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Analysis of greenhouse gas emissions in electricity systems using time-varying carbon intensity

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ABSTRACT

Greenhouse gas (GHG) emissions from electricity generation are generally assessed using a yearly average carbon intensity (in carbon dioxide equivalent emissions per unit of energy). This masks the variability of emissions associated with different forms of generation over different timescales. Variability is a characteristic of electricity systems with high levels of renewable generation, where fossil fuels are typically used to meet any shortfall in supply. In this paper we argue that quantification of the time variability of carbon intensity is necessary to understand the detailed patterns of carbon emissions in electricity systems, particularly as future systems are likely to increasingly rely on a mix of time-variable generation types such as wind, hydro and solar. We analysed the time-varying carbon intensity of New Zealand's electricity sector, which has approximately 80% renewable generation. In contrast to many other nations, we found that carbon intensity did not consistently follow daily peak demand, and was only weakly correlated with demand. This result, and the finding that carbon intensity has significant seasonal variation, stems from the dominance of hydro (albeit with limited storage capacity) in New Zealand's generation mix. Further investigation of the operating regimes of the fossil fuel generators, using time-varying analysis, indicates that New Zealand's electricity system is sub-optimal from a GHG emission perspective, with more coal generation than would seem to be required. Two policy measures, which also generalize to other countries, are proposed to address this issue: (i) the creation of an electricity capacity market – providing revenue for standby fossil fuel generation capacity without the need for continual generation; (ii) use of time-varying carbon intensity to inform demand-side measures and decisions about new renewable generation.

1. Introduction

Decarbonisation of the electricity sector is recognized as one of the key steps to achieving a low carbon future (Santos-Alamillos et al., 2017; Weldu and Assefa, 2017; Williams et al., 2012). Globally, two thirds of electricity is generated from fossil fuels, mainly from coal [40.8%] and gas [21.6%] (IEA, 2016a) and associated greenhouse gas (GHG) emissions have increased by 50% between 2000 and 2014 (IEA, 2016a). Generation from renewable sources is increasing: the global proportion of renewable generation was 19.9% in 2010, 22.7% in 2014, and is estimated to reach 25% and 31% in 2020 and 2035, respectively (IEA, 2016b; Ellabban et al., 2014; IEA, 2012). However, economic growth, population growth and industrialisation, especially in developing countries, are predicted to continue to drive an overall increase in electricity demand, and thus potentially in GHG emissions. If a reduction in global GHG emissions is to be achieved, the electricity sector faces two major challenges: firstly, ensuring that most of the new generation capacity is renewable; and secondly, optimising the relative utilisation of non-renewable and renewable capacity so that GHG emissions are minimised.

It is the latter challenge that is the main subject of this paper. Most renewable generation is temporally variable. Solar, for example, has a diurnal rhythm; hydro resources vary seasonally or annually; and wind speeds vary from minute to minute. Fossil fuelled power stations, in contrast, are permanently on call and can be used for base demand as well as supplying additional power at peak demand (Pereira et al., 2016; Kahrl et al., 2013) and to 'top-up'

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when there is a shortfall of renewable generation. The latter role may become more common as more renewable generation comes on-stream. Some analysts argue that near 100% renewable is technically feasible (Cosic et al., 2012; Connolly et al., 2011; Mason et al., 2010; Lund and Mathiesen, 2009). Others consider that additional renewables will make little difference to the need for non-renewable capacity (Heard et al., 2017; Vidal-Amaro et al., 2015; Hammond et al., 2011) and some argue that more fossil powered generation will be required due to the increasing variability in demand arising from the increase in solar generation together with the adoption of new technologies such as electric vehicles (Reese, 2017; Concept, 2016; Safaei and Keith, 2015; Kim and Rahimi, 2014; Thomas, 2012).

Assuming that fossil fuelled power stations will continue to be part of the generation mix for most nations for some time (Heuberger et al., 2016), the focus for GHG reductions in the electricity sector will need to shift from simply increasing renewable capacity, to how to most effectively mitigate GHG emissions when utilising a combination of renewable and non-renewable capacity.

Quantification of GHG emissions from electricity generation is typically measured, and targets set, by the yearly average carbon intensity of the grid. For example, Austria, France and Switzerland have targets to reduce carbon intensity from 206, 96, and 11 gCO_2/kWh in 2010 to 9, 4 and 0.5 gCO_2/kWh in 2050, respectively (Pattupara and Kannan, 2016). However, the metric of average carbon intensity masks the variability of carbon intensity associated with different combinations of generation types over different time scales. In this paper, we argue that to minimize GHG emissions in highly renewable electricity systems, quantification of GHG emissions needs to move beyond yearly average carbon intensity to a more nuanced approach that takes into account the time variability of emissions.

A better understanding of this variability can assist with two things: firstly, in managing current generation infrastructure to minimise GHG emissions; and secondly, in the long term, in incorporating an understanding of the variability of the renewable generation and implications for carbon intensity into new generation expansion plans.

Previous studies have considered electricity generation carbon intensities in a range of different contexts. A number of studies have examined emission factors and absolute emission of GHGs from electricity sectors (Ji et al., 2016; Gordon and Fung, 2009; Bettle et al., 2006; Voorspools and D'Haeseleer, 2000). Some studies have looked at changes in GHG emissions resulting from alterations in electricity demand (Gordon and Fung, 2009), electricity network expansion or replacement (Daniels et al., 2016), and arising from grid variability (Cubi et al., 2015). Hitchin and Pout have contrasted the carbon intensity of a typical marginal plant with new plant (Hitchin and Pout, 2002). Three studies have discussed carbon emission pinch analysis and future emission reduction planning for New Zealand's electricity sector (Mason et al., 2017; Walmsley et al., 2014; Atkins et al., 2010). A recent study has analysed the global and country-specific changes in aggregate carbon intensity for electricity (Ang and Su, 2016). Cubi et al. (2015) explored the correlation between GHG emission and electricity demand in Canada and found a positive correlation between total carbon emissions and total system demand; that is, higher demand led to higher GHG emissions from electricity generation (Cubi et al., 2015), indicating that demand peaks are associated with more carbon intensive generation.

Marginal GHG emissions from the electricity sector, that depend on the location and time of generation, have been considered in a number of studies (Garcia and Freire, 2016; Hawkes, 2014; Graff Zivin et al., 2014; Rogers et al., 2013; Siler-Evans et al., 2012; Hawkes, 2010; Bettle et al., 2006). Marginal GHG emission analysis has been shown to reveal relationships between changes in GHG emissions and changes in system load. For example, Hawkes estimated the marginal CO_2 emission rate for the national electricity system in Great Britain (Hawkes, 2014; Hawkes, 2010). Siler-Evans et al. (2012) have investigated regional marginal emission factors in the USA and compared the findings between marginal and average emission factors. Similar marginal emission estimation was used to evaluate the impact of plug-in electric vehicle and battery electric vehicles on total carbon emission in the USA (Graff Zivin et al., 2014) and Portugal (Garcia and Freire, 2016), respectively. Carson and Novan estimated the average hourly marginal generation share and marginal emission rate of major GHGs for the Texas region in the USA (Carson and Novan, 2013).

Kopsakangas-Savolainen et al. (2017) used hourly GHG emissions from electricity generation in Finland to investigate the best timing for demand reductions in order to reduce total GHGs, while leaving the total demand unchanged. They found that decreases of 3–8% in GHG emissions were possible through optimised timing of demand shifting (Kopsakangas-Savolainen et al., 2017). This paper extends their approach by demonstrating how time-varying carbon intensity can be characterised and analysed over different timescales, and discussing the insights that this can provide to optimising the mix of renewable to non-renewable generation and also demand response to minimise GHG emissions.

1.1. Case study: New Zealand's electricity system

An analysis of New Zealand's electricity generation system and associated GHGs emission was conducted for this study. New Zealand was chosen because it already has more than 80% electricity generation from a variety of renewable sources (see Table 1) and is therefore a good exemplar of where many countries aspire to be in the future (Staffell, 2017; Riesz et al., 2015; Cosic et al., 2012; Connolly et al., 2011; Lund and Mathiesen, 2009).

New Zealand has a longstanding policy target of achieving 90% electricity generation from renewable sources by 2025 (MBIE, 2011), and a national commitment of achieving a 30% reduction in GHG emissions from 2005 levels by 2030 (MfE, 2016a; PCE, 2012). The proportion of renewables has already increased from approximately 76% in 2013 (MBIE, 2014) to 81% in 2015 (MBIE, 2016b) (see Fig. 1). Over the same period, electricity demand (observed) increased from 38,895 GWh in 2013 to 39,609 GWh in 2015; a 1.8% increase.

Despite the increasing share of renewable generation, the electricity sector has been identified as one of the sectors for further reductions in GHG emissions (RSNZ, 2016; Atkins and Walmsley, 2016; MBIE, 2011). Under current policies, fossil fuel generation will remain a part of the generation mix for some time (MBIE, 2011), so the challenge is how to minimise emissions by optimal management of the generation mix.

Table 1
Estimated generation capacity in New Zealand [December, 2015] (MBIE, 2016a) [a].

Sl. No.	Fuel	Capacity (MW)	Type (MW)
1	Hydro	5348	Renewable (7,153)
2	Geothermal	986	
3	Wind	690	
4	Wood	63	
5	Biogas	47	
6	Waste Heat	19	
7	Gas	1555	Fossil Fuelled (2,279)
8	Coal	557	
9	Oil	167	
New Zealand (Total)		9432 MW	

[a] New Zealand has no pumped hydro.