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The significance of interconnector counter-trading in a security constrained electricity market

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HIGHLIGHTS

- Interconnector counter-trading reduces the system marginal price in the SEM.
- Dispatch-down of wind power is reduced due to interconnector counter-trading.
- A 5% increase in the SNSP limit can reduce wind power dispatched-down by 50%.
- An increase in the SNSP limit and installed wind capacity reduces the SMP.

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ABSTRACT

Throughout the European Union there is an increasing amount of wind generation being dispatched-down due to the binding of power system operating constraints from high levels of wind generation. This paper examines the impact a system non-synchronous penetration limit has on the dispatch-down of wind and quantifies the significance of interconnector counter-trading to the priority dispatching of wind power. A fully coupled economic dispatch and security constrained unit commitment model of the Single Electricity Market of the Republic of Ireland and Northern Ireland and the British Electricity Trading and Transmission Arrangement was used in this study. The key finding was interconnector counter-trading reduces the impact the system non-synchronous penetration limit has on the dispatch-down of wind. The capability to counter-trade on the interconnectors and an increase in system non-synchronous penetration limit from 50% to 55% reduces the dispatch-down of wind by 311 GW h and decreases total electricity payments to the consumer by €1.72/MW h. In terms of the European Union electricity market integration, the results show the importance of developing individual electricity markets that allow system operators to counter-trade on interconnectors to ensure the priority dispatch of the increasing levels of wind generation.

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1. Introduction

The installed wind capacity in Europe has been steadily increasing and as of the end of 2013 it was 117.3 GW (EWEA, 2014). This significant quantity of wind capacity has meant a number of European Union (EU) countries were supplying more than 15% of their 2013 national demand from wind power (International Energy Agency, 2014). Holttinen et al. (2009) showed some EU countries had wind generation providing more than 50% of the instantaneous peak demand in 2008. The growing penetration of wind generation is resulting in wind power being dispatched-down due to curtailment and constraint issues. In 2012, the majority of wind dispatched-down in Spain (148 GW h) and Germany (385 GW h) was due to constraints on the transmission and distribution network (Steurer et al., 2014). Whereas in the SEM, 106 GW h of wind was dispatched-down with an estimated 62% from curtailment issues and 38% from network constraints (EirGrid, 2014). As the installed wind capacity in Europe is expected to increase to somewhere between 165 GW and 216 GW in 2020 (EWEA, 2014), the percentage of peak demand provided by wind generation will increase as will the dispatch-down of wind generation.

In order to promote the integration of high levels of renewable energy into electricity markets the European Commission (EC)

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adopted the renewable energy sources directive (European Commission, 2009). The directive stated system operators must give priority to renewable energy generators when scheduling the generator portfolio, as far as the system security permits. In the EU target model, the coupled day ahead market (DAM) implements the priority dispatching when determining the economic dispatch schedule and cross border trading on the interconnectors. The increasing levels of wind generation in the EU could result in periods where the DAM schedules wind generation to supply high percentages of instantaneous system demand leading to system security and stability issues (Foley et al., 2013). Such instances will result in the system operator modifying the DAM dispatch schedules and curtailing wind generation. The difference between the DAM schedules and the dispatch schedules produced by a system operator can be significant as seen in the results of Denny et al. (2010) and Mcgarrigle et al. (2013). Denny et al. (2010) used an unconstrained unit commitment model of the Single Electricity Market (SEM), similar to a DAM, which produced an economic dispatch schedule that resulted in very little wind curtailment and constraints. However, an analysis of the dispatch schedules by Mcgarrigle et al. (2013) showed when system operational constraints are applied in the SEM a significant amount of wind curtailment occurs. Only in suitable electricity markets do system operators have the ability to counter-trade the interconnector flow when ensuring priority dispatching of renewable generation (Entso-E, 2012). A suitable electricity market is one that allow system operators to trade upwards and downwards on both sides of the interconnector, such as the Balancing Market in Nordpool (Entso-E, 2012). Counter trading is when the system operator trades counter to the flow on the interconnector. Interconnector counter-trading could reduce the amount of wind curtailed in system constrained electricity markets by reducing imports or increasing exports during periods of wind curtailment.

The hypothesis of the work is to examine the importance of interconnector counter-trading to a system operator in a security constraint electricity market. In the EU target model the interconnector schedules are determined through the unconstrained day ahead market. When the system operator applies the system operating constraints the ability to counter-trade the interconnector flows could be crucial. The Single Electricity Market (SEM) of the Republic of Ireland and Northern Ireland is used as a case study as the SEM had one of the highest penetrations of wind power supplying electricity demand in Europe in 2013 (International Energy Agency, 2014). It is a small electricity market where cross border interconnections are important to the system stability, security of supply and reducing price volatility (Nepal and Jamasb, 2012). More importantly the SEM currently has an agreement to counter trade on the interconnectors with the system operator of the British Electricity Trading and Transmission Arrangement (BETTA) market (EirGrid, 2013a). The test system developed in this paper is the first of its kind, known to the authors, to model both the day-ahead and dispatch schedules through a combined economic dispatch unconstrained unit commitment day-ahead model and security constrained unit commitment intra-day model. The paper presents the impact that interconnector counter-trading in the SEM in 2016 has on the dispatch-down of wind, interconnector scheduling and the wholesale price of electricity. A 2016 model was analysed as the SEM market structure will change in 2017 to comply with the EU target model. There is limited research into the I-SEM structure as it is still in development. This research highlights the importance of implementing interconnector counter-trading into the new I-SEM. In a wider EU context, the results from this work highlight the requirement to develop the necessary European market structure to accommodate system operator to system operator interconnector counter-trading in the balancing market. This paper is organised as follows. Section one introduces the issue of wind power dispatch-down and interconnection in the SEM. Section 2 discusses the test system, validation and methodology used in this study. Section 3 presents the results and discussions and Section 4 concludes the paper.

2. Methodology and test system

2.1. Test system background and architecture

A test system of the SEM in 2016 was built to accurately analyse wind power generation and dispatch-down. The operation of the SEM is an iterative process between SEM operator (SEMO) and the system operators, as illustrated in Fig. 1.

Twenty four hours before the intra-day plant owners bid into the SEM commercial offer data and technical offer data for each half hour interval in the intra-day. The commercial offer data and technical offer data contain price/quantity bids, start-up costs and no load costs. SEMO uses this generator data and produces the most economic dispatch (ED) schedule. The model used to develop the ED is an unconstrained unit commitment (UUC) model as it does not include transmission constraints. This model is replicated by the SEM Ex-Ante model in Fig. 1. The trading and settlement code for the SEM states the scheduling of the interconnectors must be performed in the Ex-Ante market 24 h before the trading period (SEMO, 2014a). Therefore the most important output of the ED is the interconnector flows across the Moyle and East–West (EW) interconnectors.

The purpose of the system operator is to ensure system security and stability of the SEM and to achieve this the system operator applies system operating constraints (SOCs) and reserves requirements to the electricity system. The constraints ensure system inertia and frequency are always maintained by scheduling a number of specific generators on at key locations in the SEM. The reserve constrained unit commitment/security constrained unit commitment (RCUC/SCUC) model of the test system replicates the

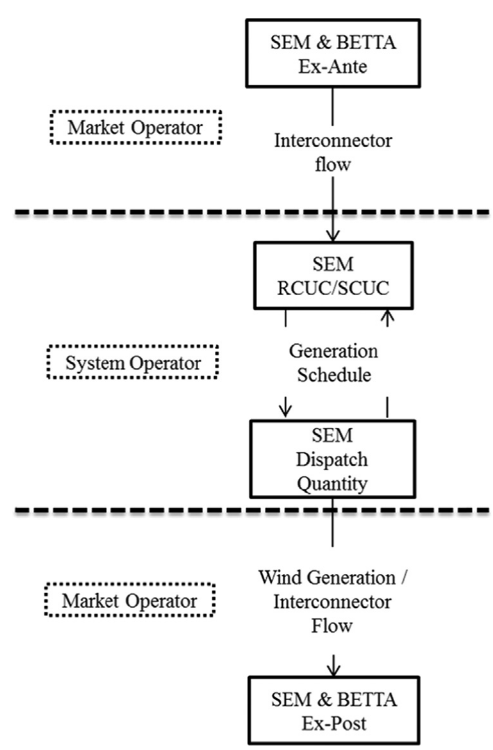

Fig. 1. SEM and BETTA test system.

Ex-Ante	RCUC/SCUC	Dispatch Quantity	Ex-Post
Inputs: 30 hour wind and load forecast No operational constraints No reserves Generator properties	Inputs: 30 hour wind and load forecast Operational constraints Reserves Generator properties	Inputs: 2 hour wind and load forecast Operational constraints Reserves Generator properties Generation per unit	Inputs: No operational constraints No reserves Generator properties Dispatched wind generation Actual Load
Model settings: Rounded Relaxation Xpress Solver Relative Gap 0.05% Day steps 6 hour look ahead 1 hour intervals	Model settings: Mixed Interger Programming Xpress Solver Relative Gap 0.5% Day steps 6 hour look ahead 1 hour intervals	Model settings: Mixed Interger Programming Xpress Solver Relative Gap 0.5% Day steps 2 hour look ahead 1 hour intervals	Model settings: Rounded Relaxation Xpress Solver Relative Gap 0.05% Day steps 6 hour look ahead 1 hour intervals
Outputs: Interconnector flow	Outputs: Generation Schedule	Outputs: Dispatch Schedule for generators	Outputs: SMP

Fig. 2. Model characteristics.

activities of the system operator. The RCUC/SCUC analysis is run 24 h before the trading period, similar to the Ex-Ante analysis. The RCUC/SCUC model is run in parallel with a dispatch quantity (DQ) model. The main difference between the models is that the RCUC/SCUC has a wind forecast profile whereas the DQ has a wind generated profile. The two models are 'interleaved' which means the DQ model re-optimises the RCUC/SCUC dispatch schedules taking into account the new DQ wind generation profile. The addition of the DQ model enables the inclusion of wind and load forecast error to the electricity system. The optimisation settings and scenarios of each model in the test system are highlighted in Fig. 2.

The system operators manage system stability and ensure supply matches demand by rescheduling generating units and lastly priority dispatch units. The system operators in the SEM have an order list of units to be rescheduled and interconnector counter-trading is highlighted as the first action to be carried out to ensure priority dispatching (CER and NIAUR, 2011). Interconnector counter-trading involves rescheduling the day-ahead interconnector flows before the trading period. Counter-trading provides the system operator with the ability to reduce imports and increase exports in order to reduce the amount of wind being dispatched-down. Oggioni and Smeers (2013) state "grid lines are overloaded and TSOs have to restore grid feasibility by reshuffling power flows among energy market participants (producers/consumers)". This is the so called counter-trading or re-dispatching function. In order not to mix up the definitions used by SEM system operator and Oggioni and Smeers (2013), in this research counter-trading is used to discuss the changing of interconnector schedules from the energy market to ensure priority dispatching. Whereas the re-dispatching of generators is performed by the RCUC/SCUC model when the system operating constraints are applied.

The last step in the operation of the SEM is replicated by the Ex-Post model. The market operator UUC model (Ex-Post) uses the DQ wind generation and interconnector flows and re-optimises the ED to calculate the system marginal price (SMP) for the SEM. The SMP from the Ex-Post is paid to the electricity generators and charged to the electricity suppliers. Constraint payments, capacity payments and Renewable Energy Feed-In Tariff (REFIT) payments are added to the SMP. Constraint payments are payments or charges to generators that are constrained off/on due to the SOCs. Capacity payments are for generating units that provide available capacity. The annual capacity payment sum was assumed to be €574,953,600, the same as in 2015 (CER and NIAUR, 2014). The REFIT is a subsidy payment for renewable energy generating units.

The combination of both the system and market operation must be modelled to accurately investigate any scenario on the SEM. The results from the RCUC/SCUC and DQ models are used to analyse system operation impacts whereas results from the Ex-Ante and Ex-Post models are used to analyse market implications. In the SEM the dispatch-down of wind is broken into 'constrained' and 'curtailed'. Wind constrained occurs when interconnectors and transmission lines are operating at full capacity and generation from wind farms is reduced. Wind curtailment occurs when wind generation is reduced so that the system operator can ensure system security through system operating constraints such as a minimum number of generators, generators operating at minimum stable levels (MSLs) and a system non-synchronous penetration (SNSP) limit.

2.2. SEM and BETTA unit commitment modelling

The SEM model was built using 2013 datasets for the base case (CER and NIAUR, 2013), but before extending the model to 2016 it was fully validated against real data from (SEMO, 2014b). The SEM is a wholesale mandatory electricity pool market consisting of 77 different generating units buying and selling into a single node. The market operator models (ExAnte and Ex-Post) of the SEM test system were built as a single node. The system operator models (RCUC/SCUC and DQ) separated the SEM into two nodes, the Republic of Ireland and Northern Ireland, with a tie-line (North–South) connecting both nodes. All the generators were attached to their respective node. The models included two interconnectors to the BETTA market, the Moyle and EW. The Moyle interconnector was between Northern Ireland and Scotland, and the EW interconnector linked Ireland to Wales. Both interconnectors had a ramp rate of 300 MW/h (SEMO, 2014c). A wheeling charge of €3/MW h was applied to both interconnectors. The reason for the two nodes in the system operator models is to replicate the running of the two electricity systems on the island by the difference system operators, EirGrid in the Republic of Ireland and SONI in Northern Ireland.

The validation results of the market and system operation

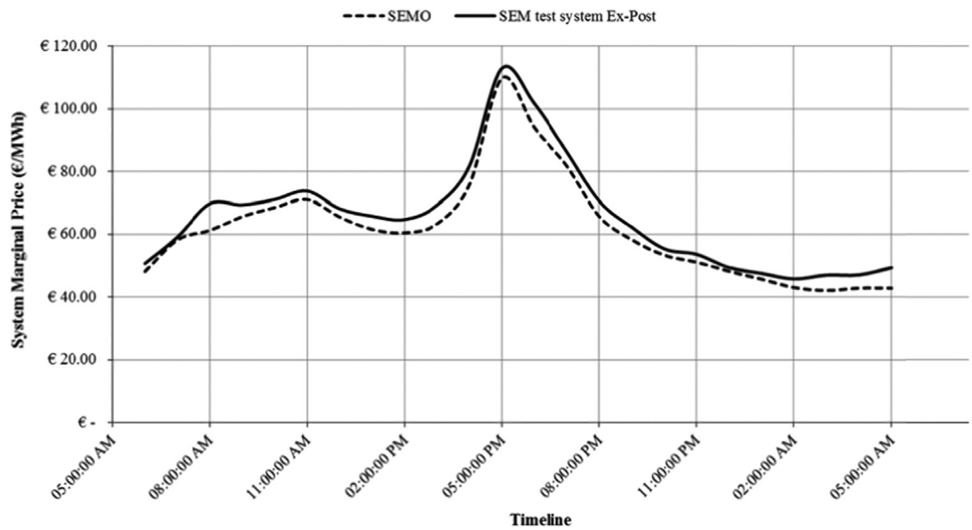

Fig. 3. 2013 SEM market model validation.

Table 1
SEM system model validation.

Unit	DQ – 2011 DQ (GW h)	SEMO (GW h)	% Difference	GW h difference
DB1	2628.55	2362.95	10%	265.60
C30	2481.62	2325.20	6%	156.40
HN2	1959.04	1968.63	−1%	−9.60
PBC	994.01	1365.92	−37%	−371.90
TYC	968.43	920.51	5%	47.90
HNC	1019.55	1270.53	−25%	−251.00
MP3	606.87	1108.68	−83%	−501.80
MP1	986.43	970.85	2%	15.60
B32	805.42	859.29	−7%	−53.90
B31	885.41	872.13	2%	13.30
MP2	735.5	981.03	−33%	−245.50
ADC	2139.38	1090.05	49%	1049.30
WG	2060.82	1956.55	5%	104.30
ED1	709.7	662.52	7%	47.20
LR4	605.21	609.28	−1%	−4.10
WO4	434.49	431.15	1%	3.30
SK4	530.58	543.23	−2%	−12.70
SK3	457.22	471.04	−3%	−13.80

models are shown in Fig. 3 and Table 1. The average SMP, calculated from the Ex-Post model, for each hour of the day was calculated and compared to the real results published on the SEMO website (SEMO, 2014b). There is a close correlation between the model results and the real data across all hours of the day. The average SMPs for the year for the model and published SEMO data were €65.74/MW h and €61.77/MW h respectively. A comparison of the generation for the top 15 generating units from published SEMO data and the DQ model is shown in Table 1. The average for the absolute error of the top 15 generating units is 15.4%, see Eq. (1). There is also an element of human interaction from the system operator when determining the DQ which can affect the accuracy of the DQ results

$$\frac{\sum_{j=1}^{N}\left(\left|DQ_j - SEMO_j\right|\right)}{N} \tag{1}$$

where DQ_j is the total dispatched generation in 2013 produced by the test system for generator j, $SEMO_j$ is the total dispatched generation in 2013 from SEMO for the $generator_j$, N is the number of generators.

The BETTA test system was developed using the National Grid's Electricity 10 Year Statement that split Great Britain into 17 'zones', Z1 to Z17 (National Grid, 2013). Each 'zone' has a node with all the generating units in that zone connected to the node. All 127 generators are modelled (National Grid, 2014a). The nodes were connected to each other through lines that represent the transmission lines of the National Grid in the BETTA. National Grid's seven year statement identified boundary interfaces between the zones and the max capacities of each boundary interface (National Grid, 2011). The schematic of the combined BETTA and SEM test system is shown in Fig. 4. The BETTA has two models, the Over the Counter (OTC) model that replicates the forward trading and the Balancing Market that replicates the spot market. The two differences between both models are the look ahead and the removal of the bilateral constraint, which is discussed in Section 2.5. The OTC model of the BETTA is combined with the Ex-Ante of the SEM and the Balancing Market is combined with the Ex-Post, as illustrated in Fig. 1. The validation of the BETTA model involved comparing the generation from the Balancing Market model with published data from ELEXON (2014), the BETTA market operator. Table 2 highlights the generation by fuel type for the OTC model, Balancing Market model and the ELEXON data. The addition of the balancing market enabled the inclusion of wind and load forecast error on BETTA generation. The Balancing Market model has good correlation with ELEXON. The private information for each power plant such as start-up costs, heat rates and variable operating and maintenance (VOM) charges are difficult to obtain, as a result it is likely to have some degree of difference between the results from the test system and published data. VOM charges are used to recover maintenance costs from wear and tear and values for the BETTA model were sourced from Mcdonald (2010).

2.3. Baseline test system

The 2016 SEM and BETTA generator portfolio load demands were estimated using datasets from National Grid (2014a) and EirGrid and SONI (2014b). The installed wind capacity of the SEM in 2016 was forecasted to increase to 2827 MW and 695 MW for the Republic of Ireland and Northern Ireland respectively. The BETTA onshore and offshore wind was separated into zones as defined by National Grid's Seven Year Statement study zones (National Grid, 2013). The capacity factor for each wind zone was determined from (DECC, 2013). The National Grid's wind generation time series for 2011 was scaled, accordingly, to achieve the 2016 targets (National Grid, 2013). The time series data was used as BETTA onshore wind. The capacity factor of each zone is

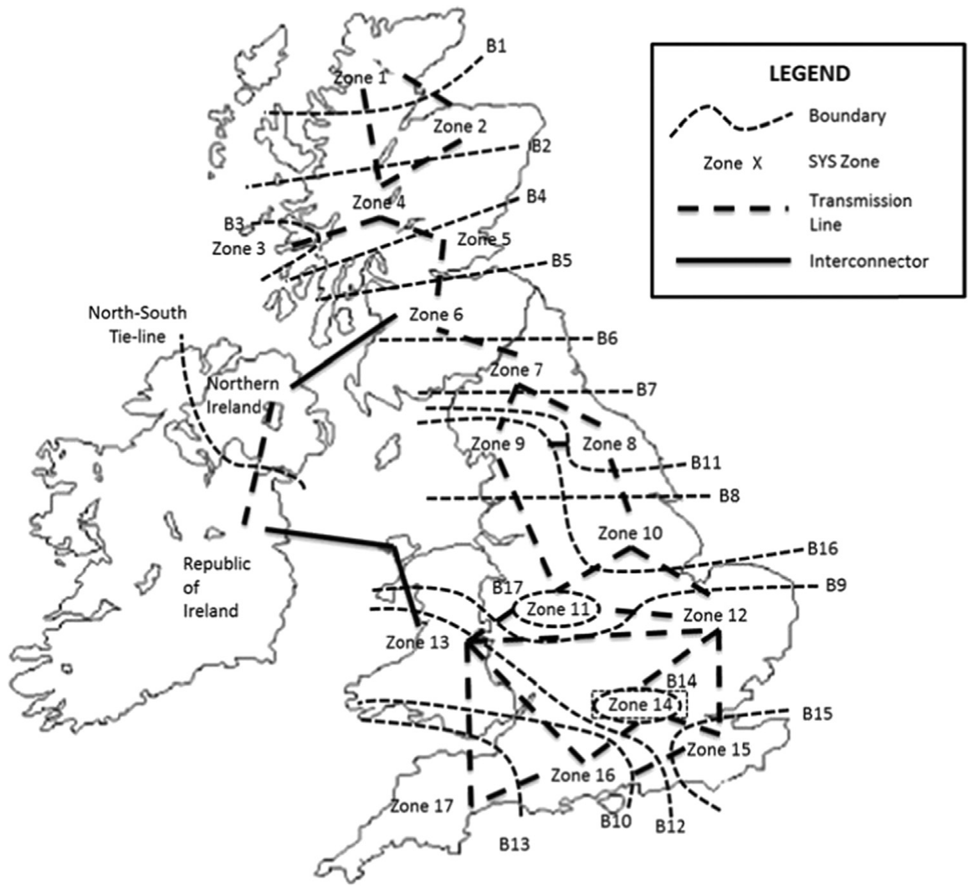

Fig. 4. SEM and BETTA test system.

Table 2
BETTA validation.

	ELEXON	OTC market	Balancing market
Gas (CCGT)	126,958	121,078	126,412
Gas (OCGT)	24	1823	2008
Oil	12	29	29
Coal	103,459	102,174	100,040
Nuclear	64,733	68,766	66,002
Pumped Storage	2917	1102	–
GB Hydro 2011	3693	3593	3517
GB Wind 2011	9716	9428	9202
Total	311,512	307,992	307,210

different therefore the wind data files were adjusted accordingly (DECC, 2014). Foley et al. (2009) showed that the BETTA onshore wind data time lagged the SEM onshore wind data by two hours. The SEM offshore wind data preceded SEM onshore by one hour. Offshore wind in the BETTA was time adjusted by an hour depending on whether the zone is to the east or west of Great Britain. Any zone with offshore wind to the east time lagged BETTA onshore wind by an hour and any zone to the west proceeded BETTA onshore wind by an hour.

2.4. Objective function

A similar set-up to Higgins and Foley (2014) was used for this research. The test system was developed using Energy Exemplar's PLEXOS for Power Systems version 6.301R02 (Energy Exemplar, 2013) and the Xpress optimiser (Fico Xpress Optimiser, 2013). The optimisation settings for each model of the test system were different, as shown in Fig. 2. The optimiser aims to minimise the objective function (Deane, 2012) shown in Eq. (2). The objective function considers the start-up costs, no load costs, variable operation and maintenance charge, and use of system charge for each plant. The objective function is conditional an energy balancing constraint (Eq. (3)) and a number of unit operational constraints; ramping constraints (Eq. (4), Eq. (5)), max capacity (Eq. (6)) and minimum stable generation (Eq. (7)) constraints

$$\min \sum_{t\in T}\sum_{j\in J}\begin{pmatrix} \mathrm{SC}_{jt}\cdot \mathrm{US}_{jt} + \mathrm{NLC}_{jt}\cdot \mathrm{UG}_{jt} + \left(\mathrm{VOM}_{jt} + \mathrm{UoS}_{jt}\right)\cdot P_{jt} \\ + \mathrm{PC}_{\mathrm{jt}}\cdot P_{jt} + \mathrm{PenLL}\cdot \mathrm{UE}_{jt} + \mathrm{PenLL}\cdot \mathrm{RES}_{jt} + \mathrm{PDE}\cdot \mathrm{ExE}_{t} \end{pmatrix} \tag{2}$$

$$\sum_{t\in T}\sum_{j\in J}\left(P_{jt} - \mathrm{Pload}_{jt} + \mathrm{UE}_t\right) = D_t \tag{3}$$

$$P_{jt} - P_{jt-1} - \mathrm{MRU}_{jt}\cdot \mathrm{UG}_{jt} \le 0 \tag{4}$$

$$P_{jt} - P_{jt-1} + \mathrm{MRD}_{jt}\cdot \mathrm{UG}_{jt} \ge 0 \tag{5}$$

$$\left(P_{jt} - \mathrm{Pmax}_{jt}\right)\cdot \mathrm{UG}_{jt} \le 0 \tag{6}$$

$$\left(P_{jt} - \mathrm{MSL}_{jt}\right)\cdot \mathrm{UG}_{jt} \ge 0 \tag{7}$$

where t indexes time periods in chronological order $t=1,\ldots,T$, j indexes generators in chronological order $j=1,\ldots,J$, SC_{jt} is the start cost of unit j in period t, US_{jt} is a binary quantity representing if unit j has started the period before t, NLC_{jt} is the no load cost of unit j, UG_{jt} is a binary quantity representing the generating status of unit j, VOM_{jt} is the variable operation and maintenance charge of unit j, UoS_{jt} is the Use of system charge for generation of unit j, PC_{jt} is the production cost of unit j, P_{jt} is the power output of unit j, PenLL is the penalty for loss load, UE_t is the unserved energy in period t, RES_t is the reserve not met by unit j, PDE is the penalty for energy that is dumped, ExE_t is the excess energy of unit j, $Pload_{jt}$ is the pump load of unit j, Dt is the system demand, MRU_{jt} is the maximum ramp up rate of unit j, MRD_{jt} is the maximum ramp down rate of unit j, $Pmax_{jt}$ is the power output of unit j and MSL_{jt} is the power output of unit j.

The BETTA test system had a constraint included that requires the 'Big 6' energy companies (i.e. Centrica, EDF, E.ON, RWE, Scottish Power and SSE) in the BETTA to attempt to fulfil their supply demands from their own generator portfolio and if they cannot a penalty price is accrued. If the following constraint was violated than a penalty price was charged

$$\sum \left(\mathrm{CompGen}_i\right) - \left(\mathrm{Load}_{BETTA}\cdot \mathrm{MS}_i\right) \geq 0 \tag{8}$$

where $CompGen_i$ is the total generation for company i, $Load_{Betta}$ is the system demand for the BETTA and MS_i is the market share of demand for company i. Munoz and Bunn (2013) identified a 20% mark-up for generating units to replicate the market behaviour, however in this study the above constraint and a 5% mark-up were modelled. The gaming in the BETTA market is difficult to replicate and therefore the assumptions described are attempt to predict the marginal pricing of the BETTA market.

2.5. System operating constraints and reserve requirements

In 2012, the SEM system operators recorded periods when 50% of system demand and 38% of daily electricity demand were met by wind generation (EirGrid, SEMO, SONI, 2012). The system operators established the SNSP limit to maintain system stability by restricting the amount of renewable generation on the system. The SNSP is a measure of the non-synchronous generation on the system at any time. It is a ratio of non-synchronous generation (i.e. onshore wind, offshore wind, wave and tidal) and imports to demand and exports. In 2011, the SNSP limit was expected to be set at 65% by 2017 and 75% by 2020 (EirGrid, SONI, SEMO, 2013b). However, the most recent information from the system operators is the SNSP limit may be set at 55% by 2017 (SEM Committee, 2014). Mcgarrigle et al. (2013) also showed that a low SNSP limit can have significant impacts on wind curtailment in the SEM in 2020. The difference between 75% and 60% in SNSP limit was shown to increase wind curtailment from 7% to 14%. A study by the system operators in Ireland found a maximum 5% wind curtailment was desired in the SEM to ensure a system security and reliability (EirGrid and SONI, 2011). The formulation for SNSP is

$$\frac{\mathrm{Non-synchronous}_{gen} + \mathrm{Imports}}{\mathrm{Demand} + \mathrm{Exports}} \leq 55\% \tag{9}$$

The system operators in the SEM have developed a number of other constraints to ensure a certain level of system inertia and frequency across the Republic of Ireland and Northern Ireland. The SOCs for Northern Ireland are system stability (Eq. (10)), replacement reserve (Eq. (11)), Northwest generation (Eq. (12)), Kilroot generation (Eq. (13)), Ballylumford generation (Eq. (14)). The SOCs for the Republic of Ireland are system stability (Eq. (15)), replacement reserve (Eq. (16)), Dublin generation (Eq. (17)), Dublin North generation (Eq. (18)), Dublin South generation (Eq. (19)), Southwest generation (Eq. (20)), Cork generation (Eq. (21)) and Moneypoint (Eq. (22))

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 3 \tag{10}$$

$$\sum_{t \in T} \left(\mathrm{PSOC}_{jt}\right) \geq 211 \tag{11}$$

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 1 \tag{12}$$

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 2 \tag{13}$$

$$\sum_{t \in T} \left(\mathrm{PSOC}_{jt}\right) \leq 1344 \tag{14}$$

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 5 \tag{15}$$

$$\sum_{t \in T} \left(\mathrm{PSOC}_{jt}\right) \leq 493 \tag{16}$$

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 2 \tag{17}$$

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 1 \tag{18}$$

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 1 \tag{19}$$

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 2 \tag{20}$$

$$\sum_{t \in T} \left(\mathrm{PSOC}_{jt}\right) \leq 1100 \tag{21}$$

$$\sum_{t \in T} \left(\mathrm{UGSOC}_{jt}\right) \geq 1 \tag{22}$$

where $UGSOC_{jt}$ is a binary quantity representing the generating status of the unit j listed for system stability, replacement reserve, north west generation, Kilroot generation, Ballylumford generation, Dublin generation, Dublin North generation, Dublin South generation, Southwest generation, Cork generation or Moneypoint and $PSOC_{jt}$ is the power output of unit j listed for system stability, replacement reserve, north west generation, Kilroot generation, Ballylumford generation, Dublin generation, Dublin North generation, Dublin South generation, Southwest generation, Cork generation or Moneypoint.

The system operators use a number of system services to maintain system security such as operating reserves, replacement reserve and steady-state reactive power (EirGrid, 2014). In this test system the operating reserves and replacement reserves were modelled. The primary (Eq. (23)), secondary (Eq. (24)), tertiary 1 (Eq. (25)) and tertiary 2 (Eq. (26)) operating reserves were modelled with a static value of 75% of the largest all island in-feed, which is the EW interconnector (500 MW). A maximum reserve response for each generator was applied depending on the max capacity of the generator. A negative reserve of 50 MW and 100 MW for Northern Ireland and the Republic of Ireland respectively was included in the RCUC/SCUC models of the SEM

$$\sum_{t \in T} (RES_{jt}) \geq 375 \tag{23}$$

$$\sum_{t \in T} (RES_{jt}) \geq 500 \tag{24}$$

$$\sum_{t \in T} (RES_{jt}) \geq 50 \tag{25}$$

$$\sum_{t \in T} (RES_{jt}) \geq 100 \tag{26}$$

where RES_{jt} is the operating or negative reserve provide by unit j.

The transmission line constraints for the BETTA were applied through boundary interfaces between the different zones (National Grid, 2011). The BETTA system operator, National Grid, produces a yearly report on the short term operating reserve (STOR) highlighting the units that provide STOR by fuel type and quantity (National Grid, 2014b). National Grid states the quantity of STOR required is approximately 2300 MW with a minimum value of 1800 MW (National Grid, 2014b). The reserve constraint was modelled through Eq. (27)

$$1800 \leq \sum_{t \in T} (RES_{jt}) \leq 2300 \tag{27}$$

2.6. Methodology

A total of 13 scenarios were developed to examine the impact interconnector counter-trading had on the dispatch-down of wind in 2016, as listed in Table 3. Scenarios 1–9 were used to examine the impact of the SNSP limits and installed wind capacity (IWC) had on the dispatch-down of wind, interconnector counter-trading and the SMP. Scenarios 1–3 and 10–12 were compared to determine the effect the Moyle interconnector capacity could have on the SEM. Scenario 2 and scenario 13 were compared to determine the impact counter-trading had on the system and market operations.

EirGrid et al. (2014) identified locations on the island where network constraints are occurring that result in the dispatch-down of wind. The test system used in this research is a unit commitment model that does not include the outages and overloading effects of the transmission and distribution network when analysing wind constraints. Since the network constraints are not recorded the amount of wind constrained could be slightly underestimated. The amount of wind curtailed could be slightly overestimated as wind power could be network constrained before the SNSP limits binds. The wind constrained in this work is only from congestion on the interconnectors.

Table 3
List of scenarios.

Scenario	Description
1	IWC=3522 MW/SNSP limit=50%/Moyle interconnector=430 MW
2	IWC=3522 MW/SNSP limit=55%/Moyle interconnector=430 MW
3	IWC=3522 MW/SNSP limit=60%/Moyle interconnector=430 MW
4	IWC=3738 MW/SNSP limit=50%/Moyle interconnector=430 MW
5	IWC=3738 MW/SNSP limit=55%/Moyle interconnector=430 MW
6	IWC=3738 MW/SNSP limit=60%/Moyle interconnector=430 MW
7	IWC=4022 MW/SNSP limit=50%/Moyle interconnector=430 MW
8	IWC=4022 MW/SNSP limit=55%/Moyle interconnector=430 MW
9	IWC=4022 MW/SNSP limit=60%/Moyle interconnector=430 MW
10	IWC=3522 MW/SNSP limit=50%/Moyle interconnector=250 MW
11	IWC=3522 MW/SNSP limit=55%/Moyle interconnector=250 MW
12	IWC=3522 MW/SNSP limit=60%/Moyle interconnector=250 MW
13	IWC=3522 MW/SNSP limit=55%/Moyle interconnector=430 MW (No interconnector counter-trading)

3. Results and discussion

3.1. Dispatch-down of wind

The total amount of wind dispatched-down for scenario 2 by hour of the day is shown in Fig. 5. Scenario 2 was examined as it is expected to be the most likely to occur as the installed wind capacity in 2016 is expected to be 3522 MW and the system operators have predicted the SNSP limit will be 55%. The dispatch-down of wind was broken into wind constrained due to the Moyle and EW interconnectors operating at full capacity and wind curtailed due to the MSLs of the scheduled generators and the SNSP limit. Some of the SOCs, such as the system stability and South West generation, require a minimum number of generators to be on load to provide system security through inertia and frequency control. The system operators have the choice to select from a list of generators to provide the SOCs. Therefore at some periods the minimum number of generators might consist of different generators. For scenario 2, the average MSL of the minimum number of generators is 1435 MW, with a maximum and minimum of 1719 MW and 1356 MW. From 12 am to 4 am the average system demand is approximately 3108 MW, with a minimum of 2408 MW. The difference between the system demand and the MSLs results in an average of 1400 MW of demand that wind generation and interconnector imports can supply. Fig. 5 illustrates from 12 am to 4 am the minimum number of generators that are operating at their MSLs, the system demand is at its lowest for the day and the interconnectors have been counter-traded to schedule as much wind generation as possible, however wind generation still has to be curtailed. The system operator is attempting to introduce new system services that will improve system security and remove a number of SOCs which should reduce the amount of wind curtailment during these periods (EirGrid, SEMO, SONI, 2012).

Outside of 12 am to 6 am the SNSP limit is the most influential factor to the dispatch-down of wind. At periods where wind generation is to be dispatched-down the priority dispatch process reduces peat generators to their minimum stable levels, hydro generation is reduced, the interconnectors are counter-traded from their Ex-Ante schedule and the last step is to reduce wind generation. The wind curtailed due to the SNSP limit occurs when the priority dispatch process has already taken place and the last option is to reduce wind generation.

Previously the system operator could not change the day-ahead interconnector schedule it received from SEMO, see Ex-Ante in Fig. 1. However, the system operator now has the ability to counter-trade an interconnector schedule once the ramp rate of 300 MW/h is not exceeded in either direction. The system operator can only counter-trade when priority dispatching is required.

Scenario 2 results in 172 GW h of wind being dispatched-down which equates to 2.9% of wind available. The ability of the system operator to counter-trade the Ex-Ante interconnector schedule reduces the dispatch-down of wind by a maximum of 855 GW h. It has been identified by the system operator that anything above 5%

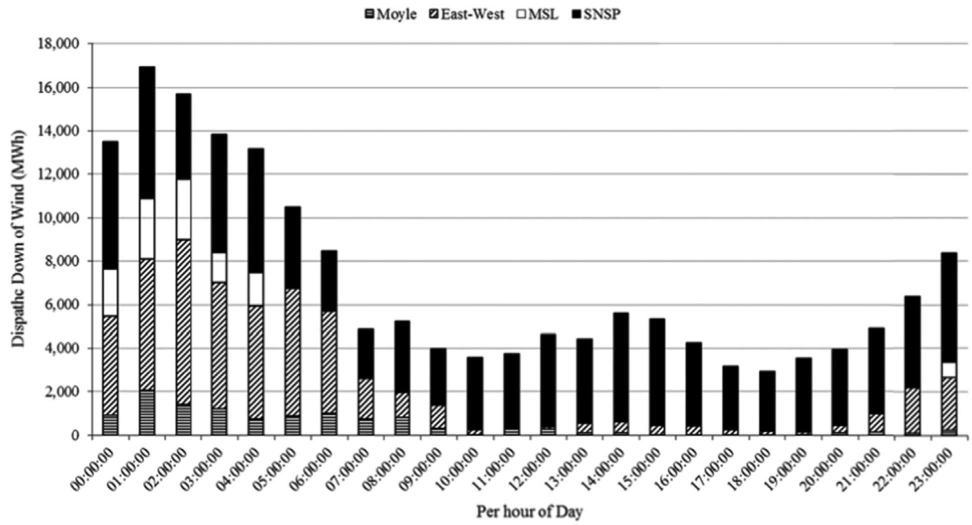

Fig. 5. Total annual dispatch-down of wind per hour of day (Scenario 2).

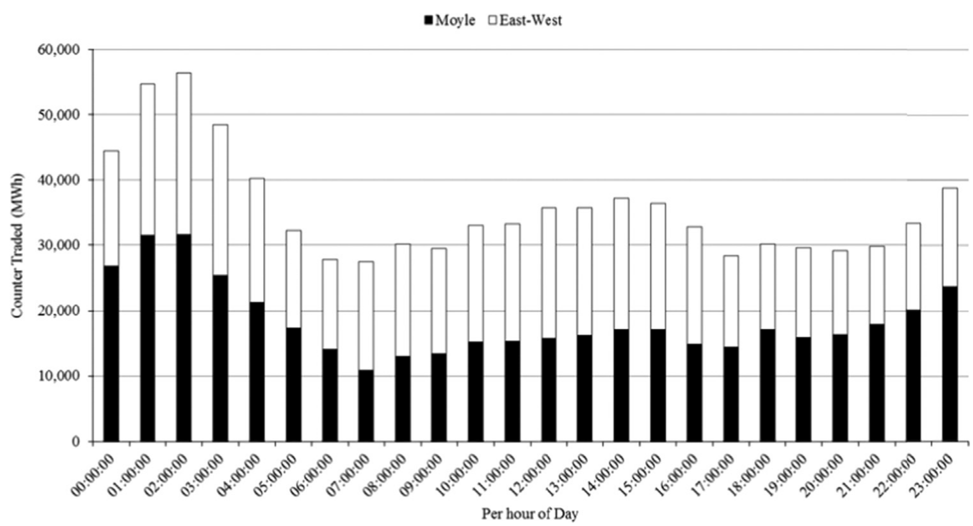

Fig. 6. Total counter-trading per hour of day (Scenario 2).

of wind being dispatched-down is undesirable and could have an impact on the installation of wind turbines. Therefore the ability for the system operator to counter-trade is vital to ensure dispatch-down of wind remains below 5% in 2016. Similar to the dispatch-down of wind, counter-trading occurs the most during 12am to 4am. Once both interconnectors are operating at their

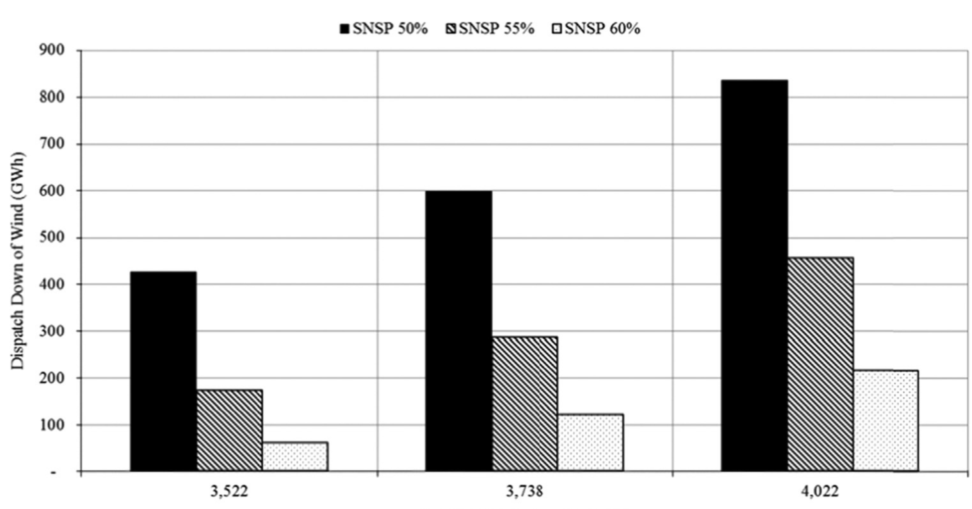

Fig. 7. Dispatch-down of wind due to SNSP limit (Scenarios 1–9).

max capacities the total annual counter-trading occurs evenly across both for each hour of the day, as shown in Fig. 6.

The SNSP limit in 2016 depends on the ability of the system operator to implement new system services that can maintain system stability with increasing levels of non-synchronous generation. The SNSP limit is expected to rise from 50% to 55% by 2017 but this might not occur if the generators and electricity system are unable to provide the necessary changes the system operator requires. The impact the SNSP limit has on the dispatch-down of wind is illustrated in Fig. 7. A number of installed wind capacity scenarios were modelled to determine the impact the SNSP limit could have on the potential wind generation in 2016. The 3522 MW and 3738 MW scenarios represent the 2016 and 2017 installed wind capacities from EirGrid and SONI (2014). The 4022 MW is a more progressive growth in wind generation by 2016. The increase in installed wind capacities from 3522 MW (scenario 1) to 3738 MW (scenario 4) results in an increase of 586 GW h of available wind generation. From a system operators perspective approximately 29% (171 GW h) of this extra available wind generation is dispatched-down. From the perspective of a wind farm developer/owner, the extra 216 MW of installed wind capacity will increase curtailment levels from approximately 4% to 6% which is undesirable. A small SNSP increase of 5% has the effect of reducing dispatch-down of wind by nearly 50% for all installed wind capacity scenarios. A SNSP limit increase from 50% to 55% and an installed capacity increase from 3522 MW and 4022 MW results in the same amount of wind dispatched-down i.e. scenario 2 and scenario 8. Both scenarios experience a dispatch-down of wind of 427 GW h and 456 GW h respectively that is approximately 4.5% of the available wind generation, which is just below the system operator accepted 5%.

The breakdown of wind dispatched-down into constraints due to the Moyle and EW interconnectors operating at full capacity and curtailment due to the SNSP limit and the minimum number of generators running at their MSLs is shown in Fig. 8. For the lower SNSP limit of 50% the majority of wind dispatch-down is due to curtailment issues. The SNSP limit for scenarios 1 and 7 curtailed wind generation by 1109 h and 1383 h of the year, respectively. A small increase of 5% in the SNSP limit had the impact of halving the percentage of available wind generation dispatched-down for all of the installed wind capacity scenarios. The SNSP limit is the reason for the majority of wind curtailment for all of the installed wind capacities when the SNSP limit is 50%. The higher the installed wind capacity the greater the number of periods when the SNSP limit is activated and wind is curtailed. The minimisation of wind dispatched-down is heavily linked to the ability of the system operator to increase the SNSP limit.

The SEM is a net importer of electricity in 2014 (EirGrid, SEMO, SONI, 2014) and with the Moyle interconnector at full capacity the results show approximately 13% of demand in 2016 could be supplied by imports across the Moyle and EW interconnectors. For periods of exporting in the Ex-Ante model, the EW interconnector is scheduled to export more often than the Moyle interconnector because of the Cheviot transmission constraint on the BETTA, boundary 6 in Fig. 4. If the flow constrained is in the direction of Scotland to England, Scotland is a net exporter of electricity and as a result the Ex-Ante model schedules exports across the EW interconnector to where the demand is in Wales and England. With more exports across the EW interconnector schedule by the Ex-Ante model whenever the system operator counter-trades, due to priority dispatching, the EW interconnector reaches its maximum capacity more often the Moyle interconnector. Therefore more wind generation is constrained due to the EW interconnector operating at maximum capacity than the Moyle interconnector, as shown in Fig. 8. Wind constrained due to the maximum capacities of the Moyle and EW interconnectors accounts for nearly 50% of the dispatch-down of wind when the SNSP limit is 60%. During these periods, priority dispatching occurs and the interconnector schedules are at their maximum capacities (430 MW for Moyle and 500 MW for EW) and counter-trading is implemented.

As installed wind capacity in the SEM increases over the next few years it is critical that the system operators implement the required system changes to increase the SNSP limit to at least 55%. Otherwise there could be an undesirable amount of wind generation paid for but not used. The current REFIT structure pays the wind generator €66.35/MW h and a balancing payment of €9.90/MW h for available wind capacity (DCENR, 2012). A 50% SNSP limit in 2016, with 3738 MW of installed wind capacity, has 598 GW h of wind dispatched-down at a potential cost of €39.7 million. An increase in SNSP limit to 55% reduces dispatch-down of wind to 287 GW h at a potential cost of €19 million.

Fig. 9 illustrates the amount of electricity that is counter-traded on the interconnectors between the SEM and BETTA for the different installed wind capacities and SNSP limits. Even though imports and exports across both interconnectors are different the amount of counter-trading on both interconnectors is similar, as shown in Fig. 6. An increase in SNSP limit reduces the amount of periods when dispatch-down of wind occurs as more wind is allowed onto the system. Therefore less counter-trading on the interconnectors occurs for the different installed wind capacity

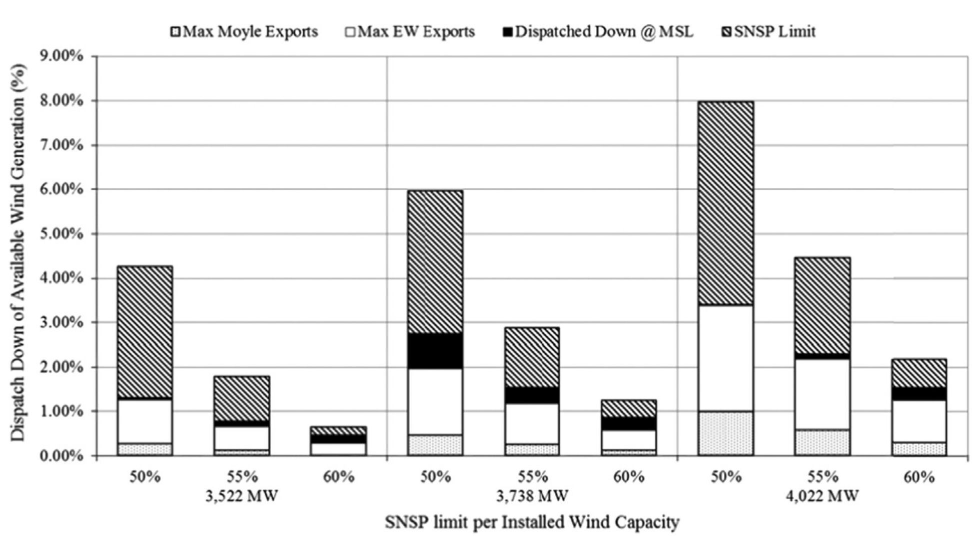

Fig. 8. Breakdown of the wind dispatched-down of available wind generation (Scenarios 1–9).

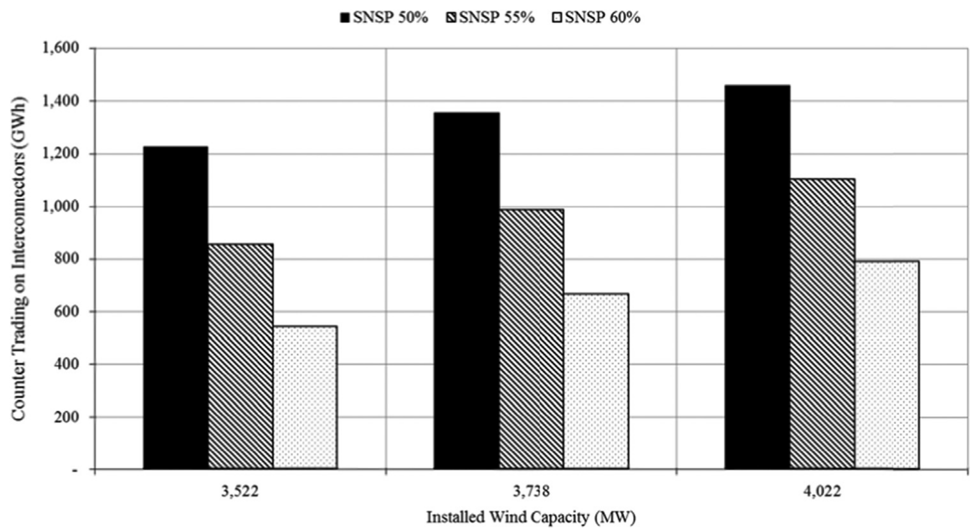

Fig. 9. Counter-trading on the SEM/BETTA interconnectors (Scenarios 1–9).

scenarios. The most realistic scenario for 2016 is 3522 MW of installed wind capacity and a SNSP of 55%. The ability to counter-trade reduces the amount of wind dispatched-down from 9.37% to 1.79%, therefore decreasing the amount of potential lost REFIT payments from €56.5 million to €11.5 million.

3.2. Moyle interconnector

For all of the previous scenarios the Moyle interconnector was operating at its full capacity of 430 MW. The Moyle interconnector has had a significant amount of problems in the past and has been restricted to 250 MW for large periods of time (EirGrid, 2014). Scenarios 10–12 with the Moyle interconnector capacity reduced to 250 MW result in the decreasing of the dispatch-down of wind, as indicated in Fig. 10. The reason for the decrease is due to the interaction of the interconnector counter-trading and the SNSP formula.

For example, on the 23/06/2016 at 17.00 the available wind generation is 1906 MW and the SEM demand is 3606 MW. If the Moyle interconnector capacity is 430 MW, SEMO has scheduled 430 MW and 500 MW to be imported across the Moyle and EW interconnectors respectively. These values result in a SNSP of 77% for SEMO, as per Eq. (28)

$$\frac{1906\text{ MW} + (500\text{ MW} + 430\text{ MW})}{3606\text{ MW} + 0\text{ MW}} = 77\% \tag{28}$$

The system operator counter-trades both interconnectors by 300 MW resulting in 130 MW and 200 MW of imports across the Moyle and EW interconnectors respectively, as per Eq. (29). With total imports of 330 MW (130 MW+200 MW), system demand of 3606 MW and a SNSP limit of 50% the maximum amount of wind allowed on the system is 1473 MW resulting in a dispatch-down of 433 MW (1906 MW – 1473 MW), Eq. (30)

$$\frac{1906\text{ MW} + (200\text{ MW} + 130\text{ MW})}{3606\text{ MW} + 0\text{ MW}} = 62\% \tag{29}$$

$$\frac{1473\text{ MW} + (200\text{ MW} + 130\text{ MW})}{3606\text{ MW} + 0\text{ MW}} = 50\% \tag{30}$$

If on the same period the Moyle interconnector was 250 MW and SEMO scheduled 250 MW of imports, SEMO's SNSP would be 72%

$$\frac{1906\text{ MW} + (500\text{ MW} + 250\text{ MW})}{3606\text{ MW} + 0\text{ MW}} = 72\% \tag{31}$$

The system operator would counter-trade both interconnectors by 300 MW resulting in the EW interconnector importing 200 MW

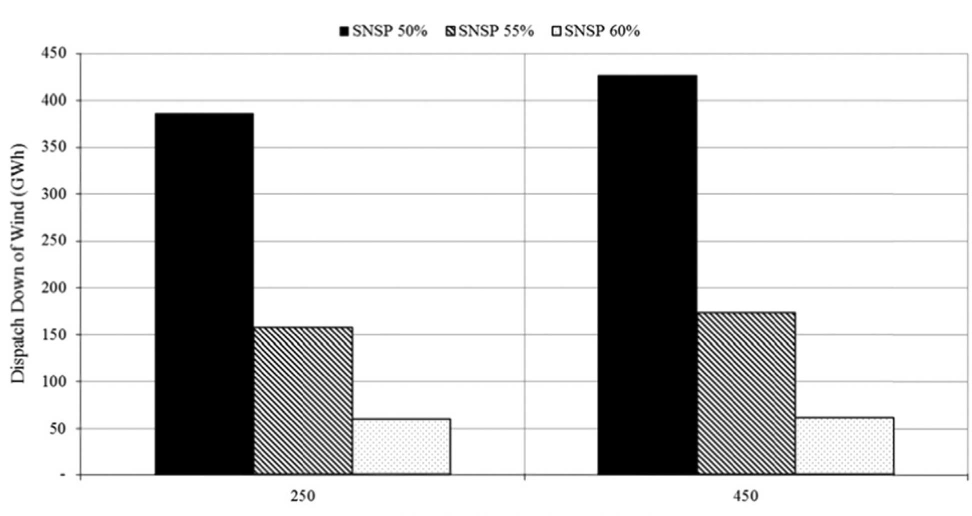

Fig. 10. Dispatch-down of wind due to Moyle interconnector capacity (Scenarios 1–3 and 10–12).

(500 MW – 300 MW) but the Moyle interconnector is now exporting 50 MW (250 MW – 300 MW). The system now experiences a system demand of 3606 MW, imports of 150 MW across the EW and exports of 50 MW across the Moyle. A 50% SNSP limit results in a maximum amount of wind allowed on the system of 1628 MW resulting in a dispatch-down of 278 MW (1906 MW – 1628 MW)

$$\frac{1906\text{ MW} + 200\text{ MW}}{3606\text{ MW} + 50\text{ MW}} = 57\% \tag{32}$$

$$\frac{1628\text{ MW} + 200\text{ MW}}{3606\text{ MW} + 50\text{ MW}} = 50\% \tag{33}$$

On the 23/06/2016 at 17.00 am Moyle interconnector capacity of 450 MW results in 433 MW of dispatched-down wind but a reduced Moyle interconnector capacity results in a reduced value of 278 MW of dispatched-down wind. The benefit of increased interconnector capacity on the dispatch-down of wind depends on the correlation of an electricity market and a system operator schedule.

3.3. System marginal price

The current market structure for calculating the SMP requires SEMO to take the interconnector schedule from the system operator and re-run the market model (Ex-Post). The Ex-Post model uses the wind generation (without forecast errors) and counter-traded interconnector schedule to determine the SMP. The Ex-Post model does not take into account any SOCs, reserve requirements or SNSP limits. Generators are paid the SMP, constraint payments and capacity payments. Wind generators are also entitled to REFIT payments. The total price of electricity for scenario 1 with 3522 MW of installed wind capacity and a SNSP limit of 50% is presented in Table 4. The REFIT was broken into 'top-up' and dispatched-down payments. A 'top-up' payment is the difference between the SMP and REFIT strike price if a wind generator is operating. The dispatched-down payment is for wind generators are dispatched-down and the REFIT structure pays the generators the SMP at that time. The energy payments are the SEM generation by the SMP. The price is total payments (i.e. energy payments, REFIT payments, constraint payments and capacity payments) divided by the generation. The price charged to the customer (without taxes and profits) consists of 71% from energy payments, 7% from REFIT payments, 2% from constraint payments and 20% from capacity payments. It must be noted that defining the capacity payment is beyond the scope of this work and since REFIT payments to generators are subject to the SMP and capacity payments, the actually REFIT payments will be lower than estimated here.

The impact the SNSP limit and installed wind capacity can have on the SMP in 2016 is presented in Table 5. The SNSP limit has a greater impact on the SMP than the installed wind capacity. A change in installed wind capacity from 3522 MW to 3738 MW results in more wind generation scheduled than an increase in

Table 4
Total price of electricity (Scenario 1).

Energy payments (SMPxGeneration) (million)	€ 2041.90
REFIT (million)	€206.08
Refit top up	€191.36
Refit dispatched-down wind	€14.72
Constraint payments (million)	€55.73
Capacity payment (million)	€565.82
Total payments (million)	€ 2869.53
Generation (GW h)	31776.89
Price (€/MW h)	€90.30

Table 5
Impact of SNSP limit and installed wind capacity on SMP.

SNSP limit (%)	**Installed wind capacity**		
	3522 MW	**3738 MW**	**4022 MW**
50	€61.52	€61.10	€61.39
55	€59.35	€59.06	€58.74
60	€58.92	€57.94	€57.70

SNSP limit from 50% to 55%, but it has less of an impact on the SMP. The higher the SNSP limit the fewer occasions the limit is reached. Therefore the SEM can schedule more wind generation and imports resulting in the removal of the more expensive SEM thermal generators from the merit order. Whereas, if the SNSP limit remains the same and installed wind capacity increases, imports are replaced by the extra wind generation which has little effect on the merit order and as a result the SMP is not changed substantially.

The total price to the consumer of the SMP including REFIT and constraint payments is highlighted in Fig. 11. The benefits of SMP reductions due to the increase in SNSP limits are reduced when the REFIT and constraint payments are included. Overall the increase in REFIT payments is outweighed by the savings in the SMP due to the increase in SNSP limit. The scenarios with SNSP limits of 50% and 55% do not produce reductions in SMP when the installed wind capacities are increased. The reduction in SMP from installed wind capacities is less than the extra cost in REFIT and constraint payments. If the SNSP is 60% the installation of extra wind capacity will not have a negative impact on the price of electricity however the benefits are less than 1% savings. If the system operator does not achieve their targets of increasing the SNSP limit in the next two years the consumer could experience a short term increase in their bills in order to stay on course for the national targets for 2020.

Scenario 2, with an installed wind capacity of 3522 MW and a 55% SNSP, was used to examine the impact the interconnector counter-trading has on the SMP. This scenario was tested with and without the interconnector counter-trading option. The impact interconnector counter-trading has on the system operator's DQ and SEMO's MSQ of each fuel type is shown in Fig. 12. The change in generation is the difference between the dispatch schedules for scenario 2 and scenario 13. Interconnector counter-trading decreases imports and replaces the imports with wind generation mainly. In the DQ model (system operator) the reduction of 855 GW h of imports due to interconnector counter-trading is met by an increase in wind generation of 723 GW h and 132 GW h of thermal generation. The change in thermal generation is a combination of an increase in peat generation and a decrease in generation from gas and coal from the Republic of Ireland and coal from Northern Ireland. Peat generation increases because the interconnector counter-trading reduces the amount of priority dispatching occurrences and the peat generators are no longer required to operate at their MSLs. Since the extra wind generation is predominately used to replace imports and not thermal generation there is only a small change of €1.507 million (0.15%) in total generation costs.

The interconnector counter-trading also has an impact on the unit commitment of the Ex-Post model as there is more wind generation and different interconnector schedules. Since the Ex-Post is an UUC model, there is no priority dispatching and therefore peat generation is not as affected as in the DQ model. In the Ex-Post model the difference between the increase in wind generation and decrease in imports is supplied by generation from gas and coal from the Republic of Ireland and coal from Northern Ireland, as seen in Fig. 12.

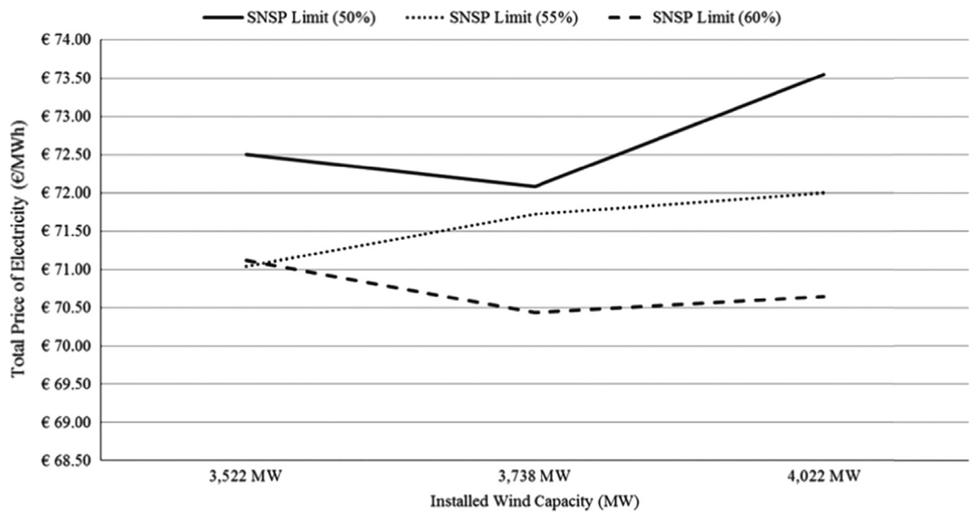

Fig. 11. Impact of SNSP limit and installed wind capacity on Price (Scenario 1–9).

In the Ex-Post model the introduction of interconnector counter-trading decreases imports, increases wind generation and more expensive thermal generation resulting in the average SMP for 2016 increasing marginally from €59.33/MW h to €59.35/MW h. The impact that counter-trading has on the hourly SMP for an average day in 2016 is displayed in Fig. 13. Mcinerney and Bunn (2013) found from 2008 to 2010, 26.22% of the flows across the interconnectors between the SEM and BETTA were against the price spread direction. From the 2016 test system 19% of the 2016 interconnector flows are against the price spread and increased to 21% when interconnector counter-trading was implemented. The majority of the flows are the SEM importing when the price spread should result in exports. Mcinerney and Bunn (2013) have presented a number of explanations for these anomalies.

The increase in thermal generation and SMP due to the counter-trading effects on the interconnector results in market energy payments for the SEM increasing from €1886 million to €1933 million. The increase is due to the increase in generation in the SEM from 30,550 GW h to 31,406 GW h. The reduction in wind dispatched-down due to interconnector counter-trading results in the REFIT decreasing by €21.6 million. The total benefits of interconnector counter-trading is realised when all of the payments are combined as shown in Table 6. For scenario 2 with an installed wind capacity of 3522 MW and a SNSP limit of 55% the ability to counter-trade on the interconnector decreases the total price of electricity per MW h by 1.89% (€1.72/MW h). The financial benefits of interconnector counter-trading are the savings in REFIT payments.

Over the next few years, changes to subsidy payments for wind power generation and the new EU energy target model could have significant impacts on the benefits and viability of wind generation in Northern Europe. The optimised scheduling and counter-trading of interconnectors will be vital to the delivery of wind power.

3.4. BETTA

The impact interconnector counter-trading has on the generating units in the BETTA and the exports to the SEM from the BETTA can be seen in Fig. 14. The installed wind capacity in the BETTA is expected to be 7897 MW and 13076 MW in Scotland and England/Wales respectively. In the test system there was little wind curtailed in the BETTA market in 2016 for a number of reasons, the significant offshore wind planned for Scotland will be installed after 2016 so the Cheviot boundary is not constraining significant quantities of wind generation in Scotland, the SNSP limit does not reach 50% and the Moyle interconnector is operating at its max capacity which means there is extra capacity to

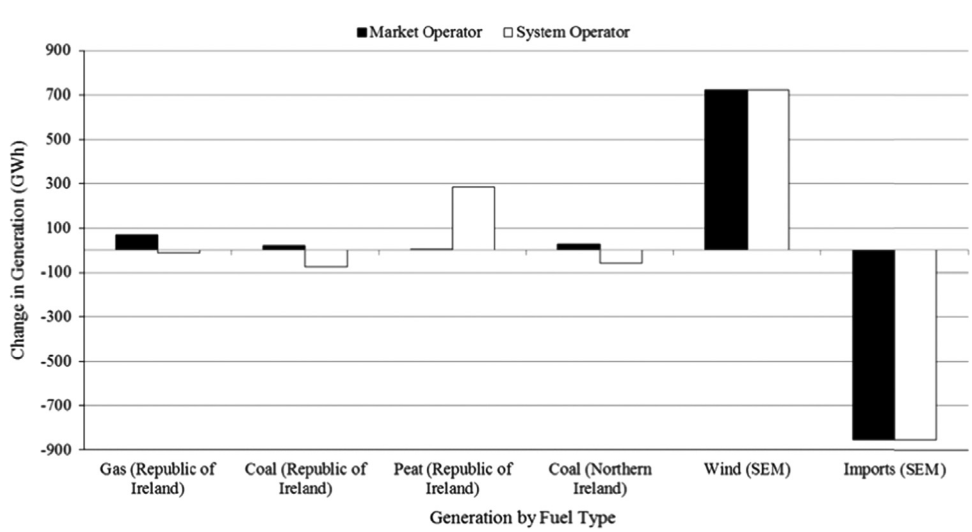

Fig. 12. System operator and SEMO Generation changes due to counter-trading (Scenario 2 and 13).

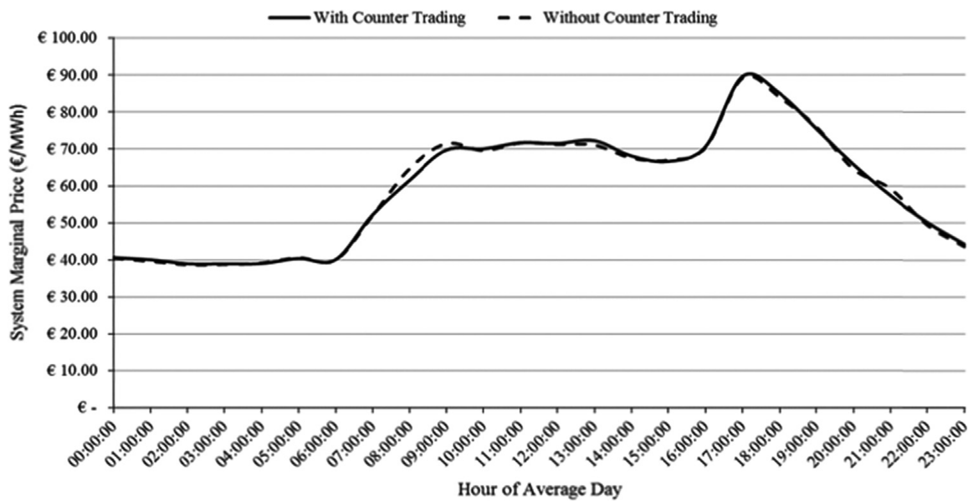

Fig. 13. Average daily SMP.

Table 6
Energy payments.

	No counter trading (Scenrio 13)	Counter trading (Scenario 2)
Energy payments (million)	€1886.49	€1933.60
REFIT (million)	€263.29	€241.70
Refit top up	€220.36	€235.74
Refit dispatched down wind	€42.93	€5.96
Constraint payments (million)	€57.69	€55.66
Capacity payment (million)	€565.82	€565.82
Total payments (million)	€ 2773.28	€ 2796.77
Generation (GW h)	30550.58	31406.05
Price (€/MW h)	€90.77	€89.05

export the wind generation.

Fig. 15 shows the change in average generation for the gas, coal and exports to the SEM due to the interconnector counter-trading. The majority of the interconnector counter-trading that reduced the exports to the SEM occurred during the early morning hours. The coal and gas units were equally affect from 22.00 to 03.00 whereas it is mainly coal generation that is reduced to accommodate the decrease in exports to the SEM in the rest of the hours. At the periods of interconnector counter-trading the coal and gas generating units are the marginal generators and therefore are the first to be reduced to accommodate the change in interconnector flow.

The implementation of the SOCs and SNSP in the SEM by the system operator results in the need for counter-trading on the interconnector if less wind is to be dispatched-down. As the SEM is a net importer of electricity the counter-trading results in less demand required from the BETTA. Therefore the marginal generators in the BETTA, coal and gas units, are re-scheduled down resulting in a reduction in the BETTA SMP. In the balancing market the yearly average SMP of the BETTA is seen to decrease from £47.01/MW h to £46.91/MW h with the introduction of interconnector counter-trading. Opposite to the SEM, the counter-trading had a reducing effect on the SMP in the BETTA. The cost of constraint payments are included in the balancing mechanism where national grid accepts bids and offers from generating units to increase or decrease generation. Future work will analyse the unit commitment of the BETTA market with high levels of wind generation and the impact to the consumer.

4. Conclusion and policy implications

This paper has presented a fully coupled economic dispatch and security constrained model of the SEM and BETTA test system and investigated the potential unit commitment issues (i.e. dispatch-down of wind, interconnector counter-trading and the wholesale price of electricity) that could face the SEM in 2016. This study is the first of its kind known to the authors that models the interaction between the market and system operation in the SEM that combines fully populated constrained SEM and BETTA models. In a security constraint electricity market with relatively small

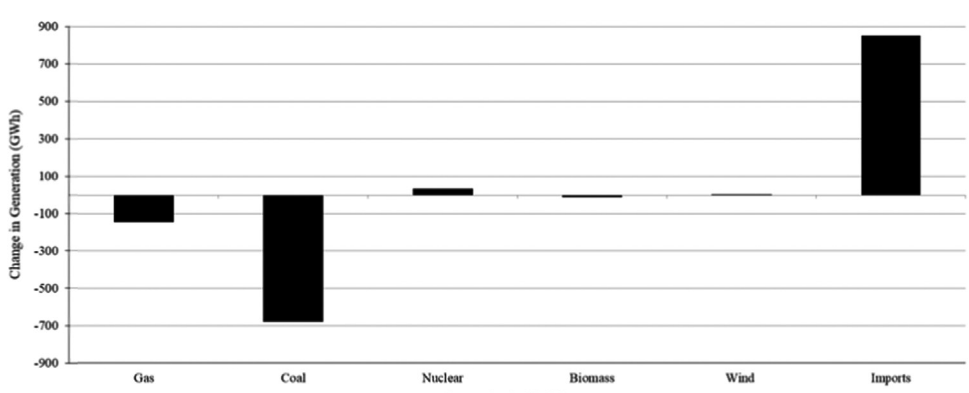

Fig. 14. Interconnector counter-trading impact on generation in the BETTA.

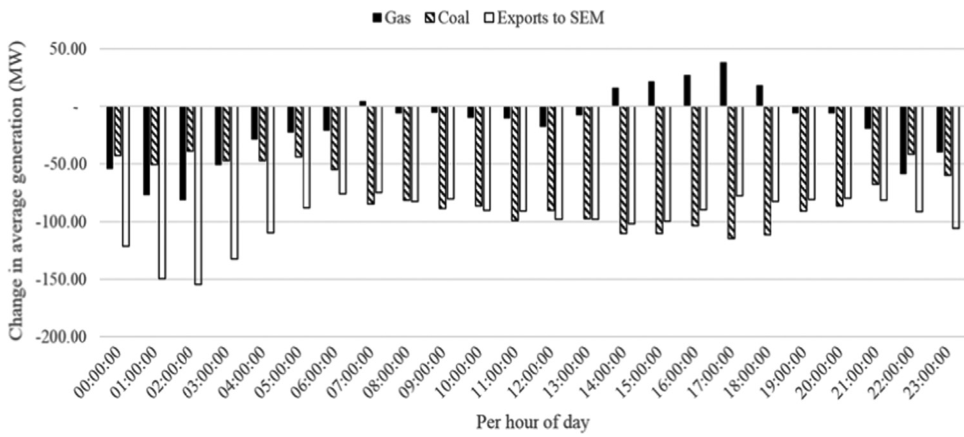

Fig. 15. Impact of interconnector counter trading on daily average generation per hour.

interconnection, counter-trading on the interconnectors is a crucial system service for reducing the dispatch-down of wind. The results show interconnector counter-trading can reduce the impact a SNSP limit has on the dispatch-down of wind. This is of particular importance to countries attempting to reach ambitious renewable energy targets. The findings from this study will be used in future work to determine the cost benefit analysis of increased interconnection in a security constrained BETTA market with significant offshore wind capacity.

In order to ensure system stability and security, the system operator in the SEM identified the requirement for a limit on the amount of wind generation that can supply demand. Considering Ireland is one of the first EU countries to experience high penetrations of wind power supplying instantaneous peak demands, such a limit could be introduced in other countries with limited interconnection. The ability of the system operator to increase the SNSP limit from 50% is vital to ensure that the dispatch-down of wind does not increase above 5% of available wind generation. An increase in SNSP limit from 50% to 55% could reduce the dispatch-down of wind by 311 GW h saving approximately €20 million in REFIT payments. Counter-trading on the interconnectors reduces the impact the SNSP limit has on the dispatch-down of wind as a decrease in imports was replaced with an increase in wind and thermal generation. These changes result in the average SMP for 2016 increasing marginally from €59.33/MW h to €59.35/MW h but the savings in REFIT payments result in a decrease in total electricity payments to the consumer of €1.72/MW h.

In 2017 the participants of the SEM will see the introduction of the I-SEM. The structure of the I-SEM means the interconnector schedules and energy market trading will occur before the system operator implements the SOCs. If interconnector counter-trading is not implemented by the system operator, large quantities of wind generation will be curtailed due to the SNSP limit. Interconnector counter-trading is a system service that the system operator can use to ensure priority dispatching and system security. Therefore the decision to include an interconnector counter-trading option is crucial to the development of a balancing market in the EU target model, as it is in the balancing market that system operator to system operator counter-trading can occur.

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