ARTICLE IN PRESS

Energy xxx (2016) 1–15

Contents lists available at ScienceDirect

Energy

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

Least cost, utility scale abatement from Australia's NEM (National Electricity Market). Part 1: Problem formulation and modelling

M. Jeppesen, M.J. Brear*, D. Chattopadhyay, C. Manzie, R. Dargaville, T. Alpcan

University of Melbourne, Parkville 3010, Australia

ARTICLE INFO

Article history:
Received 28 May 2015
Received in revised form
12 January 2016
Accepted 3 February 2016
Available online xxx

Keywords:
Decarbonisation
Abatement policy
NEM (National Electricity Market)

ABSTRACT

This paper is the first of a two part study that considers long term, least cost, GHG (greenhouse gas) abatement pathways for an electricity system. Part 1 formulates a planning model to optimise these pathways and presents results for a single reference scenario. Part 2 applies this model to different scenarios and considers the policy implications.

The planning model formulated has several constraints which are important when considering GHG abatement and widespread uptake of intermittent renewable generation. These constraints do not appear to have been integrated into a single planning model previously, and include constraints on annual GHG emissions, unit commitment, storage, plant dynamics and intermittent renewable generation. The model prioritises overall abatement, and therefore does not include a price on carbon or support for any particular technology.

The model is applied to Australia's NEM (National Electricity Market) as an example. All model inputs – for technologies, demand, and meteorological data – are from the most current and authoritative public sources. As such, the results are transparently derived and both policy and technology neutral. For the reference scenario presented here, key technologies are wind from 2015, gas generation from 2030, and solar generation from 2040.

1. Introduction

Electricity systems are a major source of global GHG (greenhouse gas) emissions, and it remains a challenge to achieve substantial abatement of emissions in this sector [1]. This challenge has been addressed in global, high level multi-sector studies, as well as more detailed studies of the electricity system in particular [2–4]. Planning decisions in the electricity industry need to consider what could happen many decades into the future, not only for abatement, but due to the nature of the technologies used. These technologies are expensive to build, can operate for many decades, and need to operate reliably as part of a complex system during that time. Once built, they are inflexible in many ways – for example, it is not usually feasible to move a power plant or to change the type of fuel it uses. Planning decisions, and the development of policies to influence them, are therefore often assisted by optimisation with long term models. This includes those done in previous studies for particular regions such as China [5], Europe [6], the US [7], California [8], and for Australia [9–11].

When modelling long term abatement from any electricity system, considerable effort is required to ensure that this modelling is sufficiently accurate whilst also computationally tractable. Of particular concern is the range of timescales involved – from fractions of seconds to decades – and the multiplicity of future system options. Bottom up, long term, technology based modelling therefore simplifies this problem in different ways, depending on the focus of the study, with modelling at different levels providing different insights [12]. Some models use predetermined values for the capacities of each plant, which permits more detailed modelling of system dynamics [13]. Planning models, i.e. those which calculate the optimal investment and divestment in new technologies over time, require simplifications to be computationally tractable, as discussed below. There are also inherent uncertainties in the problem which can be addressed with stochastic optimisation (e.g. Refs. [14,15,11]). Stochastic modelling introduces an additional computational burden which to date has required either additional simplification of system dynamics or predetermined capacities for each plant.

* Corresponding author.
E-mail address: mjbrear@unimelb.edu.au (M.J. Brear).

http://dx.doi.org/10.1016/j.energy.2016.02.017
0360-5442/

Please cite this article in press as: Jeppesen M, et al., Least cost, utility scale abatement from Australia's NEM (National Electricity Market). Part 1: Problem formulation and modelling, Energy (2016), http://dx.doi.org/10.1016/j.energy.2016.02.017

Nomenclature

Sets

$\mathscr{B}$	Biomass plant
$\mathscr{C}$	Carbon capture and storage plant
$\mathscr{D}$	Dispatchable plant
$\mathscr{F}$	Fossil plant
$\mathscr{H}$	Existing hydro plant (inflow)
$\mathscr{I}$	Intermittent (renewable) plant
$\mathscr{L}$	Transmission lines, i.e. SA-VIC, VIC-NSW, NSW-QLD, VIC-TAS interconnectors
$\mathscr{P}$	All generating plant types
$\mathscr{P}^e$	Existing generating plant
$\mathscr{P}^n$	New generating plant
$\mathscr{R}$	NEM regions, i.e. SA, VIC, NSW, QLD, TAS
$\mathscr{S}$	Pumped hydro storage plant
$\mathscr{U}$	Thermal plant with linear commitment constraints
$\mathscr{W}$	Concentrated solar thermal plant with storage

Subscripts

$l \in \mathscr{L}$	Transmission lines
$p \in \mathscr{P}$	Plant type
$r \in \mathscr{R}$	NEM region
$t \in \mathscr{T}$	Time (hours)
$y \in \mathscr{Y}$	Years

Parameters

B_y	Biomass annual generation limit (MWh net)
C^b_{pry}	Plant build cost ($/MW net)
C^f_{pry}	Fixed operating and maintenance cost ($/MW net/year)
C^l_l	Transmission line build cost ($/MW)
C^u	Cost of unserved energy ($/MWh)
C^v_{pry}	Variable operating and maintenance cost ($/MWh net)
C^{fuel}_{pry}	Fuel cost ($/$GJ_{\text{fuel}}$)
C^{CCS}_{pry}	Carbon storage and transportation storage cost ($/$t_{CO_2e}$)
D^b_{ly}	Discount factor (capex) for transmission line (dimensionless)
D^b_{py}	Discount factor (capex) for generating plant (dimensionless)
D^o_y	Discount factor for operations (dimensionless)
E^d_{ryt}	Demand (MWh net)
η_{pry}	Thermal efficiency at maximum output (dimensionless)
η^s	Round trip efficiency for pumped hydro storage (dimensionless)
f	Plant forced outage rate (dimensionless)
G_p	Fraction of emissions captured for CCS plant (dimensionless)
H_{pry}	Heat rate at maximum output (GJ_{fuel}/MWh net)
$H^{\min}_{pry}$	Heat rate at minimum output (GJ_{fuel}/MWh net)
H^{marg}_{pry}	Marginal heat rate (GJ_{fuel}/MWh net)
J_r	Hydropower annual generation limit (MWh net)
I^c	Combustion emissions intensity (pre-CCS, if applicable) ($t_{CO_2e}/GJ_{\text{fuel}}$)
I^f	Fugitive emissions intensity ($t_{CO_2e}/GJ_{\text{fuel}}$)
K_p	Minimum up time (hours)
L_p	Economic and technical life (years)
Q_p	Start up fuel consumption (GJ_{fuel}/MW net)
V_{pryt}	Time-varying hourly generation limit per MW capacity for an intermittent plant due to varying sun or wind resource (MWh net/MW)
M_y	Annual carbon emission limit (t_{CO_2e}/year)
m_p	Minimum stable generation (percentage of committed capacity)
λ_l	Transmission losses (dimensionless)
R^{on}_{pr}	Switch on ramp limit (percentage of capacity per hour)
R^{off}_{pr}	Switch off ramp limit (percentage of capacity per hour)
R^-_{pr}	Ramp down limit (percentage of capacity per hour)
R^+_{pr}	Ramp up limit (percentage of capacity per hour)
w_t	Weighting of each time period, i.e. the fraction of a year it represents (dimensionless)
X^{ex}_{pry}	Existing capacity (MW net)
z	Minimum synchronous generation as a fraction of instantaneous demand

Variables

E_{pryt}	Generated electricity (MWh net)
E^a_{pry}	Annual generation (MWh net)
E^{fuel}_{pry}	Annual fuel use (GJ_{fuel})
E^u_{ryt}	Unserved energy (MWh net)
S_{pryt}	Energy storage level (MWh net)
S^+_{pryt}	Increase in energy storage level (MWh net)
T^+_{ly}	Built transmission capacity (MW)
$T^{\max}_{ly}$	Positive flow limit (MW)
$T^{\min}_{ly}$	Negative flow limit (MW)
X_{pry}	Total installed capacity (MW net)
X^+_{pry}	Built capacity (MW net)
X^-_{pry}	Shut down (i.e. decommissioned) capacity (MW net)
Y_{pryt}	Total committed capacity (MW net)
Y^+_{pryt}	Increase in committed capacity ("switch on") (MW net)
Y^-_{pryt}	Decrease in committed capacity ("switch off") (MW net)
Y^s_{pryt}	Committed capacity able to be switched off (MW net)

Long term planning models that calculate capacity investment and divestment usually ignore unit commitment and other intertemporal constraints. In the past, inclusion of such constraints was usually computationally intractable, and, fortunately, unnecessary [16]. The optimal mix of coal, gas, hydro, and other plant, calculated primarily from the fraction of the year each plant would operate, was typically able to follow demand as it fluctuated across each season and each day. However, recent studies have shown as the proportion of intermittent generation increases, it becomes necessary to include such constraints in planning models [17,18]. At the same time, advances in computing hardware and optimisation software have made it feasible to include approximations of these effects. For example, Nweke et al. included a linear relaxation of unit commitment constraints in a 20 year planning model for South Australia, and showed that new dispatchable generation capacity was up to 50% greater than in modelling with a traditional load duration curve [19]. Palmintier et al. developed a "clustered unit commitment" approach that made it possible to include integer unit commitment for each hour in a planning model with a horizon of one year [20]. Shortt et al. compared "dispatch-only" and "unit commitment" operational models for many thousands of combinations of plant types, also with a horizon of one year [18]. They found that increased

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intermittent generation increased the frequency of starts for other generators, meaning that start up costs and low minimum stable generation levels became more important. Further, as the proportion of intermittent generation increased, Shortt et al. [18] found that the accuracy of the dispatch-only model decreased and the least cost mix of plant types found by each method diverged.

Such studies have implications for modelling long term, least cost abatement. Whilst intermittent renewable generation, in particular wind and solar PV (photovoltaics), can be a cost-effective form of abatement, its intermittent and non-synchronous nature has consequences for other generating plant and for the system as a whole. Energy storage can address these consequences, either as stand-alone storage (e.g. pumped hydro) or when integrated with intermittent generation to make a given plant dispatchable (e.g. concentrated solar thermal with storage). However, its finite storage capacity increases the need to model inter-temporal constraints in planning models [21].

In a planning model with a multi-decade horizon, many simplifications are still required, and such simplifications have limits to their validity that must be appreciated. This is a non-trivial task, particularly given the complexity of any electricity system. As a result, we consider that empiricism is the most reliable guide to these limits, i.e. these systems' historical and current performance. In our case, this includes the technical and economic performance of Australia's NEM (National Electricity Market), which is a stand alone, energy only market that already exhibits significant intermittent renewable energy generation in some regions [22] and a form of renewable portfolio standard called the RET (Renewable Energy Target) [23]. If the modelling of abatement proposes systems that are significantly different to those of today, this should be clearly identified as requiring further investigation and validation rather than simply assuming such systems to be implementable. Analogously, if we constrain our modelling such that the resulting technical and economic performance is similar to those of already operating systems, then we can have greater confidence that these modelled systems will also function reasonably. We take this latter approach in this paper.

For any given abatement target, there must be a lower bound to the cost of achieving that target. This lower bound can be no lower than the total cost of the new build required to meet this target, with investment decision making, system operation, different policies, markets and governance then serving to in general increase the total cost of meetingthis level of abatement. Hopefully, these added costs are small. Identification of this infrastructural lower bound therefore provides a reference for policy design since, for a given set of modelling inputs, no policy can achieve abatement more cheaply. In this sense, we can define a *good abatement policy* as one that stimulates the investment and divestment pathways that result in an operable system, and that achieves a targeted abatement for a total cost that is *acceptably close* – however defined – to this lower bound.

This paper therefore presents a model for determining such lower bound, GHG abatement pathways that features several constraints that need to be included when considering GHG abatement and the uptake of widespread intermittent renewable generation. These constraints do not appear to have been integrated into a single planning model previously, and include constraints on the total annual GHG emissions, unit commitment, energy storage, plant dynamics and intermittent renewable generation based on meteorological data. The model is formulated to constrain the absolute abatement, and does not include an explicit carbon price or support for renewable or other low emission technologies. The model is applied to Australia's NEM (National Electricity Market) as an example. All model inputs for technologies, demand projections and meteorological data are from the most current, publicly available and authoritative Australian sources. As such, the results presented are therefore intended to be transparently derived and both policy and technology neutral.

2. Method

2.1. Problem formulation

We formulate the model as a least cost optimisation, to identify the infrastructure lower bound as described in the introduction. In common with other electricity planning models, we formulate our model as a LP (linear program), as it is a suitable approximation for modelling the electricity system over this scale and horizon. The model minimises the total present costs of electricity generation from 2015 to 2050 subject to numerous constraints. The most important of these constraints is that the electricity generated must meet that demanded every hour within current reliability standards, and that annual greenhouse gas emissions in year must not exceed a prescribed trajectory (Fig. 1).

Many different abatement trajectories are possible. Whilst our presented method can accommodate these trajectories, we only present results for linear decreasing trajectories in this paper (Fig. 1). The final 2050 emissions range from being unconstrained to

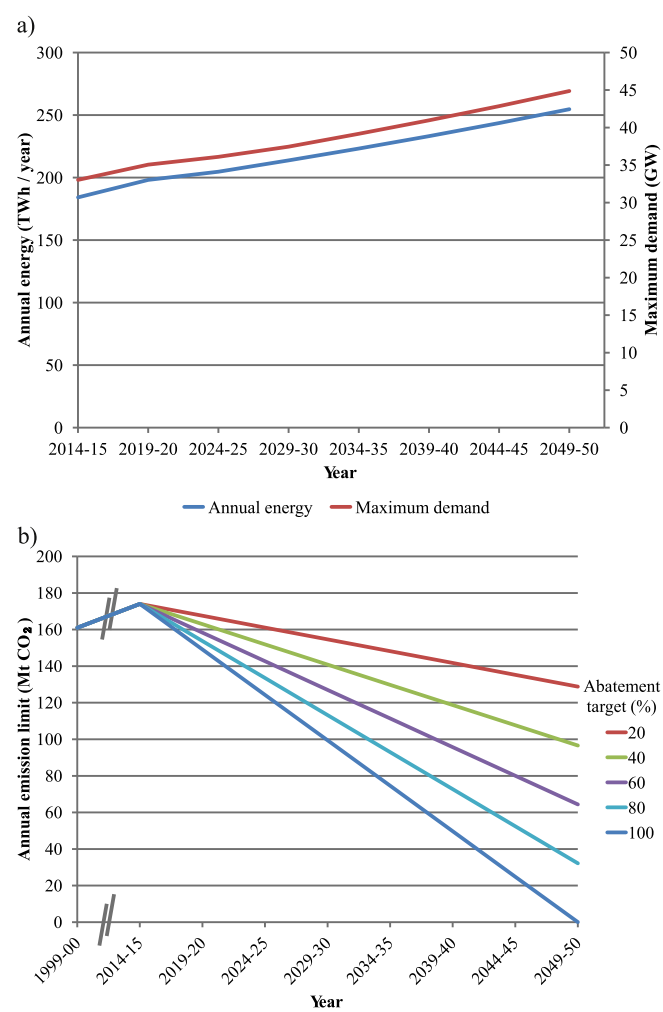

Fig. 1. a) Forecasted NEM annual (TWh) and maximum demand (GW) and b) modelled annual NEM greenhouse gas emissions (Mt_{CO_2e}) trajectories to 2050. Note that demand is modelled in each NEM region, and because each region does not experience maximum demand at the same time, the NEM's maximum demand is approximately 10% less than the sum of the maximum demand in each region.

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100% of the absolute emissions in the year 2000. For the constrained cases, the absolute emissions per year are then modelled to decrease linearly from 2015 to the stated 2050 target. The cases with no emissions constraint are also presented, and calculate the new build that may be required in the absence of any abatement policy. Of particular focus are the cases with 80% abatement in 2050, as abatement targets at this level or higher are commonly proposed for high income countries like Australia [3,24].

Whilst not presented in this paper, other abatement trajectories showed similar results to the linear trajectories for a given 2050 abatement target provided that the chosen trajectory had gradual annual abatement. More generally, for a given 2050 abatement target, modelling will always find that it is cheapest to do nothing until the final year and then build a new electricity system overnight, as this minimises the present cost of this transition by both discounting and learning. Such transitions are impossible. We therefore retain these simple, linear abatement trajectories to 2050 with all other equivalent plausible trajectories expected to exhibit similar results.

The LP models the existing and new utility scale generating, storage and transmission assets from 2015 to 2050. The distribution network and technologies at the consumer-end of the electricity supply chain are not considered. The model divides the geographical area under consideration into regions. (In the example described later, these correspond to the existing regions in the NEM). Transmission flows between regions are modelled, but flows within regions are not. The aggregated capacity and generation from each type of plant in each region is modelled, rather than individual generating units, in order to make the optimisation computationally tractable.

The objective function is as follows, with a complete statement of the optimisation and its constraints in Appendix A.

$$\min\Bigg[\sum_{p,r,y} X^{+}_{pry} C^{b}_{py} D^{b}_{py} + \sum_{p,r,y}\left(X_{pry} C^{f}_{pry} + E^{a}_{pry} C^{v}_{pry}\right) D^{o}_{y} + \sum_{p\in\mathscr{F},r,y} E^{\text{fuel}}_{pry} C^{\text{fuel}}_{pry} D^{o}_{y} + \sum_{p\in\mathscr{C},r,y} E^{\text{fuel}}_{pry} I^{c}_{pr} G_{p} C^{\text{CCS}}_{pry} D^{o}_{y} + \sum_{p\in\mathscr{F},r,y,t} (1/\eta^{s}) S^{+}_{pryt} C^{v}_{pry} w_{t} D^{o}_{y} + \sum_{l,y} T^{+}_{l,y} C^{l}_{l} D^{b}_{ly} + \sum_{r,y,t} E^{u}_{ryt} C^{u}_{ryt} w_{t} D^{o}_{y}\Bigg] \tag{1}$$

Respectively, these seven terms in the objective function model the plant capital expenditure, operating and maintenance costs, fuel costs (where applicable), CO_2 transport and storage costs (where applicable), operating costs when recharging pumped hydro storage, cost of transmission network augmentation and the costs of unserved energy.

2.1.1. Modelling of unit commitment

As discussed in the Introduction, increased intermittent generation increases the need to include unit commitment, start-up costs and minimum levels of stable generation in planning models. We do this using a linearised model adapted from an integer unit commitment model [25,26]. For all slow thermal plants, we model the committed capacity as a continuous variable for each hour [27,13], as shown in Equation (1). Increases in the committed capacity then represent units switching on and incur start up fuel costs. That committed capacity then must begin generating at least at its minimum partial load and up to its switch on ramp rate, which is assumed to be the same as the ramp up rate. Once committed, the generation by a given plant type can then ramp up and down at its ramp rate, but must generate inside its stable range and must remain committed for at least the minimum up time. In the hour before a plant is decommitted, it must generate less than its switch off ramp rate, which is assumed to be the same as the ramp down rate. In principle, the committed capacity can change by arbitrarily small amounts each hour. However, when modelling by plant type in a region, this change is typically a few hundred MW, which is a reasonable approximation to a single unit. Minimum down time constraints were not modelled in order to reduce computational complexity, and because this is unlikely to significantly affect the results. Fig. 2 shows an example of how this committed capacity modelling functions for a particular class of thermal plant.

These unit commitment approximations are important for modelling the technical and financial performance of many kinds of fossil, nuclear and renewable thermal plant. They are particularly important for existing coal plant because electricity generation in Australia (and in many other countries) is today dominated by coal. Since the construction cost of existing generation is a sunk cost in our optimisations, the optimal solution for high abatement targets without these unit commitment approximations then typically features existing coal running as peaking plants around intermittent renewable generation, which can be unrealistic. Rather, in such scenarios, existing coal generation is likely to shift to a progressively more seasonal generation pattern prior to retirement because of these limitations on their dynamic performance. The implemented unit commitment approximations enable such behaviour to be modelled.

2.2. Modelling of 'acceptable' levels of intermittency, inertia and reserves

In a conventional AC power system, generators of varying forms spin at the system frequency and therefore provide so-called *synchronous generation* capacity. This capacity provides inertia to the system, and is a key part of managing the system's stability when it is subject to a variety of potential disturbances. The most common forms of renewable generation, particularly wind and solar PV, are not synchronous generators and have little or no capability to assist in managing system stability [28]. Further, any form of intermittent generation imposes disturbances onto the system, particularly when the actual generation at any instant does not match that forecasted previously for that instant. Regardless of the accuracy of any given forecasting tool, such

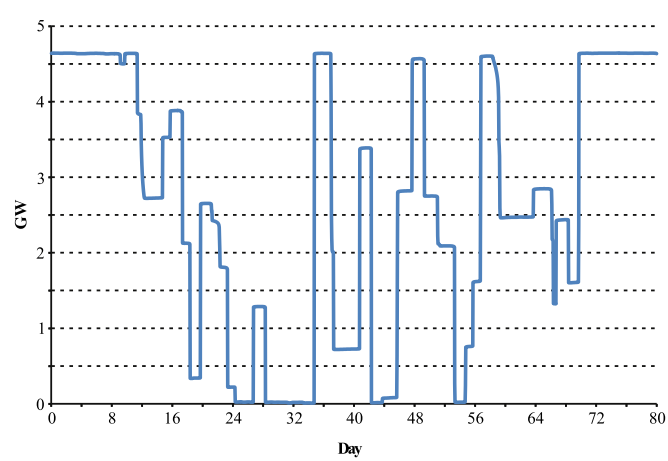

Fig. 2. Example of the committed capacity for CCGT (combined cycle gas turbine) plant across the 80 days simulated for the NSW zone in the NEM. This result is for the year 2050 and the Reference Scenario defined later in this paper.

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forecasting errors create greater system disturbances as the proportion of intermittent renewable generation increases. Finally, dispatchable generators act as both *spinning* and *non-spinning reserves*, which enable these generators to respond to system faults and disturbances over varying timescales and thus enhance system reliability. These reserves must increase as the proportion of intermittent renewables increase, adding greater costs to the system [29,30].

Determining how best to manage a power system as the proportion of intermittent generation increases is therefore a complex and open problem that continues to attract a great deal of interest in the power systems community [31,32]. Further, rigorous technical modelling of this problem is well beyond the scope of a high-level study such as this. As such, care is required to develop constraints for our LP that are simultaneously defensible whilst not unduely limiting the proportion of intermittent generation.

We first consider the need to maintain a minimum level of synchronous generation capacity. Whilst this limit depends on many factors, we apply a constraint to all regions such that, at any time, the synchronous generation capacity must be at least 30% of current demand (Appendix A). This is similar to constraints in recent studies of the Irish grid [33]. The separate requirement for each NEM region ensures that this level of synchronous generation capacity can be met even if an interconnect fails. Because a synchronous plant provides all of its inertia when online regardless of its generation, for plant where the *committed synchronous capacity* is modelled this committed capacity is used. The *current generation* is used for all other synchronous plant. Synchronous plant can be of both renewable and non-renewable forms.

We also constrain the maximum allowable proportion of intermittent renewable energy to be 30% of annual generation in each NEM region. This is done for two reasons. First, the NEM's SA (South Australian) region already has this proportion of intermittent generation [22], and this appears to be one of the highest levels currently in the world. Indeed, *all* of SA's electricity demand is already met by intermittent renewable generation at some times [22]. As a result, the SA region likely already relies on the AC interconnection to the Victorian (VIC) region and the rest of the NEM for system security. Further, a recent study of the United States' PJM Interconnection, which operates the world's largest competitive wholesale electricity market, again estimates that up to 30% of annual generation could be met by intermittent renewable energy [34]. Nonetheless, we also note that some studies have modelled higher proportions of intermittent generation, e.g. Refs. [35,10,36,7].

Finally, since synchronous generators presently provide the NEM's required reserves in return for a small portion of their total revenues [28], we expect that the imposition of this intermittency constraint then also reduces the need to include additional modelling of reserves in a study of this nature. The PJM study [34] found that regulating reserve requirements were approximately doubled with 30% of energy from intermittent renewable energy and that no extra spinning reserve was required, which is consistent with this assumption, although it should be noted that the PJM is a power system several times larger than the NEM and with a more connected network topology. A stochastic study of wind integration in Ireland considered a level of wind generation equivalent to 34% of annual energy, and found that imperfect foresight caused production costs to be approximately 2% higher compared to perfect foresight [37]. Another technical study on renewable integration in Europe noted that: “Compared to the variability of load, flexibility requirements increase strongly in systems with combined wind and PV (photovoltaics) contribution of more than 30% of total energy” [38].

In applying these constraints, we therefore again emphasise that power system management and market design with increasing, non-synchronous and intermittent renewables is a complex and open problem. We nonetheless consider our constraints to be reasonable upper bounds of what is plausibly achievable at the moment, and more detailed technical studies will determine whether this is the case.

2.3. Included generation and storage technologies

Tables A.1–A.6 list the existing and new build generation and storage technologies that are included in the model. Nuclear plant and fossil plant fitted with CCS (carbon capture and storage) are not considered in Part 1, but are shown as they are used in Part 2 of this work.

2.4. Implementation of optimisation

The optimisation is run over 35 full years from the 1st of July 2014 to the 30th of June 2050. In order to make the simulation computationally tractable, the model has a 5 year time step between decisions, and each year is comprised of 80 representative days modelled at hourly resolution, i.e. 1920 h per annum. These representative days always include the summer and winter days of peak demand, with the 78 other days drawn randomly from the 2010 reference year. As discussed earlier, hourly demand in a given year is scaled by the forecasted annual demand, whilst meteorologically based data uses the same days as those for the demand modelling. The optimisation then assumes that each modelled year is repeated for all 5 years of a given time step. The final year is assumed to repeat indefinitely, i.e. there is a perpetuity applied to all costs in that year.

Both the annual resolution and the number of days modelled per year significantly affect the computational cost of these optimisations. We therefore undertook sensitivity analyses of these parameters over shorter overall time periods, and consistently found that 5 year steps with 80 days per year resulted in optimised results for total system costs that were within a few percent of those for equivalent runs with hour-by-hour modelling of a full year and annual time steps. This is a reasonable result, since five year time steps are relatively small relative to the economic lifetimes of each plant (20–50 years) and the horizon of the model (35 years), and the capacity built at each 5 year step is typically 10–20% of the total system capacity. This was therefore considered acceptable temporal resolution, particularly given the other uncertainties in this problem.

The linear program is implemented in GAMS using CPLEX with the barrier algorithm. In total there are approximately 5 million variables and 8 million equations. The model is solved on a 16 core, 32 GB memory machine running Linux, with each run taking 1–3 h.

3. Input data for case study: Australia's NEM (National Electricity Market)

3.1. Primary data sources

We use the most current information from publicly available and independent sources to apply the presented method to Australia's NEM in this case study. In keeping with the AETA (Australian Energy Technology Assessment) study [39] and NTNDP (National Transmission Network Development Plan) published by the AEMO (Australian Energy Market Operator) [40], all analysis uses a 10% real discount rate unless stated otherwise.

1. Demand forecasts (Fig. 1a)

The AEMO (Australian Energy Market Operator) is the ISO (Independent System Operator) of the NEM. AEMO publishes annual energy and maximum demand forecasts for each NEM region in its NEFR (National Energy Forecasting Report), the most recent edition of which was published in mid-2014 [41]. Forecasts for years 2035–2050 are outside the NEFR scope and are calculated using the mean forecasted annual growth rate from 2015 to 2030 for both the maximum demand and the annual energy. These yearly forecasts are translated into hourly values for each future year using historical hourly values from the reference year 2010.

2. Technical information on generating plant (Table A.1)

AEMO also publishes technical information on the current and potential future generating fleet in its annual NTNDP (National Transmission Network Development Plan) [42]. This includes several coal, natural gas, biomass, solar and wind plants. Information on nuclear plant is not included. The NTNDP presents assumptions on the efficiency, combustion and fugitive emissions intensity, ramp rates and operating and maintenance costs for all the generating plant currently in the NEM. Since our study does not model individual plant, we weight this NTNDP data for existing plant by their capacity in each NEM region.

For all new build thermal plant, we use the thermal efficiency and combustion emissions intensity from the AETA (Australian Energy Technology Assessment) [39]. Some of the required input assumptions are not available in AETA. Plants modelled with commitment constraints also include a 15% decrease in thermal efficiency at partial output, and we use the Black and Veatch report [43] for estimating each thermal plant's minimum stable generation levels. Assumptions on thermal plant start up fuel consumption and minimum on times are adapted from the Irish All Island study [44]. For simplicity, all dispatchable plant are assumed to have a 5% forced outage rate, and planned outages are not explicitly modelled. We also assume that nuclear plant have the same dynamic response as ultra supercritical coal plant, the latter of which should be the state-of-the-art steam plant by the time that nuclear can plausibly first be implemented in Australia in the mid-2020s.

3. Financial information on generating plant and fuel costs (Tables A.1, A.3, and A.5)

The AETA (Australian Energy Technology Assessment) [39] presents data on the capital costs (capex), fixed and variable operating and maintenance costs (FOM and VOM) and fuel costs for numerous new build utility scale electricity generation technologies from today to 2050. This includes estimates of learning rates for the capex of each generating technology considered, and escalation rates for the FOM and the VOM. The AETA model [39] assumes that this escalation (excluding learning rate) is 150% of inflation in nominal terms, but does not specify the inflation rate. For this study, an inflation rate of 2.5%/year was used.

The economic life of each plant is taken from the AEMO NTNDP [42], of which the most significant difference from AETA is an assumed 50 year life for all coal plant, compared to 30 years for AETA. This agrees better with current practice in the NEM. The technical life of all plants is assumed to be the same as its economic life, and refurbishment of plant is not considered. Finally, whilst the costs of thermal plant with CCS are taken from the AETA study, the cost of CO_2 transport and storage is taken from the AEMO NTNDP.

4. Value of lost load

The value of lost load (C^u) was set to be \$13,100/MWh in accordance with the current NEM price cap [42].

5. Technical and financial information on energy storage

The Sandia National Laboratory has recently published a report on different forms of energy storage [45]. Since this report shows that pumped hydroelectricity is presently the cheapest form of utility scale energy storage, we use only this form of energy storage in the current paper, with all required technical and financial information obtained from the Sandia report.

Note also that we have not undertaken a resource availability survey for pumped hydro storage, and instead assume that suitable locations exist either inland or on the coast in each NEM region. This is a reasonable assumption because significant levels of pumped storage are only found to be required in the case of a zero emissions NEM, which we argue is unlikely to be a cost-effective option.

6. Technical and financial information on transmission assets

This is discussed further below.

Note that, where appropriate, all quantities are quoted in net terms, i.e. per energy sent out by the plant and therefore not including the energy required to run the plant (also called the auxiliary load).

3.1.1. Renewable resource estimates

Since the NEM covers a significant part of Australia, it operates in regions of widely varying wind and solar resource availability. A recent study [46] estimated the maximum capacity of wind, CST (concentrating solar thermal) and solar PV plants that could be built in 42 zones across the NEM taking into account land-use, population and elevation in each zone (Fig. 3). This meteorologically based data used measurements of wind speeds and solar irradiance from the Australian Federal Government's Bureau of Meteorology to calculate these hour-by-hour time series for hypothetical 1 MW capacity wind, CST (concentrating solar thermal) and solar photovoltaic (solar PV) power plants. The hour-by-hour wind power traces were validated against reported power output at existing wind farms. The CST and solar PV traces were not able to be validated given the lack of utility scale power generation data for these technologies. The 1 MW capacity hour-by-hour trace for each plant type in each zone can then be scaled up to this capacity constraint in our modelling.

Some of these 42 zones in Fig. 2 are not crossed by the existing NEM transmission network. We therefore exclude these zones in our study. Of those remaining, we model in each NEM region three zones for wind, one zone for CST, and one zone for utility scale solar PV. There are five NEM regions (QLD (Queensland), NSW (New South Wales), VIC (Victoria), SA (South Australia) and TAS (Tasmania)), so in total there are 15 zones for wind and 5 zones each for CST and utility scale solar PV. A higher number of zones were used for wind than solar because wind traces within the same NEM regions are less correlated than solar traces, so there is greater benefit from the inclusion of extra wind zones. At worst, increasing the number of zones for all of these renewable plants can only result in the same optimised cost for the overall system, with optimised costs with more zones likely being lower given the greater number of degrees of freedom in the optimisation. We therefore only use this set of zones per NEM region given computational constraints and note that our estimates of renewable energy potential may be conservative.

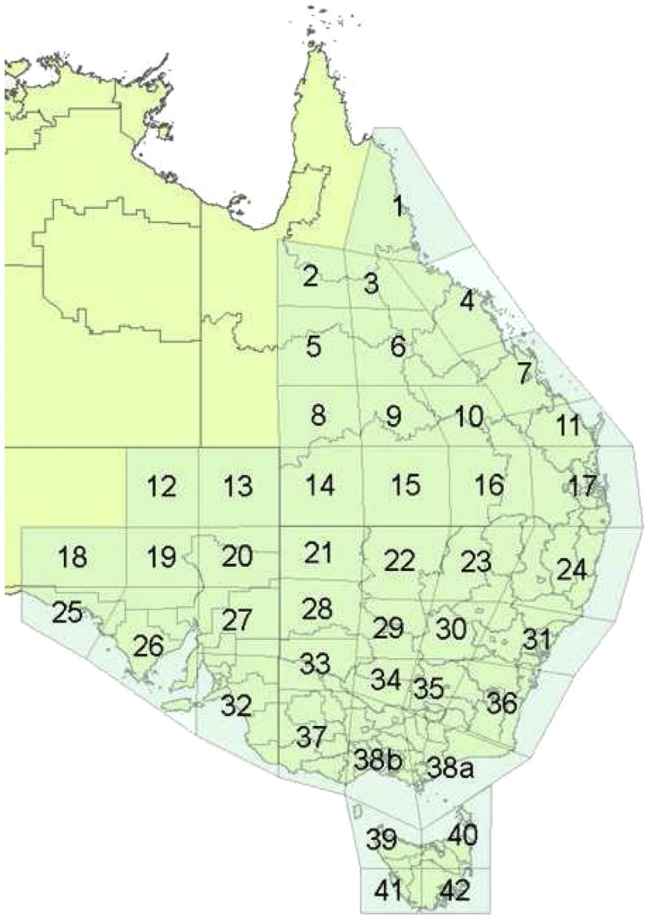

Fig. 3. The NEM zones for which wind (zones 7, 10, 17, 20, 32, 27, 23, 31, 35, 38b, 38a, 37, 40, 39, 42), CST (zones 17, 27, 31, 38b, 39) and solar PV (16, 20, 38a, 34) resource availability was estimated [46].

We also assume that existing hydro plant remains available but that no new conventional hydro is built, whilst generation from biomass can generate at most 7 TWh/year from 2020, assuming that the forecast in Ref. [47] is limited by resource availability. All generation from biomass is modelled as steam turbine plant using solid fuel with the same dynamics as coal plant. We acknowledge that these may be conservative estimates, and we make these judgements for several reasons. Most importantly, we note that whilst electricity generation from hydropower and biomass qualifies for RPS support via Australia's RET scheme, new investment in these forms of generation since the inception of the RET has been small compared to that in other forms renewable energy (approx. 200 MW of the 5 GW capacity installed to date [23]). However, since these forms of generation are dispatchable and the AETA assumptions are that they are low cost, our optimisations always find that the resulting new build is limited by the resource constraint. If resources become more widely available than is assumed here, then such forms of generation would be more widely used, reducing total costs.

3.1.2. Technical and financial information on transmission assets

The existing NEM has transmission lines (interconnectors) which connect some regions (SA-VIC, VIC-NSW, NSW-QLD and VIC-TAS). We include these interconnectors, with their existing forward and reverse capacities, and allow augmentations at each 5 year time step. The existing capacity is as per the 2014 NTNDP [42]. Augmentation is assumed to increase the transmission capacity equally in forward and reverse directions and the new capacity is assumed to be available at all times. Cost assumptions for transmission upgrades were based on the AEMO study [48] and are presented in Table A.8. Transmission operating costs are assumed to be small compared to capital costs and so are not included. Transmission losses for interconnectors are assumed to be 5%. The total cost of the augmentations is then assumed to be a fixed cost per line capacity increase times the increased capacity at each time step.

This simple approach to transmission costing has several justifications. It crudely accounts for the cost of transmitting energy from a plant to a major demand location, since the NEM serves a mainly urbanised population in major cities and along Australia's eastern and southern coasts where the transmission network already runs. Further, AEMO's more sophisticated analysis of transmission requirements for their 100% renewable study suggested that transmission augmentation was at most roughly 10% of the total cost of transitioning to a fully renewable system [48]. In this AEMO study, some of the generating plant was thousands of kilometres from the existing transmission network, thus requiring more significant new build. This is in contrast to our present study, we where have chosen only renewable generating sites which are on the existing transmission network. Of course, all non-renewable generation can be built in any location, and proximity to demand and existing transmission capacity is a normal part of site selection. Like the AEMO study [48], we find that in all the scenarios considered the transmission network costs are a small part of the total cost, suggesting that more complex transmission models do not significantly change the decisions made, and are therefore not required for a study of this nature.

4. Results and discussion for case study

Part 1 of this study presents results for the *Reference Scenario*, which is defined using the input data presented in Section 4 but with nuclear and CCS plant excluded. Other scenarios and comparisons are presented in part 2 of this work [49].

4.1. Total costs and wholesale market costs to 2050

Fig. 4 shows the present value of the total costs for the Reference Scenario with different 2050 abatement targets, together with an equivalent 2050 wholesale electricity market cost in current dollars. The wholesale market cost is obtained by dividing all costs incurred in 2050 by the annual generation in that year. This includes the costs of operating all existing plants as well as the costs of new build. The costs of new build are annualised at the specified discount rate for all plant built less than the economic life of the plant in years prior to the current year. This ensures that plants that are shut down early still contribute to the wholesale market cost if their capital cost has not yet been repaid. This wholesale market cost is course not a price obtained from any form of market clearing or marginal value calculation.

As expected, both the total costs and the estimated wholesale market cost increase with higher levels of abatement. The results without an emissions constraint show an estimated wholesale market cost that is higher than the current NEM average wholesale spot market cost, which typically ranges from $30–50/MWh [50]. There are several possible reasons for this difference, including shortcomings of our modelling. However, this relatively high price is primarily due to our requirement that no plant can operate for longer than its economic life. If we relax this constraint on current

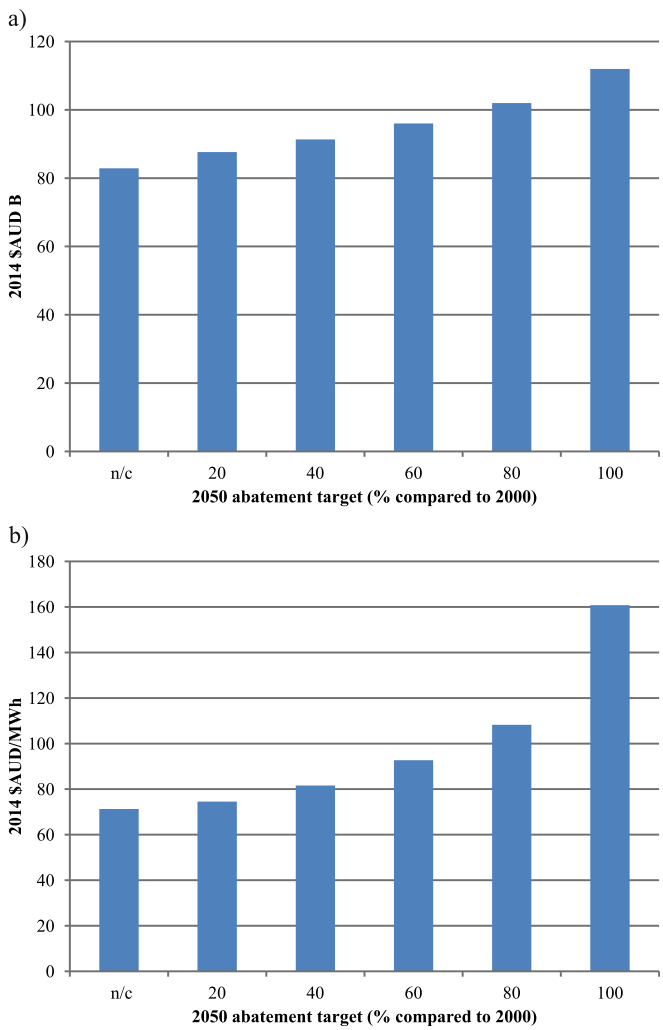

Fig. 4. a) Present value of total costs and b) estimated 2050 wholesale electricity market cost for the Reference Scenario with different 2050 abatement targets.

all plant for the case without an emissions constraint, we find that the estimated wholesale market cost is $37/MWh. This is within the above range of typical wholesale market prices and so suggests that the modelling is reasonable.

4.2. Costs of abatement

We now define the *absolute cost of abatement* $C^A_{X\%}$ ($\$/t_{CO_2e}$) in terms of the total present additional costs of achieving a given level of abatement $X\%$ relative to the case without an emissions constraint,

$$C^A_{X\%} = \frac{C_{X\%} - C_{NC}}{A_{NC} - A_{X\%}}, \tag{2}$$

Analogously, we also define the *marginal cost of abatement* $C^M_{X\%}$ ($\$/t_{CO_2e}$) in terms of the total present additional costs of achieving a given level of abatement relative to the next lowest level of abatement studied. Note that for high levels of abatement, this method likely to underestimate the marginal cost, compared to the marginal cost measured from a smaller change in abatement target (e.g. from 99% to 100% rather than 80%–100%). This is marginal cost of abatement is calculated,

$$C^M_{X\%} = \frac{C_{X\%} - C_{X\%-20\%}}{A_{X\%-20\%} - A_{X\%}}. \tag{3}$$

If the marginal cost of abatement beyond some level of absolute abatement is higher than the cost of achieving the same abatement in other sectors, it is economically and environmentally better to accept these non-zero absolute emissions in the NEM and target cheaper abatement elsewhere.

Fig. 5 shows both the absolute and marginal costs of abatement for the Reference Scenario. As expected, both costs increase with higher levels of absolute abatement. Of particular note is the relatively dramatic increase in both of these costs beyond about 80% abatement, particularly when compared to the 30–50 $\$/t_{CO_2e}$ effective cost of abatement that Australia's RET (Renewable Energy Target) currently features [23], the 20–25 $\$/t_{CO_2e}$ range of Australia's now discontinued carbon price [51] and the lower cost abatement that appears to be achievable in other Australian sectors [52,53]. These results therefore suggest that a zero emission NEM without nuclear or CCS is likely undesirable. We therefore focus most of our remaining discussion on the commonly adopted target of 80% abatement by 2050 relative to 2000 levels, since this appears to be a more reasonable *upper bound* of the costs that this sector might bear.

4.3. Installed capacity and annual generation by year to 2050

Considering now the transition from today to this 2050 generation mix, Fig. 6 shows the installed capacity and annual generation by year for 80% abatement in 2050 for the Reference Scenario. The 2050 abatement target and its associated abatement trajectory is achieved by the progressive decommissioning of existing coal plant, whilst several new generating technologies are built. This new build is initially mainly wind and then CCGT (combined cycle gas turbine) in terms of annual generation, followed by utility PV and solar thermal with storage. No new coal plant is built.

Other 2050 abatement targets yield consistent transitions, with Fig. 7 showing the resulting installed capacity and annual generation. Whilst significant new coal plant is built for the lower abatement targets, new build annual generation is once again dominated by wind, CCGT, and solar for deeper abatement.

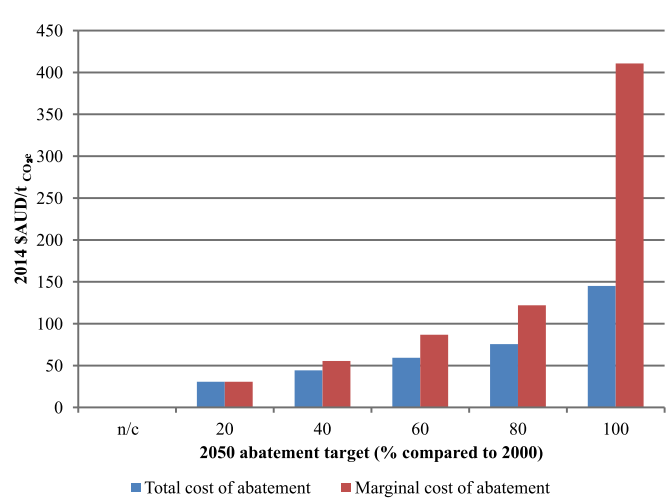

Fig. 5. Absolute and marginal costs of abatement for the Reference Scenario with different 2050 abatement targets.

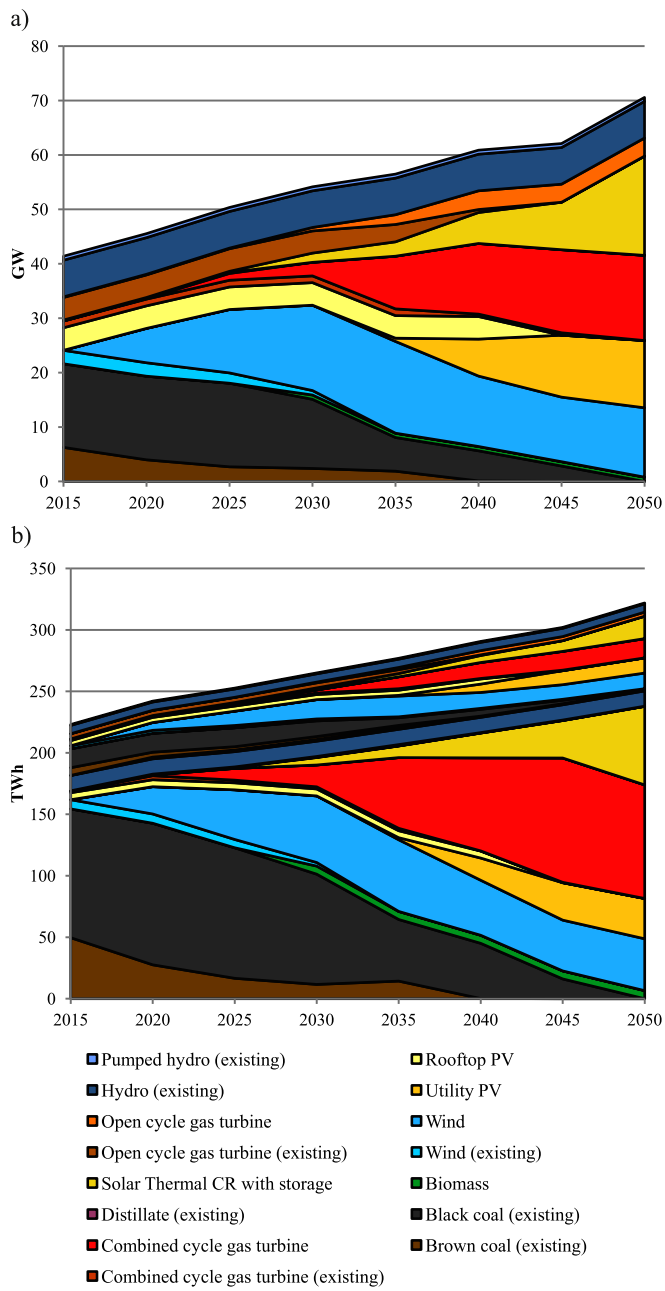

Fig. 6. a) Installed capacity and b) annual generation by year to 2050 for the Reference Scenario with an 80% abatement target.

4.4. Geographical and temporal variations in the generation mix

Fig. 8 shows the annual generation by NEM region in 2050 for the Reference Scenario with an 80% abatement target. New build is largely a result of demand growth in each region, with significant new renewable generation distributed across the NEM. Fig. 9 shows the modelled generation mix on the days of peak demand during the summer and winter of 2050. The different scheduling of intermittent and dispatchable plant can be seen. CCGT plant run in a conventional manner, with variation in intermittent generation across the day being compensated by all forms of renewable and non-renewable dispatchable plant. Importantly, the variation in intermittent variation is lower than that of the demand, and dispatchable plant must compensate for both.

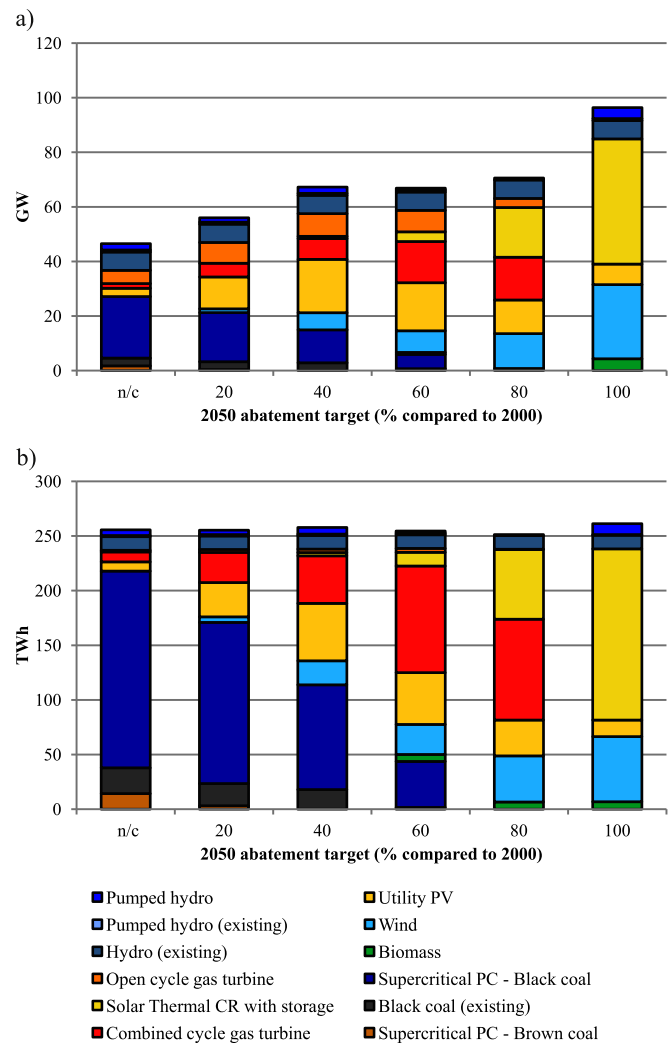

Fig. 7. a) Installed capacity and b) annual generation in 2050 for the Reference Scenario with different abatement targets.

4.5. Transmission system build by year to 2050

Finally, Fig. 10 shows the NEM interconnector capacity by year for the Reference Scenario with an 80% abatement target. Surprisingly, our modelling finds that only the VIC-NSW interconnector requires significant augmentation in the next 10 years. As discussed earlier, the total costs of this augmentation (Fig. 11) are a small part of the total costs for all abatement targets, suggesting that this simple approach is appropriate.

5. Conclusions

This paper was the first of a two part study that considers least cost, greenhouse gas abatement pathways for an electricity system. Part 1 of this study presented a bottom up model for determining these abatement pathways. This model was applied to Australia's NEM (National Electricity Market) as an example.

These least cost pathways were determined by numerical optimisation of utility scale generating, storage and transmission assets that were subject to a total greenhouse gas emissions

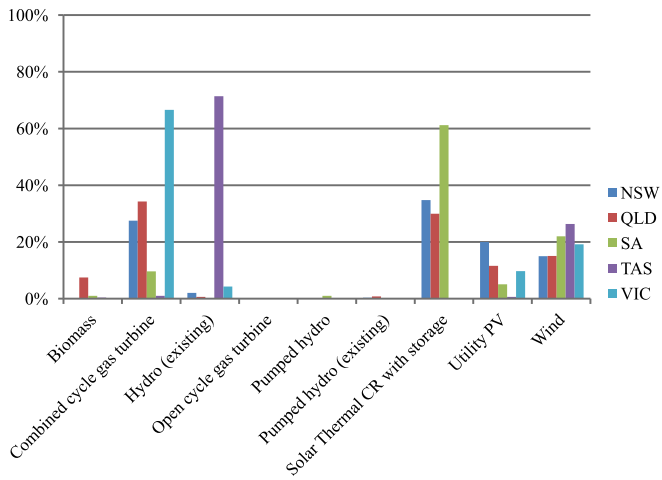

Fig. 8. Annual generation as a proportion of NEM region generation in 2050 for the Reference Scenario with an 80% abatement target.

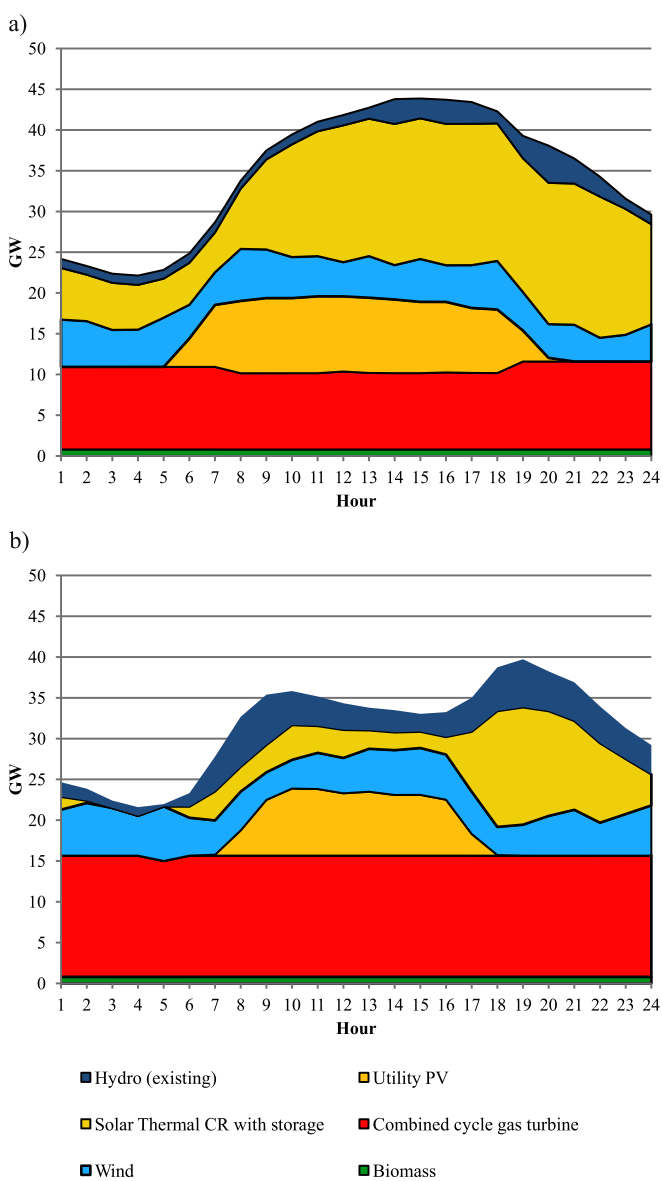

Fig. 9. Generation mix on days of 2050 peak demand in a) summer and b) winter for the Reference Scenario with an 80% abatement target.

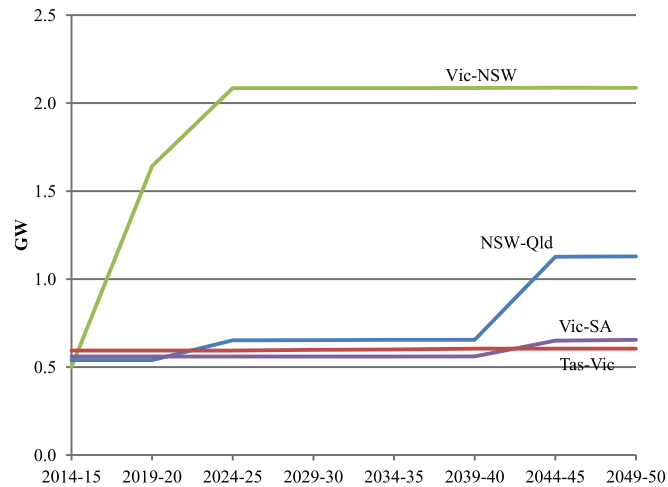

Fig. 10. Total NEM interconnector capacity by year to 2050 for the Reference Scenario with different abatement targets.

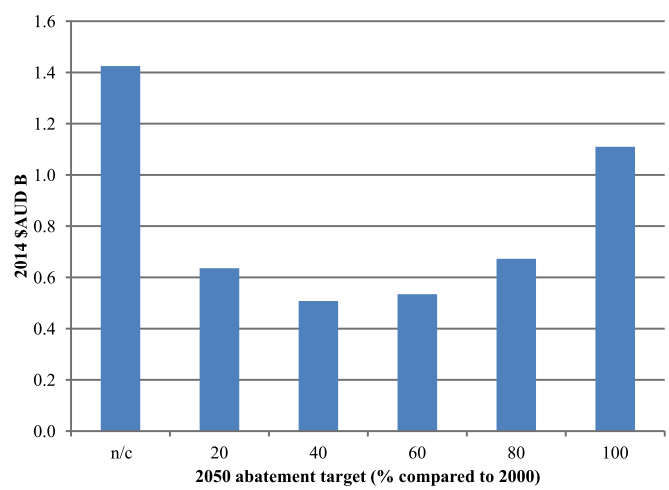

Fig. 11. Present value of total interconnector augmentation costs to 2050 for the Reference Scenario with different 2050 abatement targets.

constraint from today to 2050. The model included several, important features of electricity systems that must be included when considering GHG abatement and the uptake of intermittent renewable generation but which do not appear to have been integrated previously. This included modelling of unit commitment, energy storage, plant dynamics and intermittent renewable generation based on meteorological data. Since we constrained the absolute abatement, we did not need to assume any price on carbon or any other form of support for renewable or other low emission technologies.

The Reference Scenario defined in Part 1 of this study included all major utility scale technologies other than nuclear and fossil fuelled plant fitted with CCS (carbon capture and storage), both of which do not presently generate any electricity in Australia. For targets less than 100% abatement and without nuclear, our simulations confirmed that minimising the total cost requires a large growth in renewable generation acting in concert with CCGT (combined cycle natural gas) whilst existing coal plant is progressively decommissioned. This result shows that the large uptake of renewable generation is not an artefact of an RPS or other policy

that only supports renewables, but should also occur for any abatement policy that is close-to-optimal in terms of minimising the total cost of meeting an abatement target.

Acknowledgements

This research was supported by the Australian Renewable Energy Agency (ARENA) (agreement number 2489) and completed whilst the second author was on sabbatical in the Department of Mechanical and Aerospace Engineering at Princeton University. We also acknowledge Mr. Daniel Marshman and Mr. Avishai Lerner for checking the results presented.

Appendix A. Complete mathematical formulation of optimisation

The full mathematical formulation of the LP (linear program) solved in this paper is described below. The objective function is as follows.

$$\min\Bigg[\sum_{p,r,y} X^{+}_{pry} C^{b}_{py} D^{b}_{py} + \sum_{p,r,y}\Big(X_{pry} C^{f}_{pry} + E^{a}_{pry} C^{v}_{pry}\Big) D^{o}_{y} + \sum_{p\in\mathscr{F},r,y} E^{\text{fuel}}_{pry} C^{\text{fuel}}_{pry} D^{o}_{y} + \sum_{p\in\mathscr{C},r,y} E^{\text{fuel}}_{pry} I^{c}_{pr} G_p C^{\text{CCS}}_{pry} D^{o}_{y} + \sum_{p\in\mathscr{S},r,y,t} (1/\eta^{s}) S^{+}_{pryt} C^{v}_{pry} w_t D^{o}_{y} + \sum_{l,y} T^{+}_{l,y} C^{l}_{l} D^{b}_{ly} + \sum_{r,y,t} E^{u}_{ryt} C^{u} w_t D^{o}_{y}\Bigg]$$

The constraints of this LP are as follows.

- Generation and demand must be balanced, taking into account transmission flows between regions and recharge of pumped hydro storage.

$$\sum_{p} E_{pryt} + E^{u}_{ryt} + \sum_{\mathscr{N}(l,r',r)} (1-\lambda_l) F_{lyt} - \sum_{\mathscr{N}(l,r,r')} F_{lyt} = E^{d}_{ryt} + \sum_{p\in\mathscr{S}} S^{+}_{p^{s}ryt} \Big/ \eta^{s} \tag{A.1}$$

- The annual unserved energy must be less than or equal to 0.002% of annual energy.

$$\sum_{rt} E^{u}_{ryt} w_t \le 2\times 10^{-5} \times \sum_{rt} E^{d}_{ryt} w_t \tag{A.2}$$

- Annual greenhouse gas emissions must be less than or equal to that of a specified abatement trajectory.

$$\sum_{pr} E^{\text{fuel}}_{pry}\Big((1-G_p) I^{c}_{pr} + I^{f}_{pr}\Big) \le M_y \tag{A.3}$$

- The installed capacity in each year must equal the existing capacity built before 2015, plus the sum of the capacity built minus the sum of the capacity decommissioned.

$$X_{pry} = X^{e}_{pry} + \sum_{y'\le y}\Big(X^{+}_{pry'} - X^{-}_{pry'}\Big) \tag{A.4}$$

- The annual electricity generation for each plant type in each region is the sum of its hourly generation.

$$E^{a}_{pry} = \sum_{t} E_{pryt} w_t \tag{A.5}$$

- The annual fuel consumption for thermal plant type in each region depends on its electricity generation and start up fuel consumption (assumed to be from a cold start). For plants modelled with linearised commitment constraints, the reduction of thermal efficiency at partial output is modelled using a heat rate at minimum generation and a marginal heat rate.

$$E^{\text{fuel}}_{pry} = \sum_{t}\Big(m_p Y_{pryt} H^{\min}_{pry} + (E_{pryt} - m_p Y_{prt}) H^{\text{marg}}_{pry}\Big) w_t + \sum_{t} Y^{+}_{pryt} Q^{\text{start up}}_{pr} w_t, \quad \forall p\in\mathscr{U} \tag{A.6}$$

- For thermal plant which is not modelled with commitment constraints, the annual fuel consumption is modelled using a single heat rate, and start up fuel costs are not included.

$$E^{\text{fuel}}_{pry} = E^{a}_{pry} H_{pry}, \quad \forall p\in\mathscr{F}\notin\mathscr{U} \tag{A.7}$$

- For plant modelled with linearised commitment constraints, its committed capacity must generate at greater than or equal to its minimum stable generation.

$$E_{pryt} \ge m_p Y_{pryt}, \quad \forall p\in\mathscr{U} \tag{A.8}$$

- Further, plant that will remain committed in the next hour must generate less than or equal to its capacity, and thermal plant which will de-commit in the next hour must less generate less than or equal to its switch off ramp limit.

$$E_{pryt} \le Y_{pryt} + \Big(R^{\text{off}}_{pr} - 1\Big) Y^{-}_{pry(t+1)}, \quad \forall p\in\mathscr{U} \tag{A.9}$$

- Thermal plant that has been online for more than 1 h may generate up to its capacity, and thermal plant which which comes online during the current hour may generate up to its switch on ramp limit.

$$E_{pryt} \le Y_{pry(t-1)} + R^{\text{on}}_{pr} Y^{+}_{pryt}, \quad \forall p\in\mathscr{U} \tag{A.10}$$

- Finally, the minimum up time constraint is created by calculating the committed capacity able to be shut down in each hour.

$$Y^{-}_{prty} <= Y^{s}_{pryt} \tag{A.11}$$

$$Y^{s}_{pryt} = Y^{s}_{pry(t-1)} + Y^{+}_{pry(t-K_p)} - Y^{-}_{pryt}, \quad \forall t > K_p \tag{A.12}$$

$$Y_{pryt} = Y_{pry(t-1)} - Y^{-}_{pryt} - Y^{+}_{pry(t-1)} \tag{A.13}$$

- Note that these above six commitment constraints apply to all dispatchable plant other than hydro, open cycle gas turbine and CST plant. These latter three plant types are assumed to have fast enough dynamics and small enough commitment costs such that these effects can be neglected.
- In all regions, synchronous generation capacity must be at least 30% of current demand. For synchronous plant where the *committed capacity* is modelled, the committed capacity is used. For all other synchronous plant the current generation is used.

$$\sum_{p\in\mathscr{U}} Y_{pryt} + \sum_{p\in\mathscr{D}\notin\mathscr{U}} E_{pryt} \geq 0.3E^{d}_{ryt} \tag{A.14}$$

- For plant modelled with commitment constraints, the committed capacity (and hence generation) may not exceed the installed capacity not currently experiencing a forced outage.

$$Y_{pryt} \leq (1-f)X_{pry}, \quad \forall p\in\mathscr{U} \tag{A.15}$$

- For dispatchable plant not modelled with commitment constraints, the generation may not exceed the installed capacity not currently experiencing a forced outage. Note that this is similar to (A.15).

$$E_{pryt} \leq (1-f)X_{pry}, \quad \forall p\in\mathscr{D}\notin\mathscr{U} \tag{A.16}$$

- Intermittent generation in any hour depends on the availability of sun or wind at that hour and can be no more than 30% of annual generation in each region. Note that the maximum generation by intermittent plant V_{pryt} includes assumptions for outage rates as well as sun and wind availability.

$$E_{pryt} \leq V_{pryt}X_{pry}, \quad \forall p\in\mathscr{I} \tag{A.17}$$

$$\sum_{p\in\mathscr{I}} E^{a}_{pryt} \leq 0.3\left(\sum_{t} w_t E^{d}_{ryt}\right) \tag{A.18}$$

- We limit the generation from existing hydropower and biomass plant.

$$\sum_{p} E^{a}_{pry} \leq J_r, \quad \forall p\in\mathscr{H} \tag{A.19}$$

$$\sum_{p,r} E^{a}_{pry} \leq B_y, \quad \forall p\in\mathscr{B} \tag{A.20}$$

- For all storage plants (i.e. for this study, pumped hydro and storage plant within the CST plants) the energy stored must be greater than or equal to zero and less than or equal to the storage capacity. The storage level in any hour is equal to the storage level in the previous hour, plus the recharged energy that hour and minus the generation in that hour. For CST plant, the recharge rate is limited by the incoming solar radiation. For pumped hydro storage plant, it is limited by the amount of excess generation from other plant, with the recharge rate also limited by the plant's pumping (i.e. generation) capacity times its round trip efficiency.

$$0 \leq S_{prty} \leq R_p X_{pry}, \quad \forall p\in\mathscr{S},\mathscr{W} \tag{A.21}$$

$$S_{prty} = S_{pry(t-1)} + S^{+}_{pryt} - E_{pryt}, \quad \forall p\in\mathscr{S} \tag{A.22}$$

$$0 \leq S_{prty} = S_{pry(t-1)} + V_{pryt}X_{pry} - E_{pryt}, \quad \forall p\in\mathscr{W} \tag{A.23}$$

$$S^{+}_{pryt} \leq \eta_p^{\text{round trip}} X_{pry}, \quad \forall p\in\mathscr{S} \tag{A.24}$$

- Existing plant and new plant must be retired by the end of its technical life, but can be retired earlier if that is optimal, saving its fixed operating and maintenance cost. For existing plant, the capacity which must have be retired by a given year or earlier is known at the start of the simulation. For new plant, the sum of the retired capacity in the current year and all previous years must be greater than or equal to the sum of the capacity built more than the technical life in years before the current year.)

$$\sum_{y'\leq y} X^{-}_{pry'} \geq X^{\text{min shut down}}_{pry}, \quad \forall p\in\mathscr{P}^{e} \tag{A.25}$$

$$\sum_{y'\leq y} X^{-}_{pry'} \geq \sum_{y''\leq y-L_p} X^{+}_{pry''}, \quad \forall p\in\mathscr{P}^{n} \tag{A.26}$$

- Transmission flows must be within line capacities. The line capacity in each year is the equal to the existing line capacity plus the sum of the line capacity constructed in that year.

$$T^{\min}_{ly} \leq F_{lyt} \leq T^{\max}_{ly} \tag{A.27}$$

$$T^{\min}_{ly} = T^{\min}_{ly_0} - \sum_{y'\leq y} T^{+}_{ly'} \tag{A.28}$$

$$T^{\max}_{ly} = T^{\max}_{ly_0} + \sum_{y'\leq y} T^{+}_{ly'} \tag{A.29}$$

In one scenario, we replace the emissions constraint A.3 with a constraint on the annual renewable energy generation.

$$\sum_{p_r} E^{a}_{pry} \geq A_y \tag{A.30}$$

Table A.1
Financial information on existing generating plant. NSW data is shown, except for brown coal plant which is for VIC. Data is either directly from Ref. [42] or inferred from these sources as discussed in the text.

Plant	FOM ($/MW/year)	VOM ($/MWh)	Fuel cost ($/GJ)	η (%)	GHG intensity $t_{CO_{2e}}/MWh$
Black coal	56,532	1.38	1.7	35	1013
Brown coal	87,143	1.35	0.2	25	1332
CCGT	33,419	1.59	7.2	48	495
Distillate	14,758	10.91	33.0	28	964
OCGT	14,758	11.33	7.2	28	847
Hydro	59,033	7.00			
Pumped hydro	59,033	8.12			
Wind	26,764	3.92			

Table A.2
Information of the dynamic performance of existing generating plant. NSW data is shown, except for brown coal plant which is for VIC. Data is either directly from [42] or inferred from these sources as discussed in the text.

Plant	R^+ (% cap./hour)	R^- (% cap./hour)	K_p (hours)	Q_p (GJ)	m_p (% cap.)	η_{min}/η_{max} (%)
Black coal	45	41	12	41	50	85
Brown coal	67	67	12	41	50	85
CCGT	68	87	4	19	50	85
Distillate	100	100				
OCGT	100	100				
Hydro	100	100				
Pumped hydro	100	100				

Table A.3
Estimates of current (ie 2014) financial parameters for new plants. Data is either directly from [47] or inferred from these sources as discussed in the text.

Plant	Capex ($/kW)	FOM ($/MW/year)	VOM ($/MWh)
Biomass	5174	125,000	8.0
Combined cycle gas turbine	1092	10,000	4.0
IGCC - Black coal	5493	79,600	7.0
IGCC - Brown coal	6196	99,500	9.0
Open cycle gas turbine	737	4000	10.0
Pumped hydro	1860	5600	0.3
Solar Thermal CLF	4434	64,105	15.2
Solar Thermal CR with storage	7095	71,312	5.7
Solar Thermal PT with storage	7642	72,381	11.4
Supercritical PC - Black coal	3136	50,500	7.0
Supercritical PC - Brown coal	3786	60,500	8.0
Utility PV	2797	25,000	0.0
Wind	2276	32,500	10.0

Table A.4
Estimates of current (ie 2014) technical parameters for new plants. Some quantities depend on the NEM region. NSW data is shown below, except for brown coal plant which is for VIC. Data is either directly from Ref. [39] or inferred from these sources as discussed in the text. All of these parameters for any plant listed in the previous table but not this table is assumed to be zero.

Plant	η (%)	GHG intensity ($t_{CO_{2e}}/MWh$)	K_p (hours)
Biomass	0.27	0	12
Combined cycle gas turbine	0.51	0.46	4
IGCC - Black coal	0.39	1.03	4
IGCC - Brown coal	0.34	1.12	4
Open cycle gas turbine	0.36	0.65	12
Supercritical PC - Black coal	0.43	0.82	12
Supercritical PC - Brown coal	0.33	0.99	12

Please cite this article in press as: Jeppesen M, et al., Least cost, utility scale abatement from Australia's NEM (National Electricity Market). Part 1: Problem formulation and modelling, Energy (2016), http://dx.doi.org/10.1016/j.energy.2016.02.017

Table A.5
Estimates of 2050 financial parameters for new plants. (Some quantities depend on the NEM region. NSW data is shown below, except for brown coal plant which is for VIC). Data is either directly from Ref. [39] or inferred from these sources as discussed in the text.

Plant	Capex ($/kW)	FOM ($/MW/year)	VOM ($/MWh)
Biomass	5454	174,875	11.2
Combined cycle gas turbine	1160	13,990	5.6
IGCC - black coal	5782	111,360	9.8
IGCC - brown coal	6411	139,201	12.6
Open cycle gas turbine	782	5596	14.0
Pumped hydro	1860	7834	0.4
Rooftop PV	1594	19,688	0.0
Solar thermal CLF	2785	33,655	8.0
Solar thermal CR with storage	4399	37,439	3.0
Solar thermal PT with storage	4739	38,000	6.0
Supercritical PC - black coal	2934	70,650	9.8
Supercritical PC - brown coal	3762	84,640	11.2
Utility PV	1063	13,125	0.0
Wind	1848	45,468	14.0
CCGT with CCS	2233	23,783	12.6
IGCC with CCS - black coal	6411	138,081	11.2
IGCC with CCS - brown coal	7050	172,637	14.0
Nuclear	5852	48,126	20.6
SCPC with CCS - black coal	4343	102,407	16.8
SCPC with CCS - brown coal	5979	128,009	21.0
SCPC with oxy - black coal	4537	82,821	18.2
SCPC with oxy - brown coal	5100	86,738	19.6

Table A.6
Estimates of 2050 technical parameters for new plants. Fugitive emissions (and hence GHG intensity) depend on NEM region. NSW data is shown below, except for brown coal plant which is for VIC). Data is either directly from Ref. [39] or inferred from these sources as discussed in the text. All of these parameters for any plant listed in the previous table but not this table is assumed to be zero.

Plant	η (%)	GHG intensity ($t_{CO_{2e}}$/MWh)
Biomass	0.27	0
Combined cycle gas turbine	0.63	0.37
IGCC - Black coal	0.49	0.81
IGCC - Brown coal	0.45	0.86
Open cycle gas turbine	0.46	0.50
Supercritical PC - Black coal	0.53	0.66
Supercritical PC - Brown coal	0.44	0.75
CCGT with CCS	0.58	0.13
IGCC with CCS - Black coal	0.40	0.17
IGCC with CCS - Brown coal	0.37	0.11
Nuclear	0.34	0
SCPC with CCS - Black coal	0.44	0.15
SCPC with CCS - Brown coal	0.33	0.10
SCPC with oxy - Black coal	0.45	0.77
SCPC with oxy - Brown coal	0.46	0.07

Table A.7
Estimates of current (i.e. 2015) and 2050 fuel costs ($/GJ) [39] for the Reference Scenario. Fuel prices vary up to 10% between each state. NSW prices are shown below, except for brown coal which is the Victorian price.

Type	2015	2050
Black coal	2.0	1.7
Brown coal	0.7	0.6
Natural gas	7.2	11.7
Nuclear	0.7	0.7
Biomass	1.5	1.5

Table A.8
Assumed cost of transmission augmentation ($/MW) from Ref. [48].

Line	$M/MW
VIC to SA	1.0
NSW to QLD	1.1
VIC to NSW	0.7
TAS to VIC	1.6

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Please cite this article in press as: Jeppesen M, et al., Least cost, utility scale abatement from Australia's NEM (National Electricity Market). Part 1: Problem formulation and modelling, Energy (2016), http://dx.doi.org/10.1016/j.energy.2016.02.017