SPATIO-TEMPORAL ANALYSIS OF POSSIBLE WIND GENERATION OUTPUT REDUCTIONS FOR THE IRISH TRANSMISSION SYSTEM WITH A HIGH PENETRATION OF RENEWABLES

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Abstract

This paper outlines a modelling methodology utilised by EirGrid, the Irish Transmission System Operator, to apportion reductions in the electricity production of wind powered generators due to a variety of security of supply issues and localised transmission congestion. Studies addressing security of supply set a limit for non-synchronous generation such as wind, to between 50% and 75% of the total system generation (demand plus exports) over the period 2011-2022. The potential impact of a possible 75% maximum instantaneous wind penetration limit on the small, synchronous and relatively-isolated Irish transmission system by 2020 is assessed. Ireland is expected to achieve the majority of its 40% renewable target in electricity from wind and there will invariably be instances when the amount of wind generation will be greater than demand. This should also be seen in the context of transmission congestion where wind generation connects on a non-firm basis prior to completion of their deep assets. Both of these issues lead to reductions in the output of wind generators and these reductions are presented in this paper, together with the description of the innovative and novel methodology used to determine these reductions.

1. Introduction

According to the binding European Union targets for the year 2020, Ireland must produce 16% of its total final consumption from renewables in the electricity, heating and transport sectors [1]. As a means for achieving this, the Irish Government submitted their National Renewable Energy Action Plan (NREAP) to the European Commission in June 2010 [2], which re-affirmed the previously announced target of 40% of electricity production from renewable sources by 2020 [3]. The vast majority of this target, some 37% of the overall 40%, is expected to be sourced from wind powered generation, which is an economically feasible and abundant natural resource in Ireland. At the beginning of 2011, there was 1.4GW of wind generation plant connected to the Irish transmission and distribution systems, with a further 0.4GW of wind generation capacity in Northern Ireland. This study reflects the current Single Electricity Market (SEM) in Ireland and Northern Ireland, which treats both jurisdictions as a single entity in a production cost model yielding the optimal minimum cost commitment and dispatch. Although the operational details of all generators participating in the market are considered, only results pertinent to Ireland, spanning the period 2011 through 2022, are accounted for and presented in the analysis

In order to achieve the connection of large amounts of renewable in Ireland, a strategic Group Processing Approach (GPA) has been devised which assesses the connection of multiple generators in a single "batch". Generators are provided with firm access to the network by date order. The latest group processing scheme, known as Gate 3, is providing connection offers for 4,000MW of wind generation and 1,700MW of supporting conventional or small, renewable and low carbon generation capacity. This is in addition to Gates 1 and 2 which previously facilitated the connection of 0.4GW and 1.3GW of wind generation respectively.

EirGrid has already embarked on its long term transmission reinforcement strategy known as GRID25 [4]. The strategy was devised to support a sustainable and reliable power supply which simultaneously caters for future demand growth and the connection of renewable generation to the bulk transmission grid. This will be achieved through a series of asset upratings and refurbishments in addition to the development of necessary new infrastructure.

Furthermore, as generators in Ireland are permitted to connect to the transmission system in advance of the completion of the deep transmission reinforcement required, the Irish energy regulator know as the Commission for Energy Regulation (CER) instructed EirGrid [5] to provide an indication of any associated generator output reductions arising. The innovative analysis presented here uses a production cost modelling methodology to assess the impact on the output of wind powered generation due to transmission congestion as well as operational control measures for ensuring the safe, secure and reliable operation of the power system.

In order to maintain system integrity following the substantial increase in wind powered generation expected to connect to the Irish transmission system, rigorous operational and security constraints must be satisfied. These include system operating reserve requirements as well as a necessity for a minimum number of conventional generators to be synchronised at a system level for inertial support and at a provincial level for voltage support. As the number and magnitude of non-synchronous wind generation connecting to the system increases, limits are imposed to the maximum allowable instantaneous wind penetration. This will resolve the escalation of potential issues by ensuring an adequate frequency performance and dynamic stability. Indeed, the incorporation of these system operational controls within the model presents an upper bound to the quantity of wind that can be dispatched. Reductions in wind generation output due to various conditions are attributed to either "curtailment" or "constraints". These definitions are specified in the bullet points below:

- Curtailment refers to changes to wind generator output from the most economic dispatch to satisfy system operational requirements.
- Constraints account for reductions in wind generator output due to congestion on the transmission network.

The total wind generation output reduction is thus a function of the curtailment and constraint visible at the node to which the unit is connected.

As curtailment pertains only to non-transmission, system security aspects of the dispatch, it is normally allocated pro-rata across all wind generators with an equal bias. This inevitably leads to inefficiencies as locational signals are ignored. This novel methodology also considers the impact of transmission constraints when allocating curtailment. It ensures an optimal commitment and dispatch while maximising renewable generation. Potential power reductions due to extreme localised network congestion are treated concurrently as a subset of the system curtailment, enabling maximisation of renewable energy production on a global basis.

2. Co-optimal Methodology

The novel approach devised here for the determination and subsequent allocation of curtailment and constraints on a topological level is evolved from a chronological PROMOD IV production cost model. This software provides a full 8760 hour annual physical dispatch with objective functions to minimise production costs while respecting system constraints. An intrinsic Monte Carlo process ensures that the random forced outage probabilities and durations are conformed to when producing the commitment and dispatch schedule.

Operational standards are modelled using a deterministic N-1 line contingency criterion applied to a DC Security-Constrained Optimal Powerflow (SCOPF). This pre-empts any detrimental overloads in the possible event of losing a network element and derives a dispatch to avoid that scenario occurring. Any constraint arising from these contingencies will alter the congestion cost component of an affected node's Locational Marginal Price (LMP). It is worth noting that the All-Island SEM is not an LMP-based market. The LMP components are intrinsically calculated by the modelling tool when determining the optimal dispatch, but a further analysis of their magnitudes enables all generators with a similar impact on the constraint to share proportionally in any modifications to their output.

2.1 Previous treatment of curtailment and constraints

Previously, suggested nodal power injections were elucidated by EirGrid by a sequential two-step approach. The first step honours all system security obligations except transmission network and determines the amount of wind curtailment. When wind generation exceeds the residual demand, the methodology curtails wind generation on a pro-rata basis by output across all nodes. In the second step, network congestion is considered. This two-step approach incurs an over-estimation of the wind generation output reduction.

2.2 Novel methodology

The procedural flowchart outlined in Figure 1 indicates the workings of a novel co-optimised approach. A perfect wind foresight is presented to the stochastic unit commitment algorithm within the model to yield a least-cost security constrained optimal power flow. Any node that is subject to network congestion, where both curtailment and constraints are concurrent in that hour, will inherently have its nodal power injection reduced by the dispatch logic first. This pre-empts and diminishes the impact of unnecessary curtailment at other power insertion points elsewhere in the network that are not exposed to this congestion. The hours where a reduction in wind generation has occurred are then identified.

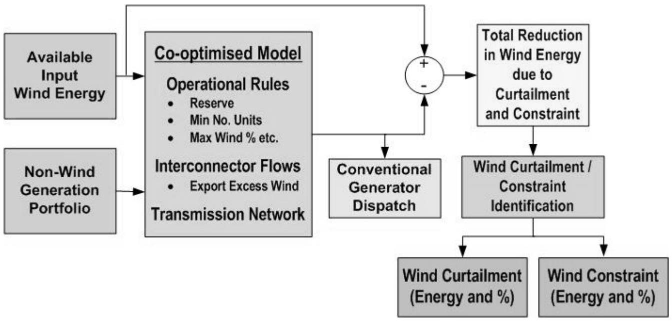

Figure 1: Flowchart depicting the co-optimised methodology.

2.3 Identifying the curtailment and constraints

The LMP is comprised of three components, namely the System Marginal Energy Cost (SMEC), the Marginal Cost of Losses (MCL) and the Marginal Cost of Congestion (MCC). Conceptually, these terms reflect the cost of supplying an increment of load at a specified location with reference to the price of power generated and its delivery. The middle term on the right hand side of the LMP Equation (1) refers to the MCL. This is denoted by λ times the loss sensitivity factor LF between nodes i and a reference and is not considered here. Only the SMEC term, λ, and the congestion component described by the summation expression in Equation (1) are required to discriminate between system curtailment and transmission constraints.

(1)

The shadow price μ refers to the change in cost of relieving a transmission constraint k by 1MW whereas the shift factor, S, is the powerflow sensitivity to the addition of 1MW at a node i on that constraint. The MCC is then calculated as the product of the shadow price times the powerflow sensitivity, summed for all K constraints. A non-zero MCC contribution indicates that congestion has occurred. As all wind generation nodes with identical MCC components on a given constraint in an hour should theoretically share any penalties arising equally, the sum of the total hourly energy reduction across this entire set of affected generators is reallocated in proportion to their original scheduled energy. Analogously, the algorithm will apply a pro-rata reduction to all wind generation plant if no transmission congestion occurs but curtailment is present.

The criteria for identifying the cause for any divergence between the final dispatched energy and the original assumed energy follow. Any instance where all nodes on the system exhibit an LMP equivalent to the wind energy price can be considered to be curtailment. Furthermore, curtailment is also credited to any occasion whereby the LMP at all wind injection points is set by the wind energy price, while all other nodes share some other identical LMP as established by the marginal unit. If all other non-wind nodes did not reflect a single LMP in the previous case, then congestion has occurred at this time since the LMPs are being generated by a number of marginal units. Although no reduction in wind output power is expected if all wind-connected nodes display an LMP that is not equal to the wind energy price, constraints are also observed should only some wind injection points meet this condition.

Although the reallocated dispatches are a linear combination of the SCOPF solution, it is prudent to iterate the procedure using the suggested wind generator outputs as an input. This will verify that the optimised dispatch is acceptable, otherwise further iterations may be required should any of the reallocated energy invite unforeseen spurious constraints.

3. Input Assumptions

The production cost model employed in this analysis assumes a realtime generator dispatch on a least cost basis with respect to the Short Run Marginal Costs (SRMC) of each unit. The SEM's 30 hour lookahead regime, uplift remuneration and capacity payment mechanisms are not considered. Calculation of the SRMC and the imposition of a carbon penalty of €36.90/tonne of CO_2 emitted results in the Merit Order indicated in Table 1. Characteristics specific to conventional generators such as forced outage rates, annual scheduled outage durations, start-up energy, reserve provision capabilities, ramping, emission and heat rates were all modelled in detail in conjunction with the merit order [6]. These were compiled using declared and historical statistical data on a per unit basis. In addition to the techno-economic merit order, certain generators deemed to have "priority dispatch" must also be dispatched when available. Plant attributed with this "Must-run" status includes renewables such as Hydro and Wind, indigenous Peat generators, and high-efficiency co-generation such as Waste-to-Energy or Combined Heat and Power (CHP) enterprises. Seasonal variations in fuel pricing are also considered within the model as fluctuations in the gas markets enable gas-powered plant to be priced more competitively against coal during the summer months.

Order dispatched	Generator Type
1	Priority Plant
2	Coal-fired steam
3	Combined-Cycle Gas Turbine
4	Peat-fired steam
5	Aero-Derivative Gas Turbine
6	Open-Cycle Gas Turbine
7	Oil-fired steam

Table 1: Merit Order utilised for production cost modelling.

Redispatch or even decommitment of conventional units serves as an important option to maintain system integrity during periods of intermittent wind while assuring ramping capabilities and reserve arrangements are effectively managed. The CER furnished EirGrid with a set of draft dispatch rules to govern scenarios where priority dispatch generation must be turned down. These guidelines specify that once the redispatch of the non-priority plant list has been exhausted, priority conventional generation must be turned down next followed by hydro units and finally wind generators. Further complexities developed when accommodating the priority conventional plant such as the significant opportunity costs associated with running boilers outside of CHP mode. Therefore, it was deemed appropriate to reduce the output from these units to their minimum stable capacity levels rather than decommit the units as per the objective principles. It is worth noting that the Ardnacrusha, Liffey, Lee and Erne hydro plant were modelled using monthly energy allocations following a peak-shave strategy.

3.1 Available Portfolio

Plant Type	Capacity (GW)
Combined Cycle Gas Turbine	5.2
Aero-Derivative Gas Turbine	1
Open-Cycle Gas Turbine	1
Coal-fired steam	1.2
Oil-fired steam	0.85
Peat-fired steam	0.35
Waste-to-Energy and CHP	0.28
Hydro (Run-of-river)	0.22
Pumped Storage	0.4
Small-scale renewables	0.25

Table 2: Hydro and Thermal generation portfolio in 2020

Although the assumed decommissioning of 1.1GW primarily of aging oil-powered units is accounted for in the analysis, the installation of anticipated gas and pumped-storage plant will offset any potential adequacy issues. Indeed, the total installed conventional generation capacity assumed to be available to the SEM by 2020 is 10.5GW, which more than accounts for the expected 7.7GW All-Island TER peak and 43TWh energy demand. This is primarily composed of gas plant, much of this it being high-efficiency Combined Cycle Gas Turbines (CCGT) or dynamic and fast-acting Aero-Derivative (ADGT) Gas Turbines which are complementary to supporting intermittent generation. The available conventional portfolio as anticipated in 2020 is indicated in Table 2. The 4 run-of-river hydro units and pumped-storage plant may serve to facilitate the wind through economic dispatch where possible. A further 0.25GW of renewable generation consisting of non-dispatchable embedded hydro and biomass generation was modelled using characteristic profiles pre-deducted from the hourly load.

Accounting for the spatial and temporally distinguished wind generator availabilities is achieved through a supplied hourly power series for each node. As EirGrid cannot speculate on the probable acceptance of offers outside of plant already connected or under contractual obligations to connect, all new wind generators eligible to receive an offer under the Gate 3 process [7] were integrated within the model on a pro-rata basis. This enabled three discrete scenarios of wind generator build-out to be analysed. These scenarios are as defined in Table 3; a High wind scenario (8175MW) whereby all wind farm developers avail of their offer, a Medium take-up of offers to connect wind (6815MW) and a Low connectivity of new wind (5490MW). The resolution of potential wind generation reductions is critically dependent on both the magnitude and distribution of the connected windfarms. The historical wind power data was synchronously recorded at 76 existing, geographically distributed windfarms in 2008 at a 15 minute resolution. This was amalgamated and normalised on a regional basis to form 8 unique wind profiles which are applied to the Group Processing Areas as indicated in Figure 2. These historical wind profiles were then used to produce future annual nodal profiles by scaling to the appropriate installed wind capacity levels, retaining any salient locational variations.

Area	High (MW)	Medium (MW)	Low (MW)	Capacity Factor (%)
A	822	712	605	**32.8**
B	1258	890	531	**30.2**
C	91	66	41	**28.6**
D	311	270	230	**28.1**
E	1725	1491	1263	**33.3**
F	185	152	120	**33.3**
G	251	213	176	**31.5**
H1	723	537	356	**28.6**
H2	321	293	267	**30.9**
I	24	17	10	**33.3**
J	783	517	258	**31.5**
K	81	57	33	**30.9**
NI	1600	1600	1600	**32.9**

Table 3: Total installed capacity per scenario studied for each Area in 2020 and average capacity factor.

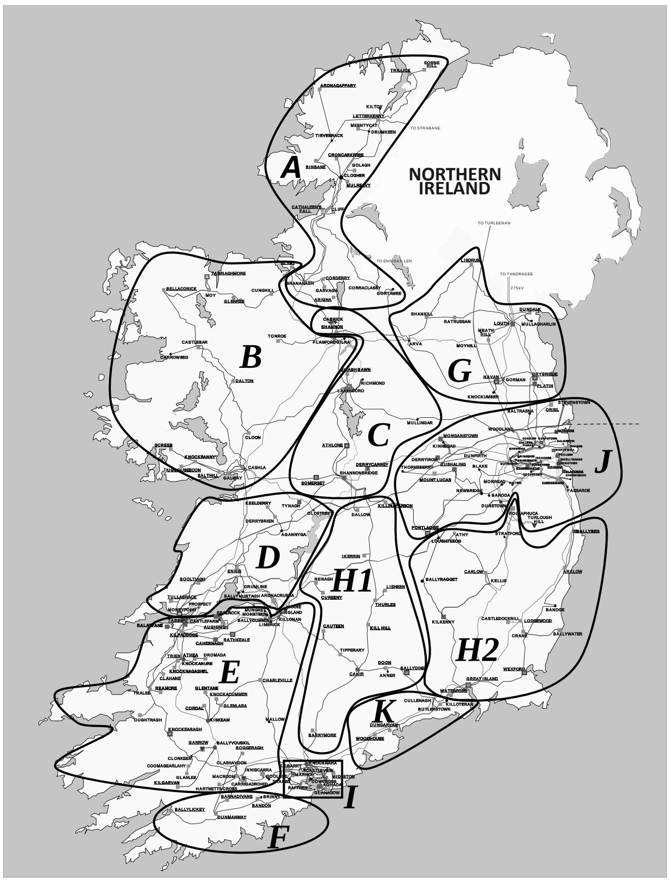

Figure 2: Group Processing Areas in Ireland.

3.2 Energy Demand and Transmission Infrastructure

The underlying Total Electricity Requirement (TER) peak and energy demand assumptions employed in the model were distilled from the TSO generation adequacy reports [8,9] that take into account the effects of the economic downturn. The effect on TER of improved efficiency metrics, the emergence of electric vehicles and adaptive consumer trends are acknowledged inherently. It was deemed prudent that the 2007 historical demand profile be utilised to project the future hourly system demand values since the more recent 2008 profile was severely skewed by the effects of the global recession. The forecasted profile was then scaled and distributed in accordance with the predicted hourly load centre profiles.

All planned and expected reinforcement works were added to the 2011 base network [10] on a yearly basis in accordance with Grid25 and industry standard lead times. The model therefore accounts for the remote locations and substantial distances from existing transmission grid infrastructure associated with the vast majority of the incoming wind farms as opposed to assuming a simpler smooth build-out regime. Significant localised quantities of generation capacity enter throughout the study in line with the estimated completion dates of their shallow connection assets. The inclusion of an optimised programme for regular annual line and station maintenance works spanning the study period was not practical. It was possible, however, to capture the various transmission outages associated with the Grid25 conductor upgrades within the methodology. Additionally, modelling of line losses was not explicitly designated since losses are captured intrinsically within the forecasted TER demand assumptions.

3.3 Ensuring Security of Supply

System security requirements are met through a series of operational rules. Although both Ireland and Northern Ireland are participants in the SEM, they are currently only connected via a 275kV double circuit and two 110kV connections controlled by phase-shifting transformers used for system support in contingency scenarios. Dynamic line restrictions help circumvent the potential for significant system disturbances in either jurisdiction. The commissioning of an additional interconnector between both SEM jurisdictions at 400kV is incorporated in the model from 2015, allowing for augmented intra-market powerflows.

The existing Moyle 2 x 250MW dual monopole HVDC interconnector and the planned 530MW East-West interconnector due to commission in late 2012 were included at the data freeze date, although the former was confined to an 80MW export limit due to contractual arrangements. Therefore, it was assumed that excess wind power, which would otherwise be curtailed, can be exported to Great Britain up to the 610MW interconnection capacity when economically feasible to do so. There was no provision for import trades within the model since they should not be expected to occur simultaneously in hours where wind generation output would be reduced due to curtailment.

The provision of operating reserve to account for a rapid reduction in wind or the abrupt loss of other plant is predominantly achieved by part loading generators in accordance with their technical capabilities. The total All-Island reserve requirement is sufficient to mitigate the risk of the loss of the largest in-feed unit. It was assumed that wind would not be curtailed to provide reserve in situ.

3.4 Facilitation of renewable integration

Limits on the maximum instantaneous wind penetration to ensure an adequate frequency performance and dynamic stability were derived after a suite of studies to examine the technical challenges with integrating significant volumes of asynchronous wind generation onto the power system of Ireland and Northern Ireland were performed [11,12]. This is achieved by enforcing the operational metric described in Equation (2):

(2)

This metric stipulates that the sum of the instantaneous wind production P_w and any imported power P_i be limited to a percentage θ of the total All-Ireland consumption at time t determined from the provision for demand P_d plus exported power P_e. It is anticipated that a number of prerequisite tasks will be completed in staggered batches over the period studied to enable the upper percentage of instantaneous wind penetration to be expanded such that $\theta \leq 75\%$. A biennial staircase transition is assumed to denote the completion of these preconditions extending from the current 50% limitation in 2011 to the envisaged 75% maximum bound in 2019. The expected measures to further the evolution of this operational limitation from 50% to 75% include:

- Rate of Change of Frequency (ROCOF) relay issues being resolved
- The conventional generation portfolio exhibiting a proven performance with regard to reserve provision and flexibility of operation
- Wind generators demonstrating appropriate controllability, advanced frequency response, reactive power and fault ride-through capabilities.
- The emergence of smart grid technologies with fast-acting network support devices and controllers.

4. Results and Discussion

The main output of the model is the resultant hourly wind generation output at each node after addressing the system security rules and transmission congestion. The results presented in Figure 3 illustrate the expected annual system average curtailment and constraints as determined by the methodology outlined above. The bottom graph reflects the overall situation and is a summation of both the curtailment and constraint constituents. As is evident, the results are heavily dependent on the level of connected wind, with the bulk expected in 2014 and the remainder facilitated by 2016.

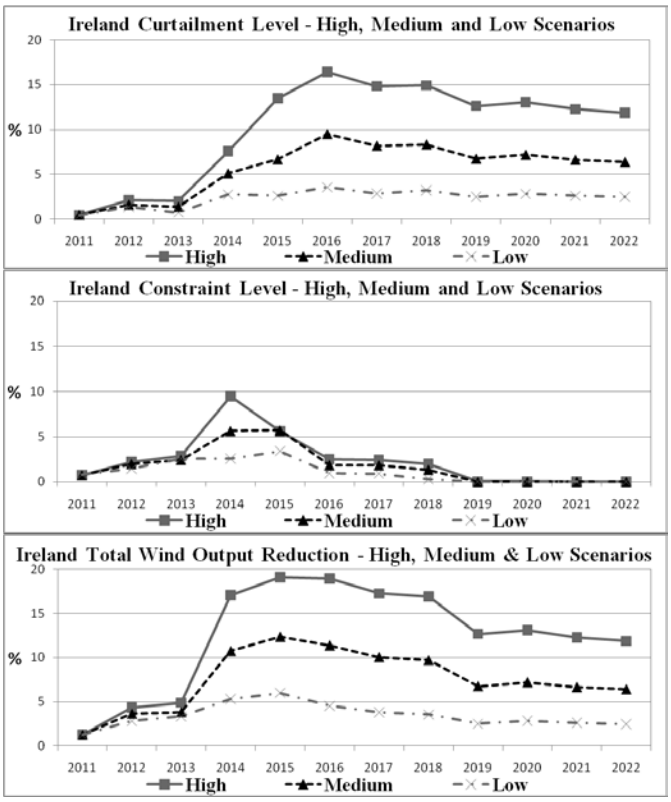

Figure 3: Average Irish Wind Generator output reductions due to System Curtailment (top) or Transmission Constraints (middle). A Combined total (bottom) is also shown.

The results presented in this analysis reflect a methodology which optimises the production of energy from wind-sourced generation. It may not be possible to replicate these figures on a real-time basis due to the computationally intensive nature of the modelling. Figure 3 shows that the transmission constraint levels for all three scenarios are relatively high in the early years before decreasing to negligible levels in the later years as the completion of network reinforcements associated with GRID25 take effect. In the high and medium scenarios, curtailment is notably higher than constraint from 2015 onwards and this shows the profound effect of security of supply issues on the system operation. An example of one of these issues is the available wind generation being greater than total system generation (demand plus exports) for a substantial number of hours per year. As the level of connected wind increases, it is also anticipated that the level of marginal curtailment increases in an according manner. A level of connected wind approximately halfway between the medium and high scenario is sufficient for Ireland to meet its 40% renewable target in the electricity sector after the resulting reduction is subtracted off the available wind generation. In otherwords, it is envisaged that there will be inherent spilling of wind energy on the system and targets of installed wind capacity for future years need to be viewed in such terms. One of the ways in which curtailment on the Irish system can be reduced is through increased interconnection, which allows more exports of wind at times when it would otherwise be reduced due to curtailment. Furthermore, the existing interconnection of 610MW between the East-West and Moyle interconnector is exporting at or near its full capacity for much of the time in the medium and high scenarios in 2020. Studies by EirGrid have shown that increasing the export capacity of the Moyle interconnector from 80MW to the 400MW line limit would have the effect of reducing curtailment levels shown above, as too would any further interconnection capacity.

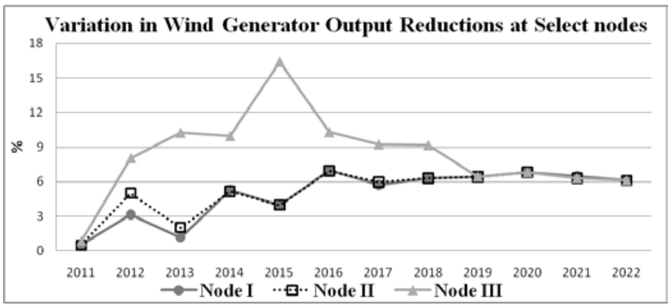

Figure 4: Net output reduction at 3 neighbouring wind nodes

It is worth noting that a vast variation may exist between the maximum and minimum nodal curtailment and constraint within Ireland. An indicative decomposition of 3 geographically close nodes within the same group processing region is revealed in Figure 4. Node I demonstrates the lowest overall reduction of the trio despite residing furthest from 220kV or 400kV infrastructure. Conversely, node III is connected at 220kV but suffers significantly due to the potential bottleneck should any of the neighbouring 220kV lines be lost. Additional 220kV reinforcements alleviate this risk in later years. It is also interesting that although nodes I and II share similar curtailment levels, constraints may be twofold higher at node II due to local transmission path congestion between I and II in the initial years. The completion of network reinforcements then cause a merging of all three plots, reflecting curtailment in the later years, when transmission congestion is no longer present.

5. Concluding Remarks

This paper has described a novel methodology which has been applied to the Irish power system over the period 2011 to 2022. The analysis accurately models the combined impact of localised system congestion and system-wide security of supply requirements on wind generation in an optimal manner. It avoids extraneous curtailment since wind generators co-located behind transmission congestion are constrained downwards on a nodal basis ahead of other plant in more favourable locations. Sample results have been presented and these show the dominance of wind reduction due to curtailment reasons over that caused by transmission constraint. The modelling methodology has been adopted for use in the Group Processing Approach for the issuance of connection offers. Prospective wind generators connecting to the system receive this information as part of their connection offer.

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