Investigation of the Impact of Load Tap Changers and Automatic Generation Control on Cascading Events

Georgios A. Nakas, Panagiotis N. Papadopoulos, *Member, IEEE*
Department of Electronic and Electrical Engineering
University of Strathclyde
Glasgow, UK
georgios.nakas@strath.ac.uk, panagiotis.papadopoulos@strath.ac.uk

***Abstract*— This paper presents an assessment of the impact of control mechanisms, specifically load tap changers (LTCs) and automatic generation control (AGC), on cascading events in power systems with renewable generation. In order to identify the impact of these voltage and frequency related mechanisms, a large number of dynamic RMS simulations for various operating conditions is performed taking into consideration renewable generation, system loading and the action of protection devices. The sequences in which the cascading events appear are analysed, and each cascading event is described by the component that trips, the time and the reason for tripping. The number and reason of cascading events, the average load loss and the time between consecutive events are used as metrics to quantify the impact of LTCs and AGC. The study is demonstrated on a modified version of the IEEE-39 bus model with renewable generation and protection devices.**

Keywords— automatic generation control, cascading failures, dynamic simulation, load tap changers, renewable generation

I. Introduction

Nowadays, the amount of renewable energy sources (RES) penetration and the uncertainty that comes with it causes significant changes in the operation of power systems, in some cases endangering their security. For this reason, there is need for developing detailed models, representing the many different mechanisms involved and the actions of protection devices. Identifying and investigating the appearance of cascading events and the effect of the different mechanisms is a very challenging task, since electrical power systems are highly complex non-linear systems. It is therefore imperative to include the accurate modelling of the various mechanisms related to voltage, frequency and transient stability [1] - [3].

In the literature, there are several studies investigating cascading events in power systems using static methods. In [4], [5] two different approaches are proposed using influence graphs to represent how cascading failures evolve in a specific network topology. The method proposed in [6] uses pattern recognition and fuzzy estimation by utilizing load flows to determine the most probable failure sequences. A different method is proposed in [7], based on a stochastic "Random Chemistry" algorithm to identify sets of multiple contingencies that can lead to blackouts.

However, detailed dynamic modelling has gained interest nowadays, as dynamic simulations can provide more details about the behaviour of the system and can capture dynamic phenomena related to voltage, frequency and transient instability. In [8], [9] comparisons between static and dynamic time domain simulations are presented. The results in both studies highlight that the initial cascading events can be captured by both models, but dynamic phenomena occurring towards the later stage of cascading sequences cannot be caught by static models.

In [10] a risk-based security assessment is applied to investigate the reliability of power systems with high penetration of RES. The proposed method is applied on a realistic network model with protection devices and the uncertainty that comes with the increased renewable penetration is simulated by a probabilistic model. While the method does not specifically target cascading events, the results show that this methodology can identify critical operating conditions. Another study using dynamic simulations to identify cascading events is presented in [11] on a network with conventional synchronous generation only. The sequence of cascading events is captured by the action of protection devices and the application of an initial contingency. The importance of transient dynamical behaviour on the appearance of cascading events is highlighted in [12], using the swing equation to represent system dynamics and eventually investigating line failures and identifying the critical lines in the network.

Although the appearance of cascading events in dynamic models has been investigated, how voltage or frequency related mechanisms affect these events has not been thoroughly examined. In [13] the importance of a model implementing the action of Load Tap Changers (LTCs) and Over-excitation Limiters (OELs) that can capture longer voltage-related instability phenomena is discussed. The LTCs change the ratio of the transformer, in order to keep the distribution voltage within limits. In some cases that will increase the power losses and require more reactive power injection. If the generators reactive power output capabilities reach the limits of the OELs, that will create reactive power imbalance in the system leading to voltage instability.

In order to realistically capture phenomena of frequency instability, it is significant to implement the main system components that take part in the power system frequency control. A sudden change in active power balance may lead to frequency deviation from the nominal value. Primary frequency control depends mainly on the droops of the synchronous machine governor, stabilizing the frequency of the system at a value which may differ from the nominal one. In order to restore the nominal frequency, secondary frequency control is used. In some systems this might require a manual intervention by the system operator or this task is performed by Automatic Generation Control (AGC). Thus, the simulation of the AGC operation [14] that considers the different dynamic characteristics of the synchronous

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generators can efficiently represent secondary frequency control mechanisms.

The main contribution of this paper is the investigation of the impact that the action of LTCs, a voltage related mechanism, and AGC, a frequency related mechanism, have on the way that cascading events propagate. Dynamic RMS simulations are performed on a model with renewables, capturing phenomena related to voltage, frequency and transient instability, as defined by the discrete action of the protection devices that have been implemented. The number and reason of cascading events, the average load loss and the time between consecutive events are compared in order to investigate the impact of these mechanisms. This information could be vital in identifying the importance of such mechanisms in dynamic modelling of cascading failures.

The remaining of the paper is structured as follows. In Section II, the detailed procedure, the test system and the modelling of the dynamic components are presented. The test cases and the results obtained for different scenarios are shown and discussed in Section III. Finally, Section IV presents some conclusions.

II. METHODOLOGY

A. Detailed procedure

In order to investigate the impact of LTCs and AGC on the appearance of cascading events, simulations for the same operating conditions with and without the action of these mechanisms are performed and the cascading event patterns that appear are compared. In this study, dynamic RMS simulations are performed on a test system with RES penetration, including the action of protection devices to capture the cascading events that may appear after an initial applied contingency. An initial screening of a wide range of possible operating conditions is performed to identify which set of pre-fault operating conditions and contingencies lead to the appearance of cascading events. For the same operating conditions, the simulations are performed again, defining a scenario in which the LTCs are not considered and a scenario enabling AGC, to investigate how this impacts the cascading event sequences that appear.

Wind generation output and system loading values are discretized within a certain step, taking into account also stressed network conditions. Following the sampling of wind generation and system loading values, an AC Optimal Power Flow (OPF) [15] problem is solved to determine the dispatch and the amount of disconnection of the SGs. Each SG is allocated a cost curve, as in [16], with the objective of the OPF being the minimisation of the total synchronous generation cost. The constraints set for the OPF problem are the active and reactive power limits of the generators, the maximum loading of the lines and the bus voltage limits.

In order to represent in a realistic way the effect of wind penetration and inertia reduction in modern networks, an amount of conventional SG is disconnected. Each SG is assumed to consist of 4 identical machines which can be set on or out of service. According to operating point of each SG, given by the solution obtained from the OPF, the number of machines for each generator that are needed and assumed to be connected is calculated.

In this study, three phase faults on lines are considered as an initial contingency. The fault occurs at t=1s and gets cleared by disconnecting the faulted line after 70ms. If the network response to the contingency causes the violation of the protection devices limits implemented in the system, then the protection devices can cause other system components to trip. Each cascading event is described by the component that trips (e.g. a synchronous generator, a wind farm, etc.), the reason for tripping (e.g. over-voltage, under-frequency, etc.) and the time of the disconnection. This intervention might potentially cause consecutive cascading events. It should be noted that the initiating fault and line disconnection can lead to cases where parts of the system become islanded due to the set-up of the test network. The cascading event sequences that may appear are consequently identified, describing how the events evolve in the system.

The base scenario consists of the system modelled as described in detail Section II. B with LTCs activated and no AGC implemented. For the operating conditions that after the initial contingency (i.e. a three-phase fault causing the disconnection of a line) lead to at least one additional component to trip for the base case, two scenarios are defined. In the first scenario, the LTCs are not modelled and the simulations are repeated. In the second scenario, AGC is implemented in addition to the base scenario (i.e. with LTCs modelled). For each scenario the number and reason of cascading events, where an event in this paper is defined as the trip of a component, the average load loss and the time of events are presented in a comparative analysis.

B. System under Study

A modified version of the IEEE 39 bus model, as shown in Fig. 1, is used in this study. The system is implemented using RMS simulations in DIgSILENT PowerFactory [17]. As described in Section II.A, the model can capture the evolution of system states and variables and capture activations of protection devices due to relevant limit violations.

The ten synchronous generators (SGs) in the network are represented by full detail four winding models (6th-order). equipped with Automatic Voltage Regulator (AVR), Power System Stabilizer (PSS), Governor (GOV), and Over-excitation Limiter (OEL). The network parameters can be found in more detail in [18].

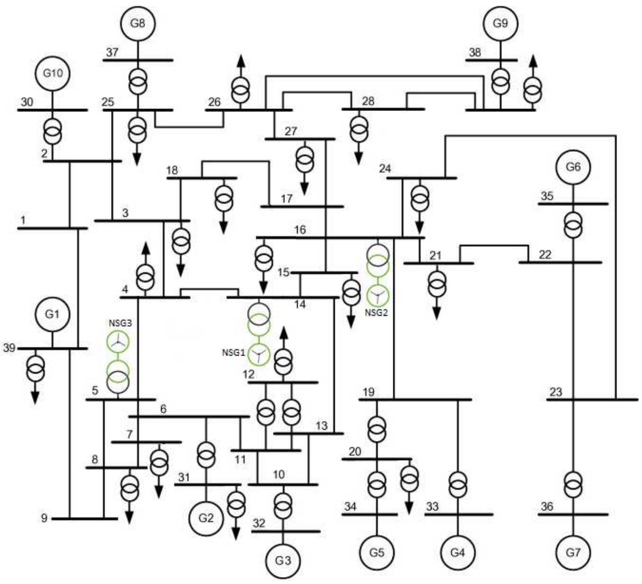

Fig. 1. Modified version of the IEEE-39 bus model.

The three wind parks in this study are connected to three different locations and are represented using International Electrotechnical Commission (IEC) type 4A wind turbines [19]. The installed capacity of wind generation is considered to be equal to 20% of the total installed conventional generation of the IEEE-39 bus system base case.

Protection devices have been modelled in the network to capture phenomena related to transient, voltage and frequency stability. The SGs are equipped with an under-/over-speed protection relay, an under-voltage protection relay and pole-slip protection. The non-synchronous generators (NSGs) in the system are protected with an under-/over-voltage protection relay with fault-ride through (FRT) and an under-/over-frequency protection relay. An Under-Frequency Load Shedding (UFLS) scheme with four stages is implemented for the disconnection of a percentage of demand at low frequency to restore the active power balance in cases of frequency instability. More details about the protection devices settings can be found in [20].

All the protection devices have been implemented using standard models found in the DIgSILENT Powerfactory library. The relays settings have been adopted from the UK grid code to comply with the transmission system limits as referred in [21].

C. Load Tap Changers (LTCs)

The loads are modelled as balanced three-phase constant impedance loads and are connected to distribution voltage rated buses via step-down transformers. These transformers are equipped with LTCs, which adjust the transformer ratios keeping the distribution voltage within the deadband [0.99-1.01] p.u. The LTCs adjust the transformer ratios in the range [-10% to +10%] over 33 positions (0.625% ratio variation per step) [13] and act with an intentional delay of 10s.

Without considering the action of LTCs, the distribution voltage may not be kept within this deadband. The step-down transformers tap positions will keep their initial value, as defined by the OPF solution. In some cases, not changing the tap positions can preserve the voltage stability of the network and prevent load shedding events [22]. On the other hand, as the loads are voltage dependent a change in the voltage will change the power absorbed, which may in turn affect frequency.

D. Automatic Generation Control (AGC)

A simplified AGC dynamic model is used to simulate the secondary frequency control in the network. The real-time system frequency measurement, obtained from a PLL at the bus connecting the generator to the network, is compared to the nominal reference frequency. Each generator acts independently, according to the local frequency measurement. The deviation of frequency is processed through a PI controller that transmits a signal to the governor adjusting the generator active power accordingly (Fig. 2.) [23][24]. The gains of the PI controller adjust the active power rate of change. It is considered that synchronous generator G10, which represents a hydropower generator, a technology appropriate for fast acting varying power injection, contributes to the AGC scheme of the network. The action time of the AGC is 30s after the start of the simulation.

So, it is expected that in the scenario including the action of AGC, it will affect the cases in which frequency related trips appear after the first 30s in the simulation and it will help to enhance the system frequency control and result in less trips and less load loss from the UFLS protection scheme.

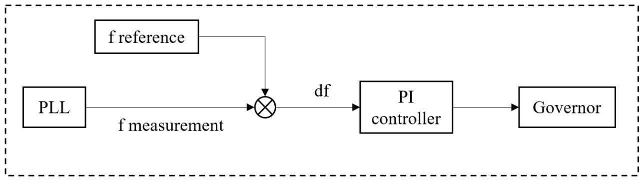

Fig. 2. AGC model structure.

E. Test Cases

The large amount of parameters affecting operating conditions in modern power systems and the different system topologies make it infeasible to predefine in a straightfoward manner which operating conditions lead to cases with cascading events, where in this paper a case is defined as an individual simulation. This creates the need for simulating a large number of possible cases to investigate how the system reacts to a contigency. In this study, the initial operating conditions are the output of the three wind generators and the system loading, which are sampled in a deterministic way, by discretizing these values within a certain step. For each individual set of operating conditions, a three-phase fault is applied on each line of the system as an initial contingency.

More specifically, the operating conditions are sampled in the following way: the system loading ranges from 70% to 120% of the total network demand (as defined in the original test network) in 10% steps. The output of each of the three wind generators in the network ranges from 0 to 100% (of the nominal capacity of each wind generator) in 20% steps. Following the sampling of the initial operating conditions, the amount of synchronous generation disconnection in the network is defined by the AC OPF solution. As initiating events, three-phase faults in the middle (50% length) of each line (34 different lines) are applied and the line is disconnected after the fault is cleared. That gives 34 different cases for each given network operating condition, multiplied by 8 different loading scenarios and by 6 different RES output scenarios. In this study, 44064 cases in total have been simulated

For the cases that cascading events have appeared, the simulations are performed again for the same initial operating conditions to investigate the effect of a voltage related and a frequency related mechanism on the cascading event sequences that have appeared. For this reason, the following scenarios have been defined:

- Base scenario: LTCs on and AGC off
- Scenario I: LTCs out of service.
- Scenario II: LTCs on and AGC implemented.

The duration of the RMS simulations has been set to 120 s, with the adaptive time step option enabled. The interface between Python and DIgSILENT Powerfactory [24] has been used to set up the dynamic simulations running multiple simulated cases in parallel in order to speed up the process.

III. RESULTS

A. Scenario I: Not including Load Tap Changers

In the base scenario, cascading events appeared in 7131 cases, out of the 44064 that are simulated (16.2% of the simulations). In this Scenario, the 7131 cases where cascading events have been observed are simulated again, setting the LTCs out of service and comparing the results to the base scenario. In Scenario I, 71922 cascading events (i.e. counting as event every activation of a protection device) in total have appeared, a higher number than in the original scenario (69175), in 2271 different sequences. As it is shown in Fig. 3.a) fewer cases with only one event have appeared. Approximately the same number of sequences with 10-40 events appear for both cases. A reduction in the number of sequences with more than about 20 events is observed for both scenarios. When the LTCs are not in action more sequences with a high number of events (70-80) have occurred.

The time of the events can also provide vital information regarding the evolution of cascading events. As it is shown in Fig. 4.a) during the early stages of the simulation (0-20s) more cascading events appear when the LTCs are not included. During the later stages (60s-120s) very few events are captured in Scenario I and less when compared to the base case, i.e. less events tend to appear in the later stages of the cascade. Both the mean value (0.95s) and the standard deviation (6.62s) of the time between cascading events in Scenario I are smaller compared to the base scenario (2.12s and 10.45s respectively) suggesting that events happen in quicker succession as highlighted in Table I. This potentially leaves shorter time window for corrective measures that could be taken to prevent cascading events from spreading.

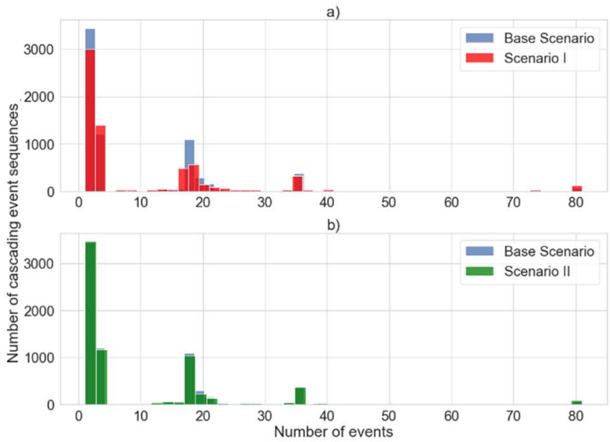

Fig. 3. Number of cascading events per sequence for: a) Scenario I and b) Scenario II compared to the base Scenario.

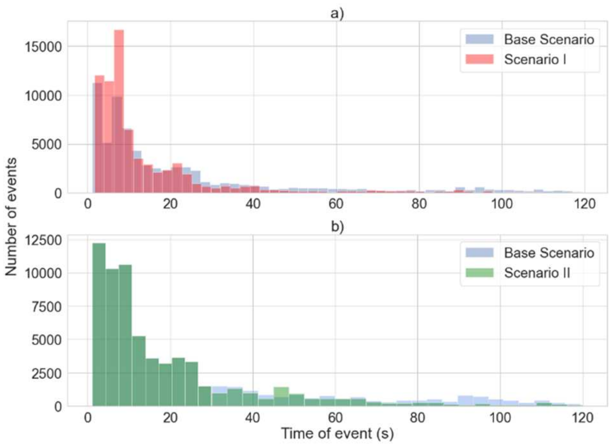

Fig. 4. Time of events for: a) Scenario I and b) Scenario II compared to the base Scenario.

The UFLS scheme implemented in the model can disconnect an amount of the system load when the network frequency is low in order to restore the active power balance. For each sequence, the percentage of load loss is calculated, by dividing the amount of load that is disconnected to the total system loading at this case. In total there are more load trips in Scenario I (57309) than in the base scenario (55711) and the total amount of load disconnection is higher. Fewer cases where observed in Scenario I when compared to the base scenario for load loss around 1% and around 7%. However, as highlighted in Fig. 5.a) in Scenario I more sequences have a large amount of load loss (30%), resulting in a larger total amount of load that gets disconnected. These additional sequences that resulted in a load loss of 30% in Scenario I, resulted in a load loss of 0% or 5-15% in the base scenario.

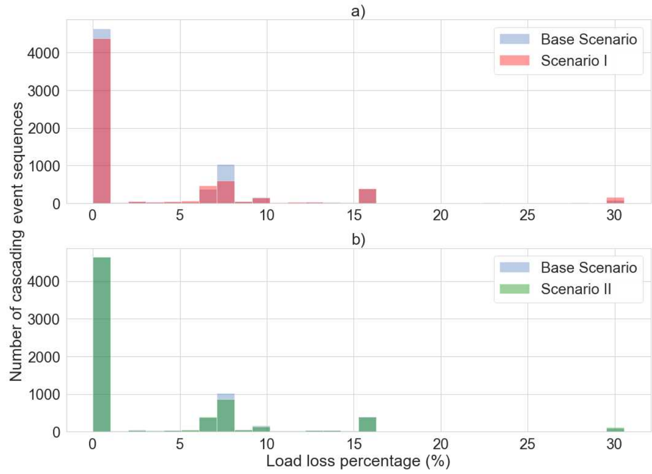

Fig. 5. Load loss percentage for: a) Scenario I and b) Scenario II compared to the base Scenario.

TABLE I. NUMBER AND TIME OF CASCADING EVENTS

	Base Scenario	Scenario I	Scenario II
Number of sequences	2546	2271	2390
Total number of events	69175	71922	68236
Load events	55711	57309	54698
Mean/ Std Deviation time between events (s)	2.12/ 10.45	0.95/ 5.62	1.61/ 8.61

B. Scenario II: Impact of Activating Automatic Generation Control

The 7131 cases in which cascading events have occurred are simulated again, this time enabling the AGC implementation that provides secondary frequency response. The AGC model gets activated at t=30s. In the base Scenario, cascading events after the first 30s have appeared in 1597 cases, so the effect of AGC is expected to be seen in these cases. The total number of trips for this scenario (68236) is smaller than in the base Scenario (69175). As it is highlighted in Fig. 3.b) the number of sequences with 10-40 events are fewer with the AGC.

The time of the cascading events is presented in Fig. 4.b). Until t=30s the time of the events for both scenarios remains the same, as the AGC gets activated after this point. In general, with the action of AGC fewer cascades appear during the earlier steps (30s-40s) and the last steps (80s-120s) of the simulation. More cascades appear compared to the original scenario at approximately t=50s. As the number of trips is in total smaller it can be concluded that secondary frequency response reduces the number of trips during the latter steps of the simulation. The mean value of the time between consecutive events, as shown in Table I, is slightly shorter than in the original scenario and with a smaller standard deviation.

In this scenario fewer cascading events (54698) are caused by the disconnection of loads, and the total amount of load loss is also reduced compared to the original one. As shown in Fig. 5.b) there are fewer sequences that cause a 5-10% load loss. This can be attributed to a reduced number of under-frequency trips.

C. Reason for tripping and System Loading impact

In order to further investigate the impact of LTCs and AGC, the reason for tripping of the cascading events is displayed in Fig. 6. In Scenario I, slightly more trips due to voltage appear, and an increased number of trips due to frequency and transient instability. When there are no LTCs there are 6858 trips that involve the disconnection of SGs, while in the base scenario there are 6006 SG related trips. This increased number of synchronous generation trips (852 more trips) leads to more cases of frequency instability, causing the disconnection of loads due to the UFLS scheme.

As expected in Scenario II, fewer trips occur due to under-frequency and under-speed. As the primary frequency response relies on the action of governors to restore the active power balance, the frequency may stabilise at a different value from the nominal. A further cascading event can deteriorate the frequency of the system and cause frequency related trips. The secondary frequency response, provided in this case by AGC, leads the SG through the governor to stabilise the frequency of the system to the nominal one, returning the power system operation to its secure state and reducing the number of frequency instability phenomena. It should also be noted that the number of trips due to voltage and pole slip in Scenario II (8236 and 1530 events, respectively) does not seem to be significantly affected compared to the base scenario (8261 and 1445 events, respectively). A slight reduction is however observed.

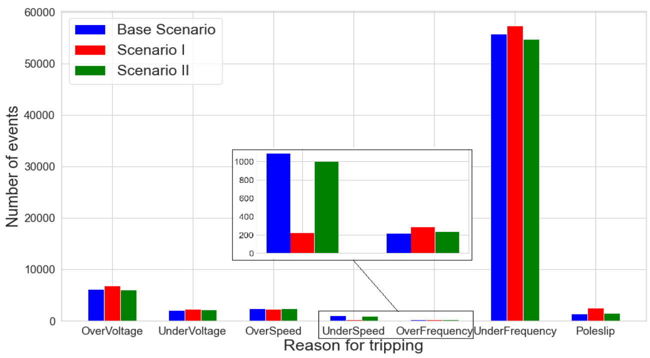

Fig. 6. Reason for tripping for all Scenarios.

The number of cascading events across the system loading and the mean value of load loss for all scenarios are presented in Fig. 7.a) and Fig. 7.b) respectively. In general, it appears that most cascading events appear at the system loading nominal value (100%) for all three scenarios, however the cases with the most impact (higher load loss) appear at high system loading (110%-120%). In Scenario I, when the loading value is low (70%-80%) and at the nominal value more cascading events appear than in the original scenario and with a higher load loss. This increased number of trips (6585 events) appears due to more Under-Voltage, Under-Frequency and Pole-Slip events. On the other hand, when the system loading is at 90% and at 110% fewer cascades (1494 events) are captured when there are no LTCs, which are caused due to Under-Voltage and Under-Frequency. At 120% system loading, it is observed that although in Scenario I the number of events is slightly lower, the sequences of events have a higher impact, as a larger amount of load trips due to the UFLS scheme when there are no LTCs. Therefore, for this particular system and case study, the impact of including LTCs can have both a positive and negative impact in the evolution of cascades due to the complex interactions and dynamic phenomena.

In Scenario II, a reduced number of cascading events and reduced resulting load loss is observed across all system loading values, due to fewer Under-Frequency trips as expected from the action of AGC. Consequently, the use of AGC has a positive impact on the appearance of cascades in all cases.

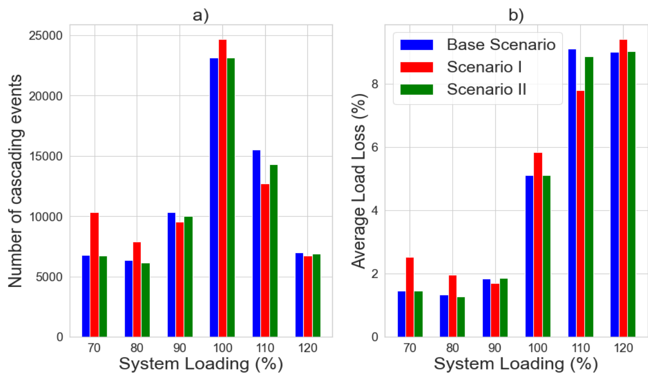

Fig. 7. Number of cascading events and average load loss according to System Loading.

D. Cascading Events Patterns Comparison

In the base scenario, the cascading events have appeared in 2546 different sequences, with some of them appearing multiple times. In Scenario I, 2271 sequences have appeared and in Scenario II, 2390, so in both scenarios fewer sequences have appeared. In In Table II. the most common cascading event sequences are presented, sorted by times of appearance in the base scenario, and how many times these sequences appear in Scenarios I and II. A unique "Id" number is assigned to each sequence in order to distinguish them. Each event is described by the component that trips and the reason for tripping. The time of each cascading event gives the sequence in which the events occur. For instance, the second most common sequence [('NSG_2', 'OverVoltage'), ('G 01', Poleslip')] describes a sequence where the first event is the disconnection of wind generator NSG-2 due to Over-Voltage, followed by the disconnection of synchronous generator G01 due to pole-slip.

The most common sequence appearing in all the scenarios includes only a single event, the disconnection of NSG-2 due to Over-Voltage. This event is also the first cascading event in the most common cascading sequences. In Scenario I, sequence "1" appears less times than in the base case, and sequences "2" and "3", which include the disconnection of

NSG-2 followed by other events appear more frequently. Sequence "5" appears more times in Scenario I as well. The disconnection of G05 due to Over-speed is a common event because when the initial fault is applied on Line 16-19 a part of the system becomes islanded. It should be noted that sequence "4", which includes the disconnection of G01 due to under-speed has not appeared in Scenario I. In this scenario, sequence [(NSG_2-OverVoltage), (G01-Poleslip), (NSG_3-UnderVoltage)] has appeared 249 times, indicating that the tripping of G01 after NSG-2 happens most commonly due to poleslip instead of under-speed. In Scenario II the most common patterns appear in general in the same manner as in the base scenario. Sequences "2" and "3" appear more times in Scenario II, as in some cases of the base scenario the disconnection of G01 in these sequences causes further cascading events due to under-frequency, which are prevented in Scenario II by the use of AGC.

TABLE II. MOST COMMON CASCADING EVENTS PATTERNS

Times pattern has appeared			Id	Cascading Event patterns
Base Case	Sc. I	Sc. II		
2219	1759	2221	1	[(NSG_2-OverVoltage)]
336	393	362	2	[(NSG_2-OverVoltage), (G01-Poleslip)]
279	403	292	3	[(NSG_2-OverVoltage), (NSG_1-OverVoltage), (G01-Poleslip)]
243	0	243	4	[(NSG_2-OverVoltage), (G01-UnderSpeed), (NSG_3-UnderVoltage)]
196	238	196	5	[(G 05-OverSpeed)]

IV. Conclusions

In this paper the effect of LTCs, a voltage related mechanism, and AGC, a frequency related one, on the evolution of cascading events in power systems with RES penetration is investigated. The main aim is to suggest a way to identify the importance and highlight potential impact from different level of modelling detail, i.e. including, or not, certain mechanisms. Dynamic RMS simulations including protection device modelling and investigation of initial operating conditions, like RES penetration and system loading, are employed to identify the possible cascading event patterns that appear. Each cascading event is characterized by the specific component that trips along with the reason for tripping. The impact of LTCs and AGC on the dynamic behaviour of the network is analysed by investigating the number and reason of cascading events, the average load loss, the time between consecutive events and the most common cascading event patterns. This investigation can provide significant information about how the different mechanisms affect the power system reaction to a contingency.

The proposed method is applied on a modified version of the IEEE-39 bus model, including RES units. The results from this specific test network showcase that not including LTCs in the network model results in more frequent appearance of cascading events and greater amount of load shedding. In the scenario that AGC is included, the frequency stability in the network is enhanced and a reduced number of load disconnection events due to under-frequency is observed. Implementation of the voltage and frequency related mechanisms found in modern power systems in dynamic network models plays a significant role in accurately capturing cascading event sequences.

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