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Least cost, utility scale abatement from Australia's NEM (National Electricity Market). Part 2: Scenarios and policy implications

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ABSTRACT

This paper is the second of a two part study that considers least cost, greenhouse gas abatement pathways for an electricity system. Part 1 of this study formulated a model for determining these abatement pathways, and applied this model to Australia's NEM (National Electricity Market) for a single reference scenario. Part 2 of this study applies this model to different scenarios and considers the policy implications. These include cases where nuclear power generation and CCS (carbon capture and storage) are implemented in Australia, which is presently not the case, as well as a more detailed examination of how an extended, RPS (renewable portfolio standard) might perform. The effect of future fuel costs and different discount rates are also examined.

Several results from this study are thought to be significant. Most importantly, this study suggests that Australia already has utility scale technologies, renewable and non-renewable resources, an electricity market design and an abatement policy that permit continued progress towards deep greenhouse gas abatement in its electricity sector. In particular, a RPS (renewable portfolio standard) appears to be close to optimal as a greenhouse gas abatement policy for Australia's electricity sector for at least the next 10–15 years.

1. Introduction

When considering the decarbonisation of electricity, all aspects of the policy and technology debates have their proponents and opponents. On policy, some advocate different forms of carbon price, whilst others argue for RPSs (renewable portfolio standards), reverse auctions, direct regulation or other measures [1–3]. There is also significant disagreement as to what our abatement targets should be. Some argue that, for high income countries at least, zero emission and/or completely renewable electricity is essential [4–6]. Others argue that since cheaper abatement is available internationally [7,8] or in other domestic sectors [9], we should therefore target less abatement in electricity as part of an overall, more cost-effective approach.

Australia is a case study of such differing policy views. In 2014, our Federal Government became the first government in the world to remove a legislated price on carbon; legislation that had been in place for only two years. It has also recently completed a lengthy negotiation on its legislated RET (Renewable Energy Target), which is the domestic form of a RPS, whilst implementing its ‘Direct Action plan’, which is a form of reverse auction that will pay for abatement across the economy [2]. Finally, even though Australia has one of the world's largest proved economic reserves of uranium and is a large uranium exporter, it does not produce any electricity from nuclear energy.

The technology debate is no less charged or confusing. In particular, it is common to find advocacy of specific technologies without fully acknowledging the difficulties that they face. At utility scale, these technologies include the several forms of renewable generation, CCGTs (combined cycle gas turbines), nuclear, coal and gas with CCS (carbon capture and storage) and different forms of energy storage, to name only a few. Of course, no technology is without problems. Even though the direct CO_{2e} emissions of CCGTs are significantly lower than those of coal plant, the fugitive emissions of methane from the well to the plant remain a topic of debate [10,11]. Intermittent renewables can create problems of network and market performance [12–16]. Biomass and biogas often face issues of resource availability [17]. Whilst some argue that nuclear power is significantly safer than alternatives, the public's perception of its risks – rightly or wrongly – remains a major challenge to

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its future prospects [18–20]. More broadly, some of these technologies are deployed at a significant scale and have a known record of performance, whilst others do not. Whilst these latter technologies may be very deserving of support for further research, development and demonstration, it is important not to overstate the role that presently undeployed technologies will play, particularly since any new energy technology usually takes decades to reach significant levels of deployment [21,22].

Following on from Part 1 of this study [23], this second part therefore considers different technology, financial and policy scenarios for achieving abatement from Australia's NEM (National Electricity Market). These include cases where nuclear power generation and CCS (carbon capture and storage) are implemented in Australia, which is presently not the case, as well as a more detailed examination of how an extended RPS might perform. The effect of future fuel costs and different discount rates are also examined. Policy implications arising from these scenarios for both the nearer (i.e. to roughly 2030) and the longer term (i.e. to 2050) are then discussed. As detailed in Part 1, all model inputs are from the most current, publicly available and authoritative Australian sources and the results presented are therefore intended to be transparently derived and both policy and technology neutral.

2. Method

The method used in this paper was presented in Part 1 of this study [23]. This includes use of a constrained LP (linear program) that minimises the net present costs of the new build and operating costs from 2015 to 2050 subject to numerous constraints.

Part 1 of this study [23] also listed the existing and new build generation and storage technologies that are included in the model. For the cases where nuclear generation is considered, it can only commence generation in 2025 or after. Nuclear electricity generation does not presently exist in Australia, and 10 years is assumed to be the shortest plausible period over which to commence nuclear powered electricity generation assuming immediate public acceptance. This includes the time required to make regulatory changes, identify suitable sites, build and commission the first plants and train personnel. Following the AETA report [24], all CCS plant (including oxy-combustion) plant can also only commence generation in 2025 or after. Once again, this is considered to be reasonable since these plant types are not presently in the NEM and, indeed, are not yet an established generating technology.

3. Results and discussion

Let us first consider the *annual* GHG (greenhouse gas) emissions from any electricity system M_y (t CO_{2e}) expressed in terms of other parameters,

$$M_y = E_y^a\left(1-\frac{\sum^{\neq\mathscr{F}}E_{py}^a}{E_y^a}\right)\left(\frac{\sum^{\mathscr{F}}M_{py}}{\sum^{\mathscr{F}}E_{py}^{fuel}}\right)\left(\frac{1}{\overline{\eta}}\right). \quad (1)$$

The first term on the right hand side shows the direct proportionality between annual demand – and therefore annual generation E_y – and annual GHG emissions. However, electricity demand is exogenous at the utility scale, and is therefore outside the scope of the present study.

The second term on the right hand side of Equation (1) quantifies the effect of zero emission generation. If we assume that there is no nuclear generation in the system, as is currently the case in Australia, this quantifies the effect of renewable energy generation, with M_y varying in proportion to the annual electricity generated from zero emission sources $\Sigma^{\neq\mathscr{F}}E_{py}^a/E_y^a$.

The third term on the right hand side of Equation (1) is the annually averaged GHG intensity (t CO_{2e}/MWh) of the fuel burnt by all fossil fuelled plants in the system. This term can also be written in terms of input parameters for this study as

$$\frac{\sum^{\mathscr{F}}M_{py}}{\sum^{\mathscr{F}}E_{py}^{fuel}} = \sum^{F}\left\{\left(\frac{M_{py}}{E_{py}}\right)\left[\frac{\left(E_{py}^a/\overline{\eta}_{py}\right)}{\sum^{\mathscr{F}}\left(E_{py}^a/\overline{\eta}_{py}\right)}\right]\right\}. \quad (2)$$

When written in this form, the GHG intensity M_{py}/E_{py} is a physical property of a given fuel consumed by a given fossil fuelled plant, e.g. the combustion of natural gas produces less CO_{2e} than coal per unit of thermal energy released. However, this term is not the sole determinant of the annually averaged GHG intensity of the fuel burnt by all fossil fuelled plants, with each plant's annual generation and annually averaged thermal efficiency also playing roles.

Finally, $\overline{\eta}$ in Equation (1) is the annually averaged thermal efficiency of all fossil fuelled plants in the system. It can be written in terms of individual plant parameters as follows.

$$\overline{\eta} = \frac{\sum^{\mathscr{F}}E_{py}^a}{\sum^{\mathscr{F}}\left(E_{py}^a/\overline{\eta}_{py}\right)}. \quad (3)$$

Equation (1) therefore summaries the principal means by which we can reduce GHG emissions from any electricity system. In order, these are *demand management*, *integration of zero emission generation* (e.g. renewables, nuclear or CCS), *fuel switching* (particularly from coal to natural gas) and *efficiency measures* for any fossil plant.

We also note that, over the course of the year, the instantaneous demand, the instantaneous proportion of zero emission generation, the instantaneous fleet-averaged fossil fuel intensity and the instantaneous fleet-averaged fossil plant efficiency will all vary such that total present costs are minimised whilst this annual emissions constraint is met along with other constraints. In this case, all four of the terms on the right hand side of Equation (1) can contribute to meeting the annual emissions constraint, and thus zero emission plant, fuel switching and efficiency measures can compete for a share of generation on a least-cost basis.

With this in mind, Equation (1) therefore highlights two conceptual shortcomings of RPS measures. First, by only subsidising renewable plant, the first term on the right hand side of Equation (1) is the *only* term by which a RPS can achieve the targeted abatement. RPS measures provide no incentive for fuel switching or increasing the efficiency of any non-renewable thermal plant, as might occur with a price on carbon. Thus, renewables gain a certain level of market penetration via the RPS subsidy, leaving the remaining demand to be met by the cheapest, non-renewable alternatives, regardless of their GHG emissions. In practice, this means that higher emission coal plant is advantaged over lower emission gas plant because they are usually of lower cost. Similarly, older plants that are cheaper, less efficient and emit more are advantaged over newer plants. Thus, Equation (1) shows that an RPS can only lead to optimal, utility scale abatement in a least-cost sense if the system level benefits of investment in new, renewable plant is superior to that achieved by other investments in some combination of zero emission plant, fuel switching and efficiency measures.

There is a second conceptual shortcoming of RPS measures that is inherently dynamic in nature. The dynamic nature of demand and the dynamic performance of each plant both affect the dynamic performance and therefore the annually averaged performance *of all other plants in the system*. Intermittent renewable plants that are justified by a RPS then must force other, dispatchable generators to ramp up and down more often, be committed and