Report.

Frequency stability contribution of Wärtsilä combustion engines

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By order of Wärtsilä Finland Oy

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EXECUTIVE SUMMARY

Due to the integration of renewable energy sources, it is expected that maintaining the power balance in the power system will become more challenging. Renewable energy sources decrease the inertia of the power system. Moreover, their power output is often fluctuating and poorly predictable. These aspects pose challenges for grid frequency stability.

Wärtsilä has built a portfolio of combustion engine based power plants which have the ability to start up and ramp up very fast compared to conventional power plants. These properties enable the combustion engine based power plants to contribute to frequency stability.

In this study the effect of introducing combustion engines for frequency stability is investigated using a model of an isolated Dutch power system. This model is used to simulate a number of case studies with varying penetrations of renewable generation and varying penetration levels of combustion engines. The simulations are used to determine the effect of introducing renewable energy sources on frequency stability and the positive contribution of fast responding generation like combustion engines. Therefore, possible future scenarios with a large share of renewable generation have been studied.

Based on the study it can be concluded that no negative effects of introducing combustion engines have been found. On the contrary, improvements regarding frequency stability were noted. More in detail:

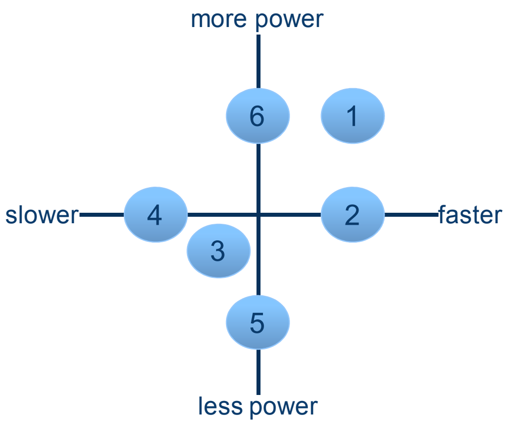
- Regarding second-scale power frequency deviations, the frequency response is dominated by the combined contributions of primary control by conventional generators and inertia. Introducing combustion engines decreases the system inertia, but this effect is compensated by the fast response and high ramping capabilities of the engines. The frequency stability is improving when combustion engines are added to the system.
- For slower frequency deviations (30 seconds and more), the speed of the automatic generation control is the main limiting factor. As long as the generators providing control power for secondary control in the power system are fast enough to track the automatic generation control signal, adding more combustion engines does not contribute extra to improving frequency stability.
- It is possible to replace all existing up-regulating secondary control with non-spinning combustion engines. The system behavior on a trip event does change, but the resulting response matches the ENTSO-E requirements.

CONTENTS

1 INTRODUCTION

1.1 Problem description

Worldwide, the power system is changing profoundly. The integration of renewable energy sources is advancing rapidly, and while the environmental benefits of these sources are obvious, the intermittency and unpredictability of their power output pose challenges for grid frequency stability. This is enhanced by the fact that renewable sources do not always contribute to stability services and system inertia, and are replacing power plants that were contributing to those services. This also increases the vulnerability of the system during disturbances such as power plant trips. Frequency stability is therefore becoming a prominent issue in the power systems of the future.



1. **Increasing share of renewable generation**
2. **Decreasing system inertia**
3. **Demand side management**
4. **Growth of the synchronously interconnected grid**
5. **Allowing cross-border balancing**
6. **Market dynamics**

Figure 1: A number of future changes affect the balancing requirements. The increasing share of renewable generation, in combination with the decreasing system inertia and the market dynamics are driving forces to have fast responding combustion engines participating in power balancing.

Wärtsilä has built up a portfolio of combustion engine based power plants. These types of plants distinguish themselves for their fast start-up and ramping capabilities compared to conventional power plants. Therefore, they might be able to contribute to frequency stability in the power system, by offering primary and secondary reserve power faster than conventional power plants.

This report presents the results of a concept study performed to investigate the effects of integrating a high degree of Wärtsilä combustion engines in a representative future power system. The report shows when and how combustion engines can support the current and future power system (including a high degree of renewable generation sources) to mitigate some of the challenges posed by higher amounts of renewable electricity generation.

1.2 Research question

The study presented here focuses on the following research question:
Given the challenges regarding frequency stability in the power system, what is the possible contribution of combustion engine-based power generation to frequency stability from a systems point of view?
This research question will be investigated by studying the system response of a realistic power system model of a European country. This power system will be used with a high level of renewable energy generation, and will be modified to incorporate a large amount of combustion engine-based power plants. The modeled power system will then be exposed to several events that are commonly regarded as the main challenging events regarding frequency stability for the power system. The resulting system responses will be analyzed to answer the question posed above.

2 BACKGROUND AND METHODOLOGY

2.1 Power system background

2.1.1 Power balance and grid frequency

In a power system, most of the electricity is generated with synchronous generators and supplied to the power grid. The frequency of the grid is created and sustained by these rotating machines. As long as generation and load of electricity are in balance, the frequency of the grid will remain nominal. However, any imbalance between generation and load will be compensated by a change in the stored kinetic energy of the rotating machines thus leading to a frequency deviation. Frequency deviations should remain within certain limits to avoid blackouts or damaged equipment. To ensure this, several control strategies have been incorporated into the power system [1].

The power balance can, in an AC power system, be regarded as a flywheel which rotates with a certain frequency (Figure 2). This frequency is also called the grid frequency which is, depending on the system, 50 Hz (e.g., Europe) or 60 Hz (e.g., North America). The flywheel is constantly being accelerated by a number of generators that insert energy into the flywheel. At the same time, the flywheel is being decelerated by loads that extract energy from the flywheel. As long as the sum of accelerating and decelerating powers is zero, the wheel will continue to spin at a constant frequency. If however, a mismatch between generation and load appears, the accelerating and decelerating powers do not cancel out, leading to a change of the rotational frequency of the wheel. The rate of change of frequency during this event is inversely proportional with the inertia of the wheel. In a power system, this inertia is represented by the total inertia of all rotating masses (e.g. generators and motors) connected to the power system using synchronous machines [2].
Many of the distributed generators based on renewable energy sources (DG-RES) are connected via power electronics which are unresponsive to changes of the grid frequency. The unresponsiveness of these DG-RES leads to a reduction of the inertia of the system [2].

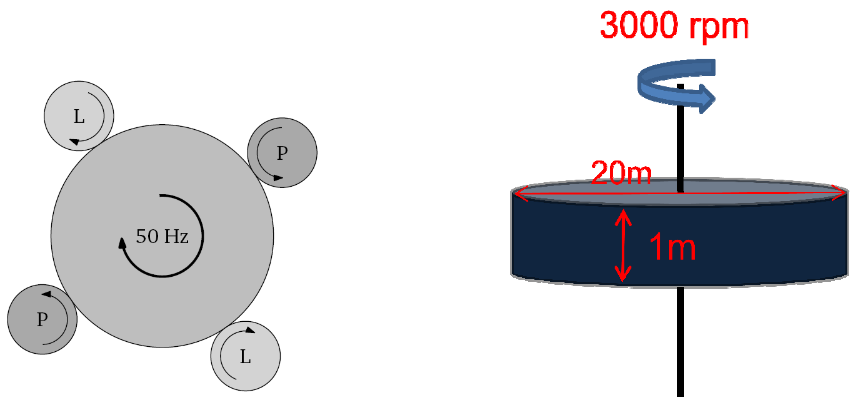


Figure 2: The power system balance can be represented by a wheel, accelerated by generation (P) and decelerated by load (L). For the synchronously interconnected continental European power system, the wheel in this analog has an inertia that is comparable to the inertia of a steel disc of 1m thickness and approximately 20m diameter, spinning with a speed of 3000 rpm (50 Hz) [2].

2.1.2 Maintaining and restoring power balance

The Transmission System Operators (TSOs) are responsible for maintaining the balance between generation and load in (a part of) the power system. Every TSO is responsible for maintaining its internal power balance of its area since it is expected that each TSO is liable for maintaining the sum of its generation, loads, imports and exports balanced. To realize the area balance, TSOs often imposes balance responsibility on suppliers, generators and traders in the system [4]. The power balance in the system is maintained in the following way [5]:

- Ahead of actual system operation, the TSO checks whether the sum of scheduled generation, imports and exports match with the expected load in the system. This holds for each trading period (or program time unit, PTU) which is (for the Dutch case to be investigated) a period of 15 minutes.
- In real time, the parties that bear derivative balance responsibility (called balance responsible parties or BRPs) are incentivized to follow their scheduled generation by a system of imbalance pricing, penalties or other means.
- In real time the real values of power generation and load will deviate from their predicted values. This will cause a power imbalance which leads to a frequency deviation as explained above. In the European power system, there are four control loops in place to arrest and restore the power balance and therewith the frequency deviation in the system [6]:
    - Primary control (PC): generators have the obligation to act on the frequency deviation observed locally in the grid by providing extra power if needed. This will cause the frequency to be arrested at a certain stable level.

- Secondary control (SC): for each control area in the European grid (usually a country) the local TSO is responsible to maintain area balance. The TSO has a control algorithm in place that calculates how the power setpoint of the control area should be changed to restore power balance. This power is then commanded from the generators in the control area, either through a market mechanism or through direct control of the plant power setpoint by the TSO. This mechanism is often called Automatic Generation Control (AGC).
- Tertiary control (TC): after secondary control reserves are used, they can be freed up by tertiary control reserves.
- Time control: the integral of the frequency is monitored at system level. If this integral starts to deviate too much from the integrated nominal frequency, the frequency setpoint will be adjusted to compensate for this.

2.2 Phenomena affecting power balance

In the power system, there are three main events that regularly affect power balance. These effects will be introduced in this section, and will play an important role in defining the case studies used to investigate the research questions.

2.2.1 Trip of power plant

When studying frequency stability, the classical event to consider is a trip of the biggest production unit in the system. In practice a power system should be capable of overcoming a trip of the largest power plant. Such a contingency would lead to a sudden drop in frequency. Primary response from the other production units should halt this drop and restore frequency to a level that is lower than the nominal frequency but stable. After this event, secondary response takes over to restore primary reserves and bring the frequency back to its nominal level. Desired system behavior during and after a trip is defined by the European Network of Transmission System Operators for Electricity (ENTSO-E) [6].

2.2.2 Imbalance due to renewable generation

Conventional generators can be controlled such that their power output is equal to a preset value. For renewable generation the power output depends on the momentary availability of their respective primary energy source. As this primary energy source is often solar or wind, the power generation depends on meteorological phenomena. The variability of renewable generation leads to an increase of control actions by conventional, controllable generators to cancel out the fluctuations. Besides the variability of the power output, generators based on renewable energy sources are also characterized by a certain unpredictability of their power output. These two phenomena together cause additional imbalance in the power system:

- Regarding predictability: In order to keep the power balance per program time unit, suppliers make predictions of the amount of renewable energy they expect per program time unit. Any deviations from these predictions in real-time will cause imbalance which should then be settled either within the portfolio of the balance responsible party or by the imbalance settlement system operated by the transmission system operator.
- Regarding variability: suppliers of electricity and balance responsible parties have a responsibility in terms of energy per program time unit. Therefore they have an incentive to make predictions also in terms of energy per program time unit. However, within the program time unit, the power output of renewable generators will vary as well, leading to intra-PTU imbalances which are to be settled by the imbalance settlement system.

2.2.3 **Block energy trading**

With the restructuring of the electricity business, producers, traders, network operators and system operators became separate entities in a market environment. Being privatized companies, traders and producers are incentivized to maximize their profits by adjusting their behavior. In the current markets, producers, consumers and traders are represented by balance responsible parties which enable the transmission system operator in a control area to maintain the power balance. While the transmission system operator is responsible for maintaining the power balance on a momentary base, the balance responsible parties have the obligation or the target to balance their position over a program time unit. Therefore a balance responsible party is either penalized or rewarded based on its behavior over a period of time instead of on its momentary behavior.

A balance responsible party will use this freedom to optimize its resources within a program time unit. The optimal solution for a balance responsible party with generation capacity is to keep his generation setpoints constant during a program time unit, and ramp up or down to a new generation setpoint for the next program time unit as fast as possible. At the same time, the load will change only gradually. Therefore, during the program time unit, power imbalances will occur between generation and load, as illustrated in Figure 3. This leads to imbalance at the PTU crossings and frequency disturbances as illustrated.

It should be noted that several countries in Europe operate with PTUs of 15 minutes while others operate with PTUs of 30 or 60 minutes. Combined, the effect on hourly transitions is most visible in the real system.

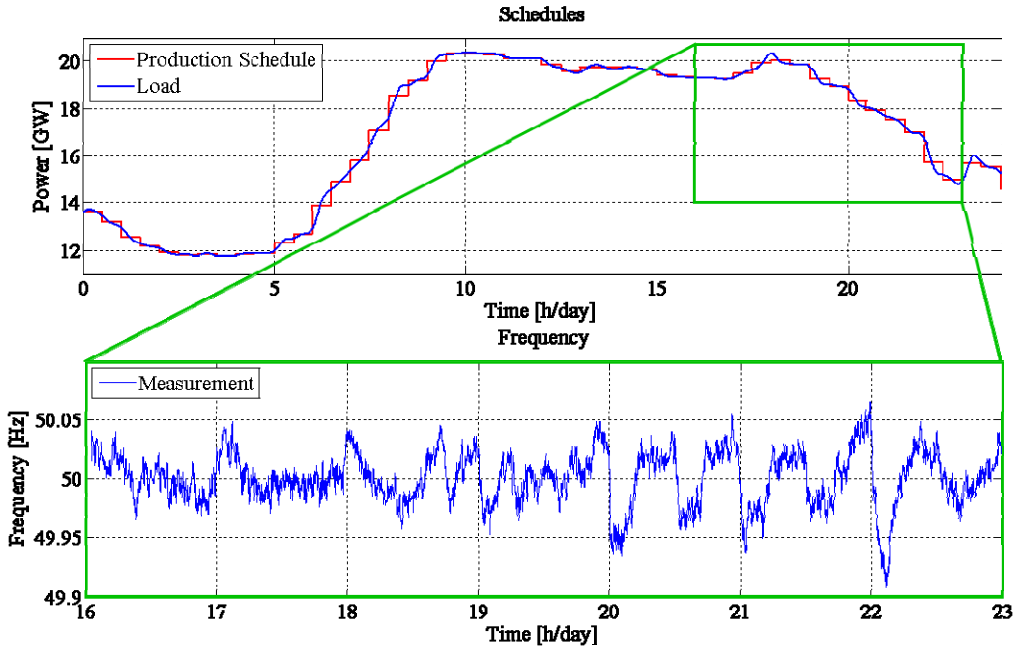


Figure 3: Frequency disturbances related to block-wise schedule changes.

2.3 The Dutch power system

Now the power system background is covered and the three main events threatening frequency stability are introduced, the power system that is used in the study can be described. For the study reported here, the Dutch power system is used. The Dutch power system has the following characteristics based on data from 2010 [8]:

			Share of ENTSO-E
Total net generation:	113.7	TWh	3.3%
Generation capacity:	25465	MW	2.8%
Consumption:	116.5	TWh	3.5%

The difference between the total net generation and the consumption in the table above is caused by the net import of the Netherlands which was 2.8 TWh in 2010 [8]. For 2010, the energy balance for the Netherlands shows that the total electricity needed for consumption, grid loss and export is covered for 12% by electricity import, 32% by cogeneration (partly by decentralized units), and 56% by the production of power stations [9]. Compared to other countries, the proportion of cogeneration is high. These CHP (combined heat and power) plants are installed in industry and horticulture. Sustainable generation provided 9.1% of the electricity consumed in 2010. Of this amount, 60% was produced by biomass (mainly by conventional power plants and waste incinerators) and 38% by wind turbines [10].

The case studies are applied to a model of the isolated Dutch power system as introduced above. In practice, the Dutch power system is synchronously interconnected within the ENTSO-E Continental European grid. The arguments to evaluate the contribution of combustion engines in an isolated system are:

- An isolated system has smaller inertia and therefore:
    - Power imbalances lead to larger frequency deviations;
    - The contribution of combustion engines is more visible;
- The high availability of realistic power plant data for the Dutch system;
- Reduced computational time.

The argument to take 2020 as the year under study is the expected expansion of renewable energy generation, as prescribed to be fulfilled by the European Union climate and energy package, which leads to decreasing inertia as well as more imbalance as covered in the previous chapters. The expected expansion of renewable is based on National Renewable Energy Action plans. Further underlying assumptions to create a realistic 2020 scenario are covered in chapter 4.

2.4 **Methodology**

In the light of the research question and the background covered in this chapter, the following approach was defined:

1. A model of a power system was created in which the model of multiple Wärtsilä combustion engines is integrated. The model applied for this analysis is introduced in chapter 3. The isolated Dutch power system for the year 2020 was selected as suitable power system to study.
2. For this system, the three events were taken as a starting point to assess the impact of adding combustion engines to the system;
3. Different levels of combustion engine penetration and different ways of using these combustion engines in secondary control were explored.

Multiple case studies that explore different combinations of combustion engine penetration, combustion engine parameters and operational regimes in combination with the three events covered in section 2.2 will be simulated. Analysis of the simulation results should be able to provide answers to the research question posed before.

3 MODELING

In the previous chapter, the power systems background was introduced as well as the methodology taken in this study. In this chapter, the simulation framework that is used for these simulations will be described. Details about the model implementation are presented in section 3.1. In this description, settings and assumptions for the specific case of the Dutch isolated system are mentioned as well. The validation of the model is covered in section 3.2. The power system simulation model used in this study is KEMA's proprietary KERMIT (KEMA Renewable Model Integrating Technologies) model. This model is geared towards simulating the electricity system's performance in one second to one day time frames. In that way, it captures the range of dynamics that concern technical stability issues and control loops on the one hand, and economical considerations on the other hand.

3.1 Model implementation details

On a generic level the model can be represented by a block scheme as given in Figure 4. Details on these blocks will be given in the following subsections.

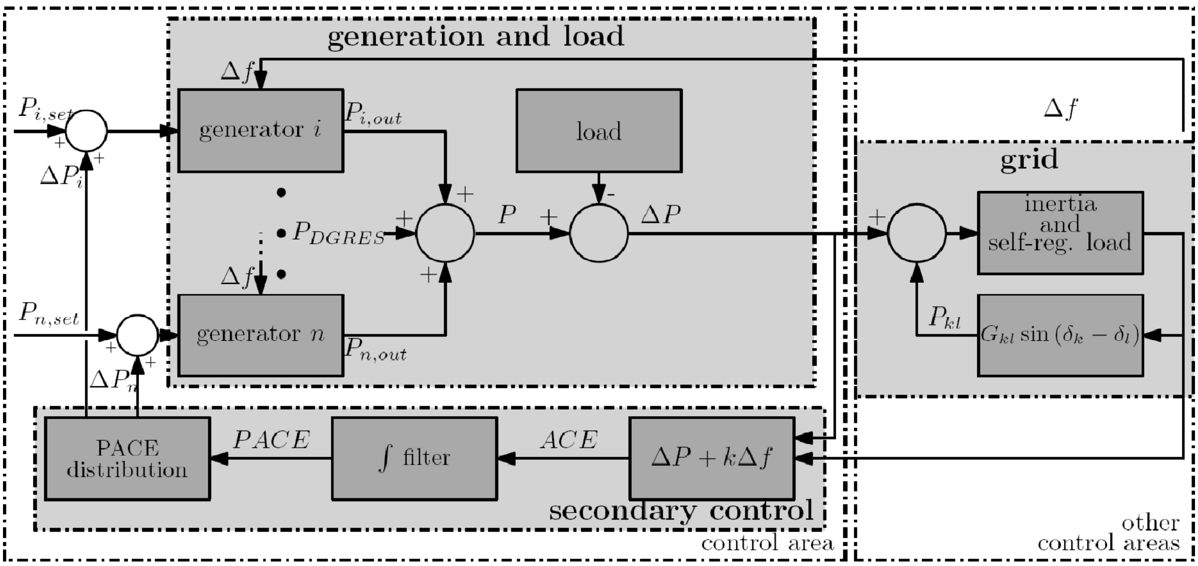


Figure 4: KERMIT Model setup.

3.1.1 Modeling secondary control

When a power imbalance occurs, primary control will stabilize the grid frequency. After that, secondary control is activated to bring the frequency back from its quasi steady-state frequency to its nominal value. All TSOs of the control areas measure the cross-border exchange and frequency. They combine these data into the Area Control Error (ACE) which gives information on the balance in the control area using the following equation [2].

$$ACE = \Delta P + K\Delta f$$

Here ΔP is the difference between the scheduled cross-border exchange and the actual cross-border exchange. K is the primary contribution of each control area. After an imbalance is detected, the TSOs use market mechanisms to deploy secondary control capacity. The goal of secondary control is to drive the ACE to zero using a proportional-integral (PI) controller. This controller transforms the ACE into a Processed Area Control Error (PACE). The PI-controller can be represented as follows [2].

$$PACE = \beta \cdot ACE + \frac{1}{T_{PACE}} \int ACE\, dt$$

Here β is the proportional gain which has to be between 0.1 and 0.5 and T_{pace} is the integrating time constant which has to be between 50 and 200 s [9]. The amount of power calculated as the PACE has to be generated by the suppliers in the system. This is done by matching the PACE with the results from an ahead bidding procedure. The supplier that offered the cheapest bid will be activated. This will continue until enough energy is activated to restore the ACE to zero. All bids can be activated with a maximum speed of 7% of the nominal value of the bid per minute. The selected bids receive payments for their activity [2] if they actually contribute to minimize the ACE. In the KERMIT model the bidding procedure is not modeled to limit complexity. Instead PACE is divided over all operating units available for secondary control based on their available headroom. The secondary control loop is calibrated to historical data and used previously in projects with the Dutch TSO.

3.1.2 Modeling load

The load is modeled to vary only as a function of time and is given as an input to the model. The self-regulating effect of the load is modeled in the grid model as covered in the next section. For each of the case studies, a load profile for a day has been generated based on existing load data and load forecasts.

3.1.3 Modeling generation

All individual generators (>60 MW) are modeled for the control area under study. This includes both conventional and renewable/distributed generation. All large conventional generators have primary control, i.e., they are responsive to frequency deviations and proportionally increase their power output in case of a frequency drop and vice versa. The primary controller increases the setpoint of a power plant proportionally with the frequency deviation. Primary controllers operate with a droop function as given in the equation below.

$$S = \frac{-\Delta f / f_0}{\Delta P / P_0}$$

Here S is the droop, Δf is the frequency deviation from nominal frequency f_0, ΔP is the power deviation caused by primary control with respect to the nominal power output P_0. In KERMIT, the droop S for all generators larger than 60 MW has been set to 10% as prescribed by the Dutch TSO [12]. Primary control is modeled without any deadband. In the Dutch system, the requirement is that 50% of primary control is active within 15 seconds, and 100% is active within 30 seconds. The maximum amount (100%) must be allocated at 200 mHz frequency disturbance. For all plants bigger than 60 MW there is a requirement to reserve 1% of the nominal power output of the plant for primary control.

Each generator has a setpoint which defines the power output under normal conditions. This power setpoint is defined using a process of unit commitment and economic dispatch (see section 4.2 for details). During this process of unit commitment and economic dispatch inputs such as predicted load and predicted renewable generation as well as boundary conditions such as required reserves are taken into account. The standard process of unit commitment and economic dispatch is explained in [13].

For modeling the power plants, standard models from literature were taken as basis. Then, measured responses for representative plants of the Dutch system were taken to tune and validate those models. In Figure 5, the actual response is compared with the model response for one of those plants.

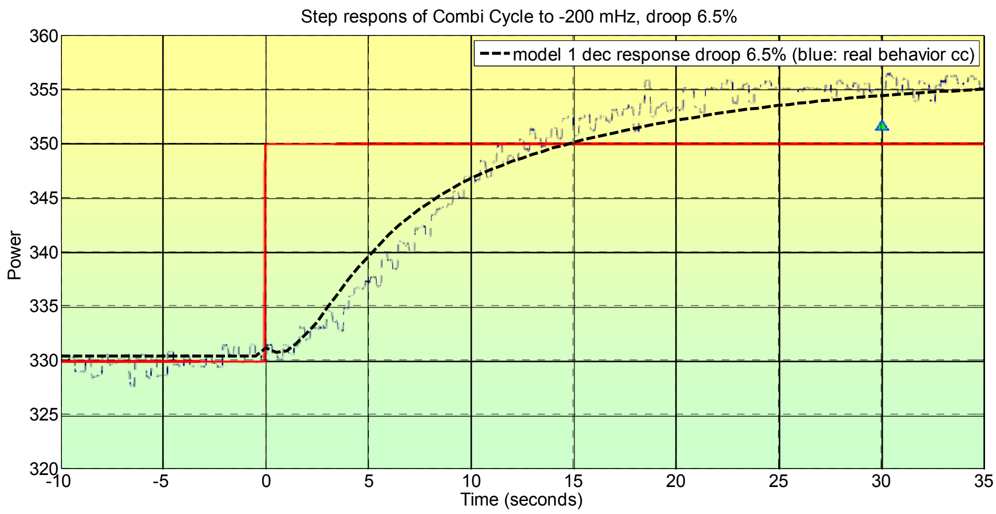


Figure 5: Response of the combined cycle power plant and KERMIT combined cycle model on a frequency step of -200 mHz, droop 6.5%.

A model of the combustion engine specifically suited for this type of studies has been developed in cooperation between Wärtsilä and KEMA. Figure 6 shows the match between this model and a fully detailed Wärtsilä model, which runs in a preselected load control with a frequency bias, for a typical frequency disturbance. Differences between the models are considered negligible.

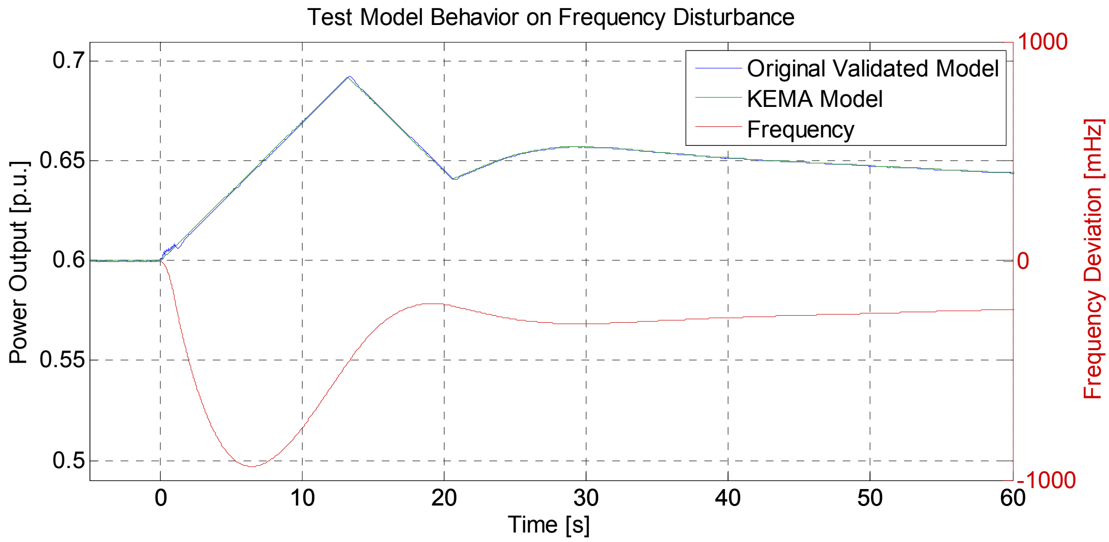


Figure 6: Validation of the combustion engine model behavior on frequency disturbance. In the first 21 seconds the control signal (using droop control this is proportional to the frequency deviation) exceeds the maximum ramping capability of the generator. After 21 seconds the maximum ramping capability by the generator is not exceeded anymore by the control signal and from that point the power output is proportional to the frequency deviation.

3.1.4 Modeling the grid

3.1.4.1 Power flow equations

To model grid dynamics and inter-area power flows, each area is modeled to have inertia and self-regulating load. The transfer function $H_{grid,i}(s)$ of this inertia and self-regulating load is modeled as follows.

$$H_{grid,i}(s) = \frac{\Delta f_i}{\Delta \mathrm{P}_i} = \frac{1}{M_i s + DL_i}$$

Here Δf/ΔP is the rate of change of frequency for each area i with moment of inertia M_i, self-regulating effect D and load L_i. The inertia for the Continental European grid is $2.1 \cdot 10^5$ MWs/Hz approximately [2]. This inertia is proportionally distributed among the areas. So, the inertia in the power system is modeled as being aggregated per country. Consequently each area has different frequency deviations which lead to correcting power flows [19].

For the Dutch power system under study, the inertia is assumed to be aggregated as well. However, for this area an inertia value is defined per plant. Therefore, for each moment in time during simulation, the actual inertia of the Dutch system at that specific moment is derived, based on which power plants are operating. It is assumed that wind turbines do not contribute to inertia. This aggregation method is taken from [20].

The load is modeled as being proportionally dependent on the grid frequency [19]. The self-regulating effect is assumed to be 2%/Hz and corresponds to parameter D in the equation above [6]. The load L is the actual load of each area.

Any frequency deviation will lead to inter-area exchange of power due to angle differences among the multiple areas. As each area has different inertia, the phase angles in between the areas will deviate leading to cross-border power flows. These power flows are calculated using a DC load flow approximation.

3.1.4.2 Renewable generation and grid inertia

The development of the inertia during the day is given in Figure 7. It can be observed that due to changes in the composition of the running production units during the day, the inertia varies. Secondly, it can be observed that introducing large shares of wind generation affects the inertia. Thirdly it can be seen that introducing combustion engines for frequency support decreases the inertia in the grid due to the fact that they replace existing production units that generally have higher inertia. Both for high and low inertia cases, the effect of introducing combustion engines for frequency stability will be evaluated. The vertical black line indicates the moment at which a generator trips at the trip event.

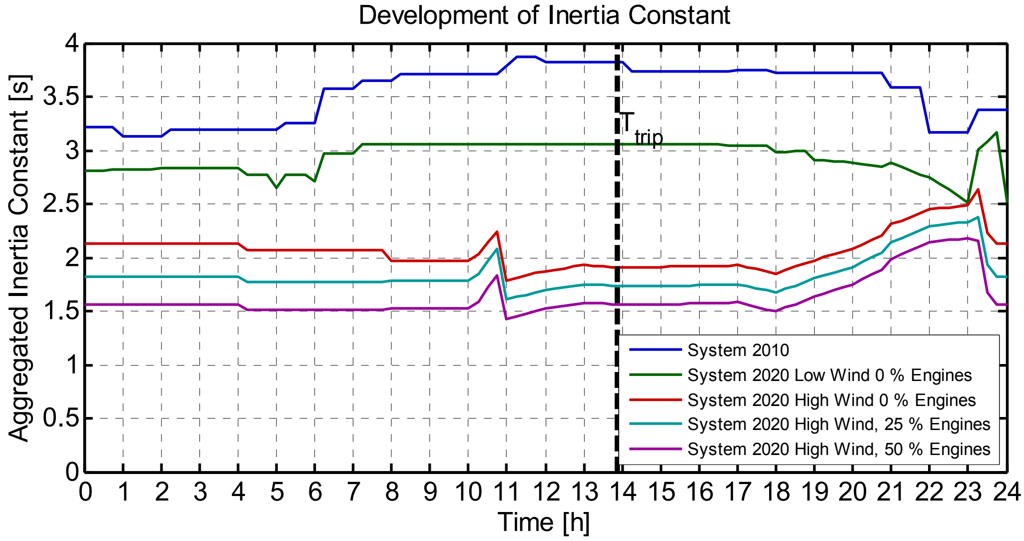


Figure 7: Development of the inertia during the day for several case studies.

3.2 KERMIT model validation

The KERMIT model will be used to model the Dutch power system in isolation. However, in reality the Dutch power system is part of the ENTSO-E synchronously interconnected area. Therefore, validation efforts were undertaken for the interconnected case as well. The results from the simulations have been verified using measurements whenever possible, otherwise using observations from realistic situations. Whenever possible the results have also been calculated for verification separately from the model to analytically validate the model result.

One example of the validation results is shown in Figure 8. Here, a 1500 MW power plant trip is simulated at time = 0 s. In the first case the AGC has a 7%/minute ramp rate limit. In the second case this 7%/minute ramp rate limit has been removed. Reason for testing the model with and without this ramp rate limit is because not all AGCs are equipped with a ramp rate limiter. Therefore, depending on which AGC is activated (or in other words, in which country the trip took place) the frequency response will be different. The modeled results have been compared with four frequency measurements in the European grid during known power plant disturbances. It can be observed that the modeled results correspond to the measured responses.

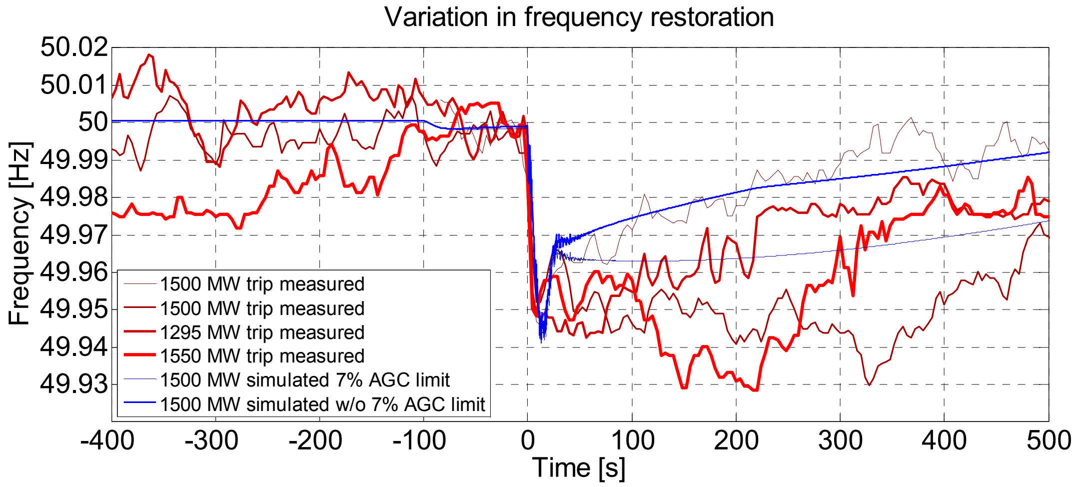


Figure 8: Simulated and measured system frequency response during large power plant trips in the European interconnected power system.

4 CASE STUDIES

In the previous chapters, the concepts to be studied as well as the model to be used were presented. In this chapter the case studies performed with the model will be elaborated. The purpose of this chapter is to give the reader a clear view of the background of the case studies performed and provide technical detail about the simulation inputs. In the next chapter, the simulation results are then shown and analyzed.

4.1 Background, definition and description of case studies

In chapter 2 it was explained that there are three relevant issues when studying frequency stability:

- The event of a sudden loss of generation (referred to as a 'trip event');
- The occurrence of instantaneous power imbalances due to block-wise operated power plants while the load grows smoothly (referred to as 'block trade effect');
- The power imbalances due to wind power variation and wind power forecast errors (referred to as 'forecast error effect').

For all these effects, it is evaluated how combustion engines affect frequency stability using the following simulations:

- Simulations in which the typical system behavior is shown. These results will serve as base line to compare the other case studies against.
- Simulations in which the penetration of combustion engines in the system is increased to 25% and to 50% of the total thermal generation respectively.
- Simulate the effect of making the available combustion engines the only plants that contribute to secondary control.
- The effect of replacing up-regulating spinning secondary reserve with non-spinning secondary reserve by having non-spinning combustion engines in the system that will be activated as soon as there is a need for more secondary spinning reserve.

In the next section, the specific variations in input profiles for these case study sets are discussed.

4.2 Description of the simulation profiles

For each of these case studies, the same simulation model as introduced in chapter 3 is used. The difference between the simulations is made by changing the input profiles for the simulation. The input profiles that vary over the case studies are defined below.

4.2.1 Input profiles: generation dispatch profile

The KERMIT simulator uses power plant schedules covering 24 hours as an input. These schedules represent the day ahead commitment of the power plants, based on the wind forecast, load forecast and import commitments.
For the case studies a dispatch profile for 2020 was used, based on the expected plant portfolio for that year. This schedule was prepared with a market simulation tool PLEXOS. PLEXOS simulates “real-world” dispatch, following the least cost principle under consideration of unit constraints and available interconnection capacity. The schedule assumes a sustainable development scenario, in which load and generation figures reflect EU targets and where the expected expansion of renewable is based on National Renewable Energy Action plans. Fossil fuel and carbon prices are based on IEA's World Energy Outlook 2010. The profile has high amounts of wind power production during the biggest part of the day. Due to the high wind power production, the amount of running thermal generation is reduced, which leads to a lower inertia. Figure 9 displays this dispatch profile. The vertical blue line indicates the moment at which the generator trip takes place. The areas are limited on the lower side by the net import/export, and on the upper side the daily load profile is displayed. The net import/export changes significantly over the day. Any import is considered to contribute to the system inertia with a composition similar to the average Dutch conventional power plant portfolio.

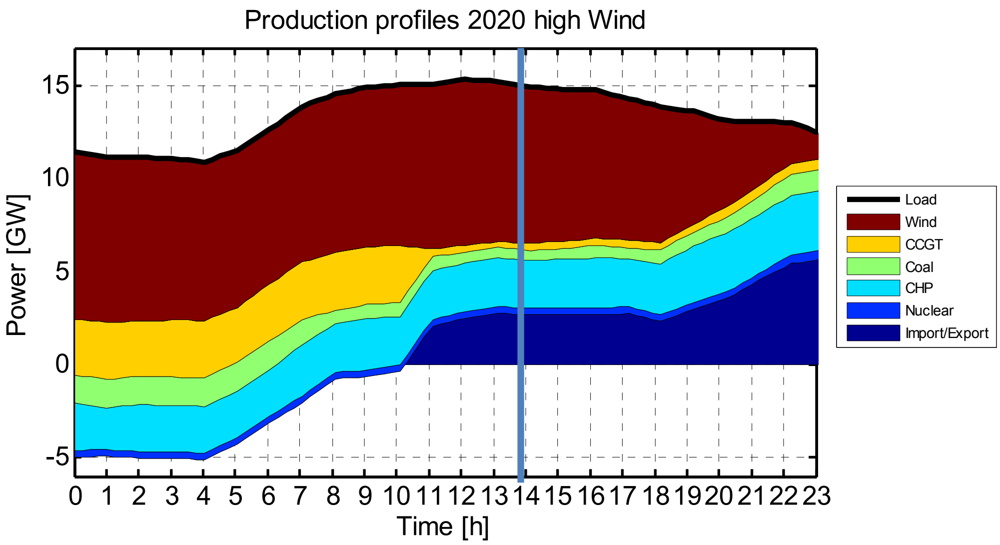


Figure 9: Dispatch profile for the 2020 high wind scenario.

4.2.2 Input profiles: events to be simulated

As indicated earlier in this chapter, the study focuses on three effects: the trip event, the block trade effect, and the wind forecast effect. Regarding simulation inputs, this has the following consequences:

- For trip events, the wind forecast is assumed to be perfect and intra-PTU fluctuations on the wind production are not active. In this way, the trip event can be studied without interference of the wind-induced imbalances. Moreover, the time horizon over which a trip is simulated is not the full 24 hours but a shorter period of about 30 minutes. A trip of 500 MW in the system base load was taken as the trip event under study. This is a significant trip for the isolated system: when using the UCTE guidelines, the Dutch system is obliged to have about 350 MW secondary control available [6].
- For the block trade effect, the wind forecast is again assumed to be perfect, and intra-PTU fluctuations are not active. The trip event is also not active. The simulation is run over 24 hours. The effect of block trading is simulated by defining the production schedule for the load selected in each case study. As only the Dutch system is modeled with PTUs of 15 minutes, frequency excursions take place on the 15 minute intersections.
- For the wind forecast effect, the wind forecast error is present in the system as well as the intra-PTU fluctuations. As the block trade effect is fundamental to the system behavior, this effect was not suppressed during the wind forecast simulations. The simulation is run over 24 hours. To implement prediction imbalances and to determine the effect of introducing combustion engines two different prediction methods have been used to predict wind energy in the power system model.
    - Perfect prediction, the actual power output of the wind generation equals the prediction exactly.
    - Persistence forecast, the actual power output of wind generation is predicted using the persistence prediction algorithm using a forecasting time of 15 minutes [22]. This leads to an average forecasting error of approximately 4% of the installed capacity [2].

4.2.3 Input profiles: different settings and operating regimes of the combustion engines

The combustion engines can be used in multiple ways and with multiple engine settings. The following variations are used in the case studies:

- Combustion engine settings:
  - The ramp speed of the combustion engines: the default ramp speed of the Wärtsilä engine is 102% of the nominal power per minute. To study the effect of a faster response, a faster ramping capability of 168% of the nominal power per minute was used as well. For this higher ramping capability additional boundary conditions might apply, like combustion engine type, configuration and location specific conditions like operational patterns, temperatures and fuel.
  - Ramp speed of non-spinning combustion engines: the use of non-spinning reserves for secondary control is considered. Due to thermal effects, their ramp speed will be lower. Ramp speeds of 48%/minute and 66%/minute for non-spinning engines are investigated. Non-spinning combustion engines require a starting time of 30 seconds.
- Combustion engine operating regimes:
  - For much of the case studies, the combustion engine penetration in the system is 25% and 50% respectively. This is shown in Figure 10 and Figure 11. Here, some of the coal and CCGT plants were replaced by combustion engine-based plants, until the average combustion engine penetration over the day became approximately 50% of the thermal generation excluding nuclear and cogeneration plants.

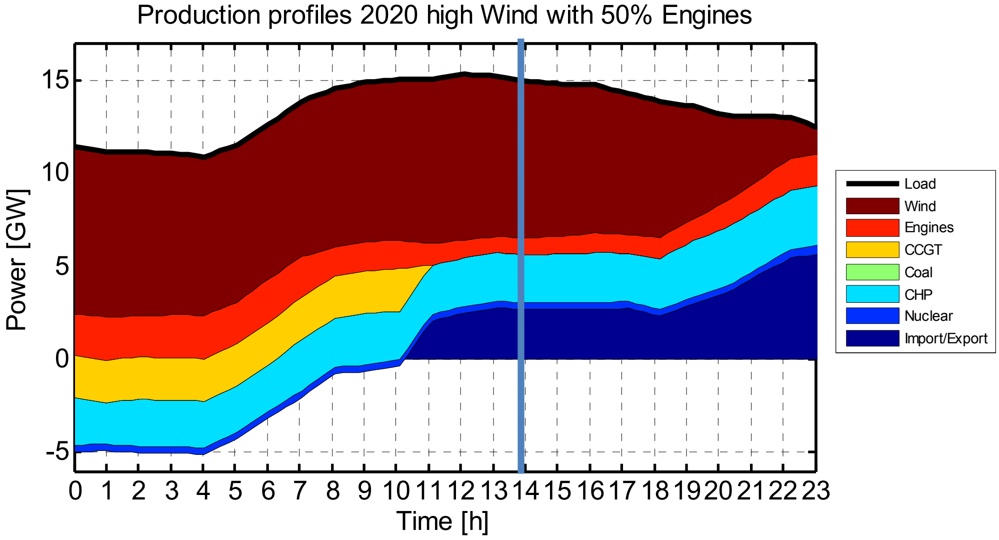


Figure 10: Production profile for a day in 2020 with high wind and 50% combustion engines.

- For some simulations, the secondary control effort only comes from the combustion engines and not from the classic thermal plants. To achieve this, the settings of the AGC were changed such that the requested power output was distributed only over the combustion engines and no longer to the other thermal plants.
- For some simulations, non-spinning combustion engines were added to the system. The AGC logic considers those plants to be available for secondary control, and would therefore give those plants a request for power if secondary control is needed. If this power setpoint exceeds a certain limit, the engines become active and will start to deliver secondary control. In this setup, the non-spinning combustion engines are not capable of delivering negative secondary control power. This power will be delivered by the spinning combustion engines.

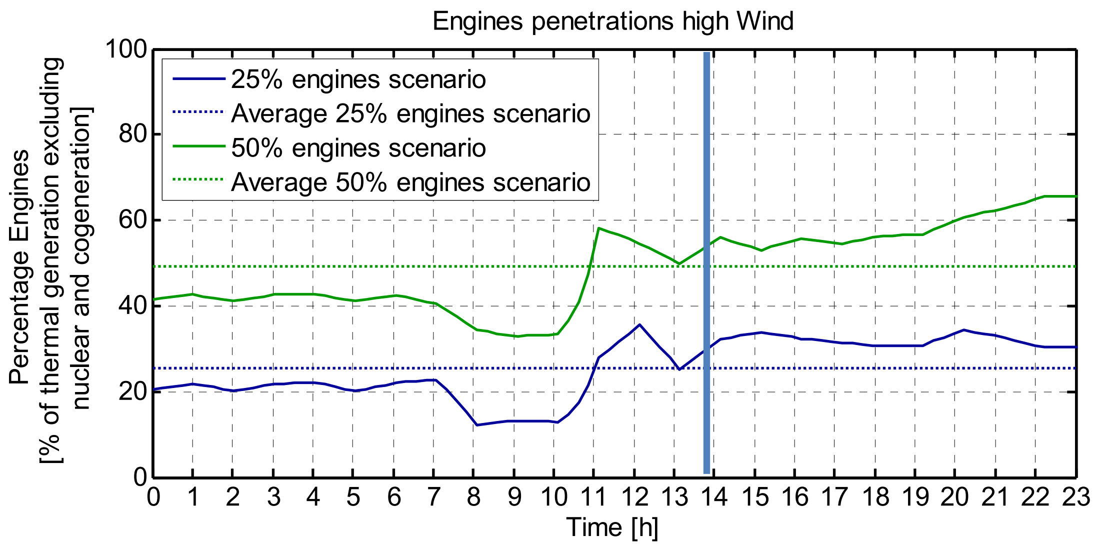


Figure 11: Fraction of combustion engines for a day in 2020 with high wind and 25% and 50% combustion engines.

5 PRESENTATION AND ANALYSIS OF RESULTS

In the next sections, the results will be presented and elaborated upon.

5.1 Typical system behavior

The first comparison made is the system behavior in cases of high wind and low wind. The event under study is the trip event of 500 MW. Results are shown in Figure 12.

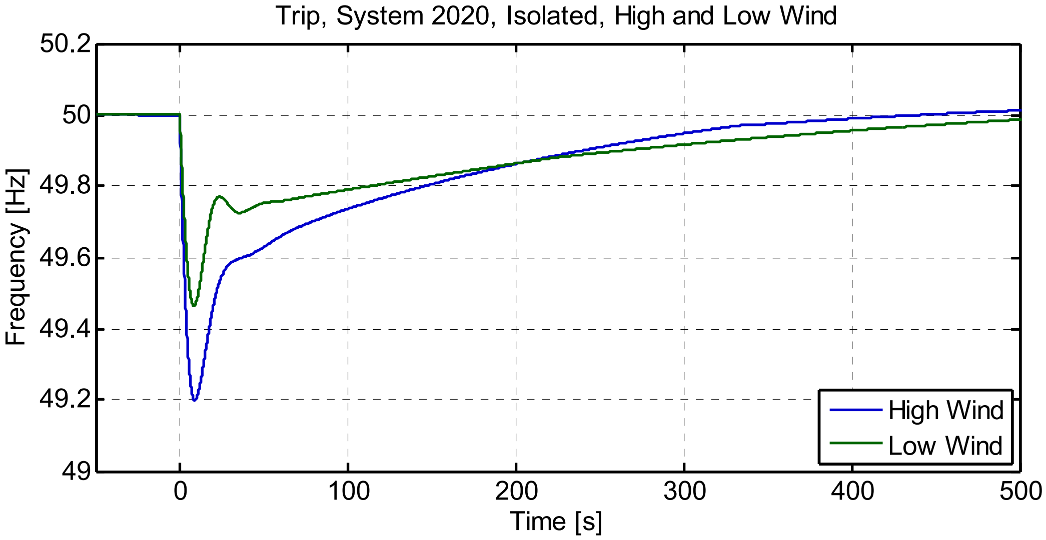


Figure 12: System behavior on trip event

As the inertia is lower when there is a lot of wind in the system, the frequency will drop faster. Therefore, the lowest point of the frequency (or 'frequency nadir') is significantly lower in the case with high wind. After the frequency is arrested, the secondary controller restores the frequency at its nominal value. The lower frequency drop in the case with high wind results in a more aggressive response of the AGC, which results in a faster frequency restoration.

The forecast error and wind volatility effect as introduced in chapters 2 and 4 is shown in Figure 13. This effect is shown by using a duration curve. A duration curve indicates the distribution of frequency deviations as a function of the cumulative number of hours that the frequency deviation exceeds a certain value in a year[1]. In the ideal case, the frequency

[1] The interpretation of the curve is as follows: at the left side, one sees how often during this particular day the frequency is higher than a certain value. In this case for the 2020 case, a deviation of more than 50 mHz or more occurs during less than 0.25 hours or 15 minutes on this day. Something similar holds for negative deviations, which can be observed in the right hand side of the figure.

deviations would be always zero, and the duration curve would be a flat line at 50 Hz. The closer the duration curve is to this ideal, the better the system performance. For this case, it is clear that the frequency deviations for 2020 are much more pronounced than for 2010. This is caused by the increased amount of wind in the system.

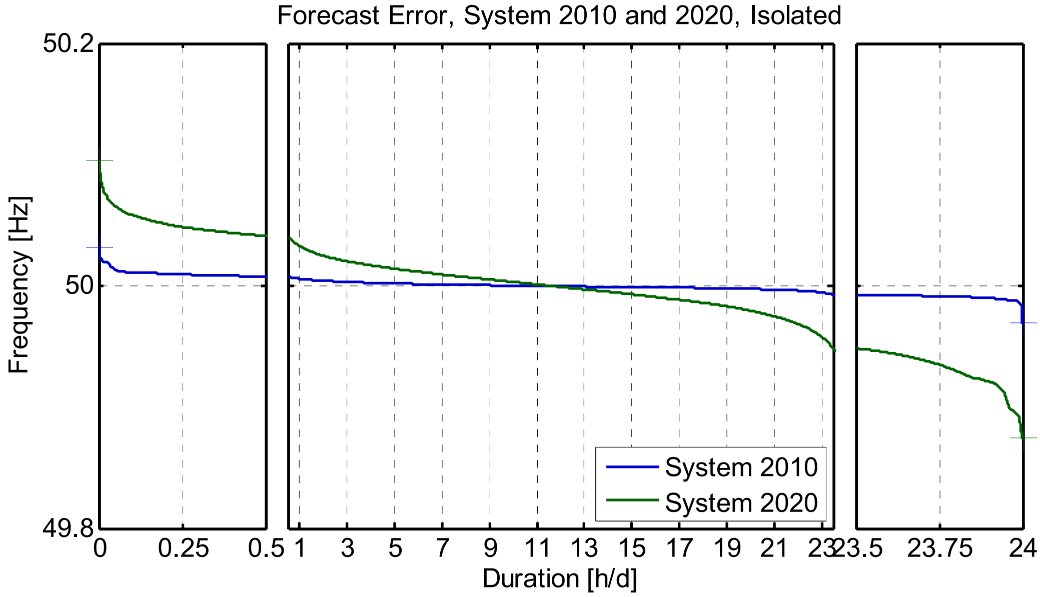


Figure 13: Forecast error 2010 vs. 2020.

From these studies, it is observed that the model is capable of simulating and representing system behavior for trips, block trade effects and forecasting errors. Also, a system with large amounts of wind energy is found to be more sensitive for imbalances due to its lower inertia. When the forecast error is compared, the system with more wind shows clearly a higher amount of frequency deviations.

5.2 Increasing combustion engine penetration level

Now the default system behavior is presented, those results can be used as base line simulations against which the effect of adding combustion engines to the system can be compared. The analysis below starts with analysis of the trip event for the two types of combustion engines introduced in chapter 4. The results are displayed in Figure 14 and Figure 15.

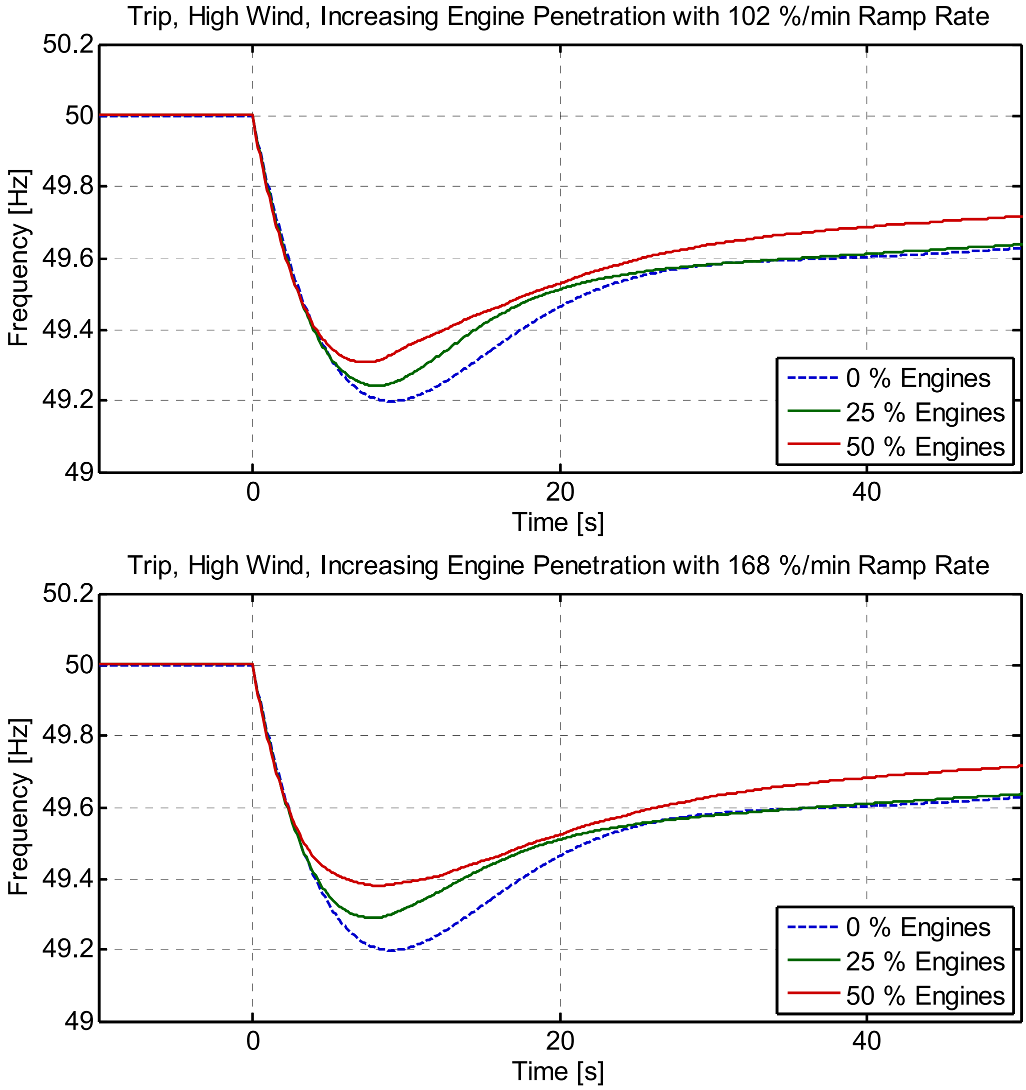


Figure 14: Trip event with increasing combustion engine penetration, high wind, first 50 seconds.

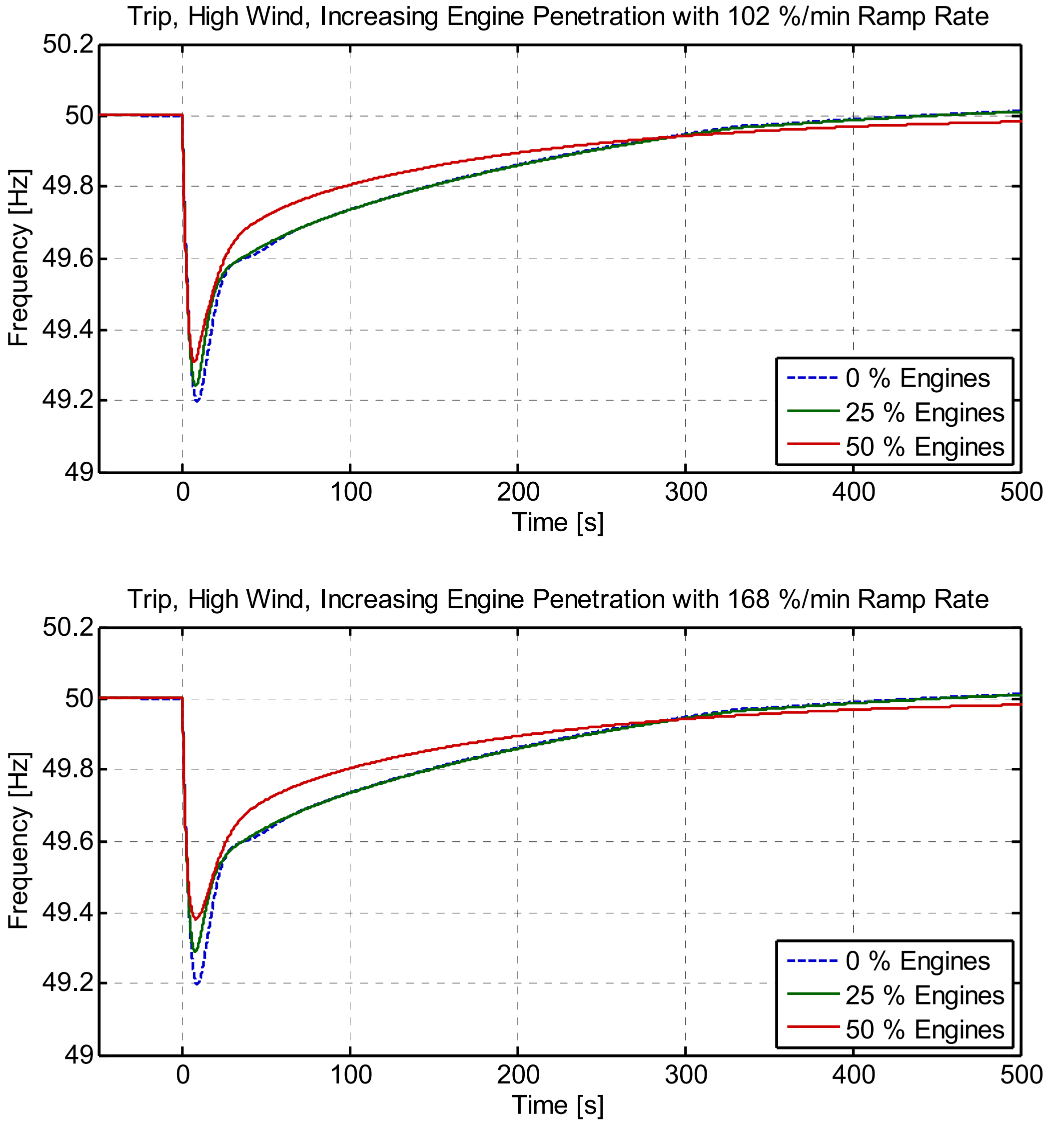


Figure 15: Trip event with increasing combustion engine penetration, high wind, first 500 seconds.

From these figures, note the following:

- Regarding overall system behavior on a longer time scale, the responses are all very similar. Differences are mainly found in the first 30 seconds after the trip event.
- As combustion engines have a lower inertia than the replaced conventional thermal power plants, the inertia of the system drops. This makes the frequency drop faster if there are more combustion engines. However, the difference between the rates of change in the first seconds is found to be limited.
- The primary control of the system stabilizes the frequency in about the same time for all three cases.

- The frequency nadir becomes less severe when more combustion engines are added. Having a higher ramping capability leads to an even better improvement. The most extreme case with 50% combustion engines for the highest ramping capability shows an improvement of 200 mHz in this system compared to the base case without combustion engines.

The next effect under study here is the block trade effect. Figure 16 shows the results for the two different combustion engine ramping capabilities.

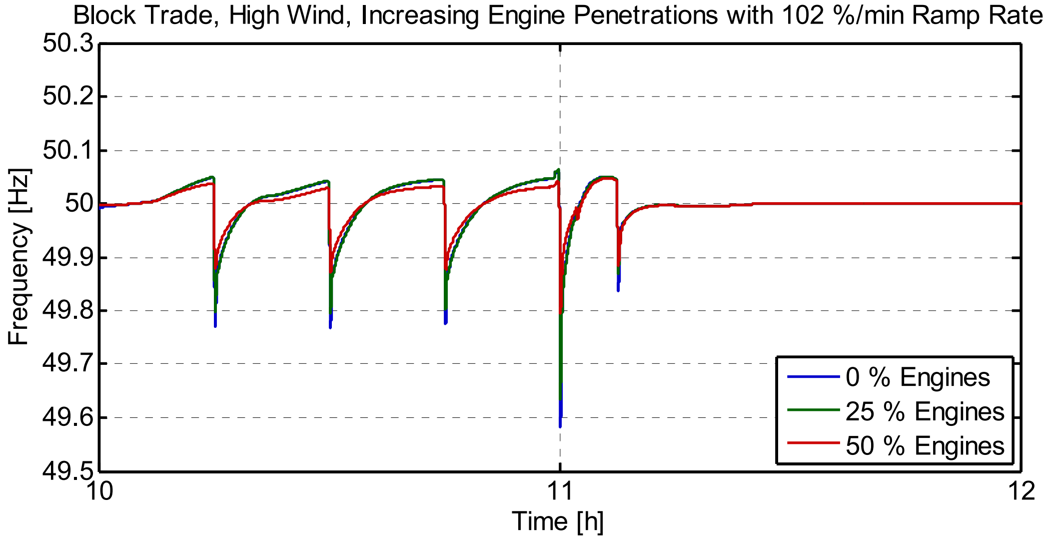


Figure 16: Block trade effect with increasing combustion engine penetration, high wind.

Note the following:

- The difference occurs during the start of the block trade phenomenon, at the moment the setpoint of the plants is changed.
- A high combustion engine penetration leads to a more limited block trade effect. The sudden power imbalance after the change in power setpoint of the plants is partly reduced by the fast primary response of the combustion engines.
- After the sudden imbalance occurred, the load is still changing while the power plant setpoints remain the same. Therefore, the power balance will restore itself automatically, aided by the AGC. For this slower time scale effect, the difference in response between the case studies is limited: the automatic restoration and the AGC have more influence on the response than the individual plants.
- The increased ramping capability of 168% per minute does not help in reducing the block trade effect further. No difference with the 102% per minute ramping capability is observed. This is due to the fact that the required increase in primary response is limited by the rate of change of frequency. The maximum required increase in primary response can be reached using the 102% per minute combustion engines.

The results of studying the forecast error effect are displayed in Figure 17. Here it becomes clear that for this effect, adding combustion engines does not significantly affect the response, neither positively nor negatively. The variation in wind power is relatively slow and can be handled by secondary control and economic dispatch.

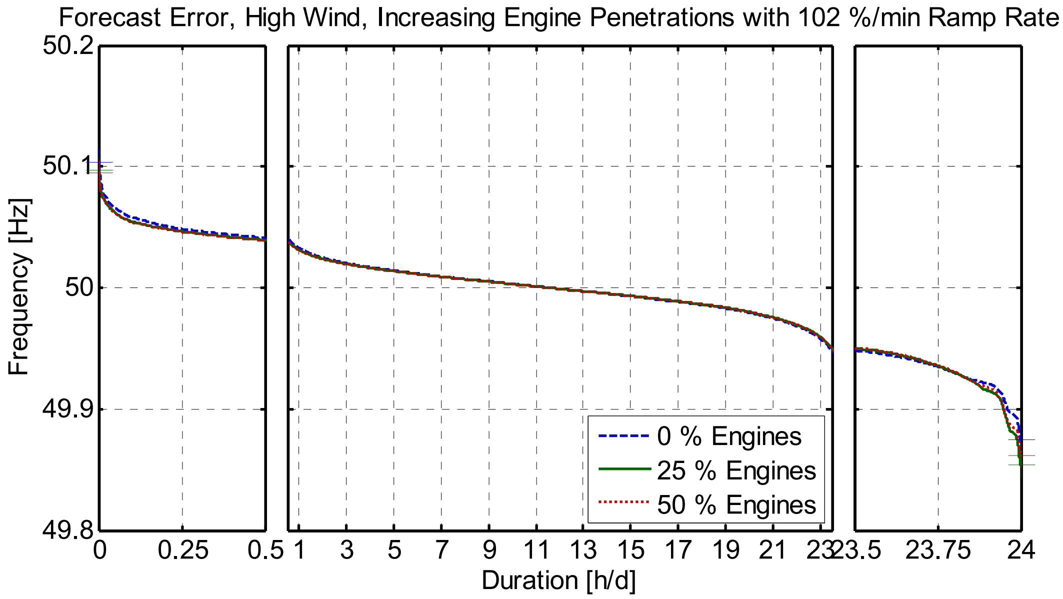


Figure 17: Forecast effect with increasing combustion engine penetration, high wind.

From these effects the following can be concluded:

- Increasing the share of combustion engines does reduce the inertia which could lead to a faster frequency drop. However, because of the speed of the engines under study, this is compensated by the speed of primary response of these engines.
- A higher ramping capability for the combustion engines improves the behavior on a trip: the lowest frequency reached is higher when the ramping capability increases. The lowest frequency when adding combustion engines is always higher than for the base case with 0% combustion engines.
- Increasing the share of combustion engines mitigates frequency disturbances due to block trade effects. The ramping capability of individual combustion engines does not increase the effect here due to the fact that the required primary response by combustion engines is limited by the rate of change of frequency which can be met with the 102%/min combustion engines. Increasing the combustion engine penetration does not show any negative effect for block trade and forecast error studies.

5.3 Using only combustion engines for secondary control

In the previous case studies, it was already noted that adding combustion engines improves the system response. In another simulation set, a further step was taken: it was assumed that the combustion engines will take responsibility for all secondary control effort needed. Conventional plants did not contribute to secondary control here, but only contributed to primary control. The effect of this changed operational regime was studied for the two ramping capability variations and for the three effects under study. For these cases, the behavior is very similar to the cases described in section 5.2, in Figure 14, Figure 15, and Figure 16, where the start of the secondary control action can be observed approximately 30 seconds after the disturbance. The fact that the behavior for combustion engines providing all secondary control is very similar to these cases can be explained as follows:

- For fast effects like the first seconds of generator trips and block events, primary control dominates the response. As the primary control settings are the same as in section 5.2, the behavior is similar.
- For slower effects, secondary control takes over. For secondary control, the speed of change of the AGC employed in the system is the dominating factor. As soon as the generation portfolio is fully capable of following the AGC signal, there is no extra gain of having a faster response. This optimal following of the AGC is already reached with limited amounts of combustion engine penetration. Making only combustion engines responsible for secondary control does not give an extra benefit here. So for frequency recovery, the extra ramping capability of the combustion engines does not affect system behavior as this is limited by the AGC controller. Removing the AGC ramp rate limit would enhance the frequency recovery capabilities of the combustion engines.

5.4 Using combustion engines for non-spinning secondary control

To carry the results of section 5.3 even further, the possibility of having only non-spinning secondary reserve was explored as well. Details on the method used for this can be found in section 4.2.3. Recall that there are already multiple combustion engines spinning in the system that provide part of the primary control. The secondary control is delivered by a subset of the combustion engines. The results for the trip event are shown in Figure 18, Figure 19 and Figure 20.

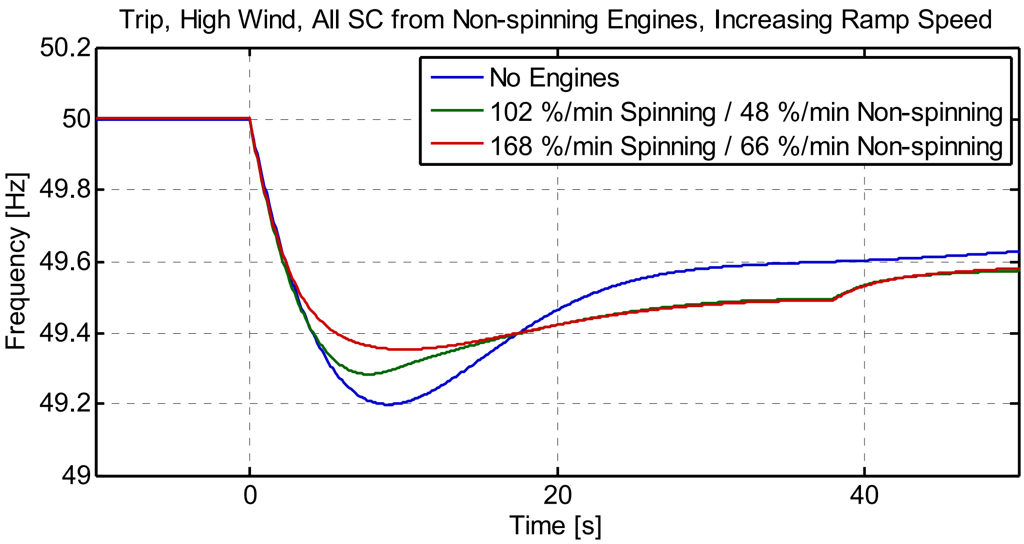


Figure 18: Trip event for non-spinning secondary reserves (close up).

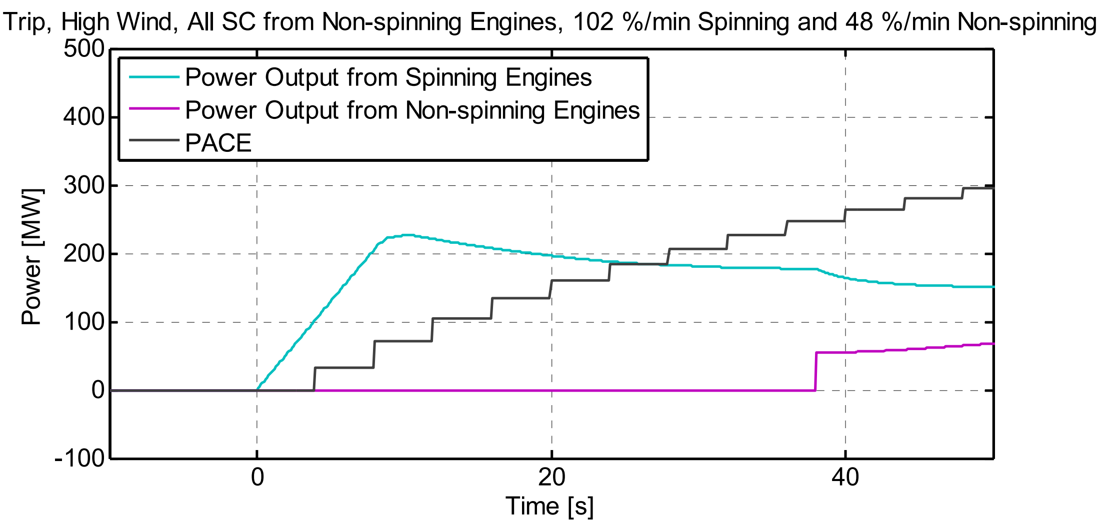


Figure 19: Trip event for non-spinning secondary reserves, power responses.

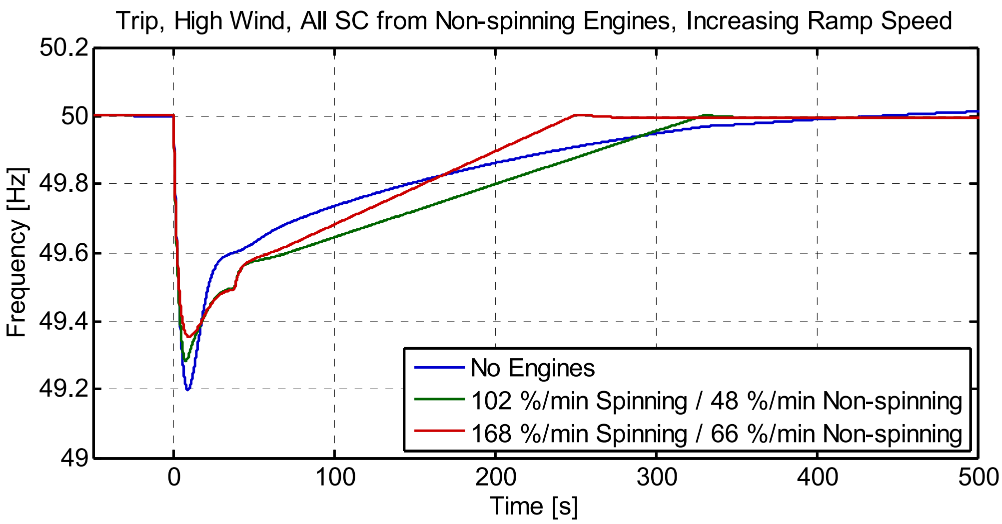


Figure 20: Trip event for non-spinning secondary reserves.

In Figure 18, the frequency response is given for the first 50 seconds. Here it can be observed that the system provides sufficient primary control capacity to overcome the initial frequency drop. As the ramping capability of combustion engines increases, the frequency drop is mitigated. Therefore the combustion engines with the highest ramping capability mitigate the frequency drop the most. It can be observed that around 35 – 40 seconds the non-spinning combustion engines start to generate electricity to provide secondary control. At this point a sudden increase in the frequency recovery occurs. The effect of the non-spinning combustion engines starting up is also observable in Figure 19 where the power output from the spinning and non-spinning combustion engines are displayed. It can be observed that around 35 seconds after the trip, the non-spinning combustion engines are starting to generate electricity which leads to a decreased demand for primary control from the spinning combustion engines.

In Figure 20, the frequency response is given for a longer period of 500 seconds. The result of having multiple ramping capabilities can clearly be observed in the frequency recovery. In this case only 500 MW is available for secondary control and the ramping capability limits the provision of secondary control power. The fact that the frequency signal in the cases with combustion engines crosses the frequency signal for the case without combustion engines is due to the fact that the PACE cannot be traced by the non-spinning combustion engines from the initial point it starts to increase. Therefore the non-spinning combustion engines, providing secondary control power are lagging the PACE. Observe that in the end, the frequency is restored quicker than in the case without combustion engines. If primary control would have been provided with conventional generation and combustion engines would replace conventional secondary control, the trip response would initially (up to 30 seconds) be as the line without engines. Afterwards (after 30 seconds) the frequency would return to its nominal value of 50 Hz with a ramping capability as similar to cases with non-spinning combustion engines.

These simulations show the effect of adding non-spinning combustion engines to the system. All secondary control capacity is generated by engines which are normally switched off. After switching on, the non-spinning combustion engines need 30 seconds to start generating power. The main findings from the case study set are the following:

- Secondary control can be provided by non-spinning combustion engines without significantly affecting system behavior.
- The ramping capability of the spinning combustion engines significantly affects the frequency nadir.
- The ramping capability of the non-spinning combustion engines significantly affects the frequency recovery. In all cases, the frequency is restored quicker than in the case without combustion engines.

6 CONCLUSIONS

This report presents the results of a concept study performed to investigate the effects of integrating a high degree of combustion engines in a representative future power system. In Chapter 1 of this report, the following research question was formulated:

Given the challenges regarding frequency stability in the power system, what is the possible contribution of combustion engine-based power generation to frequency stability from a systems point of view?

To answer this question a model has been created to simulate a number of case studies in which the effects of adding combustion engines to the power system were evaluated. Several events occurring in the system were simulated in combination with several operating regimes and parameter settings of the combustion engines under study. The main conclusions are the summarized below.

Adding combustion engines to this system has the following effect:

- Regarding second-scale events, as in the first seconds after a trip event, the frequency response is dominated by the trade-off between response time and ramping capability of the power plants versus the system inertia. The lowest frequency that is reached is higher in the system with combustion engines than in the system without combustion engines. For combustion engines with a faster ramping capability, this effect is even more pronounced. So for the system, there is no visible negative effect of the decreasing inertia in the system as this is compensated by the high ramping capabilities of the combustion engines.
- Regarding slightly slower effects (multiple seconds), adding combustion engines to the system increases the primary response of the system which leads to better frequency stability. This is visible when studying the block trade effect. Any negative effects can not be noticed in block trade or forecast error studies.
- For effects that are even slower (30 seconds and more) like forecast errors and trip restoration, in most cases the speed of the AGC is the main limiting factor. As soon as the system is fast enough to track the AGC signal, adding more combustion engines is not beneficial or detrimental to the system. Faster AGC would enhance the frequency recovery capabilities of combustion engines.

When comparing the different operational regimes under which the combustion engines are tested, the following is concluded:

- Comparing a system in which the combustion engines take part in secondary control with a system in which the combustion engines take all secondary control shows no significant differences. Therefore, it is possible to let the combustion engines provide all secondary control needed in the system.

- It has been tested whether all secondary control power can be provided by non-spinning combustion engines which are to be started in case of any imbalance in the system. After starting the non-spinning combustion engines, it takes 30 seconds before they start to generate power. Primary control is provided by spinning combustion engines and other conventional units. It was concluded that in this system, it is possible to replace all existing secondary control with non-spinning combustion engines. The system behavior on a trip event does change, but the resulting response matches the grid code requirements.

Additional notes that qualify this conclusion:

- If secondary control would be replaced completely by fast non-spinning combustion engines, the system performance would not be jeopardized. Moreover, especially in power systems with high penetration levels of renewable energy sources, this replacement could possibly lead to both cost savings and reduction of emissions. To identify and address the exact benefits further research would be required.
- These studies are performed on an isolated system with relatively high combustion engine penetration. Therefore, the effects observed are more substantial than they would be in a large interconnected system with lower combustion engine penetration. The qualitative conclusions as presented above however are representative for other systems as well.
- All studies are performed with response times and ramping capabilities typical for Wärtsilä's combustion engines with modern control technology. Therefore, the conclusions only hold for engines that can achieve these ramping capabilities and response times and do not hold for combustion engines with more conventional control systems.

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