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Probabilistic evaluation of the long-term power system resource adequacy: The Greek case

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ABSTRACT

This paper deals with the probabilistic evaluation of the long-term resource adequacy of an interconnected power system. An integrated software tool that solves the long-term scheduling problem using a sophisticated unit commitment model is employed, while both traditional capacity and flexibility adequacy concepts are addressed. A novel methodology to assess the flexibility adequacy using the operational power system schedule is presented. Multi-year simulations of the Greek interconnected power system on an hour-by-hour basis for the forthcoming 10-year study horizon (period 2018–2027) under a set of scenarios regarding the future operating conditions have been performed, providing the key operational data for the calculation of all probabilistic indicators. Test results indicate that the existence of all currently available thermal generating units as well as the timely realization of all scheduled construction plans is of utmost importance for the long-term secure and reliable operation of the Greek interconnected power system. In a more generalized framework, the ambitious EU goals regarding decarbonization and increasing RES shares in electricity generation should be accompanied by detailed studies in order to ensure that no resource adequacy problems will arise in the near future due to the massive withdrawal of conventional base-load and, possibly, flexible generating units.

1. Introduction

Electricity supply needs to balance demand in real-time while meeting quality and reliability standards. As large-scale electricity storage possibilities are still limited, meeting reliability standards at all times implies ensuring availability of sufficient resources well before actual requirements. Since the construction of a new conventional generation facility has a multi-year lead time, long-term resource adequacy studies are typically carried out by System Operators for long time horizons (e.g. 10 years ahead) on a rolling annual basis, in order to calculate the near future reliability metrics of a power system.

Traditionally, in the absence of notable shares of Renewable Energy Sources (RES) electricity production, generation adequacy studies focused exclusively on whether a power system was capable of adequately meeting system load demand during all hours of the year. For this purpose, certain metrics such as the Equivalent Forced Outage Rate (EFOR) and specific probabilistic indicators, such as the Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE), were commonly used to evaluate the capacity adequacy of the power system, considering specific target reliability levels (e.g. the “1 day of load loss during a 10-year period” or, equivalently, “2.4 h of load loss per year” criterion) (Billinton and Allan, 1996; Cochran et al., 2014; Doherty and O'Malley, 2005; Lannoye, 2010, 2012a, b; NERC, 2009). Such analyses were proven robust and yielded satisfactory results regarding system adequacy as the RES penetration rate remained low.

However, during the latest years, strong environmental concerns worldwide have promoted the transition to a cleaner and sustainable power system, where RES are expected to play a crucial role. For instance, the EU climate and energy policy has set specific intermediate targets for 2020 and 2030 in order to achieve the ambitious long-term goal of reducing greenhouse gas emissions by 80–95%, when compared to 1990 levels, by 2050 (European Commission, 2009, 2011, 2014).

Apart from the obvious environmental benefits, the increasing share of RES in the generation mix presents a big challenge in the efficient operation and management of the power systems. This is due to the limited predictability and high variability of renewable generation, features that make RES plants non-dispatchable, in contrast to the conventional generating units (i.e. nuclear units, lignite units, CCGTs, large hydro units, etc.) that can be regularly dispatched and managed by the System Operator (Simoglou et al., 2015). Under such conditions, system planners are seeking new tools to understand and quantify the challenges associated with the integration of variable renewable generation. The significant changes of net system load due to the accommodation of large-scale RES generation are already present and are

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expected to accentuate in the forthcoming years. As noted in the NERC / IVGTF report (NERC, 2009), high penetrations of variable generation will result in a significant increase in the overall system variability whether measured from the net-load (load – variable generation output) or resource perspective.

The important new concept on system resource adequacy studies is related to flexibility, namely sufficient (upward and downward) ramping capability provided by eligible resources, in order to follow the increased net load variations under high penetration levels of variable and uncertain RES generation. Flexibility has not been previously addressed predominantly in power system planning studies, since meeting demand using all available capacity resources was the single key factor in related studies. However, during the latest years, flexibility is incorporated in the adequacy and reliability studies, to describe the system's capability not only to meet load demand but also to timely manage net system load variations at all times. A failure to meet the system flexibility requirements is multifaceted; it can manifest as power balance violations and/or Area Control Error (ACE) deviations, which are likely to lead to unnecessary curtailment of RES production and/or undesired de-synchronization of a thermal plant in order to resolve the inherent system balancing issues and, therefore, restore the power system to its normal operation. Such failures are valued from a society perspective, along with the cost of electricity supply, and therefore, have to be efficiently avoided as a result of system planning.

There have been a variety of approaches to assess the supply of flexibility ranging from examining the characteristics of the physical resources on the system without considering how they may operate, through to detailed simulation of the system operation. The most common methods comprise (Bonneville Power Administration, 2015):

- *Screening available flexibility method*: Screening the available flexibility in a system means assessing the resources based purely on their physical characteristics, without assessing how they may operate. The purpose here is to determine what the capability to ramp is for a set of resources (IEA, 2011; Ma et al., 2013; Portland General Electric, 2009).
- *Intermediate assessment method:* Intermediate assessment methods are defined as methods which follow a more detailed approach, but still do not examine a full commitment and dispatch study, with all the associated modeling implications and challenges (EPRI, 2013; Lannoye et al., 2012a, b; Müller, 2012; Schilmoeller, 2012).
- *Detailed assessment method:* The final set of approaches requires more detail on system operations, generally meaning a full unit commitment and economic dispatch is required (CAISO, 2014; Hargreaves et al., 2013; NERC, 2011; Studarus et al., 2013). New metrics and techniques have evolved to use existing or adopted production simulation tools to assess flexibility. The insufficient ramping resource expectation (IRRE) metric is a probabilistic method of assessing the frequency of flexibility deficits (Lannoye et al., 2012a,2012b). This metric is dependent on the outcome of production cost modeling that determines the dispatch level of each resource over a study period. Based on the dispatch level, resource parameters and availability, a distribution of flexibility available in the system can be determined. This can then be used to determine the probability of meeting net load ramping events throughout the course of the year. When those probabilities are aggregated into an expected value, the result is a metric for the overall flexibility of the system. This metric can be applied to ramping in the upward and downwards directions and for a range of time horizons, so that distinct flexibility issues can be identified.

2. Scope and contribution

The scope of this paper is to present a comprehensive methodology to be used for the probabilistic evaluation of the long-term resource adequacy of an interconnected power system. Both traditional capacity and flexibility adequacy are addressed using specific probabilistic indicators, which are properly defined. A simulation approach that falls under the detailed assessment methods described in the previous paragraph is used for the evaluation of the power system resource adequacy. In order to assess the power system flexibility, we extend the concept of IRRE by presenting a novel method to calculate IRRE taking into account the forced outage rate of conventional generating units, contrary to (Lannoye et al., 2012a, b), where an empirical cumulative distribution of the system flexibility was used. In addition, the upward and downward IRRE are calculated taking into account the detailed commitment state of the generator (offline, synchronization, dispatchable) as well as the unit minimum up and down time.

All probabilistic indicators are calculated for the Greek interconnected power system for the forthcoming 10-year study horizon (period 2018–2027) under a set of scenarios regarding the future operating conditions, such as the system load forecast, the commitment of new production units and the withdrawal of existing units, the forecasted fuel and CO_2 emissions prices, the projected increase in RES installed capacity, etc. The operation of the Greek power system is simulated on an hour-by-hour basis using the full unit commitment model currently used for the solution of the Day-Ahead Scheduling optimization problem of the Greek wholesale electricity market (Simoglou et al., 2014). The multi-year simulations produce, among others, the projected hourly commitment and scheduled energy injection of all conventional (thermal and hydro) units, which are the key inputs for the detailed calculation of the respective probabilistic resource adequacy indicators.

3. Methodology

3.1. Simulation tool

The simulation tool used for the scenario-based analysis is an integrated software called "Long-Term Scheduling" (LTS). LTS was developed in the Power Systems Lab, Aristotle University of Thessaloniki, Greece, for the solution of the mid-/long-term scheduling problem of the Greek wholesale electricity market. In fact, LTS simulates the operation of any power system for many years in the future on a year-by-year basis with hourly granularity aiming at the minimization of the total system production cost (or, equivalently, the maximization of the social welfare) over the predefined scheduling period. In order to simulate the optimal yearly operation of the power system on a cost minimization basis, a decomposition approach is followed:

a) a Peak-Shaving problem is initially solved to simulate the twelve-month usage of hydro resources (Mid-Term Hydro Scheduling), and then
b) the simulation of the system operation for the entire year is performed (Mid-Term Scheduling (MTS) problem) by day-by-day successive solution of the day-ahead unit commitment (Day-Ahead-Scheduling (DAS)) problem.

In short, an N-year LTS problem is decomposed in N single-year MTS problems, each of which is decomposed in 365 DAS problems, solved sequentially. The solution of Mid-Term Hydro Scheduling allocates the yearly water resources to each day of the year. The daily hydro production is required input to the DAS problem.

The goal of the DAS model solution, for each day, is the minimization of the total operating cost over all hours of the scheduling horizon (i.e. 24 h of the next day) subject to a large set of problem constraints, representing various system and unit operating constraints.

The total operating cost to be minimized includes: a) the energy production cost, as reflected on the respective units' marginal cost functions, b) the reserves provision costs, and c) the units' start-up and shut-down costs. In this sense, the optimization model has the following generalized form: