Applied Energy 113 (2014) 152–158

Contents lists available at SciVerse ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

The impact of sub-hourly modelling in power systems with significant levels of renewable generation ☆

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HIGHLIGHTS

- This work investigates the impact of temporal resolution on power systems modelling.
- Increased temporal resolution captures more variability and costs.
- Increased resolution betters captures the inflexibilities of thermal units.
- Significant cycling and ramping of units is also captured.

ARTICLE INFO

Article history:
Received 25 March 2013
Received in revised form 13 June 2013
Accepted 12 July 2013
Available online 2 August 2013

Keywords:
Unit commitment and economic dispatch
Power systems modelling
Wind power
System flexibility

ABSTRACT

The objective of this work is to determine the impact of sub-hourly modelling of a power system with significant amounts of wind generation. This paper presents the modelling of the Irish power system for a one year period at 5 min, 15 min, 30 min and 60 min resolution simulations using a unit commitment and economic dispatch model assuming perfect foresight. The work examines how much operational costs increase with more accurate resolution. Results show that increased temporal resolution captures more variability in system load and renewable generation, and is necessary to capture the inflexibilities of thermal units that lead to more realistic estimations in total generation costs. Significant cycling and ramping of units is also captured in higher resolution modelling that hourly resolution modelling is unable to capture.

1. Introduction

Over 38 GW of wind power was installed globally in 2010 with a projected doubling in capacity over the next 5 years [1]. While wind energy generation is a clean and relatively cheap power source, it is not without its drawbacks, namely in the form of variability and unpredictability. Power system issues associated with wind energy's variability and unpredictability are well documented [2,3] and have been the focus of many wind integration studies such as in [4,5]. The integration of variable renewable resources such as wind power will require increased operational flexibility—notably capability to provide load-following and regulation in wider operating ranges and at ramp rates that are faster and of longer sustained duration than are currently experienced. In providing these capabilities, existing and planned thermal generation units will likely need to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling over the operating day [6]. To assess the future impact of wind power on systems, wind integration studies usually simulate a future power system with large penetrations of wind power production and evaluate the system impacts in term of costs. These studies generally use sophisticated economic unit commitment and dispatch models to simulate the operation of the power system. A standard approach to determining the optimal unit commitment and dispatch in a power system subject to technical and economic constraints using mixed integer programming is given in [7]. Modelling the unit commitment and economic dispatch of a power system is not a trivial problem and to solve the problem sophisticated mathematical optimisation software and techniques are used to determine the least cost production schedule [8].

Many research and commercial models [9–12] have been used in recent wind integration studies [13–16]. A limitation with most of these studies and highlighted by [17] is that they run at hourly resolutions and impacts that occur inside the hour may be hidden. This means that start ups and ramp rates on conventional units are approximated by hourly rates. Recent work in [18] also highlighted the need to investigate hourly chronological simulation with sub

☆ Eirgrid plc provided Ph.D financial support for J.P. Deane's research on the topic of "Improved modelling of pumped hydro storage".

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http://dx.doi.org/10.1016/j.apenergy.2013.07.027

hourly (5–15 min) simulation to investigate the fidelity of a models ability to capture the operation of the system. Although there is widespread interest in capturing these sub-hourly impacts in the modelling framework, it is not yet clear how important these impacts will be [19]. Note that while some studies undertake operational modelling that is performed on an hourly time step, they generally analyse sub-hourly wind and load data using statistical techniques to provide insight into the intra-hour impacts and variability characteristics [20].

The goal therefore of this paper is to investigate the value of sub-hourly unit commitment and economic dispatch modelling of an actual power system with a high level of wind penetration. This work presented in this paper is similar in concept to that of [21] in that a high resolution unit commitment and economic dispatch model is used to simulate a system. The work in this paper is different as it applies mixed integer linear programming (MILP) to solve the unit commitment and economic dispatch problem (unit commitment and economic dispatch are solved simultaneously) and aims to qualify and quantify the differences between high resolution simulations (i.e. 5 min) and hourly simulation results. This is important because in large power systems hourly simulation may have to be undertaken to keep the problem computationally manageable so it is useful to understand the implication of higher resolution modelling.

Section 2 provides a review of the model used in this analysis. Section 3 presents the modelling methodology used in this analysis and the test system. Section 4 presents the results and Section 5 draws conclusions.

2. Model

The software used throughout this work to solve the unit commitment and dispatch problem is PLEXOS [22]. PLEXOS is a power systems modelling tool used for electricity market modelling and planning [23,24] and [6]. The PLEXOS modelling tool is used by the Commission for Energy Regulation (CER) in Ireland to validate Ireland's Single Electricity market and has a history of use in Ireland [25].

In this set-up PLEXOS co-optimises hydro, thermal, renewable, and reserve classes and no heuristic or sequential approach is taken. Modelling is carried out using mixed integer linear programming that aims to minimise an objective function subject to the expected cost of electricity dispatch and a number of constraints. The objective function of the model includes operational costs, consisting of fuel costs and carbon costs; start-up costs consisting of a fuel offtake at start up of a unit and a fixed unit start-up cost. Penalty costs for unserved energy and a penalty cost for not meeting reserve requirements are also included in the objective function. Fuel consumption is calculated using piecewise linear functions as in [26]. System level constraints consist of an energy balance equation ensuring supply (net pumping demand) meets regional demand at each simulation period. Water balance equations ensure water flow within pumped storage units is conserved and tracked. System operational constraints unique to this work are described in the next section. Constraints on unit operation include minimum and maximum generation, maximum and minimum up and down time and ramp up and down rates. Constraints in relation to each unit's ability to provide reserve are also included. Start up/shutdown profiles and times are enforced via run up rates. This means that units cannot 'block load' and cannot provide reserve or capacity during a start-up period. This is shown in Fig. 1 for an exemplarily 300 MW unit with a minimum stable level of 120 MW, a run up rate of 2 MW/min and a ramp up rate of 3 MW/min. The unit is committed at 01:00 and must then follow its start profile or run up rate of 2 MW/min to the minimum stable level. Assuming a 15 min simulation interval this takes 4 periods. Once the unit reaches minimum stable level it can ramp at a regular ramp rate of 3 MW/min up to maximum capacity. This is in contrast to the block loading method where the unit can instantaneously come online at the minimum stable level.

Ancillary services within the model are optimised using techniques set out in [26]. In chronological mode PLEXOS solves for each period and maintains consistency across the full problem horizon. Temporal resolutions settings in relation to solving are user defined and flexible. Users can choose interval lengths of 1 min to multiple hours in hourly, daily or weekly steps over the full problem horizon (typically 1 year or more). For example, a model run with an optimisation length of 1 h and period of 1 day with a horizon of 1 year will run 365 individual daily optimisations at a resolution of 1 h each. To avoid issues with intertemporal constraints (i.e. unit commitment of large units and storage end levels) at the simulation step boundaries a 'look ahead' period is used. This look ahead period is user defined. Look ahead means that the optimiser is given information about what happens ahead of the period of optimisation and solves for this full period (i.e. simulation period + look ahead period) however only results for the simulation period are kept. The look ahead period shares the same temporal resolution as the optimisation interval (see Table 1).

Within the model maintenance schedules for generation units can be fixed exogenously if a known maintenance schedule is available, otherwise the model can determine an optimal maintenance schedule based on the annual maintenance rate for each unit. The objective function of the maintenance scheduling formulation is to equalise the capacity reserves across all peak periods. Outages for units are calculated based on Monte Carlo simulations. In this work outages for all models occur at the same periods. At simulation run time PLEXOS dynamically constructs the linear equations for the problem using AMMO[1] software and uses a solver to solve the equation. In this work Xpress MP [27] with a duality gap set to 0.2% is used with a solver timeout at 800 s. These setting were chosen based on previous PLEXOS simulations on large systems. All simulations were checked for correct completion.

3. Approach and methodology

We developed a detailed PLEXOS model of the All Island (AI) power system for the year 2020. The model was run at varying temporal resolutions (5 min, 15 min, 30 min and 60 min) to investigate the effect of increased model resolution on results. All model simulations assume perfect foresight so as to isolate and examine the effect of increased model resolution on simulation results. Note that all model simulations share the same model inputs as well as maintenance and forced outages patterns and times.

3.1. Test system

The 2020 generation portfolio is taken from EirGrid's (Ireland's transmission operator) All-Island Generation Capacity Statement 2012–2021 [28] which gives projections of generation capacity out to the year 2021. The 2020 power system includes approximately 8320 MW of synchronous generation (coal, peat and hydro plant, OCGT's, and CCGT's). In total the All Island system has 72 individual units with 2 interconnectors to Great Britain (GB) and 1 pumped storage plant comprised of 4 individual units. Details of the 2020 power system are provided in Fig. 2. Further details of the system in relation to adequacy and reliability can be found

[1] AMMO performs a similar role in PLEXOS as other mathematical languages such as AIMMS, AMPL, or GAMS but is written exclusively for PLEXOS.