Conventional Generation for Balancing 6 GW Offshore Wind Power

B.C. Ummels*, M. Gibescu*, W.L. Kling** and G.C. Paap*

***Abstract* - The Dutch government has set the objective of 6 GW installed offshore wind power capacity by 2020. Due to the variability and unpredictability of wind power production, this amount of offshore wind power can be foreseen to have large consequences for power system balancing in the Netherlands. Notably, Dutch wind power is subject to program responsibility like any other energy source: therefore, market parties make arrangements to minimize program deviations as a result of wind power imbalances. This paper presents simulation results of wind power balancing by conventional generation in a liberalized environment. A two-area power system model is set up, which includes conventional generation units, loads and wind parks. The capabilities of conventional generation units to follow wind power fluctuations and load changes are investigated. The modelling in this work is focused on load-frequency control mechanisms, e.g. classical primary and secondary control. The novel contribution consists in modelling the imbalance control by program-responsible parties via minimization of their energy program deviations. Simulations presented include imbalance management under a low load with high wind situation, a load step with a high load and high wind situation, and generation scheduling transitions. The model is set up to ultimately simulate long term power system stability with large-scale offshore wind power in the Netherlands.**

I. Introduction

WIND power is a rapidly growing renewable energy production technology. In the Dutch power system, about 1.1 GW of onshore wind power has been installed, while 300 MW of offshore wind power is presently under development. Governmental objectives include 1.5 GW of installed capacity onshore by 2010, while additional offshore development is being anticipated [1]. Due to the variability and unpredictability of wind power production, large amounts of wind power can be foreseen to have large consequences for balancing generation and demand in the Dutch power system.

This research is focused around long-term frequency stability: *the ability of a power system to maintain steady frequency following a severe system upset, resulting in a significant imbalance between generation and load* [2]. In power systems, a stead-state balance between generation and demand must be maintained at all times. Because the load changes during operation, generation units are continually managed in order to follow the load. Due to the variability and unpredictability of the wind, wind power cannot be controlled to the same extent as conventional generation can. For the large-scale integration of wind power in power systems, reserve and regulating power management, and capabilities of generation units must be investigated [3], [4], [5]. Generally, it can be noted that this is more problematic for systems with little or no hydro or pumped-storage units [6], which is the case for the Netherlands.

In the liberalized environment of the Netherlands, the Transmission System Operator (TSO) TenneT does neither own nor dispatch generation units. Instead, *program responsible parties* (PRP) have been introduced for keeping their own energy balance (kWh) (a program of MWhs per 15 minutes) [7]. A PRP not delivering power according to its program, pays an imbalance price to the TSO. Because wind power is subject to program responsibility as well, market parties use the capabilities of their thermal units to take care of wind power unpredictability and variability, as well as other unscheduled load and generation changes.

This paper presents some initial results of long-term power system stability simulations with anticipated large-scale offshore wind power production, in a control area similar in size and frequency response characteristics to the Netherlands. First, a power system model is set up and described. Second, models of a number of thermal generation units (coal, gas) are investigated. These units are part of the generation portfolios of to program responsible parties (PRPs), which also include wind power. Two wind park models are set up and discussed. Third, these models are incorporated into the power system. Fourth, some initial simulations are run in order to illustrate the operating principles of the developed model. Simulations include wind ramping up under light load conditions, load step under high wind power production and heavy load conditions and the ramping of thermal generation units at PTU-transition. Finally, an outlook on future work is presented and the conclusions on the work so far are drawn. A research framework is used to explain the overall objective and organization of this research, which investigates the feasibility of the objective of 6 GW offshore wind power in the Netherlands.

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II. Power System Model

Investigating power system stability is in fact investigating the dynamics of a power system in response to disturbances, which in this case are generation-load imbalances. For this research, time-domain simulations are used, which enable the computation of the complete response of a system to a disturbance [8]. The simulations provide information on the response of all connected generators and loads to specific disturbances. In order to investigate the performance of frequency and area interchange control in response to wind power imbalances, the real power balancing mechanisms must be modelled. As the focus of this paper is power system balancing, the power system set up here is modelled as a two-area system as described in [9], incorporating the real power flow through the inter-area tie-lines.

In steady state, i.e. at constant rotating speed or frequency f, the power balance is maintained. In this case, the mechanical power input of generators equals the electrical power consumed in the system:

$$P_{m,in} - P_{e,out} = 0 \tag{1}$$

The swing equation relates rotational speed changes and power imbalances as follows:

$$df/dt = 1/M * (P_{m,in} - P_{e,out}) \tag{2}$$

where M represents the aggregated moment of inertia of all rotating generators (at rated power) in the area:

$$M = P_r * 2H/f_0 \tag{3}$$

in which f_0 is the nominal frequency, P_r is the total control area installed power and H is the aggregated inertia constant. Expressing power in MW and frequency in Hz results in a moment of inertia expressed in MWs/Hz.

Equation 2 can be rewritten to show the relationship between frequency change, generated power and load:

$$df/dt = 1/M * (P_G - P_L) \tag{4}$$

in which P_G is the mechanical power output of all generators and P_L equals the load including electrical losses in the system. It can be noted, that an area-wide swing equation is used in this model, as all machines are assumed to be rotating at the same speed, proportional to the unique area frequency.

A. Load Damping

Load damping can also be referred to as the self-regulation of load in response to a frequency change, due to the changes in motor speed with frequency. Load damping D (in MW/Hz) can be expressed as follows:

$$D = C * P_L * /f_0 \tag{5}$$

in which C equals the load damping coefficient, P_L the load in MW and f_0 the nominal frequency in Hz. In the model, C is set as 1 (a 1% change in frequency implies a 1% change in load), as is typically assumed for power systems [10]. From the above, it follows that D increases linearly with system load.

B. Primary Response of Generators

In power systems, generators participate in stabilizing system frequency after an imbalance. The governor will change the power input in proportion to the frequency deviation, for immediate frequency stabilization following a significant incident. The size of the response of the unit to the frequency change depends on the speed droop R, the percent generation output change per percentage of relative frequency change. The primary response of a generation unit to a frequency deviation can be calculated from:

$$\Delta P_{G,i} = -1/R_i * \Delta f \tag{6}$$

where Δ_f is the change in frequency and Δ_P is the resulting change in power input.

System operators require certain minimum values for the speed droop of generators connected to the system. For Dutch generation units, requirements include a maximum droop of 10% (10% or less; 10% change in frequency implies a 100% change in generation) [11], as well as a full response within 30 s. [10].

C. System Power Frequency Characteristic and ACE

The system power frequency characteristic β, or natural response coefficient [12], is calculated from summing the primary responses of both generators and load:

$$\beta = 1/\Sigma_i R_i + D \tag{7}$$

The system power frequency characteristic β (MW/Hz) comprises the system frequency response to any imbalance between generation and load and varies depending on the amount of load and generation connected to the system:

$$\Delta P_{G,i+L} = -(1/\Sigma_i R_i + D) * \Delta f \tag{8}$$

where Δf equals the true frequency deviation from f_0 (Hz).

Furthermore, β is considered the optimal setting for the coefficient of the frequency bias term in the area control error ACE (MW):

$$ACE = \beta * \Delta f + \Delta P_{tie} \tag{9}$$

in which Δf is the frequency deviation from f_0 and ΔP_{tie} equals the interchange flow deviation from the scheduled value.

D. Two-Mass Model

The power system model developed for this paper consists of two separate areas, area 1 and area 2, which are strongly interconnected. For each area, frequency and power imbalance are related as in equation 8. The two areas in the system are connected trough tie lines, modelled here as one equivalent tie-line. The power flow on this line can be calculated from:

$$P_{1-2} = T * sin(\int (\Delta \tilde{f}_1 dt - \int (\Delta \tilde{f}_2 dt) \tag{10}$$

TABLE I
VALIDATION OF THE TWO-MASS MODEL

	Area 1	Area 2
Nominal Frequency (Hz)	50	50
Load (MW)	10000	250000
Installed Generation (MW)	9000	300000
Inertia Constant M (MWs/Hz)	1800	60000
Primary Control Participation (%)	100	50
Primary Response 1/R (MW/Hz)	900	15000
Load Damping D (MW/Hz)	200	6000
Load Step at t = 10 s. (MW)	100	0

in which T equals the synchronizing torque coefficient and $\Delta\tilde{f}_1$ and $\Delta\tilde{f}_2$ are the per unit frequency deviations from nominal for each area:

$$\Delta\tilde{f}_i = \Delta f_i/50 - 1,\ i = 1, 2 \tag{11}$$

T can be approximated by assuming constant voltages for areas 1 and 2, which are then divided by the equivalent reactance for the parallel tie-lines between the two areas:

$$T = E_1 * E_2/X_{1-2} \tag{12}$$

where

$$X_{1-2} = 1/\Sigma_{i=1}^{n}(1/X_i) \tag{13}$$

With inter-ties between areas of separate frequencies, inter-area oscillations between generation and load can be expected. In fact, such oscillations are a common phenomenon in power systems. In strongly interconnected power system, the equivalent tie-line reactance will be small, resulting in a large synchronizing torque coefficient and therefore fast oscillations between areas. For model validation, it may be useful to compare the two-mass model with a single-mass model, comprising the same generation and load and one system frequency.

The two area system modelled has the values as shown in table I and includes load damping and primary response. Generation has been aggregated for each area into one large generator, as inter-machine oscillations are not of interest here.

In figure 1, the response of both areas to a load step of 100 MW (t = 10 s.) in area 1 are shown. In area 2, not all generators participate in primary response, which may be expected for larger power systems, as discussed in [13]. The oscillations that occur between the areas can clearly be seen.

In the single-mass model, the inertia constants and load damping of areas 1 and 2 are summed. Because there is only one power system, the power interchange between areas 1 and 2 is assumed to be the instantaneous power difference between the two areas. This means that the load step mentioned above immediately results in additional imports into area 1 of 100 MW, as can be seen in figure 2.

From figures 1 and 2, it can be concluded that both models converge to the same values. Inter-area oscillations as a result of the modelled tie-line in the two-mass system are only transitory, but give some additional insight into short-term behavior during a power imbalance. Therefore, a two-area model will be used in simulations later on in this paper.

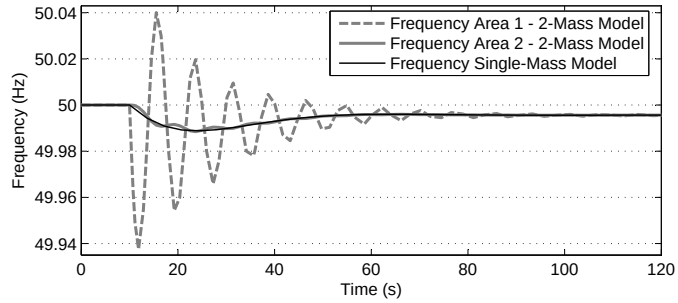

Fig. 1. Comparison of primary responses of a two-mass vs. a single-mass model to a load step of 100 MW in area 1.

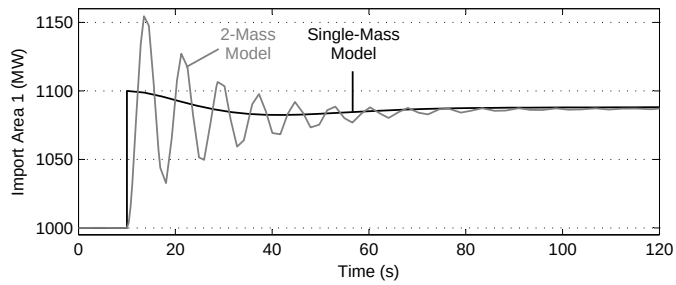

Fig. 2. Comparison of Area 1 imports of a two-mass vs. a single-mass model in response to a load step of 100 MW in area 1, primary response only.

E. Secondary Control

After the activation of primary control, interchange between control areas will differ from scheduled interchange, as can be derived from figure 2. In order to restore the power balance in each control zone, and hence the interchange schedule, secondary control is used. It is the objective of secondary control to return the Area Control Error (equation 9) to zero. Typically, ACE feeds into an integrator and gain [14], [15] before it is sent to units on secondary control.

In this model, ACE is first processed (PACE) through a PI-controller [16], which is based on a PACE-model developed by Dutch TSO TenneT. The controller consists of a filter term, which responds immediately to significant changes in ACE but decays rapidly, and an integral term, which responds slower but is more persistent (PI-controller). Furthermore, in case ACE exceeds a certain threshold, the PI-controller is by-passed and PACE is set to its maximum/minimum value until ACE is within bounds again.

It can be noted that, in a liberalized environment, the TSO does in fact not send unit dispatch signals, but instead financial signals to PRPs which have offered reserves in the market. The PRPs will respond to these signals with maximum profit in mind, usually resulting in the desired adjustment of generation/load for secondary control. For now, these costs aspects will be neglected and it will be assumed, that units under secondary control will follow PACE perfectly.

F. Tertiary Control - Program Responsibility

In central dispatch operation, tertiary control changes the working points of generators in order to re-distribute secondary control most economically [17]. It can be noted that in a liberalized environment, secondary reserves are offered to the TSO through market bidding: therefore, secondary control is to a certain extent already distributed economically (lowest bid selection). As a power imbalance is picked up by the TSO and secondary control is activated, a power imbalance will also be picked up by the PRP responsible for it. Along with secondary control, it is also the program responsible party causing the imbalance that takes measures in order to minimize its imbalance and the program deviation as a result of it. The incentive for doing so lies in the imbalance price that must be paid to the TSO. Thus, power imbalances are detected and managed with economic efficiency in mind both at system level and at PRP level.

Continuously, the PRP monitors its power imbalance $P_{\pm}$:

$$P_{\pm} = (\Delta P_G - P_{2nd}) - \Delta P_L \tag{14}$$

in which ΔP_G and ΔP_L equal the generation and load deviations from scheduled values and P_{2nd} equals the secondary response from generators within the PRPs' portfolio.
Also, the PRP monitors its energy imbalance for each PTU $E_{\pm,PTU}$:

$$E_{\pm,PTU} = \int_{t_0}^{t_{PTU}} P_{\pm} dt \tag{15}$$

For tertiary control of units, a fraction of $\int P_{\pm}$ is subtracted from the set point of generation units selected by the PRP for imbalance management. Because participation in secondary control is taken into account in calculating $P_{\pm}$ and $\int P_{\pm}$, tertiary control returns both the PRP's imbalance and the system imbalance to zero.

Even though tertiary control reduces the PRPs actual imbalance (MW) to zero, tertiary control does *not* fulfill the objective for program responsibility: delivering according to the program, which is MWh-value per program time unit (PTU). Therefore, instead of minimizing its power imbalance, it is the objective of each PRP to minimize its energy imbalance for each PTU $E_{\pm,PTU}$ separately. In order to do this, the MWh-value specified in the program is the target of generation management. Thus, within PTU, the energy deficit or surplus must must be counterbalanced. The less time before $t = t_{PTU}$, the larger the power overshoot must be in order to arrive at the scheduled MWh-value.

Now the power system model, including primary, secondary and program responsibility, has been defined, models for the various generation units of the PRPs must be set up. These will then be integrated into the power system model in order to enable long-term simulation of power system stability in the presence of large-scale wind power.

III. Program Responsible Parties' Portfolios

In the Netherlands, generation and load are administratively assigned to a small number of programme responsible parties.

TABLE II
PRP1 and PRP2 Installed Generation Portfolio

	PRP 1	PRP 2
Gas-Fired (MW)	100	100
Coal-Fired (MW)	100	200
Wind Power (MW)	100	120

At the moment, total installed capacity of thermal generation units is about 20 GW. The main fuel types are gas (70%), coal (21%) and nuclear (3%), while hydro-power is negligible.[1] Total installed wind power capacity is about 1.1 GW. In 2020, total installed wind power capacity is expected to be 7.5 - 8 GW, or about 40% of thermal generation presently installed.

Here, the generation portfolios of two fictitious PRPs (PRP1 and PRP2) are modelled, including coal and gas units and wind parks. An overview of the generation portfolio of each PRP is provided in table II).

A. Thermal Generation Units

For long term simulation purposes, a number of generation unit models can be found in literature, such as in [9], [18], [19]. From these models it can be learned that, for long term real power and frequency control, a differentiation must be made between the initial response of a unit and the longer term response. The initial response of a thermal unit depends on the governing system (speed droop, turbine-governor systems), while in the longer term, the control logic and the physical processes in the boiler become more important. For unit start-up or shut-down, these physical processes may require hours up to days, which must be taken into account when committing such units. However, this is not considered in this work.

For the modelling of thermal generations units in this study, existing models from literature have been compared to models of existing Dutch generation units. The models used here incorporate typical aspects as primary reaction, speed controls, power-frequency controls and turbine controls. Therefore, the models describe most of the longer-term behavior of the generation units, excluding unit start-up, shut-down and boiler dynamics. The models have been used as a first approximation of the capabilities of thermal generation units in wind power balancing.

In figure 3, simulated responses can be observed of four generation units modelled for this paper. At t = 10.s, a load step of 0.005 p.u. is introduced, resulting in a generation step of the same size within 20-45 s. (gas) and 60-100 s. (coal). At $t = 110s.$, a frequency drop of 0.001 p.u. is initiated, leading to a primary response of the units, assuming a dead band of zero. As can clearly be seen, the units all show a fast initial and a slower persistent response.

B. Wind Power

A number of models have been developed for the dynamic simulation of wind turbines and wind farms [20], [21], [22]. Typically, such models consist of aerodynamical, mechanical

[1] http://www.tennet.nl/, report on Monitoring the Reliability of Supply

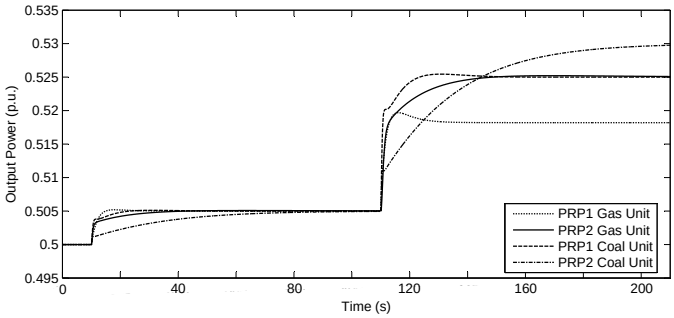

Fig. 3. Responses of four generation units to a load step of 0.005 p.u. and a frequency change of -0.001 p.u.

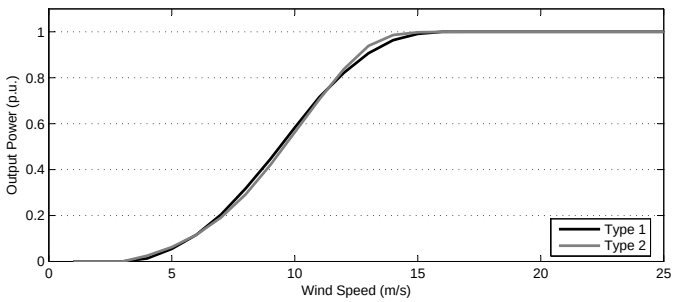

Fig. 4. Power curve of two commercial wind turbines. Type 1 is a constant speed turbines with an asynchronous generator (Danish design), Type 2 is a variable speed turbine with a doubly-fed induction generator.

and electrical subsystems, which describe the interactions of the different parts of wind turbines. Modelling of the rotor is usually done through an algebraic relation between wind speed and mechanical power, while numerical approximations are used for the validation of coefficients. Then, different parts of the electrical system are modelled (generator, convertor, transformer etc.) to include a correct mechanical-to-electrical power transfer.

As it is the objective of this paper to develop a test-model for long-term power system simulations only, the extensive wind turbine models mentioned above will not be applied here. Instead, a wind model will be connected to a wind turbine power curve and a small moment of inertia, representing the rotating mass of the rotor. The wind speed model used here was developed by Risø National Laboratory [23]. This model is based on Kaimal spectra and uses a normally distributed white noise generator. The generated wind speed is fed into a power curve, converting wind speed into output power. Power curves used in this research are shown in figure 4. To take into account the moment of inertia of the rotating mass of the turbine (generator), the power output is fed into a an equation of motion with moment of inertia M, where M is assumed to be 3-4 s. [20]).

Figure 5 shows a wind speed series, generated by the wind speed model. For $0 < t < 300\ s.$, the average wind speed is 9 m/s, ramping up to 12 m/s between $300 < t < 600\ s.$ and continuing at 12 m/s up to $t = 900\ s$. As can be seen from the figure, the differences in power curves between the turbines are translated into slightly different power outputs (assuming no curtailment of wind power). Furthermore, it can be seen

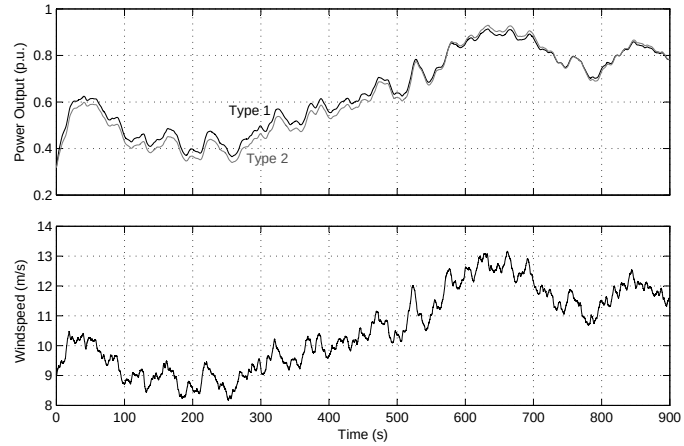

Fig. 5. Output power of the two turbines at a generated wind speed series.

that the moment of inertia of the wind turbines smoothes out some of the fast wind power fluctuations.

In the simulations made in this paper, it is assumed that the wind turbines are aggregated into two wind parks, one for each PRP. Turbines are of type 1 for PRP1 and of type 2 for PRP2 and assumed to be of 2 MW size. Both wind parks consist of a number of rows of wind turbines, each wind turbine at 5R from the next. Wind direction is perpendicular to the rows, while the wake effect of the turbines is assumed to be zero. PRP1 has 100 MW in its wind park, consisting of 10 rows of 5 turbines, while PRP2 has 120 MW in its wind park, consisting of 5 rows of 12 turbines. Wind speed series and wind power output for both PRPs are simulated beforehand in order to develop time-wind power series for each PRP.

C. Load

In this model, it is assumed that loads are frequency-dependent as explained in section IIA. Positive or negative load steps may be applied for simulation purposes. Wind power variability and unpredictability is therefore the only continuous power imbalance observed by the system and the PRPs. PRPs are assumed to monitor generation and load levels continuously and are therefore able to determine their imbalance and program deviations perfectly.

IV. Simulations and Results

In the simulations below, the management of thermal generation units by PRPs in response to wind power and load imbalances will be examined. The overall objective of each PRP is the minimization of program deviations, resulting from wind power intermittency and load changes. Simultaneously, PRPs will respond to the secondary control signal (PACE) resulting from frequency and deviations from interchange schedule with neighboring area 2. The simulations comprise the unit dispatch of three PRPs, PRP1, PRP2 and PRP3. PRP3 is an aggregation of all remaining units in control area 1, outside the portfolios of PRP1 and PRP2. While the aggregated unit responds to secondary control signals, PRP3 itself is assumed to have zero power imbalance and will therefore not be considered further. In all simulations, it is assumed that

a dead band of 20 mHz is used for all generation units on primary control. Therefore, no primary response will occur at small frequency changes. The frequency bias coefficient is empirically set to 900 MW/Hz. Area 2, which is much larger, has only the primary reaction modelled. Different scenarios will be simulated, which are described below. In order to bring up generation unit outputs from zero to the scheduled values for each PTU, an initialization period is used for all simulations. At $t = 0$, some simulation time has therefore passed already; due to the variability of wind power, deviations in generation output are therefore already present at the start of the actual simulation.

A. Simulations 1a and 1b: Low Load, High Wind Power and Imbalance Management

At low load, for example during night-time, base loading of generation units will be sufficient to cover most of the load. Base-load units having low fuel cost and longer start-up and shut down-times, such as coal, will continue operation while gas units, having high fuel cost and relatively short start-up time, will be taken out of operation. If such a base-load situation coincides with high wind power production, a relatively small amount of generation capacity will be available for balancing wind power production. This scenario is the case in simulations 1a and 1b.

PRP1 and PRP2 are both located in control area 1. It is assumed, that both PRP1 and PRP2 have their coal unit in operation and their gas unit shut down. PRP1 and PRP2 have a load of 100 MW and 120 MW and an expected wind power production of 60 MW and 84 MW, respectively. Thus, generation from the coal unit need only be 40 MW and 36 MW, if wind power predictions are correct. Both coal units are set to respond to secondary control signals from the TSO. In simulation 1a, the PRPs do not make arrangements for minimizing imbalances. Therefore, their generation units will respond to secondary control signals only. In simulation 1b, the PRPs do make arrangements for managing their wind power imbalance, by adjusting their coal unit production. The results from simulations 1a and 1b can be observed in figure 6.

During the simulated program time unit (PTU) of 900 s., the wind speed increases and wind power production exceeds the predicted values. In case of no imbalance management (grey lines), both PRPs let their coal unit produce according to schedule plus/minus secondary control. An increase of wind power will therefore result in a higher overall generation level of each PRP. In case of imbalance management, PRPs do not only respond to secondary control signals, but also manage their generation units in order to minimize their individual power imbalance.

From figure 6, it can be seen that imbalance minimization by the PRPs significantly decreases both the ACE and the PACE. As wind power increases from approximately $t = 500\ s.$, the ACE increases as well, as no specific actions are undertaken by the PRPs. Program responsibility significantly reduces the ACE as well as the PACE, as the need for secondary control on a system level is reduced. Secondary control continues to be required however in case some PRPs fail to respond to

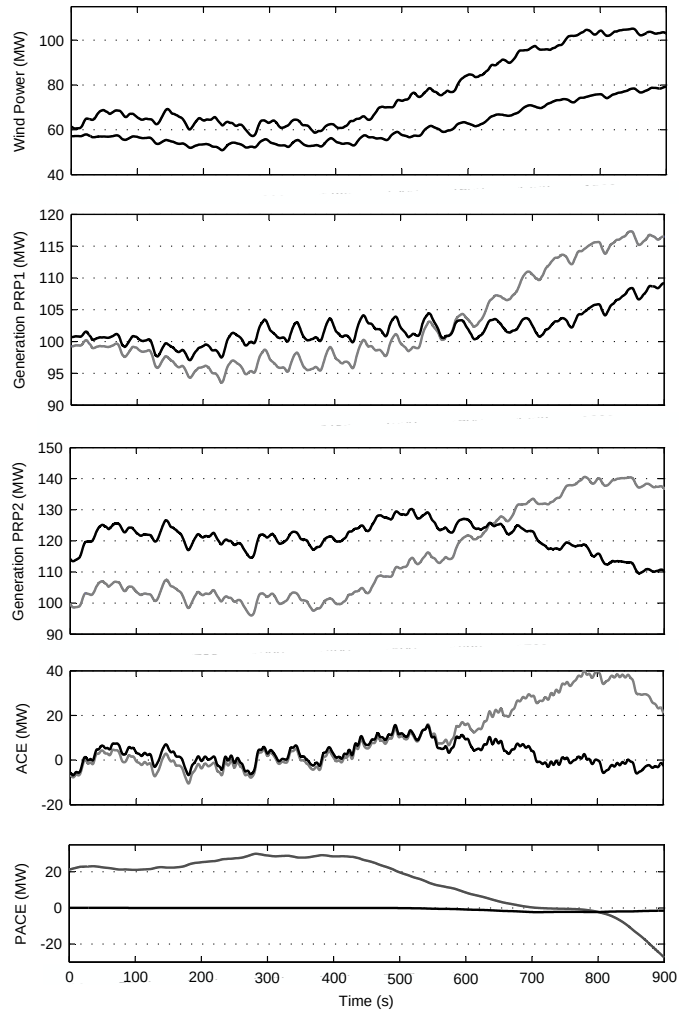

Fig. 6. Wind power, total generation for PRP 1 and PRP 2, ACE and PACE for one PTU. Wind power inputs are the same for both simulations; simulation without imbalance management in grey, simulation with imbalance management by PRPs in black.

secondary control signals from the TSO. Such is the case with PRP1 from $t > 700\ s$, due to the fact that its coal unit has a minimum load of 30 MW. As the wind power increases, PRP1 is not able to regulate its thermal generation unit down any further for secondary control purposes. The imbalance is then taken over by other generation units in the area, removing the imbalance caused by PRP1.

While the PRPs have not set their coal units to follow short term wind power fluctuations (up to 100 s.), they do use these for balancing long term fluctuations in simulation 1b. In both simulations the wind power fluctuations can clearly be recognized in the generation graphs of each PRP. It can be noted that, due to secondary control and strategic behavior (minimization of program deviation instead of power imbalance), PRP2 reduces its generation below its target value of 120 MW at the end of the PTU.

B. Simulation 2: High Load, High Wind, Load Step

During real-time operation, PRPs experience not only variations in wind power, but also variations in load. Both

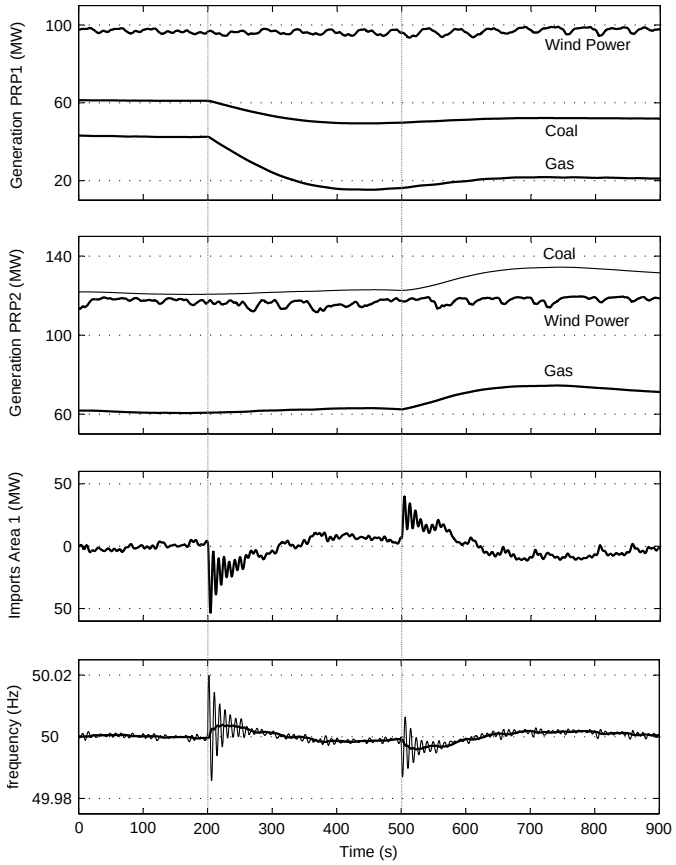

Fig. 7. Wind power, generation from coal and gas units, power exchange between areas 1 and area 2 frequencies for one PTU.

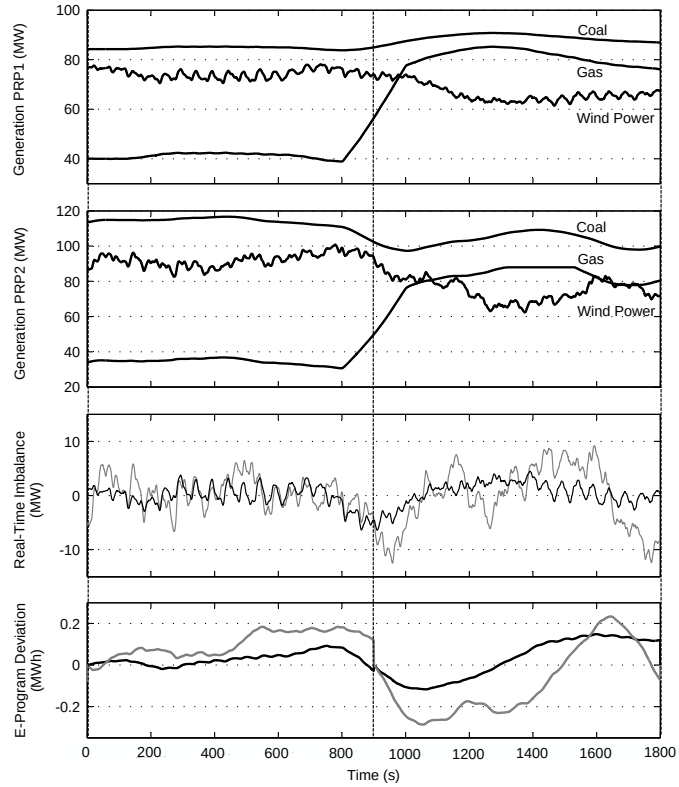

Fig. 8. Wind power, generation from coal and gas units for PRP1 and PRP2, power imbalance and program deviation for PRP1 (black) and PRP2 (gray) for two PTUs.

variations in load and variations in wind power must be balanced by the PRP in order to deliver the MWh-value specified in the program for each PTU. Variations in load and wind power will alternately counterbalance and reinforce each-other. Here, an attempt is made at simulating concurrent wind power and load variability.

In this simulation, the impacts of wind power variability at a constant average wind speed as well as load steps are investigated during high load and high wind power. PRP1 has a load of 200 MW and PRP2 of 320 MW and have dispatched their units as to meet these loads, taking into account predictions of average wind power production for a given 15-minute program time unit (figure 7).

At t = 200 s., PRP1 experiences a load step of -30 MW, while PRP2 experiences a load step of +20 MW at t = 500 s. Both load step have an influence on the exchange between area 1, in which both PRPs are located, and area 2 as well as the frequency in both areas. Because of the large size of area 2 relative to area 1, the frequency in area 2 is much more stable. It can be noted that, after both load steps, generation units are not set to return the real-time imbalance to zero immediately. Rather, the MWh deviation is taken into account before the real-time imbalance is minimized. Therefore, area 1 frequency does not return to 50 Hz. at once after an imbalance.

C. Simulation 3: PTU Transition

At the change of a program time unit, PRPs may wish to dispatch their units differently in order to meet their changed loads at lower cost. As a result, generation is scheduled for a transition to the new value around a PTU-transition. Below, such a transition from one PTU to the next is simulated.

PTU 1 starts at t = 0 s. During this PTU, PRP1 has predicted wind power to produce 80 MW and scheduled its coal and gas units to produce 80 MW and 40 MW respectively, in order to meet its load, which is now assumed to be 200 MW. Likewise, PRP2 has predicted wind power to be 80 MW and scheduled its coal and gas units to produce 120 MW and 40 MW in order to cover its load of 240 MW. For PTU 2, starting at t = 900 s., PRP1 increases its generation from the gas unit to 60 in order to match an expected load increase of 30 MW. PRP2 regulates its gas unit up to 80 MW and its coal unit down to 100 MW in order to match its load increase of 20 MW. All units are set to respond to any power imbalances: therefore, production for all units will deviate somewhat from scheduled production in order to minimize program deviations.

As can be seen from figure 8, the generation units respond to their scheduled values and manage the PRPs' imbalance at the same time. This results in a power imbalance which is continuously within bounds. Likewise, the program deviation keeps returning to zero. It can be noted that at t = 1300 s., PRP2s' gas unit reaches its maximum production due to a dip in the wind power. The remaining, coal unit responds by increasing its production in order to decrease the power

imbalance. As soon as the wind power increases again, the gas unit starts to return at its scheduled value.

D. Discussion

From the simulations above, it can be concluded that the modelled generation units are able to follow the amount of wind power variability and load steps simulated here. The maximum ramp rates simulated and shown in figure 3 appear to be sufficient for minimization of program deviations and hence imbalance costs to the PRP involved. The wind power fluctuations, ramp rates and PTU-transitions simulated did not push the imbalance-following capabilities of the generation units to their limits.

Program responsibility has been shown to significantly reduce the ACE. Instead of secondary control on a system level, PRPs reduce their imbalance themselves. Obviously, the extent to which PRPs do so depends on their market strategy. For example, it may prove to be profitable not to respond to the program deviation until the last minutes of each PTU, in order to avoid continuous ramping of units.

From the above, it can be concluded that, apart from the technical capabilities of generation units, also the control strategies are of importance when simulating wind power balancing. In a liberalized environment, the unit operation philosophy of market parties determines the extent to which the technical capabilities will be exploited. Therefore, cost aspects (imbalance costs, unit marginal costs, impacts of ramping on maintenance costs) should be taken into account as well.

V. Research Framework

With a significant penetration of wind power, the uncertainty and variability of wind power production will cause problems in maintaining the balance in a power system. Even though power balancing is not a new issue, large-scale wind power poses new challenges for balancing its intermittency. Existing solutions for power system balancing comprise mainly conventional generation unit control; however, little knowledge exists on the advantages and disadvantages of the use of their capabilities. The same holds for innovative solutions such as demand-side management, energy storage and wind park control. Insight is needed into the opportunities of the solutions available and their technical and economical constraints. For the integration of large-scale offshore wind power into power systems, a growing need exists for optimal balancing strategies in a liberalized environment. For this purpose, a long term simulation tool is being developed, of which this paper presents some exemplary preliminary results. The model will be used to assess long term power system frequency stability in the presence of large-scale offshore wind power. Performance of the balancing mechanisms can be assessed by measuring frequency excursions and deviations from area interchange schedules.

Apart from the technical possibilities for power system balancing with offshore wind power, economic aspects will be included in the model. Typical aspects include program responsibility, energy trading and market party strategic behavior in a liberalized environment.

The simulations presented in this paper have shown the working principles of the model. Future work will include validation of the power system model; addition, specification and validation of conventional generation unit models; analysis of offshore wind data for minute and hour timescales; analysis of load profiles. Ultimately, a decision support tool has to be developed to determine optimal (technically and economically) strategies for power system balancing with offshore wind power.

VI. Conclusions

In this paper, a power system model has been developed for the simulation of long term power system stability in the presence of large-scale wind power. It has been shown that a two-mass representation of a power system converges to the same values as a one-mass system in response to a power imbalances, but provides some additional insight into inter-area oscillations. The model incorporates typical aspects as primary control, load damping and secondary control. Furthermore, the Dutch system of program responsibility has been modelled.

Models of thermal generation units (coal, gas) and two wind parks have been set-up and discussed. Conventional generation units all show an initial, fast response and a more persistent, longer term response to set-point step and a frequency change. This response is in fact the maximum capability of the unit's response to imbalances. Straightforward wind turbine models, based around a power curve and moment of inertia, smooth out some of the very fast (seconds) wind fluctuations.

Example simulations have been used to demonstrate the operation of the developed model. In the simulations, it has been shown that the system of program responsibility may significantly reduce the need for secondary control at the area (system) level. Program responsible parties (PRPs) will however be inclined to minimize program deviations, thus compensating power imbalances. It has been shown, that the extent to which the capabilities of conventional generation units are used are highly dependent on the operating philosophy of the PRP. The generation unit models developed here show a good capability of balancing wind power fluctuations and load changes. By adding and extending generation unit models, the further developed system model could be used to simulate the operation of the whole system of generation units, loads and large-scale wind parks in a liberalized environment as in the case of the Netherlands.

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