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Martin Almenta, M., Morrow, D., Best, R., Fox, B., & Foley, A. (2016). An analysis of wind curtailment and constraint at a nodal level. IEEE Transactions on Sustainable Energy. DOI: 10.1109/TSTE.2016.2607799

Published in:

IEEE Transactions on Sustainable Energy

Document Version:

Publisher's PDF, also known as Version of record

Queen's University Belfast - Research Portal:

[Link to publication record in Queen's University Belfast Research Portal](#)

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An analysis of wind curtailment and constraint at a nodal level

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Abstract— Many countries have set challenging wind power targets to achieve by 2020. This paper implements a realistic analysis of curtailment and constraint of wind energy at a nodal level using a unit commitment and economic dispatch model of the Irish Single Electricity Market in 2020. The key findings show that significant reduction in curtailment can be achieved when the system non-synchronous penetration limit increases from 65% to 75%. For the period analyzed, this results in a decreased total generation cost and a reduction in the dispatch-down of wind. However, some nodes experience significant dispatch-down of wind, which can be in the order of 40%. This work illustrates the importance of implementing analysis at a nodal level for the purpose of power system planning.

Index Terms-- power generation dispatch, power generation planning, power systems, power transmission, wind energy.

I. INTRODUCTION

THE Republic of Ireland (ROI) [1] and Northern Ireland (NI) [2] have set some of the most ambitious global wind power targets with 40% electricity consumption to come from mainly wind energy by 2020. In January 2015 ROI and NI experienced maximum instantaneous wind penetration of 66.2% and 74.8% respectively while maintaining the system non-synchronous penetration (SNSP) limit at 50% [3]. Due to the Irish Single Electricity Market (SEM)'s size, ambitious renewable energy target, high levels of wind power and relative isolation, the SEM has a unique opportunity to lead the way in smart grid introduction and the development of an exemplar European system. This opportunity has been recognised already by the European Union, and a large smart grid project has been allocated for Ireland under the Innovation and Networks Executive Agency (INEA) as a Project of Common Interest (PCI) [4]. Ireland like other regions is already, and will increasingly, experience problems related to large stochastic generation. For example the Electric Reliability Council of Texas (ERCOT) in the USA [5] has

reduced wind curtailment by heavily investing in the transmission network and redesigning the market [6].

There is substantial research from countries experiencing high renewable penetration. Söder *et al.* [7] analysed the need for balancing services in European power systems with high stochastic generation. Foley *et al.* [8] noted that more research of ramping is needed. Devlin *et al.* [9] showed the potential for wind curtailment reduction using energy storage coupled to a gas thermal generator. McGarrigle *et al.* [10] highlighted the strong relationship between wind curtailment and the system operation constraints, stating that the system operation constraints will need to be relaxed to increase the current technical limit of the instantaneous penetration of nonsynchronous generation. Kubik *et al.* [11] showed that there is financial risk for new wind developers due to wind curtailment because of grid constraint and suggested that new smart grid technologies are needed to ameliorate constraint issues. Previous publications have focused on transmission grid dynamic studies and unit commitment modelling to quantify curtailment, carbon savings, energy costs and frequency response, but have not quantified this at a nodal level.

Hence the aim of this work is to identify and quantify wind curtailment and constraint using a NI district level unit commitment and economic dispatch model of the SEM in 2020. The term dispatch-down of wind refers to wind energy that is not exported to the grid due to power system or local network limits [12]. When dispatch-down is caused by overall power system limits it is referred to as wind curtailment, and any dispatch-down that is due to local network limits is referred to as wind constraint. The key difference between this work and previous publications is that a full model of the NI transmission grid at nodal level is included. Therefore, in this work, wind power dispatch-down occurs at each node rather than assuming equal dispatch-down at all nodes. This allows the effect of wind constraint due to local network limits to be included in the analysis, which could then be used to support power system planning.

The paper is divided into 5 sections. Section 1 contextualises the paper. Section 2 presents the methodology in which the SEM is explained in detail, the test system used for the analysis, the objective function and the operational system constraints. Section 3 shows the results and analysis. Section 4 and 5 present the discussion and conclusions respectively.

This work was supported by a Charles Parsons Energy Research Award, which is funded by the Science Foundation Ireland (SFI), award (06/CP/E002).

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II. METHODOLOGY

A. Single Electricity Market

The SEM is a centralised, dual currency (i.e. euro and sterling) and mandatory gross pool electricity market operated by the Single Electricity Market Operator (SEMO) where electricity generation over 10 MW is traded between the generators and supplier [13]. The generators bid into the pool using short run marginal cost (SRMC, €/MWh), based on the technical specification of the unit. The system marginal price (SMP) is calculated for every 30 minute trading period using generator bids and the system demand. All generators are paid the same SMP for a trading period for the power generated. A generator is out of merit when its SRMC is greater than the SMP.

Fig. 1 illustrates the operation of the SEM [14]. The market operator SEMO models the Ex Ante SMP, solving an unconstrained unit commitment model to determine the economic dispatch of generation to meet forecast demand. A day later the intraday trading is run by the transmission system operators (TSO), EirGrid in ROI and SONI in NI, to solve the constrained unit commitment model, which includes system operational constraints. The simulation of the intraday model includes two stages. These are the day ahead model and real time model, with the intraday trading imitated by a two way information exchange between them. The inclusion of the system operational constraints, system non-synchronous penetration limit and reserve requirements in the intraday model, increases the accuracy of the required dispatch schedule of generators in order to meet the system demand while securing the frequency and power system inertia. This is secured by scheduling specific generators in the SEM. Four days later SEMO calculates the SMP by solving the unconstrained economic dispatch model using the unit commitment calculated from the intraday model solution.

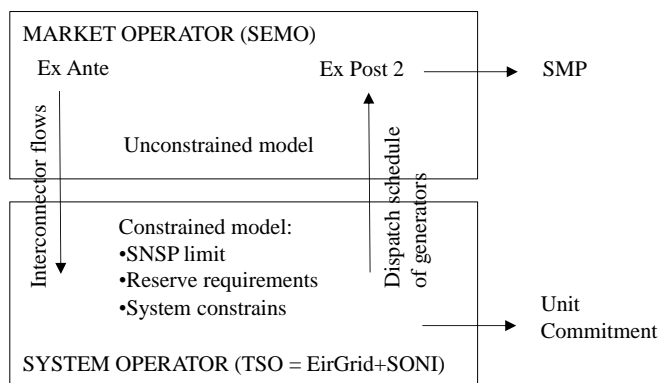


Fig. 1. Representation of the SEM.

B. Test system

The software used in this study to solve the unit commitment and economic dispatch problem is PLEXOS [15]. The version of PLEXOS used in this research is 6.301 R03 on a Dell Optiplex 7010 with an Intel Core i7-3770. A mixed integer solver Xpress-MP 25.01.05 provided by FICO is used

to optimise the unit commitment and economic dispatch problem [16].

A standard deviation of errors of 1% and 12% are assumed for the demand and wind power forecast [17] respectively, and are used to retrospectively generate forecasts using the real values thus adding stochasticity to the analysis. The forecast values are included in the Ex Ante model and the day ahead part of the intraday model. The real system demand and wind generation values are used in the real time part of the intraday model. Interleaved simulation is used in the system operator model in order to simulate the intraday trading run by the TSOs. The solution of the day ahead is passed to the real time model, considering the real wind generation and demand. The day ahead model and real time model pass information backwards and forwards to imitate the actual intraday trading of the SEM [14]. In the market operator and system operator models the interval period for analysis is, 30 minutes and 15 minutes respectively. In both models 24 hour look ahead has been considered.

Next, a 25 node system of the NI transmission grid at the district level is added to the unit commitment and economic dispatch model of the SEM in 2020. In Fig. 2, the 275 kV transmission lines between ROI and NI are represented by a dotted line, 110 kV lines by a double dash line, the HVDC interconnectors (one connects NI and Great Britain (GB), and the other connects ROI and GB, as shown in the inset) are represented by a continuous line and the HVAC interconnector (connecting ROI and NI) by a double continuous line. In the model one node represents GB, one node represents ROI and the rest of the nodes represent the different districts in NI, as shown in Fig. 2.

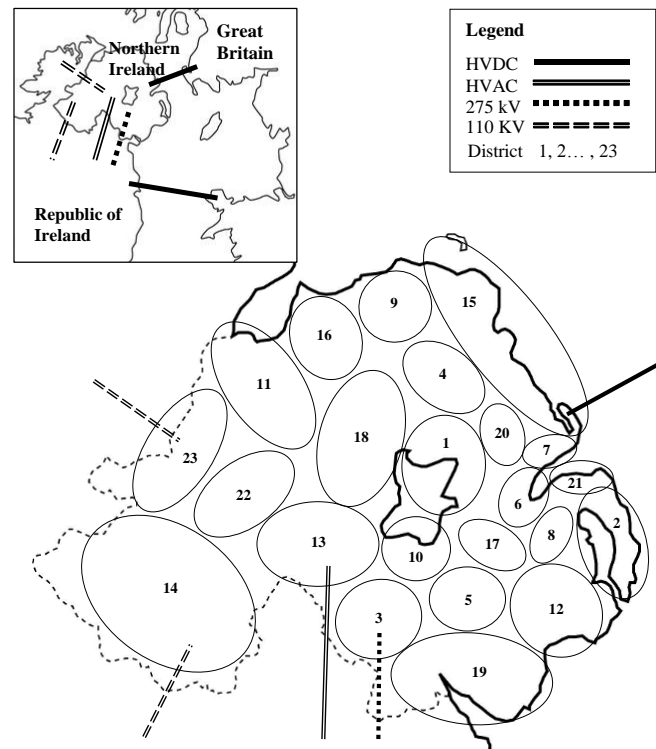


Fig. 2. NI test system. Inset shows NI, ROI and GB interconnection.

The 26 nodal districts in [18] have been reduced to 23 districts, with some integrated into adjacent areas due to the limited 275 kV or 110 kV transmission lines and small demand.

The NI equivalent power network has been built using data provided by [19]. The network, shown in Fig. 3, is based on the 275 kV and 110 kV transmission lines and 23 areas. The length of the longest line in NI is 80.8 km and connects the districts 3 and 7 [20]. The use of the short line equivalent circuit [21], neglecting line capacitance, to represent the lines is thus justified.

There are two HVDC interconnections to GB; the Moyle interconnector that links district 23 in NI and GB and the East-West (EWIC) interconnector which links ROI to GB. A new 400 kV HVAC interconnector called the HVAC ROI-NI line running between district 13 in NI and ROI has been included in the analysis as it is expected to be fully commissioned by 2020 [22]. Currently the maximum ramp rate, both up and down, for the Moyle interconnector is 5 MW/min [23]. The same ramp rate has been assumed for the other two interconnectors. It is assumed that by 2020 the import capacity of the Moyle interconnector will revert to its nominal capacity following repair [24].

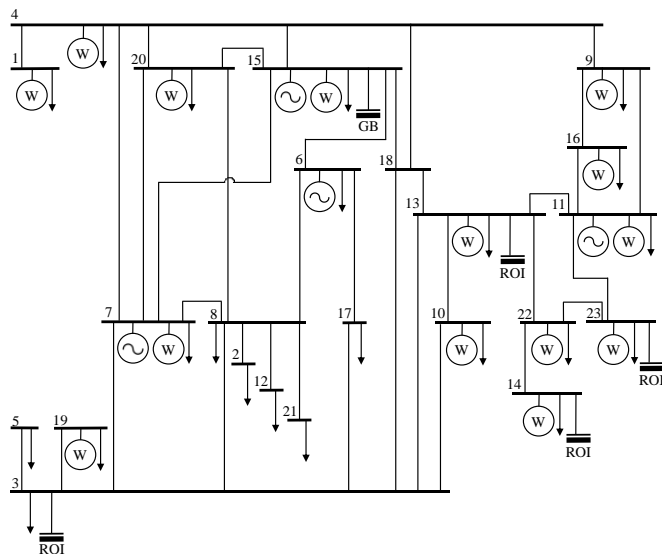


Fig. 3. Equivalent power network in NI.

1) Generation

The portfolio of dispatchable generation and the generator characteristics in ROI and NI in 2020 has been obtained from [24] and [25]. There is a total installed dispatchable capacity of 10,344 MW and 3,135 MW, respectively, projected in ROI and NI in 2020, as shown in Table I.

A wind generation capacity of 3,449 MW and 1,234 MW will be installed by 2020 in ROI and NI respectively. It is forecast [24] that in NI by 2020 there will be more wind generation capacity installed than gas fired power stations. Gas fired power stations will continue to play an important role in power systems with high renewable penetrations due to the fast

response required to compensate for fluctuation from the renewable resource.

In NI most of the wind capacity [20] will be located in the western counties, districts 11 and 22, as shown in Fig. 4. District 11 is the only location in NI where there is a combination of conventional generation, high wind penetration and significant population [18].

TABLE I
Installed capacity in 2020 by fuel type in ROI and NI

Fuel type	Installed capacity ROI (MW)	Installed capacity NI (MW)
Coal	855	476
Gas	4,257	1,017
Oil	588	0
Distillate Oil	324	390
Peat	346	0
Waste	17	18
Hydro	216	0
Pumped Storage	292	0
Wind	3,449	1,234
TOTAL	10,344	3,135

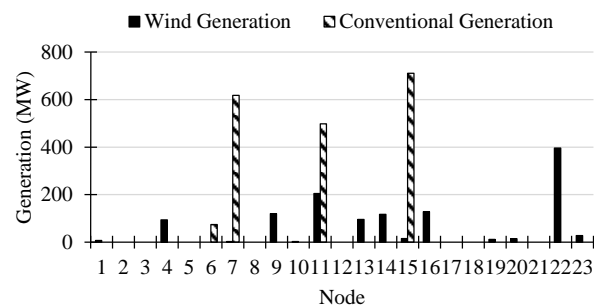


Fig. 4. Comparison of wind and conventional generation installed at each node in NI.

The wind generation in each district in NI is modelled by applying the same wind profile to each of the districts. The wind profile used is the historical measured wind generation data from 2009 [25]. Data from real wind farms for the year 2008 located in ROI are used in this study. Using two different wind years is considered acceptable as the wind capacity factor was almost equal, 31.7% and 31.3% in 2008 and 2009, respectively [24]. This study has assumed the wind capacity factor in 2020 to be the same as it was in 2008 and 2009. The total installed wind capacity in the ROI was 993 MW in 2008. This is forecast to increase to 3,449 MW by 2020 [20].

2) System demand

The total electricity requirement (TER) in 2020 is forecast to be 28,973 GWh in ROI and 9,443 GWh in NI [24]. The system demand profiles used are based on the demand profiles available for 2009 [25]. The data are scaled to meet the TER in 2020. The system demand is divided between ROI and NI nodes, with 75% attributed to the ROI node, and the remaining 25% is divided between the different nodes in NI, taking into account the total consumption of every district in 2011 [18]. The biggest load in NI occurs in node 6, which represents 20.6% of the total demand in NI. The next district load is node 10 with 7.8% and the smallest district load is node 16 with 1.2% of the total demand in NI. Great Britain is modelled with

a constant demand of 1000 MW, which represents the trade capacity between SEM and GB [24] rather than actual demand.

3) Fuel prices

The fuel prices used in the model are based on the prices provided for coal, gas, oil and carbon in the World Energy Outlook 2014 [26]. The prices are assumed to remain constant during the studied analysis period in 2020. The prices are 75.75 €/tonne, 0.78 €/therm, 84 €/barrel and 16.50 €/tonne for coal, gas, oil and CO₂, respectively. The fuel prices obtained from [25] for the generators in ROI and NI are shown in Table II. The fuel price for peat is assumed to be 2.12 €/GJ and for waste 5 €/GJ.

TABLE II
Fuel prices in ROI and NI

Fuel	ROI (€/GJ)	NI (€/GJ)
Coal	3.13	3.62
Gas	8.43	8.49
Distillate Oil	17.77	17.45
Oil	13.08	12.75

C. Objective function

The objective function that is solved in each trading period is shown in (1) [27]. The simulations must satisfy the constraints of the energy balance (2), ramp rate, minimum up (3) and down (4) times of generators, maximum generation capacity (5), minimum stable level of generation (6) [28] and transmission constraints (7). PLEXOS uses the DC power flow approximation. Wind priority dispatch has been modelled by applying zero operational cost to the wind generators. The unserved energy variable is minimised in the objective function in order to determine if system demand is met and evaluate the requirement for additional generation or reinforcement.

$$\min \sum_{t \in T} \sum_{j \in J} \left(SC_{jt} US_{jt} + NLC_{jt} UG_{jt} + (VOM_{jt} + UoS_{jt}) P_{jt} \right. \\ \left. + PC_{jt} P_{jt} + PenLLUE_{jt} + PenLLRES_{jt} + PDE.ExE_t \right) \quad (1)$$

$$\sum_{t \in T} \sum_{j \in J} (P_{jt} - Pload_{jt} + UE_t) = D_t \quad (2)$$

$$P_{jt} - P_{j,t-1} - MRU_{jt} UG_{jt} \leq 0 \quad (3)$$

$$P_{jt} - P_{j,t-1} + MRD_{jt} UG_{jt} \geq 0 \quad (4)$$

$$(P_{jt} - Pmax_{jt}) UG_{jt} \leq 0 \quad (5)$$

$$(P_{jt} - MSL_{jt}) UG_{jt} \geq 0 \quad (6)$$

$$Pline_t - DPLine_t \leq 0 \quad (7)$$

where t is the index of time periods until T , j is the index of generator units until J , SC_{jt} is the unit j start-up cost at time t , US_{jt} is a binary number representing if unit j has been committed at time $t-1$, NLC_{jt} is the unit j no load cost, UG_{jt} is the binary number representing the generating state of unit j , VOM_{jt} is the unit j operation and maintenance cost, UoS_{jt} is the unit j use of system cost, PC_{jt} is the unit j production cost, P_{jt} is the unit j power output, $PenLL$ is the penalty incurred for load loss, UE_t is the unserved energy by unit j , RES_t is the

reserve energy provision not fulfilled by unit j , PDE is the penalty for dumped energy, ExE_t is the unit j excess energy, $Pload_{jt}$ is the unit j pump load, D_t is the system demand, MRU_{jt} is the unit j maximum ramp up rate, MRD_{jt} is the unit j maximum ramp down rate, $Pmax_{jt}$ is the unit j power output, MSL_{jt} is the unit j power output, $Pline_t$ is the power transmitted through the line and $DPLine_t$ is the design line power rating.

D. Operational system constraints

The operational system constraints published by the TSOs [29] were used. These additional constraints are applied to the model to guarantee the efficient and secure operation of the power systems, preventing voltage, frequency and system stability issues.

1) System non-synchronous penetration limit

The system non-synchronous penetration limit (SNSP) is set to secure the system frequency and dynamic stability with the purpose of ensuring the reliability of the power system [30]. The SNSP is calculated every trading period using (8) [31]. The interconnectors that participate in the import and export of electricity in (8) are Moyle interconnector and EWIC. Currently the SNSP is limited to 50% [29]. However, it is planned to increase the SNSP to 75% by 2020 [32].

$$SNSP = \frac{Wind\ Gen + HVDC\ imports}{Demand + HVDC\ Exports} \quad (8)$$

2) Operating reserve requirements

The operating reserve is provided by conventional generators to mitigate the loss of a generator. The primary operating reserve (POR) and secondary operating reserve (SOR) are required to equal 75% of the capacity of the largest generator-in-feed [29]. However, the tertiary operating reserve 1 (TOR 1) and the tertiary operating reserve 2 (TOR 2) are required to equal 100%. The largest synchronous generator has a maximum capacity of 466 MW (Poolbeg in the ROI) and the largest generator-in-feed has a maximum capacity of 500 MW (EWIC). Between 00:00 and 07:00 the minimum operating reserve required is reduced to 160 MW. To mitigate unexpected reduction in the system demand, negative reserve is also required by the power systems to maintain balance; 100 MW and 50 MW of negative reserve are applied in ROI and in NI, respectively.

3) Minimum synchronous generation and interarea flow

A minimum number of synchronous generation units are required to be online in different parts of the power system to maintain system inertia, avoid voltage issues and keep the network working within its technical limits [29]. The constraints regarding which generation units in ROI and NI are required and the inter-area flow between the areas have been added to the model. It is assumed that the new HVAC ROI-NI interconnector does not affect the inter-area flow constraint of the existing transmission lines between ROI and NI as this is determined by their technical limits.

III. RESULTS AND ANALYSIS

A detailed analysis of power system generation costs, dispatch-down of wind and effect on grid constraints has been performed for a week in December 2020 (16th to 22th December), when there are significant stochastic events. This week was selected based on the analysis of when the SNSP constraint is binding in the Ex Ante model solution for the year 2020 for different SNSP limits. The analysis is performed at a sub-hourly time resolution. As shown in [33] and [34] this analysis gives a better understanding of ramping requirement, compared to the more typical hourly time resolution. All the wind power and SEM demand data were upscaled using linear interpolation from the original interval period (time resolution) to the interval period needed for each model in the analysis. The raw SEM demand data used in this study have a resolution of 30 minutes, the raw wind generation in ROI 15 minutes and the raw wind generation in NI 1 hour.

It is expected that at the end of 2017 the current SNSP limit will be increased to 55% and by 2020 it is expected to be 75% due to significant grid reinforcements [31]. Due to the requirement of new technological developments and their implementation in the power system, the limit of 75% is considered unachievable at the moment. For this reason a study of the impacts of varying the SNSP from 65% (forecast SNSP limit in 2018) to 75% has been performed.

The number of hours in which the SNSP constraint in the SEM is binding for different values of SNSP for the days under study are shown in Table III. The 19th December is the day that for SNSP of 65% the constraint is binding for 23 hours of the day. This day is also the winter demand peak. At an SNSP of 75% the restriction is non-binding, meaning that the wind curtailment has been eliminated and any dispatch-down of wind is due to local network constraints only (wind constraint). The average hours of binding during the week is reduced by 8.8 hours by increasing the SNSP from 65% to 70%, and reduced to 0 hours for 75%.

TABLE III
Hours binding of the SNSP constraint in the SEM

SNSP	65%	70%	75%
16/12/2020	0.75	0	0
17/12/2020	13	5.5	0
18/12/2020	21	3.75	0
19/12/2020	23	9	0
20/12/2020	12	2.25	0
21/12/2020	19	7	0
22/12/2020	0	0	0
Average	12.7	3.9	0

The calculated total generation cost that the system operator would incur during the week analysed in NI is shown in Table IV. The analysis is validated because the calculated total generation costs for NI is of the same order of magnitude of the NI energy cost for the month of December 2014 published by SEMO [35], which was £24,123,260. The wind capacity factor in December 2014 was 36% and 42.8% in NI and ROI, respectively. The lowest generation cost occurs for the highest SNSP, as shown in Table IV.

TABLE IV

Total generation costs, total conventional generation, total wind generation, dispatch-down of wind and net imports in NI

SNSP	65%	70%	75%
Total generation cost (€)	6,275,115	6,064,744	6,042,777
Total gas generation (GWh)	55.7	56.7	56.9
Total coal generation (GWh)	33.3	29.9	29.5
Total other conventional generation (GWh)	3.1	2.8	2.5
Total wind generation (GWh)	94.7	108.1	116.4
Total dispatch-down of wind (%)	24.7	14.1	7.5
Net Imports (GWh)	30.0	24.7	21.5

The total generation during the week is 187 GWh, 198 GWh and 205 GWh for SNSP's of 65%, 70% and 75%, respectively. The total generation cost for gas generators increases by 4.1% when increasing the SNSP from 65% to 75% due to the need of more flexible power plants because of the higher SNSP limit, therefore lowering the need for coal and distillate generators. In other words, the extra wind generation allows more de-commitment of coal. Delayed re-commitment, due to the long start-up times of conventional generation would typically require the dispatch of more fast acting flexible gas generation. For the scenarios modelled there is sufficient interconnector capacity available to ensure security of supply, thus the unserved energy is negligible.

Fig. 5 illustrates the wind generation for different SNSP limits in each of the wind generator districts in NI. In total, 14 of the 23 districts have wind generation. District 22 has the greatest wind capacity installed and it presents the greatest increase in wind generation when the SNSP limit is raised.

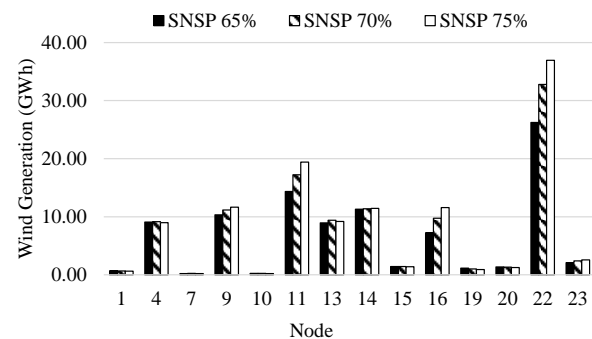


Fig. 5. Wind generation in each wind generator district in NI.

The implementation of the transmission network of NI in the SEM also allows the analysis of wind power dispatch-down in each node of NI. The dispatch-down of wind is expressed as a percentage and it is calculated as follows in (9):

$$\begin{aligned}
 \text{Dispatch-down of wind (\%)} &= \\
 &= \frac{\text{Wind}_{\max \text{ gen}} - \text{Wind}_{\text{gen}}}{\text{Wind}_{\max \text{ gen}}} \cdot 100 \quad (9)
 \end{aligned}$$

where $\text{Wind}_{\max \text{ gen}}$ is the maximum wind generated and Wind_{gen} is the actual wind generated in each district.

The value of wind dispatch-down allows the TSO's to make decisions regarding the measures that should be put in place to reduce wind power dispatch-down, thus allowing more wind generation on the system and reducing the price of total energy generated. Fig. 6 illustrates wind dispatch-down in each wind generator district in NI. The maximum wind dispatch-down occurs in district 16, 44.2%, followed by 22, 35.0%, for an SNSP of 65%. Generally wind dispatch-down decreases when the SNSP is higher. Specifically this occurs in the districts with the most installed wind capacity, such as 22, 11 and 16. These districts experience a reduction of around 50% wind dispatch-down as the SNSP increases. However, wind power dispatch-down can also increase with higher SNSP due to local network constraints, for example in district 10. This is because in district 10 the wind generation capacity is smaller compared to districts 22, 11 and 16. Thus, if the TSO decides to increase the installed wind capacity in district 10 then, to prevent wind constraint, more grid infrastructure would be needed, or the demand in that district would need to be increased to accommodate the extra generation. The total wind dispatch-down during this week is calculated to be 24.7%, 14.1% and 7.5% for SNSP of 65%, 70% and 75% respectively, as shown in Table IV.

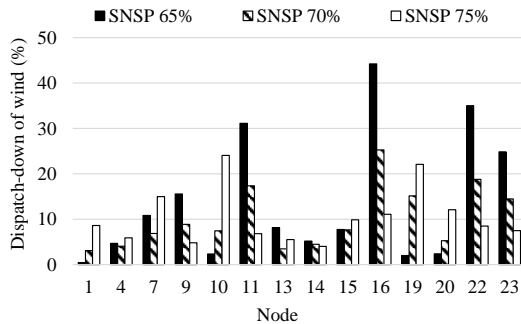


Fig. 6. Dispatch-down of wind in each wind generator district in NI.

Fig. 7 and Fig. 8 illustrate the dispatched wind generation profile for an SNSP of 65% and the unconstrained wind generation data in 2020 in districts 13 and 16, respectively. Fig. 7 shows that on the night of the 17th December and morning of the 18th December wind generation is significantly dispatched down. District 16 experiences a significant wind constraint, as shown in Fig. 8. However, there are wind generator districts that do not experience any wind dispatch-down such as 1. District 1 is in the strongest part of the NI network, as shown in Fig. 9. The reason that the wind power fluctuates on the night of the 17th December in district 13 is that this district is affected by the 400 kV HVAC interconnector and priority dispatch constraint that determines power flow. The priority dispatch constraint takes into account the demand, wind power generation and the HVDC interconnector flows of Moyle and EWIC. In the SEM power system peat fuelled generators [13] have priority dispatch and wind power generation is dispatched down to meet the SNSP constraint.

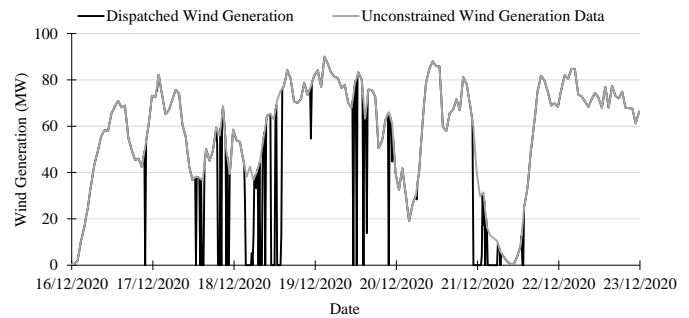


Fig. 7. Dispatched wind generation for an SNSP of 65% and unconstrained wind generation data in 2020 in district 13.

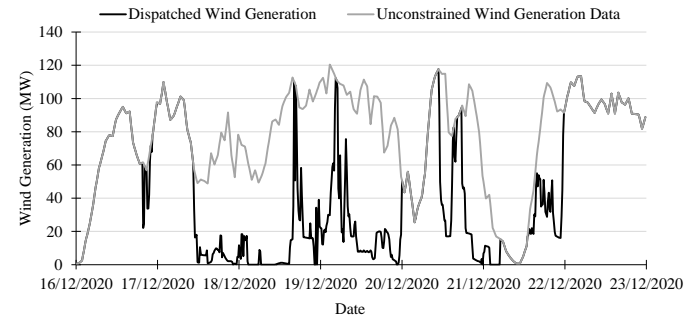


Fig. 8. Dispatched wind generation for an SNSP of 65% and unconstrained wind generation data in 2020 in district 16.

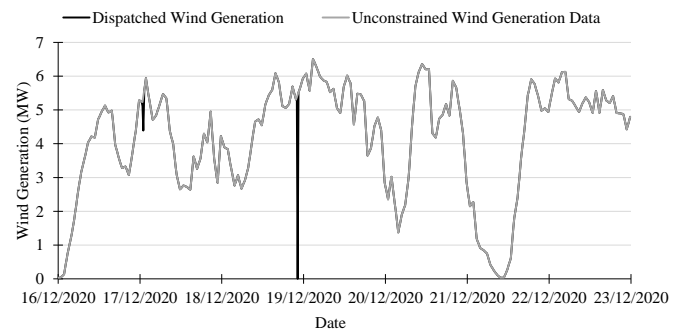


Fig. 9. Dispatched wind generation for an SNSP of 65% and unconstrained wind generation data in 2020 in district 1.

The interconnector and transmission line flows, have been analysed in detail for different values of SNSP. Specifically the flows in the Moyle interconnector, which are determined by the Ex Ante model. The flows in the HVAC ROI-NI interconnector and ROI-3, ROI-14 and ROI-23 transmission lines are determined by the solution of the real time model which is run by the TSO's. Positive flow directions are defined from the name of the interconnector, i.e. from ROI to NI, etc. During the week analysed NI is a net importer through the Moyle interconnector and ROI-3 transmission lines and a net exporter through the others, as shown in Table V.

TABLE V
Net imports in NI from each interconnector

Net imports (GWh)	SNSP 65%	SNSP 70%	SNSP 75%
Moyle Interconnector	42.2	42.2	42.2
HVAC ROI-NI	-20.1	-25.7	-29.1
ROI-3	17.6	19.8	21.2
ROI-14	-4.1	-5.1	-5.8
ROI-23	-5.6	-6.4	-7.1

Typically NI is a net importer of energy. However, in the analysis the difference in energy imported and exported in 2020 decreases when the SNSP limit is higher, as shown in Table V. The calculated net imported energies for the week analysed are 30 GWh, 24.7 GWh and 21.5 GWh for SNSP of 65%, 70% and 75% respectively. This is a significant finding for network planning in NI in terms of wind power and the TSO operational rules, namely priority peat and wind power dispatch. As with many power systems, NI is under pressure to retire aging fossil fuel power plants, but without replacement capacity such as new conventional generation or new interconnectors having been constructed. Thus the ability to operate the power system at higher SNSP, thereby making greater use of indigenous wind resource and reducing reliance on import via interconnection would be particularly advantageous. Even with the anticipated growth of wind power generation by 2020 and an increase in the SNSP, NI is expected to have a deficit of generation capacity and will be a net importer of energy. This suggests that NI will have a generation capacity requirement in 2020.

IV. DISCUSSION

A realistic unit commitment and economic dispatch model is built in PLEXOS of the SEM to quantify the system generation costs, wind dispatch-down and the effect of grid constraints from the perspective of the NI TSO (i.e. SONI). The results of the study have shown that the total generation cost in NI decreases by 3.7%, mainly due to the 22.9% increase in wind generation, when the SNSP is increased from 65% to 75%. Also the total wind power dispatch-down is reduced from 24.7% to 7.5% when the SNSP is increased from 65% to 75%. This is a reduction to almost a third for an increase in the SNSP of 10%. The greatest reduction in wind power dispatch-down occurs in the NI districts with more installed wind power capacity such as 22, 11 and 16 experiencing a reduction of around 50% of wind power dispatch-down when the SNSP increases.

The analysis has clearly shown the benefits of increasing the SNSP to 75%, as in this case wind curtailment is eliminated for the week analysed, meaning that the SNSP constraint has zero-hours binding. Any remaining dispatch-down of wind is due to wind constraint. The TSO in NI could use the results obtained in this study to inform grid reinforcement prioritisation as installed wind power increases by 2020.

District 16 experiences significant wind constraint during the week analysed. District 13 is affected by the HVAC ROI-NI interconnector and priority dispatch constraint which determine its power flow. However, district 1 that belongs to the strongest part of the network does not experience any wind constraint.

Overall NI is shown to be a net importer of energy even in 2020 despite the large investment in wind power and grid reinforcement. The impact of planned grid reinforcements shows that net imports decrease by 8.1 GWh for the period analysed in 2020 when the SNSP increases from 65% to 75%.

This indicates that NI could use local grid nodal balancing at the district level more efficiently when increasing the SNSP limit as part of smart grid deployment.

The increase of SNSP brings new challenges and costs to the TSO, mainly due to the requirements to maintain security of supply. It is proposed that future work will examine the opportunity for demand response in the SEM using a unit commitment and economic dispatch model.

V. CONCLUSION

An equivalent power network of Northern Ireland has been built in a realistic unit commitment and economic dispatch model of the Single Electricity Market. The study shows that the total generation cost decreases by 3.7% for the week analysed, the dispatch-down of wind decreases by 17.2% and the net imports decrease by 28.3% for Northern Ireland when the system non-synchronous penetration limit increases from 65% to 75%. The implementation of the transmission network of Northern Ireland in the System Operator model has allowed the identification of districts where the dispatch-down of wind is significant for different values of system non-synchronous penetration limit. Some districts experience significant dispatch-down of wind, which in one case is over 44% for a system non-synchronous penetration limit of 65%. The model is an important planning tool for the system operator to decide where more stochastic generation could be added to the power network.

ACKNOWLEDGMENT

This work was supported by a Charles Parsons Energy Research Award, which is funded by the Science Foundation Ireland (SFI), award (06/CP/E002). The authors thank EirGrid, SONI and SEMO for the datasets provided and Energy Exemplar for the provision of the academic license of PLEXOS for power systems and support.

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