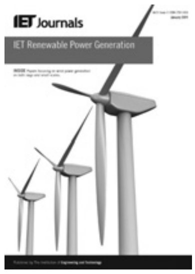
www.ietdl.org

Published in IET Renewable Power Generation
Received on 9th October 2011
Revised on 30th April 2013
Accepted on 9th May 2013
doi: 10.1049/iet-rpg.2011.0272



ISSN 1752-1416

Should unit commitment be endogenously included in wind power transmission planning optimisation models?

Daniel J. Burke[1], *Aidan Tuohy*[2], *Jody Dillon*[3], *Mark J. O'Malley*[3]

[1]*Australian Energy Market Operator (AEMO), Melbourne, Victoria, Australia*
[2]*Grid Operations and Planning Department, Electric Power Research Institute (EPRI), Knoxville, Tennessee, USA*
[3]*Electricity Research Centre, School of Electrical, Electronic and Mechanical Engineering, University College Dublin, Belfield, Dublin 4, Ireland*
E-mail: DNLBRK157@gmail.com

Abstract: The historical time series data or Monte Carlo simulation approaches that are often used to represent wind power in transmission planning models will lead to large-scale optimisation problems. The complexity of such problems will be further compounded if advanced techniques for wind variability and wind forecast uncertainty management are also endogenously included, corresponding to a merging of the traditionally separate 'real-time operations' and 'long-term planning' analysis timeframes in power system analysis. A stochastic mixed-integer scheduling model is applied here to investigate the likely transmission planning model formulation impacts of advanced wind forecast techniques, and to determine whether any additional optimal transmission planning model precisions offered justify the associated very-large-scale computational burden. Results indicate that power-flow modelling is only significantly influenced in a small subset of the network branches associated with major interconnections and flexible/inflexible conventional generation locations. Model sensitivity analysis also suggests that even at high wind penetrations, such power-flow modelling differences may be overshadowed by the impact of general uncertainty in fuel price volatility and demand profile that is systemic to long-term planning problems. Such trade-offs have significant practical relevance to the many researchers currently investigating formulations of this class of optimisation problem.

1 Introduction

Increasing wind energy penetration is recognised as a key contributor to reducing carbon emissions and maintaining diversity of primary energy supply [1]. Detailed wind-integration studies have been carried out in many power systems [2–4], with transmission network limitations universally acknowledged as a significant challenge. Prudent allocation of new wind farm connection licences or optimal transmission development plans could be determined to accelerate wind connection to transmission networks.

Indeed there has been significant focus in recent times on the formulation of these types of wind and transmission planning optimisation models. For example, an optimal firm wind power connection model (i.e. no wind curtailment assumed) is proposed in [5], with corresponding optimal non-firm wind power connection models of varying levels of detail given in [6–8]. A market-equilibrium-constrained model is given in [9], while the model in [10] focuses on regional interconnection investments. An interesting model incorporating how independent generators might dynamically respond to transmission investments by the system operator (and vice versa) is given in [11], while the efforts of [12] focus on determining the optimal transfer capacity and wind curtailment trade-offs for a given transmission system location. The focus is not limited to onshore wind power connections either – an optimal offshore grid topology formulation is offered in [13] for example.

Transmission access study for large-scale centralised conventional generation was traditionally carried out either in a deterministic manner at onerous snapshot hours such as the 'winter-day-peak' and/or the 'summer-night-valley' of system load profile, or by using a sliced load-demand duration curve approach. In contrast, wind power is a low capacity factor, geographically distributed and statistically interdependent source of power generation. Clearly, transmission planning methods require suitable adaptation over a much broader number of study cases to incorporate such characteristics – some related modelling techniques have been studied in the recent literature as a result. For example, a random Monte-Carlo sampling approach to statistical dependency modelling using copula theory is outlined in [14], while noting that simple random sampling methods cannot recreate sequential hour-to-hour wind variability patterns. Basic auto-regressive moving-average sequential time series synthesis with statistical transformation methods has been reported in [15]. Wind production profiles based on historical data behaviour have also been widely applied in practice for wind-integration study [2]. A historical wind time series data approach is also presented for distribution system analysis in [16] for example. Although a practical drawback is that sometimes there may not be enough data available to give completely statistically robust conclusions, the benefit of using historical data is that any multivariate statistical and auto-correlative sequential dependencies are implicitly contained in the recorded data set, and can be easily incorporated to the optimal transmission planning model, if so desired.

Equally importantly however, the recent development of advanced unit commitment and reserve scheduling strategies to account for wind variability and forecast uncertainty through stochastic optimisation techniques [17–22] now necessitates a consideration of how the traditional separation of 'operations' timeframe and 'planning' timeframe power-flow assumptions may not be as distinct as often assumed in the past. Appropriate choice of model formulation for combined wind-generation/transmission optimisation studies such as in [5–13] therefore requires detailed consideration. If integer variables are retained to model the hourly unit commitment process, the problem complexity will be greatly increased. On the other hand, if the temporal link from hour-to-hour can be relaxed, then there will be significant implications for model formulation and solution approach [23, 24] as will be discussed further in later sections. In the past literature, unit commitment for wind variability (but not forecast uncertainty) issues has been included in [5, 8] but is rarely discussed in most other transmission planning works.

In any case, the wind generation/transmission optimisation problem must also be formulated with some consideration of long-term model parameter uncertainty. Although future customer demand growth and conventional plant fuel prices are always difficult to predict accurately, the impacts of electric transportation or smart-meter efficiency applications on the future power system load flow patterns are furthermore uncertain at this present time. The future location of new generation plants is also rather uncertain. Models incorporating short-term operations timeframe issues such as stochastic unit commitment, applied over the extended number of samples necessary to represent wind variance characteristics, and under a number of alternative long-term demand-profile/fuel-price uncertainty scenarios will require unprecedented computational efforts (for complexity and dimensionality reasons) to be solved for power system transmission networks of realistic size. The important question of whether stochastic unit commitment issues should in future be endogenously included in the optimal transmission planning model formulation has not yet been studied in detail, and is therefore the subject matter of this paper.

To this end, varying levels of operations timeframe scheduling complexity are applied to a test power system in this paper. A key issue explored is whether the additional computational rigor of endogenously including either a traditional deterministic unit commitment, or even an advanced stochastic unit commitment, in the optimal transmission planning model is likely to be justified, or whether a judiciously simplified operations timeframe model would be reasonably adequate with pragmatic acknowledgment of the general uncertainty in the long-term power system model itself. This hypothesis list is summarised in Table 1.

Section 2 outlines the operations timeframe complexity issues considered, whereas the test system is presented in Section 3. The results, and a contextual discussion of their implications for optimal wind transmission planning models, are outlined in Sections 4 and 5, respectively.

Table 1 Hypotheses under consideration

1 – Does the complexity of plant scheduling model applied for the system dispatch materially influence the annual power flows modelled?
2 – Are these differences, if any, relative in scale to other long-term uncertainty influences?
3 – Are there any implications for optimal transmission planning model formulation?

2 System power-flow modelling

2.1 *Impact of operations timeframe wind issues in long-term network planning timeframes*

The 'unit commitment' task could be described as how to optimally schedule the turning on and off of generators to meet variations in net electricity demand spanning timeframes of hours, days or weeks. The 'economic dispatch' task refers to the here-and-now decision of how to optimally decide the generation levels of generators that are already turned on. With significant wind capacity installed, more flexible and robust conventional plant commitment and dispatch schedules must be produced so that the system can balance with respect to the wind that actually occurs at the operations timeframe time-horizons of the near future.

Operations timeframe real-time wind forecast uncertainty can be represented with a spread of probability-weighted 'scenarios' [25]. Techniques such as 'rolling-planning' and stochastic mixed-integer programming (MIP) using probability-weighted wind forecast scenarios have been reported for generation production-cost analysis in the literature [17–20]. As the power production, and crucially for this paper, the transmission system load flow patterns, may now deviate somewhat from those modelled by a simple 'merit-order' (MO) based economic dispatch alone (which is generally assumed in most optimal transmission planning models [26]), then the relevance and merits of including the additional complexity in the long-term transmission planning model should now be assessed.

The power flow in each transmission network branch can be considered (in a first-order simplistic manner at least) as the superposition of individual power-flow 'contributions' from generator source nodes and customer demand sink locations. From a 'real-time' network operations timeframe perspective, any one of the wind forecast uncertainty scenarios could potentially occur for each stage of the 24–36–48 h scheduling horizon ahead [27]. Various alternative network congestion management plans would need to be prepared accordingly in advance [28]. From the transmission planning perspective however, only one of the wind power forecast uncertainty scenarios (that help define the forecast error probability) will actually occur at any given operations timeframe time-step and therefore result in a specifically wind-related power-flow contribution which the network design must accommodate – the other wind forecast scenarios that do not end up occurring (once real-time for that given forecast horizon actually arrives) will therefore not influence the power flows directly. Therefore if a historical wind power time series of a number of years' length is available to clarify the actual wind-power-flow contribution requirements in the