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Market Integration Scheme of a Multi-Terminal HVDC Grid in the North Seas

Stamatios Chondrogiannis and Marta Poncela Blanco

Abstract—**The development of a multi-terminal (MT) high voltage DC (HVDC) grid based on voltage source converter (VSC) technology has been envisaged as a key development for harnessing the vast offshore wind production potential of the North Seas. In this paper, market integration of a centrally dispatched MT HVDC Grid based on droop control is examined. Particular emphasis is given on the management of onshore imbalance volumes due to offshore wind power forecast errors. The economic importance of the control choices of the operator of such an active transmission grid is highlighted, and regulatory implications are briefly discussed. The main contribution of the paper is the coherent development of a droop-controlled MT HVDC grid scheme that integrates optimal power flow (OPF) dispatch, and imbalance volume management.**

Index Terms—**Control strategy, imbalance settlement, implicit auctions, load flow control, market integration, multi-terminal high voltage DC (HVDC) transmission, offshore wind farms, voltage source converters (VSC).**

I. Introduction

THE European Union has put some ambitious goals for the de-carbonization of its economy. Renewable energy sources (RES) are playing a key role in increasing the share of renewable energy to at least 30% of EU's energy consumption by 2030, enhancing at the same time the long-term energy security of the European countries [1]. Among them, wind energy is expected to play a significant role in the future European power systems.

With many of the best onshore sites, in terms of wind resource and/or public acceptance, having already been exploited, harnessing the vast offshore wind potential in Europe becomes of major importance. Quite a few offshore wind farms have already been developed, but near-onshore [2]. As the need to move further offshore comes in the future, a major development is needed, if the full potential of offshore wind is to be met. Such a step is, for the particular case of the North Seas, the development of a multi-terminal HVDC grid, interconnecting large clusters of offshore wind farms between them and to the onshore grids according to several studies (indicatively [3]–[5]). Specific benefits include increased market competition, better allocation of reserves, and interconnection redundancy.

The development of an MT HVDC Grid based on VSCs can be considered as the first truly active transmission network, since the power flows in it can be fully controlled in principle. Thus, the control scheme of the MT HVDC grid is of major importance. An "intelligent" control scheme should deliver at the same time the following functions: Being able to realize the cleared market bids as actual power injections to the onshore terminals. Remain secure under contingencies, preferably without the need for additional equipment. Lastly, to allocate in an optimum way the power mismatches caused by wind limited predictability and the consequent necessary reserves [6].

Many control strategies have been presented in the literature for MT HVDC grid [7]. Among them, of particular interest is droop-control, which is the adaptation of the well-known principle for frequency control in AC systems to the MT HVDC case where DC Voltage control is of importance.

Pinto *et al.* [8] presented a centrally dispatched OPF scheme, in which all onshore voltage source inverters (VSIs) operate as DC slack buses. Yet, the impact of the control choices on the allocation among the onshore nodes of the offshore imbalance volumes was out of the scope of the work. Haileselassie and Uhlen [9] presented power flow control in an MT HVDC grid operating on droop control. However, the analysis does not incorporate economic signals and market integration. Bianchi and Gomis-Bellmunt [10] formulated a multi-objective optimization for the droop gains with the optimization criterion being the minimization of voltage deviations. Yet, such a criterion does not relate to the economic impact caused by wind limited predictability. Beerten and Belmans [11] expanded the optimization criterion to include additionally the minimization of current deviations under a contingency. Still, the scheme does not react to market signals.

This paper presents a market integration scheme for a Centrally Dispatched droop-controlled MT HVDC Grid where: a. Dispatch schedule is determined based on implicit auctions incorporating the economic cost of losses, and b. The control variables are determined with the goal of minimizing the overall imbalance charges at the onshore terminals. Two optimization problems are mathematically developed and solved respectively for every market settlement period.

II. Case Study

The same conceptual case study used in [8] (Fig. 1) is employed, of a six-terminal bipolar ±320 kV offshore DC grid

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The authors are with the Joint Research Centre (JRC), Institute of Energy and Transport, Energy Security, Systems and Market Unit, Ispra 21027, Italy (e-mail: stamatios.chondrogiannis@jrc.ec.europa.eu; marta.poncela-blanco@jrc.ec.europa.eu).

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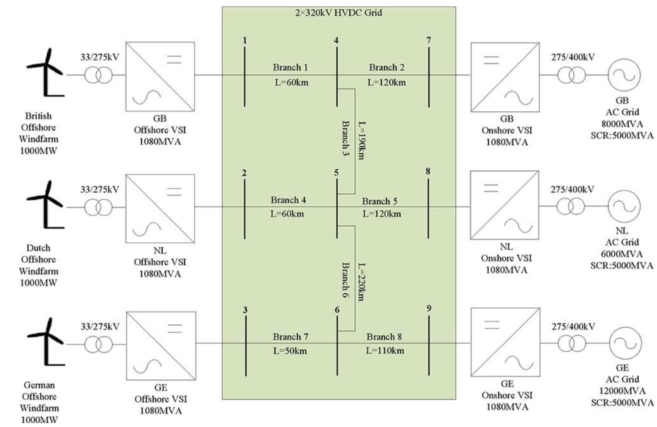

Fig. 1. Examined case study of MT HVDC grid.

inter-connecting the Great Britain (GB), The Netherlands, and German power systems and respective markets. At the same time three offshore wind farms, each in a different national territory, are connected to the MT HVDC grid. DC cable resistance, reactance and capacitance are 0.0195 Ω/km, 19 mH/km, and 220 nF/km, respectively, while the cable's rated current is 2086 kA.

III. Assumptions on the Market Integration of the MT HVDC Scheme

The trade arrangement denoted as "Virtual Case Study 1" by the North Seas Countries' Offshore Grid Initiative (NSGOCI) consortium is assumed in this work [12]. Each offshore wind farm participates in only one market, which in this paper is its respective national market. Intra-trade between the onshore networks is made by implicit auctions, which determine the cleared onshore power injections at the day ahead market (DAM) at each settlement period.

The proposed Market Integration scheme considers the participation of the MT HVDC operator as an independent entity into the onshore imbalance settlements, since he operates an active transmission network: While the total imbalance volume inside the HVDC grid is the responsibility of the offshore wind farm operators, its exact distribution among the onshore nodes, and thus overall cost, is determined by the control variable choices of the MT HVDC operator.

An optimization algorithm is developed aiming to minimize the expected total imbalance charge which is calculated based on the onshore imbalance volumes and prices. While the MT HVDC operator is responsible for this charge, he in return charges the offshore wind farm operators based on their respective imbalance volumes and national imbalance prices.

It is noted that regulatory issues arising from the participation of the MT HVDC operator into the onshore imbalance settlements are discussed at the end of the paper.

IV. Load Flow Control in an MT HVDC Scheme

A. Load Flow Formulation

Precise load flow control in a droop-controlled MT HVDC grid has been presented in a series of works (indicatively [9], [13] and [14]). Following, a short presentation of the mathematical formulation of the DC power flow solution is provided.

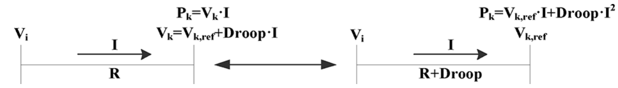

Fig. 2. Left: Power flow between two DC nodes. Right: Equivalent circuit.

Consider the power flow between two DC buses, one of which (the k node) is droop controlled (left side of Fig. 2).

According to Kirchhoff voltage law, the following is true under steady-state (R is the resistance of the line):

$$V_i - IR = V_k. \tag{1}$$

The mathematical expression of a current-based droop control is

$$V_k = V_{k,ref} + Droop \cdot I, Droop > 0. \tag{2}$$

Thus

$$V_i - V_{k,ref} = (R + Droop) \cdot I. \tag{3}$$

Formulation of the power flow problem is based on the transformation from the actual DC network to an equivalent (in terms of power flows) DC network with bus voltages equal to the DC reference voltages (for the droop controlled buses) and additional line resistances equal to the droop gains (see right side of Fig. 2).

Given L offshore wind farm nodes, M onshore (droop-controlled) nodes, N total nodes and S branches, the power flow equations for an MT HVDC grid, are as follows (the L buses of the offshore wind farms are numbered first and the M buses with the droop control, i.e., the onshore nodes, are numbered last):

$$P_j = V'_j \cdot \boldsymbol{Y'_j} \cdot \boldsymbol{V'} + Droop_j \cdot (\boldsymbol{Y'_j} \cdot \boldsymbol{V'})^2, \quad j = 1, \ldots, N \tag{4}$$

where P_j is the power injected at node j

$$P_j : \begin{cases} < 0, & \text{for nodes injecting power into the HVDC Grid} \\ > 0, & \text{for nodes taking power out of the HVDC Grid} \\ = 0, & \text{for intermediate nodes.} \end{cases}$$

$\boldsymbol{Y'}$ and $\boldsymbol{V'}$ are the admittance matrix and the voltage vector of the equivalent network, with dimensions N × N and N× 1, respectively. ***$\boldsymbol{Y'_j}$ is the jth row of $\boldsymbol{Y'}$.***

The vector of branch currents is given according to

$$\boldsymbol{I_{Lines}} = \boldsymbol{I_{inc}^{-1}} \cdot \boldsymbol{Y'} \cdot \boldsymbol{V'} \tag{5}$$

where $\boldsymbol{I_{inc}}$ is the incidence matrix.

The vector of actual node voltages is given according to

$$\boldsymbol{V} = \boldsymbol{V'} + \begin{bmatrix} & \boldsymbol{0_1} \\ \boldsymbol{0_2} & \boldsymbol{Droop} \end{bmatrix} \cdot (\boldsymbol{Y'} \cdot \boldsymbol{V'}) \tag{6}$$

where $\boldsymbol{0_1}$ is an (N − M) × N matrix full with zeroes, $\boldsymbol{0_2}$ an M × (**N** − M) matrix full with zeroes, and ***Droop*** a diagonal M×M matrix with the non-zero elements equal to the respective droop gains.

B. Security Constraints

An acceptable power dispatch should satisfy the following security constraints:

1) Lines' Current Constraints:

$$-I_{rating,j} \leq I_j \leq I_{rating,j},\ j = 1, \ldots, S. \tag{7}$$

2) Undervoltage Limit Constraint: DC undervoltages can lead to reduced AC voltage output capability which may result to AC voltage instability and/or reduced power injection capability by the VSI when operating in inverter mode. A minimum necessary DC voltage at each inverter, noted thereof as $\mathrm{V}_{DC,\min}$, must be maintained:

$$V_{DC,j} \geq V_{DC,\min},\ j = 1, \ldots, N. \tag{8}$$

3) Overvoltage Limit Constraint: Under normal operation, the steady-state upper voltage limit $\mathrm{V}_{DC,\mathrm{Lim,ss}}$ should not be exceeded:

$$V_{DC,j} \leq V_{DC,\mathrm{Lim,ss}},\ j = 1, \ldots, N. \tag{9}$$

4) Onshore VSIs Rating Constraints: The real power capacity of the onshore VSIs should also not be exceeded:

$$-P_{rating,j} \leq P_j \leq P_{rating,j},\ j = N - M + 1, \ldots, N. \tag{10}$$

V. Scheme for Optimum Market Integration of the MT HVDC Grid

A. Considered Offshore Power Injection Scenarios

In a droop control scheme the power injections at the onshore nodes are defined by two factors:

- the power injections by the offshore wind farms, which operate as power buses;
- the control variables (droop gain and DC voltage reference) of the onshore nodes.

When setting the control variables, the actual power injections by the offshore wind farms are unknown. As such, the operation of the MT HVDC Grid must be based upon scenarios. Three scenarios are employed in this work:

1) Scenario 1: Injections According to the Gate Closure Bids: The bids by the offshore wind farms' operators are employed:

$$P_i = P_{con,i}, i = 1, \ldots, L. \tag{11}$$

This scenario is used for defining the power dispatch for optimum implicit auctions. Furthermore, it is considered for evaluating the risk taken by the MT HVDC Operator in his try to arbitrage the expected offshore power imbalance volumes among the onshore nodes.

2) Scenario 2: Injections According to the MT HVDC Operator Forecast: It is considered that the MT HVDC Operator employs his own forecast for the power injections by the offshore wind farms:

$$P_i = P_{predicted,i}, i = 1, \ldots, L. \tag{12}$$

This scenario is used for minimizing the expected total imbalance charge for the next settlement period.

3) Scenario 3: Injections According to the Maximum Upward Forecast Error: This scenario is considered for securing the steady-state limits for line currents, onshore VSI ratings, and DC voltages given that the offshore power injections may actually be larger than the expected. In an actual application, the worst case upward short-term forecast error for each offshore node should be employed, which changes through time. For simplicity, a maximum forecast error of $+30\%$ for all nodes is considered in this work:

$$P_i = 1.3 \cdot P_{predicted,i}, i = 1, \ldots, L. \tag{13}$$

B. Implicit Auctions Power Dispatch

The implicit auctions determine the scheduled onshore power injections based on the price differentials between the national Day Ahead Markets. They employ *Scenario 1* for the offshore wind farms' injections, i.e., the bids by their operators.

The optimization problem can be described as "Determine control variables in order that the Total Revenue is maximized". The total revenue (TR) is

$$TR = \sum_{i=1}^{N} (P_i \cdot p_i) \tag{14}$$

where p_i is the price of energy at node i for the examined settlement period (i.e., the day ahead market price). Since the power injections depend on the control variables, so does the total revenue.

The mathematic formulation of the optimization problem is

$$\max_{V_{dc,ref,i}, Droop_i} \{TR\}\ considering\ Scenario\ 1 \qquad i = N - M + 1, \ldots, N$$

subject to

1) the inequality constraints (7)–(10) considering *Scenario 1*;
2) the inequality constraints (7)–(10) considering *Scenario 3*.

The optimization algorithm solves two power flows (one for *Scenario 1* and one for *Scenario 3*) at each iteration. The final solution incorporates also the cost of losses. If the price of energy in all nodes is the same, then the onshore injections are determined in order that the overall losses are minimized. On the other hand, when different prices exist, power trade volumes are limited when equilibrium with the additional cost of losses is reached.

Losses are allocated according to a simple pro rata method [15] to the nodes injecting power into the MT HVDC grid (rectifiers). Their economic value is calculated according to the respective national DAM price of electricity.

C. Control Variables Determination for Minimization of the Total Imbalance Charge

From the point of view of the MT HVDC grid central dispatch controller, the imbalance volumes, and respective costs, at the onshore nodes are of importance. The imbalance charge (payment) at each onshore node i is a function of the following:

- the actual offshore energy injections during the examined period. For relatively short dispatch periods (in the order of 15 min), the assumption of semi-constant power output can be made;

- the imbalance prices at the onshore nodes;
- the control variables which determine how the offshore imbalance volumes will be distributed among the onshore nodes.

Imbalance management in most EU power systems is conducted in real-time balancing markets. Thus, before each settlement period not only the offshore imbalance volumes, but also the onshore imbalance prices are unknown. As a consequence, the total imbalance charge is a multivariate stochastic variable:

$$\widehat{C}_{imb} = f\left(V_{ref,i}, Droop_i, \widehat{p}_{imb,i}, \widehat{P_j}\right)$$
$$i = N - M + 1, \ldots, N, j = 1, \ldots, L \quad (15)$$

where $p_{imb,i}$ is the imbalance price in the ith AC network for the examined settlement period. The superscript "^" denotes an estimate of a stochastic variable.

In the general case where probabilistic forecasts are employed, the median value of the expected total imbalance charge can be used as the minimization function. However, a considerable computational effort is required, since a power flow has to be conducted for every probable combination of offshore power injections and onshore imbalance prices, at each iteration of the optimization algorithm.

A much simpler solution, albeit expected to result in reduced value for the MT HVDC operator, is to employ point forecasts. At each iteration of the optimization algorithm, a single load flow solution has to be made in order to determine the expected Total Imbalance Charge. Point forecasts are considered in this study due to both computational constraints, and the fact that probabilistic forecasts are not widely used in real operation.

1) Formulation of the Optimization Algorithm for Minimization of the Expected Total Imbalance Charge: For the calculation of the expected total imbalance charge, the offshore wind farm injections of *Scenario 2* are employed, i.e., the forecast by the MT HVDC operator. The mathematic formulation of the optimization problem is

$$\max_{V_{dc,ref,i}, Droop_i} \left\{\widehat{C}_{imb}\right\} \, considering \, Scenario \, 2$$
$$i = N - M + 1, \ldots, N$$

subject to

1) the inequality constraints (7)–(10) considering *Scenario 2*;
2) the inequality constraints (7)–(10) considering *Scenario 3*.

If the formulation of the optimization problem stops here, the MT HVDC operator effectively sets the actual power dispatch at the onshore nodes solely with the criterion of minimizing the expected total imbalance charge. This can be considered a risk-prone behavior, since its efficiency depends on the quality of both his forecasts for the wind power injections and the imbalance prices.

A risk-containment strategy would be the MT HVDC operator to limit the choice of control variables among the combinations that satisfy the dispatch set in the implicit auctions up to a certain degree. This is conducted by incorporating into the optimization algorithm a third set of inequality constraints:

3)
$$|P_{con,k} - Risk| \le |P_{k,risk}| \le |P_{con,k} + Risk|$$
$$k = N - M + 1, \ldots, N \quad (16)$$

where $P_{k,risk}$ are the onshore node injections under *Scenario 1*, i.e., in the case that the offshore injections turn out to be the bided ones by the offshore wind farm operators (instead of the predicted ones by the MT HVDC operator).

"*Risk*" can be considered as the level of the acceptable risk taken by the MT HVDC operator. In case that the wind farms' operators forecasts turn to be true, while MT HVDC operator erred, the imbalance volume at each onshore node is restricted to the space $[-Risk, +Risk]$. In case that both wind farms' and MT HVDC operators make a perfect forecast, "*Risk*" is the volume of power at each onshore terminal that can be allocated for reserve arbitrage and optimization between the AC networks.

The flow-chart of the risk-containment strategy is shown in Fig. 3.

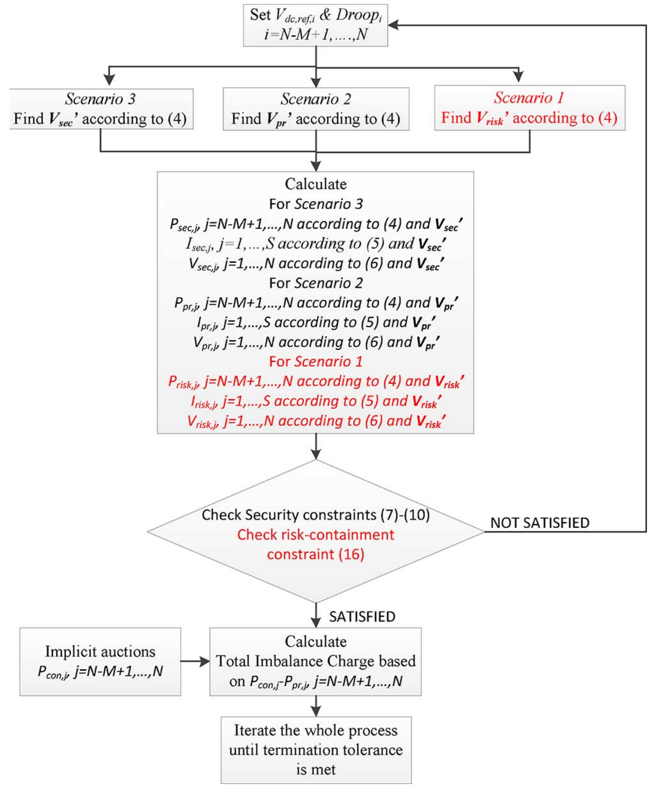

Fig. 3. Flow-chart of risk-containment minimization algorithm of expected total imbalance charge. With red the risk-containment elements. Without them the algorithm turns to risk-prone.

D. Evaluation of the Proposed Market Integration Scheme

Actual wind speed measurements taken from the European Centre for Medium-Range Weather Forecasts [16] has been used for Dogger Bank Project, GB, Q4, The Netherlands, and KASKASI, Germany for 2013, along with the Respective Day Ahead Market and imbalance prices as publicly reported.

The scope of this work is not to evaluate forecast methods (for wind power output and imbalance prices). Rather, it is to describe an operational scheme, and its potential benefits, for the market integration of an MT HVDC grid. Thus, the following assumptions are made:

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- It is supposed that the additional wind power injections do not change the prices both in the day ahead and the balancing markets. This assumption is justified if these injections are small in respect to the overall traded volumes, which holds true particularly for the day ahead markets. Still, a more extensive study should model the dynamics in both markets in order to quantify the impact of the additional wind capacity considered in the case study.
- Even under negative day ahead market prices it is assumed that wind farm producers bid their expected production. Moreover, it is supposed that wind farm operators do not bid into the balancing markets, even when the respective system is long (i.e., a reduction in generation and/or an increase in load is needed).
- In the implicit auctions, offshore wind farm bids are always accepted. This is reasonable since their marginal cost is close to zero and in agreement with the NSGOCI assumptions followed in this work [12].
- Operational constraints at the AC networks that could limit imbalance volume trading are neglected.

For the evaluation of the proposed scheme, an approach of maximum-minimum benefit envelope is taken. In all cases a 5% forecast error is considered, which generally can be considered as realistic for time horizons of 15-min ahead [17]. The impact of the error depends on the case:

- Case A: MT HVDC operator makes perfect forecasts. Each wind farm bids in such a way that ends-up minimizing its imbalance charge due to the forecast error. In fact, in most cases it will earn money by the imbalance settlement.
- Case B: MT HVDC operator makes perfect forecasts. Each wind farm bids in such a way that ends-up paying maximum imbalance charge due to the forecast error.
- Case C: Wind farms' operators make perfect forecasts. MT HVDC operator uses the erroneous forecasts of Case A.
- Case D: Wind farms' operators make perfect forecasts. MT HVDC operator uses the erroneous forecasts of Case B.

In all the above cases MT HVDC Operator makes perfect forecasts for the imbalance prices. Additional two cases are considered, where the MT-HVDC Operator uses a simple random walk model for the forecast of the imbalance prices:

$$\widehat{p}_{imb,i}(t) = p_{imb,i}\left(t - T_{set}\right), \; i = N - M + 1, \ldots, N \quad (17)$$

where T_{set} is the settlement period.

These are cases E and F, where the wind power forecasts are like cases A and B, respectively.

In all cases both risk-prone and risk-containment ($Risk$ $=$ 0.05 pu) behavior by the MT HVDC operator is examined. The optimization problems are solved according to the already built-in active-set algorithm of the Matlab Optimization Toolbox.

1) Results on Implicit Auctions: Implicit auctions power flows are determined according to the DAM prices and wind farms' operators bids. Here, the results only for Cases A and B are presented, which are also the results for Cases E and F (the results of the other cases are available from the authors upon request).

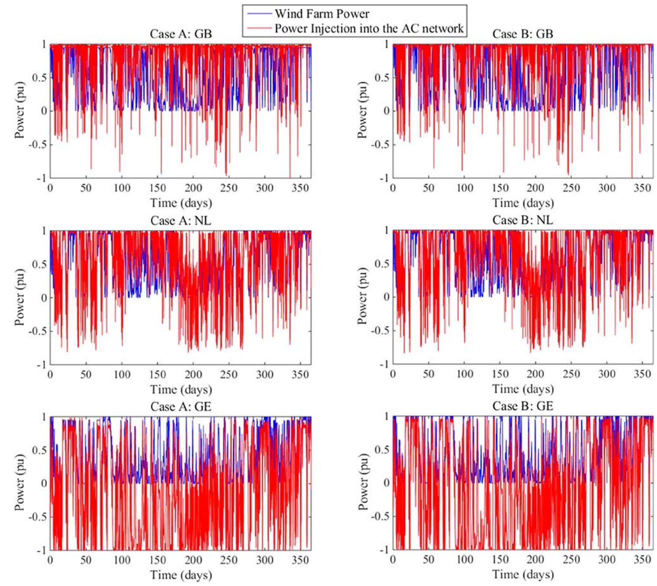

Fig. 4. Implicit auction power flows for Cases A (E) and B (F).

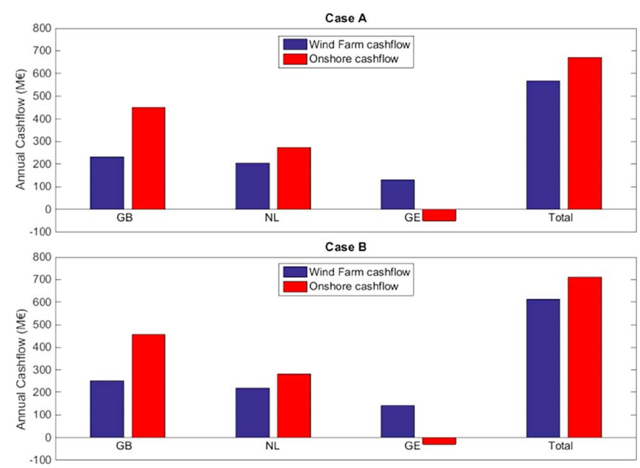

Fig. 5. Implicit auctions annual cash flows for Cases A (E) and B (F).

In Fig. 4, the power flows are shown. Negative power injections at the onshore nodes signify rectifier operation (node injecting power into the HVDC grid). The general direction of trade is from Germany to The Netherlands and GB, as a result of the price differentials in the respective day ahead markets.

Fig. 5 shows the respective net (i.e., including the charges for losses) annual cash flows. The difference between the cash flows of the offshore wind farms are basically due to the different price of electrical energy in the respective markets.

2) Results on Imbalance Settlements: The profit of the MT HVDC Operator is used as an economic indicator:

$$Profit = \sum_{i=1}^{3} C_{imb,i} - \sum_{i=7}^{9} C_{imb,i}. \quad (18)$$

It is mentioned that a negative imbalance charge indicates an earning.

In Fig. 6, the final power flows according to the overall scheme are presented for Case A and the 128th day of the year. In risk-containment strategy, the final power flows deviate from

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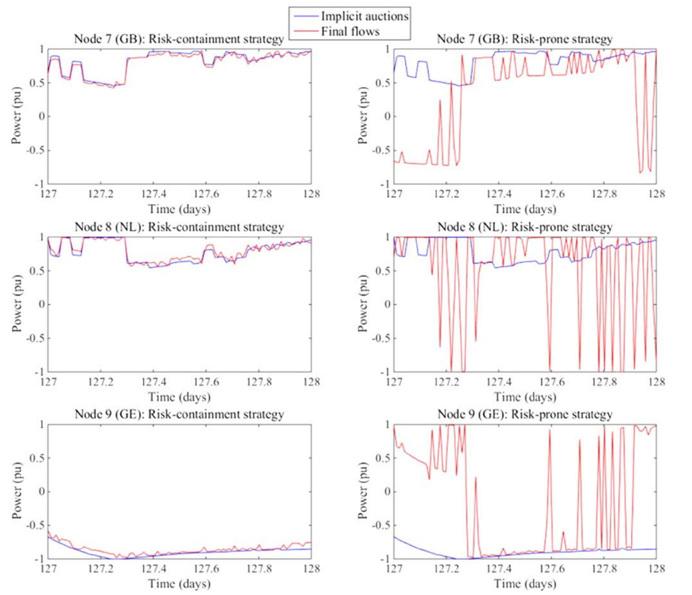

Fig. 6. Final power flows. Case A. Day: 128.

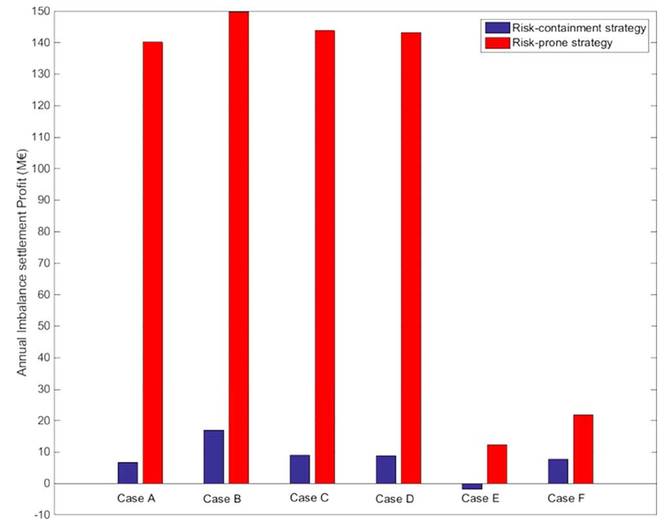

Fig. 7. Annual imbalance settlement profit of MT HVDC grid operator.

the scheduled in the implicit auctions minimally, as determined by the level of *Risk*. The deviations are due to both the imperfect power forecasts, and the effort to arbitrage the expected imbalance volumes at the onshore nodes. On the contrary, the latter consideration is by far the predominant factor when risk-prone strategy is employed. As a result, the final power flows a. deviate considerably from the implicit auctions power dispatch, and b. show large excursions between consecutive settlement periods following the respective changes in the (perfectly predicted in Case A) imbalance prices.

In Fig. 7, the MT HVDC operator annual imbalance settlement profit is shown for all the examined cases. It is noted that the results should be understood as a theoretical maximum, under the assumptions taken in this work. In an actual case, onshore AC network constraints would limit the trade imbalance volumes and imbalance prices would be affected by the decisions of the MT HVDC operator reducing the imbalance price differentials.

Based on the results the following are deduced:

a) Impact of Wind Farm Operators Imperfect Wind Power Forecasts: Both in Case B in comparison to Case A, and in Case F in comparison to Case E, the MT HVDC operator imbalance settlement profit is larger, irrespective of the risk strategy. This is to be expected, since in Cases B and F the imbalance payments by the wind farm operators are added to the MT HVDC profit, while in Cases A and E the opposite is true.

Impact of MT HVDC Operator Imperfect Wind Power Forecasts: Comparing Cases C and D, it is seen that the direction of the forecasts error has minimal impact. The arbitrage of imbalance volumes is the main factor determining the MT HVDC operator imbalance settlement profit.

b) Impact of MT HVDC Operator Imperfect Imbalance Price Forecasts: Comparing Cases E and F to Cases A and B, respectively, it is deduced that the quality of the imbalance price forecasts is the main factor determining the imbalance settlement profit. This is particularly seen under risk-prone strategy, in which imbalance volume arbitrage is only limited due to security constraints.

c) Impact of Risk Strategy Employed: Under the assumption that MT HVDC operator makes perfect imbalance price forecasts (and his actions do not impact these prices), risk-prone strategy produces an order of magnitude higher imbalance settlement profits (Cases A to D). Things change dramatically when imperfect imbalance price forecasts are considered in Cases E and F. Risk-prone strategy is still preferable, but the profits between the two strategies are now in a comparable level. In fact, if larger forecast errors were examined, it could well turn-out that risk-containment strategy becomes preferable.

VI. Discussion

Integration of an MT HVDC grid into the onshore imbalance settlements has to recognise the fundamental fact that this is an active transmission grid. Even though the total imbalance volume is caused by the imperfect forecasts of the offshore wind farm operators, its economic cost depends on its distribution among the different onshore markets. The latter, however, depends fundamentally on the control choices by the MT HVDC operator.

In this work, MT HVDC operator has been considered as an independent entity into the onshore imbalance settlements. As such, his control choices are guided by an economic drive, i.e., to maximize the overall imbalance settlement profit. Obviously, this comes into contradiction with the current regulatory regimes, where grid operators are mainly concerned with system's security. Still, it is an interesting exercise especially in a policy frame where there is a goal to attract private investments in building the offshore transmission grid.

Realization of an imbalance settlement profit is possible because of the fundamental assumption that offshore wind farms' operators are charged according to their respective imbalance prices. If the MT HVDC grid formed an independent imbalance settlement zone, arbitrage would not make economic sense to the MT HVDC Operator. The sum of the onshore imbalance charges would be allocated to the offshore wind farms proportionally to their imbalance volumes under a single price. Yet, MT HVDC operator should still try to minimize the onshore total imbalance charge, since this translates into a minimization of the cumulative market cost of balancing energy at the onshore AC networks. Since an economic drive would not exist anymore, this goal could only be attained by regulation. Still, this road also presents an obvious problem: It would be difficult to be supervised, since onshore imbalance prices are unknown at the beginning of the settlement period.

The results in this work show that the MT HVDC operator's profit is maximized when he does not take at all into account the scheduled in the implicit auctions onshore power injections (risk-prone strategy). This is mainly due to the assumptions made, with the main one being the neglect of the impact of the MT HVDC decisions on the imbalance volumes (and thus the ex-post final imbalance prices) in each national market. Still, the MT HVDC operator could also take into account market dynamics into his forecast of the imbalance prices, something that would be increasingly necessary with larger offshore wind power capacity in a real MT HVDC grid case.

Implementation of a risk-prone strategy could pose significant strain into the AC onshore power networks, as a result of the great excursions between the scheduled and the actual power injections. Most probably, a security limit should be necessary for the maximum permissible level of these excursions (both positive and negative). As such, the "risk-containment" strategy presented in this work is of greater practical interest, since it can incorporate such constraints into a single metric, i.e., the level of *Risk*.

Here, the particular value of droop control for an MT HVDC grid can be recognized. A certain power dispatch, which corresponds to a specific forecast of the offshore power injections, can be implemented by more than one combination of control variables. As a result, it can be also controlled, to a certain degree, how deviations from the forecasted wind power injections will be allocated among the onshore nodes. Hence, droop control offers additional flexibility for integrating the limited predictable and variable offshore wind fleet in the North Seas.

In this work, the MT HVDC operator makes his control decisions ex-ante. An obvious alternative would be his active participation into the onshore balancing markets. Even in such a case the work presented would be relevant. An acceptance of bids and offers by the MT HVDC operator would be effectively nothing but a new dispatch schedule. The great benefit would be that this schedule would be based on an actual knowledge of the offshore power injections so far, and an updated forecast for the immediate future, along with an agreed, known price for the onshore imbalance volumes. Still, the wind power forecast would still be imperfect and the economic impact of the error on the onshore power injections for the remaining of the settlement period should still had to be managed. It is noted that with active participation into balancing markets the MT HVDC operator would have real-time indications on the final imbalance prices at each settlement period, hedging the risk implicated with forecasting them ex-ante.

Finally, a significant issue that should be remarked is the non-harmonization between the considered in this work, imbalance settlements. GB employs a two-price scheme in which the main economic drive for showing balance responsibility is the opportunity cost. On the contrary, Germany and The Netherlands, the latter to a great extent, employ single price schemes where the main economic drive for showing balance responsibility is the actual imbalance cost. Interconnection between these two different in principle schemes can lead to sub-optimum behavior from a global point of view. This is evident in the case that the GB system being long is considered. If the price differential is adequate, the economic incentive of the MT HVDC Operator could well be to transfer power from Germany or Netherlands—even if these systems are short—to Great Britain. Obviously, such behavior would aggravate the imbalance in the national systems. This shows the importance of harmonizing not only the day ahead (and intraday) market rules, but also the balancing market rules, following the road to the internal energy market in Europe.

VII. Conclusions

Integration of an MT HVDC scheme in the North Seas into market operation, with particular weight given to imbalance settlements, was discussed in this work based on a conceptual case study. The economic importance of the MT HVDC Operator control decisions was highlighted. The regulatory challenges facing the operation of such an active transmission grid in the North Seas were briefly discussed.

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Stamatios Chondrogiannis received the Electrical Engineering degree from the Department of Electrical & Computer Engineering of Aristotle University of Thessaloniki, Greece, in 2001; the M.Sc. degree in power system engineering & economics from UMIST, U.K., in 2004; and the Ph.D. degree in electrical engineering from the University of Manchester, U.K., in 2007.

During his Ph.D. studies, he worked on the integration of offshore wind farms to the UK Grid, under a DTI project. He worked in the EPC Photovoltaic sector for 5 and a half years. He joined the European Commission in the Joint Research Centre, in October 2013. His research interests include smart grids, renewable generation, and power system analysis.

Marta Poncela Blanco received the Electrical Engineering degree from the Universidad de Valladolid, Spain, in 1998, and the Ph.D. degree in automation and systems engineering in 2012.

She joined the European Commission in the Joint Research Centre, in October 2013. Her research interests include system integration of renewables, forecasting, and operations and planning of electric energy systems.