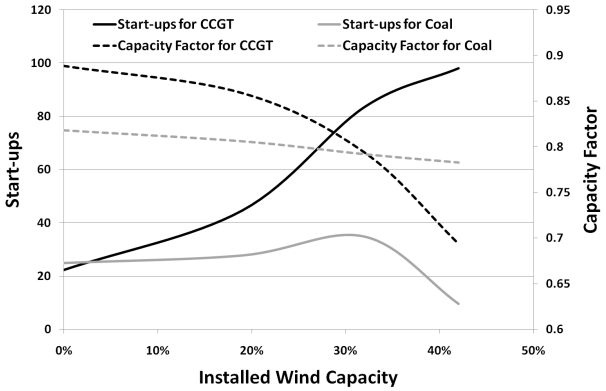

Fig. 1. Annual number of start-ups and capacity factor for an average CCGT and coal unit with increasing wind penetration

TABLE V
Number of Thermal Units Online with Increasing Wind Penetration (averaged at each hour shown over a two week period in April)

Time	00	03	06	09	12	15	18	21
0% Wind	19	16	17	27	30	27	27	27
19% Wind	17	14	15	24	26	23	23	24
32% Wind	15	13	13	22	23	19	20	22
42% Wind	15	12	13	18	19	17	17	18

Therefore the onus on thermal units to compensate fluctuations in the wind power output becomes more demanding with increasing wind penetration. Fig. 1 shows the annual number of start-ups and capacity factor for an average sized CCGT and coal unit of 400 MW and 260 MW respectively, as wind penetration increases. The capacity factor is the ratio of actual generation to maximum possible generation in a given time period. As the wind penetration grows and the variability and unpredictability involved in system operation is increased, the operation of a base-load CCGT unit is severely impacted. Moving from 0% to 42% installed wind capacity the annual start-ups for a typical CCGT unit rise from 22 to 98, an increase of 340%. This increase in CCGT start-ups corresponds to a plummeting capacity factor as seen in Fig. 1. Thus increasing levels of wind effectively displaces CCGT units into mid-merit operation.

Similar to a CCGT unit, start-ups for a coal unit increase with wind penetration up to 32% installed wind capacity, albeit not as drastically as a CCGT unit. However, at penetrations greater than 32% installed wind capacity, this correlation diverges and the start-ups for a coal unit begin to decrease, as seen in Fig. 1. As wind penetration grows, demand for primary reserve will grow. Due to high part-load efficiencies, as indicated by the minimum load heat rates seen in Table III, coal units are the main thermal providers of primary reserve on this system. In addition to this they have low minimum outputs so at times of high wind more coal units can remain online to meet the minimum units online constraint thus minimizing wind curtailment. Coal units are also highly inflexible; once taken offline it is a minimum of ten hours (minimum down time plus synchronization time as seen in Table III) before the

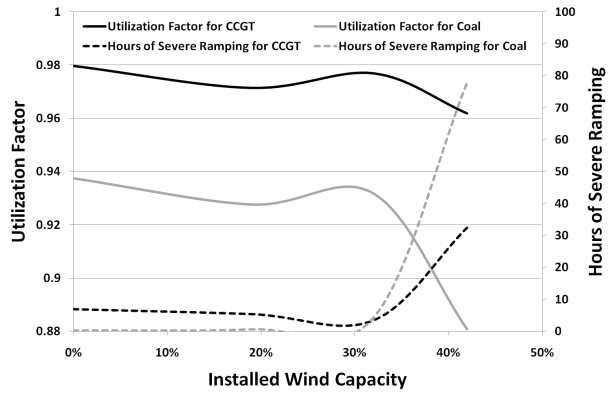

Fig. 2. Utilization factor and annual number of hours where severe ramping is performed for an average CCGT and Coal unit with increasing wind penetration

unit can be online and generating again. The combination of these characteristics, increases the need for these units to be kept online to provide primary reserve to the system as high levels of wind are reached. Thus, despite the fact that the cost of starting a CCGT unit on this system is greater than the cost of starting a coal unit as seen in Table III, the CCGT unit has the greatest increase in start-stop cycling with increasing wind as it does not supply a large amount of reserve to the system, has a large minimum output and can come online in a shorter time compared to a coal unit.

As CCGT units are taken offline more frequently with increasing wind penetration, the requirement on coal units to provide reserve to the system is driven even higher. Thus, although the capacity factor of a coal unit decreases as wind increases, the rate of decrease is much less than for a CCGT as seen in Fig. 1. Therefore, as wind penetration exceeds approximately 32% installed capacity a crossover point occurs and the inflexible coal units now become the most base-loaded units on the system whilst the relatively more flexible CCGT are forced into two-shifting, as seen by the capacity factors in Fig. 1. Thus, if capacity factor is indicative of the revenue earned by these units, the units with the most limited operational flexibility are the most rewarded at high levels of wind. This would suggest that some form of incentive may be needed to secure investment in flexible plants (for example OCGTs), which are commonly reported as beneficial to system operation with large amounts of wind [28], [29].

Fig. 2 shows the utilization factor for an average base-load coal and CCGT unit and the number of hours they perform severe ramping as wind penetration increases. The utilization factor is the ratio of actual generation to maximum possible generation during hours of operation in a given period. Severe ramping is defined in this paper as a change in output greater than half the difference between a unit's maximum and minimum output over one hour. Hours when the unit was staring up or shutting down were not included. Although coal units will avoid heavy start-stop cycling as wind levels grow by being the main thermal providers of primary reserve and highly inflexible, they do experience increased part-load operation. This is indicated by a drop in utilization factor from 0.94 to 0.88 as wind levels increase from 0% to 42% installed wind capacity, as seen in Fig. 2. The utilization factor for a CCGT unit also decreases with increasing levels of wind as seen in Fig. 2, however, it remains high in comparison with a coal unit, indicating the small contribution of reserve it provides to the system and correspondingly the infrequent periods of part-load operation. As seen in Fig. 2, both types of unit experience a dramatic increase in hours where severe ramping is required, as wind penetration exceeds 32% installed capacity. As wind penetration moves from 32% to 42% installed wind capacity a coal unit experiences the greatest increase in severe ramping operation going from 4 to 78 hours, compared to an increase from 4 to 32 hours for a CCGT unit, as these units are now offline more often. The sharp increase in ramping corresponds to the substantial increase in wind fluctuations seen in Table IV between 32% and 42% installed wind capacity, which must be compensated by a smaller number of online units. Such an increase in part-load operation and ramping can lead to fatigue damage, boiler corrosion, cracking of headers and component depreciation through a variety of damage mechanisms. This is of major concern to plant managers.

The results reported are for "average" CCGT and coal units. In order to show how these results correspond to the actual results for the real units modeled, the maximum value, minimum value, average value and standard deviation of the number of start-ups and capacity factor for the modeled CCGT and coal units are given in Appendix B.

B. Sensitivity Analysis

Section III-A showed the serious impact increasing levels of wind will have on the operation of base-load units. The extent of this impact will be determined by the generation portfolio and the characteristics of the system. This section provides a sensitivity analysis of the effect of the portfolio on the results, by examining the operation of the base-load units with increasing levels of wind power when storage and interconnection are removed from the system.

1) No Storage Case: Fig. 3 shows the number of hours online for an average CCGT and coal unit on systems with and without pumped storage and an increasing wind penetration. On the system without pumped storage the base-load units spend more hours online compared to the system with storage, until a very high wind penetration (greater than 32% installed capacity for a CCGT and greater than 42% installed capacity for a coal unit) is reached. The presence of pumped storage on a system will displace the primary reserve contribution required from conventional units and thus reduce the need for them to be online. Correspondingly, an average base-load unit spends more hours online on the system without pumped storage as there is more requirement on the unit to be online providing primary reserve to the system. As coal units, in this case, are the main thermal provider of primary reserve to the system they are the most affected by the addition of a storage unit, as seen for a typical coal unit in Fig. 3. The difference in hours online for a typical CCGT unit on the system with storage compared to the system without storage is small as they are not large contributors to primary reserve.

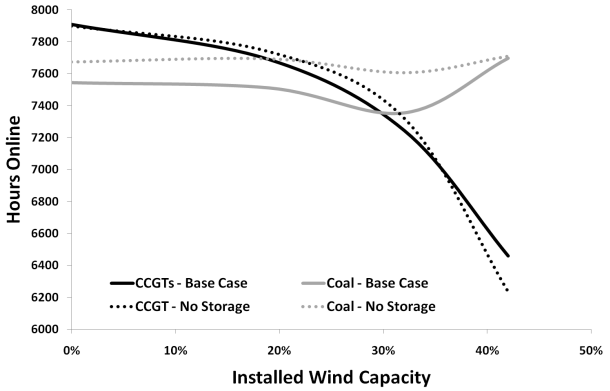

Fig. 3. Number of hours online for an average CCGT and Coal unit with/without storage and an increasing wind penetration

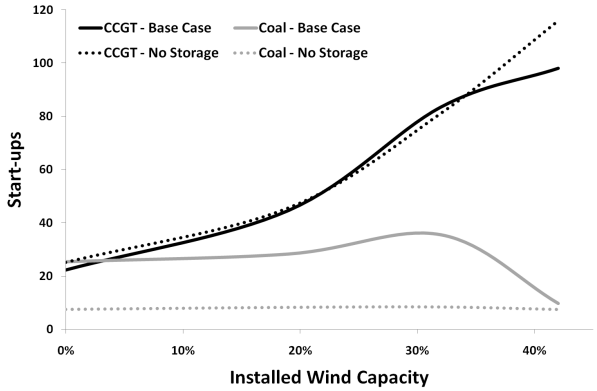

Fig. 4. Number of start-ups for an average CCGT and Coal unit with/without storage and an increasing wind penetration

However, at very high wind penetrations a crossover point occurs when large fluctuations in wind power output occur more frequently, as seen in Table IV, and now the system with pumped storage is more equipped to balance these fluctuations. As the demand for reserve is sufficiently large at very high wind penetrations, such that reserve from many thermal units is needed in addition to the reserve from the storage units, storage will no longer be a factor in base-load units going offline. Thus, at very high levels of wind, base-load units now spend more hours online on the system with storage compared to the system without storage.

Fig. 4 shows the number of start-ups for an average base-load CCGT and coal unit on a system with and without pumped storage as wind penetration increases. Almost no difference in the number of start-ups for a typical CCGT unit is seen on the systems with and without storage until installed wind reaches greater than 32%. However, the number of start-ups for a typical coal unit is seen to be much greater on the system with storage compared to the system without storage, again indicating that storage will most adversely affect the units that provide the largest portion of primary reserve to the system. Again a crossover point is reached at some very high wind penetration after which start-ups rise rapidly on the system without storage due to large and frequent fluctuations in wind power output. This occurs at 32% installed wind for a CCGT and greater than 42% installed wind capacity for a coal unit. Thus, until very high wind penetrations are reached the existence of a pumped storage unit is shown to actually exacerbate cycling of base-load units.

2) No Interconnection Case: Fig. 5 compares the number of hours spent online by a typical CCGT and coal unit on systems with and without interconnection, as wind is increased. The base-load units are seen to spend significantly more hours online on the system without interconnection compared to the system with interconnection until a very high wind penetration is reached.

Due to a large portion of base-load nuclear plant and cheaper gas prices compared with Ireland, the market price for electricity tends to be cheaper in Great Britain. As a consequence Ireland tends to be a net importer of electricity from Great Britain and as such will import electricity before

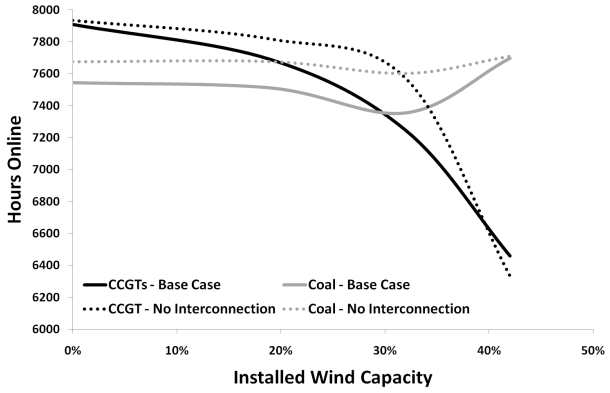

Fig. 5. Number of hours online for an average CCGT and Coal unit with/without interconnection and an increasing wind penetration

turning on domestic units. Thus interconnection to Great Britain displaces conventional generation on the Irish system, forcing units down the merit order and exacerbating plant cycling. Without the option to import electricity, as in the "no interconnection case", all demand must be met by domestic units requiring more units to be online generating more often. Thus a typical CCGT and coal unit are seen in Fig. 5 and Fig. 6 to spend more hours online and have less start-ups on the system without interconnection.

However, as seen in Fig. 5 at some wind penetration between 32% and 42% installed wind capacity for a CCGT unit and greater than 42% installed capacity for a coal unit, a crossover point will occur when the units spend more hours online on the system with interconnection. As very high wind penetrations are reached, the electricity price in Ireland undercuts British prices more often making exports economically viable. Thus at very high penetrations of wind, the system with interconnection can deal with large fluctuations in the wind power output via imports/exports more favorably and avoid plant shut-downs. Thus interconnection is shown not to benefit the operation of base-load units on a system that is a net importer until wind penetration increases to such point that exports are economically viable.

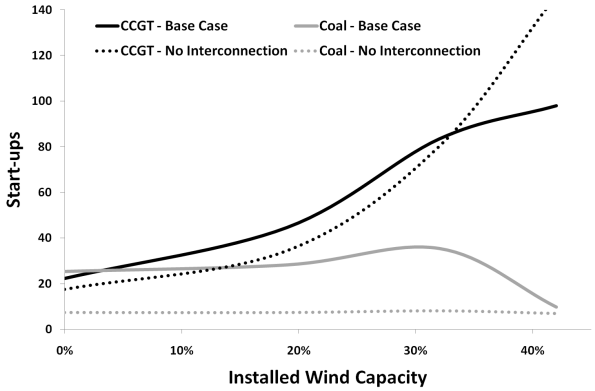

Fig. 6. Number of start-ups for an average CCGT and Coal unit with/without interconnection and an increasing wind penetration

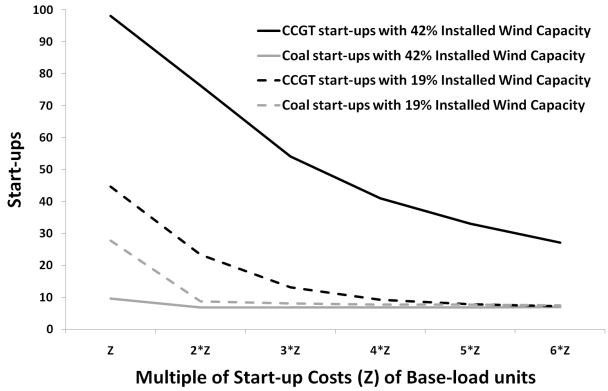

Fig. 7. Number of base-load start-ups for increasing start-up costs

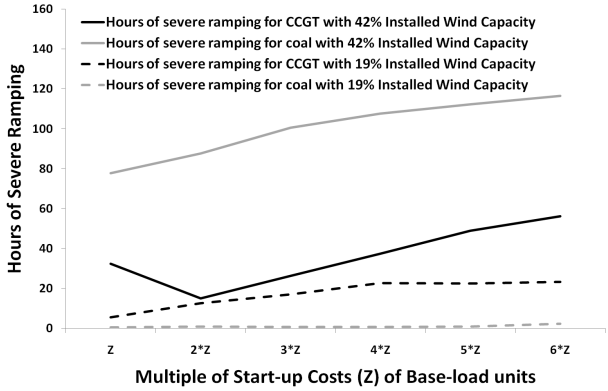

Fig. 8. Number of hours of severe ramping duty for increasing start-up costs

C. Effect of Increasing Start-up Costs

Having shown in Section III-A and III-B the severe impact increasing wind penetration will have on the operation of the base-load units, this section now examines how the increasing costs imposed on these units by cycling operation, will subsequently affect their operation. A component of a unit's start-up cost should be the cost of wear and tear inflicted on the unit during the start-up process [16]. However, given the uncertainty in determining such a cost, this aspect is often neglected, leading to the units being scheduled to start more frequently, yielding more cycling related damage. This section examines how the operation of the base-load units changes as the start-up costs are incrementally increased to represent the increasing depreciation of the unit.

1) Start-ups: The number of start-ups for an average CCGT and coal unit is shown in Fig. 7, as start-up costs are increased, with 19% and 42% installed wind capacity respectively. Increasing the start-up costs of a CCGT unit results in a substantial reduction in start-stop cycling, particularly at the higher wind penetration. This indicates a feedback effect, whereby increased cycling will lead to increased costs, but when these costs are included in the cost function, cycling will subsequently be reduced. With 42% installed wind capacity, increasing the start-up costs by a factor of 6 sees the start-ups for a CCGT drop from 98 to 27, a decrease of 72%. Doubling the start-up costs of a coal unit in the low wind case reduced start-ups by 19, a 68% reduction. No further reduction in coal start-ups was possible as these units were then at their minimum number of annual start-ups (governed by scheduled and forced outages).

A greater reduction in cycling is achieved by increasing start-up costs on the system with 42% installed wind capacity compared to the system with 19% installed wind capacity, as this system can export more due to lower electricity prices. Increasing the start-up costs of the base-load units in Ireland by a factor of 6, results in a 29% increase in exports on the system with 42% installed wind capacity as it becomes more economical to allow the base-load units in Ireland to stay online and avoid shut-downs by increasing exports to Britain.

2) Ramping and Part-load Operation: Fig. 8 shows the number of hours that severe ramping is required by an average CCGT and coal unit, as start-up costs are increased with 19% and 42% installed wind capacity. Fig. 9 shows the utilization factor for an average CCGT and coal unit, with 19% and 42% installed wind capacity as their start-up costs are increased. The trade-off for the reduction in start-stop cycling of base-load units, achieved by increasing the start-up costs, is an increase in ramping activity as seen in Fig. 8 and part-load operation as seen in Fig. 9, which will also leads to plant deterioration although it is reported to be less costly compared with start-ups [30].

By increasing the start-up costs of the base-load units, start-ups are reduced and these units are kept online more, but at the expense of more flexible units which are taken offline. As a result the number of hours when the base-load units are the only thermal units online increases with increasing start-up costs. During such hours there will be a considerable ramping requirement on these units to balance fluctuations in the wind power output. As there will be even less thermal units online in the 42% installed wind capacity case compared to the 19% installed capacity case the greatest increase in ramping is observed for the 42% installed wind capacity case as start-up costs are increased, as seen in Fig. 8. Some inconsistencies in the trend can occur because "severe ramping" is defined discretely, as seen for a CCGT with 42% installed wind.

As the base-load units are being kept online more often, as their start-up costs are increased, they will experience

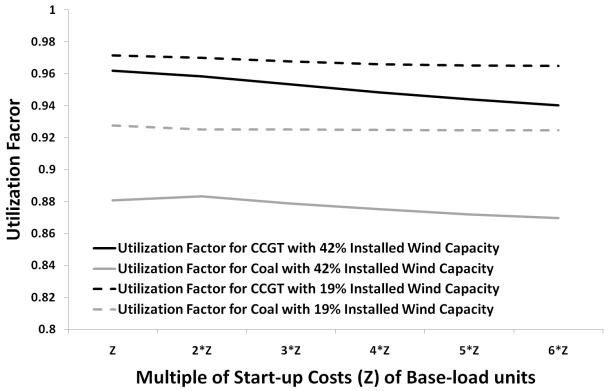

Fig. 9. Utilization factor for increasing start-up costs

increased part-load operation as indicated by the reduction in utilization factor in Fig. 9. As start-up costs are increased sufficiently it becomes more economical to run these units at part-load, than to take them offline and forgo expensive start-up costs at a later time. The greater increase in part-load operation occurs on the system with 42% installed wind capacity compared to the system with 19% installed wind capacity, corresponding to the large reduction in start-ups seen at 42% installed wind capacity. The difference in start-ups and ramping for a CCGT and coal unit between 19% installed wind and 42% installed wind is also seen in Fig. 1 and Fig. 2 for the original start-up costs and for brevity is not discussed again here.

D. Effect of Modeling Assumptions

The model used was limited to hourly time resolution. The lack of intra-hourly data may have lead to the severity of the cycling being seriously underestimated, for example the severe ramping events. The frequency of severe ramping events found in the study may be underestimated as severe ramps may have occurred over shorter time frames than one hour. Also, such a sizeable ramp occurring over a period shorter than one hour would have a much more damaging effect on the unit.

For all simulations, rolling planning with a three hour time step was used. Had the system been re-optimized more regularly, the wind and load forecasts would have been updated more often. However, [22] shows this would have minimal impact on the operation of the base-load units examined here so a three hour time step was deemed adequate.

IV. Discussion

How electricity markets evolve to manage plant cycling is beyond the scope of this paper, however, this section offers some discussion as to how cycling costs could be represented and areas for future market development with a large wind penetration. In many electricity markets generators submit complex bids for energy in addition to the technical characteristics of the plant. If the current trend for wind development continues, plant cycling, as shown in this paper, will inevitably becoming an increasing concern and generators may subsequently alter their bids or plant characteristics in order to minimize cycling damage. Section III-C examines how by taking the cost of cycling into consideration in a unit's start-up cost, subsequent cycling can be reduced. Generators in SEM, the Irish electricity market, are directed to include cycling costs in their start-up costs so this approach was taken in this paper.

Cycling costs could also be included in no-load or energy costs, or even defined as a new market product such as ramping costs [31]. However, increasing the energy cost will also increase the marginal cost of the unit, which risks changing the position of the unit in the merit order and inducing further cycling. Alternatively cycling costs could be incorporated in a unit's shut-down costs. The Wilmar Planning Tool used in this study does not model shut-down costs at present. Future work could investigate the effect of incorporating shut-down costs in the scheduling algorithm on a generators dispatch.

As cycling costs are difficult to quantify, generators may use the opportunity to exercise market power. For example a generator may increase the start-up costs excessively in order to avoid shut-down, although this strategy may result in them being left offline following a trip or scheduled shut-down because of their excessive start-up cost. Thus some may instead favor setting a maximum number of start-ups a unit can carry out over a period of time, however, this approach would unfairly reward inflexible units and provide no incentive to improve operational flexibility.

In some electricity markets generators submit simple bids. This can result in increased start-ups for generators as no explicit consideration of the cost of starting the unit is taken. Incorporating wind in such a market would induce further cycling, indicating that a move to complex bidding could be beneficial. Longer scheduling horizons that take future wind forecasts into consideration may also reduce plant start-ups, however the forecast error increases with the time horizon. Thus enabling a later gate closure in a market with a significant wind penetration, which would allow the most up-to-date wind forecasts to be employed, could be more effective at reducing unnecessary plant start-ups [32].

V. Conclusions

Increasing wind penetration on a power system will lead to changes in the operation of the thermal units on that system, but most worryingly to the base-load units. The base-load units are impacted differently by increasing levels of wind, depending on their characteristics. CCGT units see rapid increases in start-stop cycling and plummeting capacity factor and are essentially displaced into mid-merit operation. On the test system examined coal units are the main thermal providers of primary reserve to the system and as a result see increased part-load operation and ramping. This increase in cycling operation will lead to increased outages and plant depreciation.

Certain power system assets are widely reported to assist the integration of wind power. This paper examined if storage and interconnection reduced cycling of base-load units by comparing a system with storage and interconnection to a system without storage and without interconnection, across a

range of wind penetrations. It was found that until very high penetrations of wind are reached storage will actually displace the need for base-load units to be online providing reserve to the system. This results in increased cycling of base-load units compared to the system without storage. Similarly, for a system that is a net importer, interconnection will actually displace generation from domestic units, also resulting in increased cycling of base-load units compared to a system without interconnection. At very large penetrations of wind a crossover point exists, where larger and more frequent fluctuations in the wind power output, can be dealt with more effectively on a system with interconnection and storage and thus the system with storage and interconnection becomes the most favorable to the operation of base-load units.

Having shown how the operation of the base-load units is dramatically affected by increasing levels of wind power and assuming this would lead to added costs in various guises, the effect that increasing start-up costs for base-load units had on their subsequent operation was examined. This showed that as the cost of starting a base-loaded CCGT unit increased, start-stop cycling of the unit was subsequently reduced. However, a reduction in start-ups is seen to be correlated with an increase in part-load operation and ramping.

APPENDIX A
WILMAR OBJECTIVE FUNCTION

The objective function shown in (A.1) consists of operating fuel cost, start up fuel cost (if a unit starts in that hour), emissions costs and penalties incurred for not meeting load or reserve targets. If a unit is online at the end of the day, its start-up costs are subtracted from the objective function to ensure that there are still units online at the end of the optimization period. The decision variable is given in the first three lines, showing whether a unit is online or offline. Further detail on the formulation of the unit commitment problem is given in [22].

A. Indices

F	Fuel
i,I	Unit group
r,R	Region
s,S	Scenario
START	Units with start up fuel consumption
t,T	Time
USEFUEL	Unit using fuel

B. Parameters

EMISSION	Rate of emission
END	Endtime of optimization period
k	Probability of scenario
L	Infeasibility Penalty
LOAD	Penalty for loss of load
PRICE	Fuel price
REP	Penalty for not meeting replacement reserve
SPIN	Penalty for not meeting primary reserve
TAX	Emission tax

C. Variables

CONS	Fuel consumed
OBJ	Objective function
U	Relaxation variable
V	Decision variable - on or off
ONLINE	Integer on/off for unit
QDAY	Day ahead demand not met
QINTRA	Intra day demand not met
QREP	Replacement reserve not met
QSPIN	Primary reserve not met
+, -	Up, Down regulation

$$
\begin{aligned}
V_{obj} = & \sum_{i\in I^{USEFUEL}} \sum_{s\in S} \sum_{t\in T} k_S F^{CONS}_{i,r,s,t} F^{PRICE}_{f,r,t} V^{ONLINE}_{i,t} \\
& + \sum_{i\in I^{START}} \sum_{s\in S} \sum_{t\in T} k_S F^{START}_{i,r,s,t} F^{PRICE}_{f,r,t} V^{ONLINE}_{i,t} \\
& - \sum_{i\in I^{START}} \sum_{s\in S} k_S F^{START}_{i,r,s,T_{END}} F^{PRICE}_{f,r,T_{END}} V^{ONLINE}_{i,T_{END}} \\
& + \sum_{i\in I^{USEFUEL}} \sum_{s\in S} \sum_{t\in T} k_S F^{CONS}_{i,r,s,t} F^{TAX}_{f,r} F^{EMISSION}_{f} \\
& + \sum_{s\in S} \sum_{t\in T} k_S L^{LOAD} (U^{QINTRA,+}_{r,s,t} + U^{QINTRA,-}_{r,s,t}) \\
& + \sum_{t\in T} k_S L^{LOAD} (U^{QDAY,+}_{r,t} + U^{QDAY,-}_{r,t}) \\
& + \sum_{s\in S} \sum_{t\in T} k_S L^{SPIN} U^{QSPIN,-}_{r,s,t} \\
& + \sum_{s\in S} \sum_{t\in T} k_S L^{REP} U^{QREP,-}_{r,s,t}
\end{aligned}
\tag{A.1}
$$

APPENDIX B
SUMMARY OF NON-NORMALIZED BASE CASE RESULTS

Tables VI to IX indicate the variation in start-ups and capacity factor of the CCGT and coal units in the base case (i.e. Tables VI to IX relate to Fig. 1), for each of the wind penetrations. The maximum value, minimum value, average and standard deviation are shown. It can be seen that the CCGT units have a greater spread in start-ups compared to the coal units and the standard deviation of start-ups is least at the highest wind case for both types of units. For capacity factor the spread in results across the units increased as the wind increased, with the CCGT units again having a greater variation compared to the coal units, however, there are more CCGT units than coal units in each of the wind cases.

TABLE VI
VARIATION IN CCGT START-UPS WITH INCREASING WIND

Installed Wind Capacity	0%	19%	32%	42%
Maximum value	98	115	175	204
Minimum value	4	6	6	4
Average	21.9	42.5	78.1	95.7
Standard Deviation	18.0	17.4	20.2	15.0

TABLE VII
VARIATION IN COAL START-UPS WITH INCREASING WIND

Installed Wind Capacity	0%	19%	32%	42%
Maximum value	52	54	67	14
Minimum value	8	8	12	5
Average	23.6	26.2	33.2	9.6
Standard Deviation	8.6	9.4	9.1	2.3

TABLE VIII
VARIATION IN CCGT CAPACITY FACTOR WITH INCREASING WIND

Installed Wind Capacity	0%	19%	32%	42%
Maximum value	0.92	0.91	0.88	0.88
Minimum value	0.85	0.79	0.56	0.50
Average	0.89	0.86	0.79	0.69
Standard Deviation	0.06	0.10	0.32	0.36

TABLE IX
VARIATION IN COAL CAPACITY FACTOR WITH INCREASING WIND

Installed Wind Capacity	0%	19%	32%	42%
Maximum value	0.85	0.83	0.83	0.84
Minimum value	0.78	0.77	0.76	0.72
Average	0.82	0.80	0.79	0.78
Standard Deviation	0.05	0.05	0.07	0.13

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