Electric Power Systems Research 136 (2016) 232–241

Contents lists available at ScienceDirect

Electric Power Systems Research

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

A column generation approach for solving generation expansion planning problems with high renewable energy penetration

Angela Flores-Quiroz [a], Rodrigo Palma-Behnke [a,*], Golbon Zakeri [b], Rodrigo Moreno [a,c]

[a] Energy Centre, Faculty of Mathematical and Physical Sciences, University of Chile, Santiago, Chile
[b] Department of Engineering Science, University of Auckland, New Zealand
[c] Department of Electrical and Electronic Engineering, Imperial College London, UK

ARTICLE INFO

Article history:
Received 3 November 2015
Received in revised form 4 February 2016
Accepted 6 February 2016

Keywords:
Column generation
Generation expansion planning
Flexibility
Renewable energy integration
Unit commitment

ABSTRACT

The high penetration of renewables envisaged for future power systems will significantly increase the need for flexible operational measures and generation technologies, whose associated investment decisions must be properly planned in the long term. To achieve this, expansion models will need to incorporate unit commitment constraints, which can result in large scale MILP problems that require significant computational resources to be solved. In this context, this paper proposes a novel Dantzig–Wolfe decomposition and a column generation approach to reduce the computational burden and overcome intractability. We demonstrate through multiple case studies that the proposed approach outperforms direct application of commercial solvers, significantly reducing both computational times and memory usage. Using the Chilean power system as a reference case, we also confirm and highlight the importance of considering unit commitment constraints in generation expansion models.

1. Introduction

1.1. Motivation: increased need for system flexibility

The high penetration of renewables envisaged for future power systems will significantly increase the requirement for flexible operational measures and generation technologies [1]. This requirement and the associated resources that can provide it must be properly considered in short term system operation and long term investment decisions [2].

In this framework, several papers have studied the impacts of variable renewable generation on the scheduling regime of thermal units, number of startup and shutdown operations of conventional plants, ramping requirements, and reserve requirements [3]. Although most studies focus on operational aspects of renewables, several papers report on impacts on the planned generation capacity mix [4,5], and fundamentally question the ability of traditional planning approaches (e.g. screening curve criteria [6]) to properly incorporate the need for resources that can provide various frequency control services and flexibility to systems with high penetration of renewables. Traditional planning approaches are usually based on a non-chronological representation of the load, ignoring short term complexity, such as startup costs, minimum operational times, ramp rates, and minimum stable output constraints [4]. However, [5] shows that ignoring short term constraints in generation planning can lead to a suboptimal capacity mix with up to 17% higher operational costs in the case of the Electric Reliability Council of Texas.

1.2. Current generation expansion planning approaches

Although generation capacity expansion models have historically ignored short term constraints, recent effort attempted to include them in long term planning [5,7–10]. These were largely focused on solving the generation planning problem based on either heuristic [9,10] or optimization [5,7,8] methods. Heuristic methods such as those developed by Batlle and Rodilla [9] aim to improve the screening curve criteria to include renewable generation and the need for system flexibility. Although some improvements can be obtained with these types of methods, no optimality metrics have been reported.

Regarding optimization methods, [7] proposes stochastic expansion planning to increase system security with high penetration of renewables through integration of fast response (flexible) thermal units. They used a unit commitment model to represent the system operation (although startup costs and minimum up and down time constraints were neglected) and considered a 10-year horizon, where the computational burden was tackled by applying

* Corresponding author. Tel.: +56 2 2978 4203.
E-mail address: rodpalma@cec.uchile.cl (R. Palma-Behnke).

http://dx.doi.org/10.1016/j.epsr.2016.02.011
0378-7796/

Nomenclature

Investment variables

$IG_{y,g}$	additional units installed in year y of generator type g
$\mathbf{IG}_y$	vector of additional units installed in year y
$IG'_{y,g}$	total available units to operate in year y of generator type g
IG'_y	vector of total available units to operate in year y

Operational variables

$D_{y,t,g}$	number of shutdowns at hour t in year y for generator type g
$LS_{y,t}$	load shedding at hour t in year y [MW]
$P_{y,t,g}$	power supplied by generator type g at hour t in year y [MW]
$Rp_{y,t,g}$	primary reserve of generator type g at hour t in year y [MW]
$Rs^{up}_{y,t,g}$	up secondary reserve provided by generator type g at hour t in year y [MW]
$Rs^{down}_{y,t,g}$	down secondary reserve provided by generator type g at hour t in year y [MW]
$S_{y,t,g}$	number of startups at hour t in year y of generator type g
$u_{y,t,g}$	number of committed units at hour t in year y of generator type g
$\mathbf{X}_y$	vector of operational variables in year y

Parameters

α^{VR}	percentage of the variable generation output covered by secondary reserve
A_y	matrix that couples operational and investment decisions in year y
C_{UD}	unsupplied demand cost [USD/MWh]
$c^{inv}_{y,g}$	investment cost annuity of generator type g in year y [USD/MW]
$\mathrm{c}^{\mathrm{inv}}_{\mathrm{y}}$	vector of discounted investment cost in year y [USD/MW]
$\mathrm{c}^{\mathrm{op}}_{\mathrm{y}}$	vector of discounted operational cost in year y [USD/MWh]
c^{s}_{g}	startup cost of generator type g [USD]
$c^{var}_{y,g}$	variable cost of generator type g in year y [USD/MWh]
$L_{y,g}$	load at hour t in year y [MW]
$L^{\max}_{y}$	maximum load in year y [MW]
$I^{\max}_{g}$	maximum units to be installed of generator type g
NG	number of generators types
$P^{avail}_{y,t,g}$	available generation at hour t in year y as a proportion of the maximum capacity of one unit of generator type g
P^{firm}_{g}	firm capacity of generator type g
$P^{\max}_{g}$	maximum capacity of a unit of generator type g [MW]
$P^{\min}_{g}$	minimum capacity of a unit of generator type g [MW]
P^{s}_{g}	maximum output of generator type g when started [MW]
r	discount rate
Rdn_g	maximum down ramp rate of a unit of generator type g [MW/h]
RM	planning reserve margin
$Rp^{\max}_{g}$	maximum primary reserve capacity of generator type g [MW]
$Rs^{\max}_{g}$	maximum secondary reserve capacity of generator type g [MW]
$Rrp_{y,t}$	primary reserve requirement at hour t in year y [MW]
$Rrs_{y,t}$	secondary reserve requirement at hour t in year y [MW]
Rup_g	maximum up ramp rate of a unit of generator type g [MW/h]
T	number of subperiods
t^{off}_{g}	minimum down time of generator type g [h]
t^{on}_{g}	minimum up time of generator type g [h]
Y	number of years in the planning horizon

Operational set and index

g	index of generator types
$g \in TH$	set of thermal generators
$g \in F$	set of fast response generators
$g \in VR$	set of variable renewable generators
t	index of subperiod
y	index of planning year

Benders decomposition. However, under this approach slave subproblems must be linear and, hence, all integer variables, such as unit commitment states, have to lie in the master problem [11], leading to a high dimensional integer programming (IP) master problem. Consequently, [7] considered planning for a reduced set of fast response gas turbines, with future wind and thermal generation capacity assumed to be fixed.

The unit commitment problem was extended by Ma et al. [8] to control investment decisions in the entire generation mix, minimizing the sum of investment and operational costs. The resulting combined unit commitment and capacity expansion (C-UC-CE) model, was a high dimensional mixed integer linear problem (MILP). Computational burden was limited by considering a small number of units (e.g. 26 units) with a planning horizon of a single year, represented by a reduced number of typical weeks (e.g. 5 weeks). Similarly, [5] proposed a C-UC-CE model that aimed to avoid combinatorial explosion by grouping similar generators into equivalent plants, driving reductions in computational time by approximately a factor of 400. In addition to including unit commitment constraints, [12] represented long term uncertainty through a reduced number of sample weeks for wind and load profiles, and short term wind forecast error was included as an additional amount of operating reserves as a fraction of wind power forecast. Although these methods have reported clear improvements in terms of computational performance, only static planning was performed and further developments are necessary to solve planning problems on realistic sized systems in a multi-stage fashion.

1.3. Paper contribution and structure

Development of C-UC-CE models is critical for improving investment decisions in generation infrastructure in future power systems. New methods to tackle the high complexity of such problems are required to obtain fast and timely solutions of large C-UC-CE models. We propose using a Dantzig–Wolfe decomposition together with a Column Generation approach [13], to solve C-UC-CE models in a multi stage fashion with significant reduction in solution times. Additionally, we use concepts and methods from current power system literature to overcome intractability through clustering techniques, tight formulations of the unit commitment problem, and classical screening curves as an initial point for the Column Generation approach. We analyze the benefits of our proposed approach through multiple case studies and demonstrate that C-UC-CE problems can be solved with reduced