Performance of Wholesale Electricity Markets with High Wind Penetration

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Abstract

This paper examines the impact of progressively deeper levels of wind generation and/or abatement on the performance of a wholesale market and its incumbent thermal generators with non-convex unit commitment constraints. Comparison is made to the result that marginal cost pricing should induce investors to build the least-cost capacity mix, since it is not clear that this will hold in renewable-rich systems.

It is first found that unit commitment and forecast uncertainty do not cause significant departure from this result when the generator fleet is optimal. 'Optimality" in this sense is determined in a capacity expansion problem that does not feature unit commitment, and which allows thermal generators to be built or retired as greater renewable generation or abatement is mandated. In contrast, the wholesale market with no retirement of thermal generation experiences progressively greater disparity between total system prices and costs, and lower returns to generators, simply due to over-capacity rather than any form of variability-related market failure. A carbon price is observed to be far superior to a renewable portfolio standard when the existing set of thermal generators do not retire, but this difference is less stark when the generation mix is optimal. The implications of these results for market design and system planning are then discussed.

Keywords: Wholesale electricity markets, unit commitment, wind power, revenue sufficiency

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1. Introduction

Electricity markets around the world have added significant Variable Renewable Generation (VRG), particularly wind and solar, in response to the challenges posed by climate change. As well as having near-zero operational greenhouse gas emissions, these technologies have limited predictability, variable output and low operating costs. Some kind of policy is also normally used to encourage investment, such as a renewable portfolio standard (RPS) or a carbon price [1, 2]. An RPS requires a certain proportion of electricity to come from renewable energy. This usually means that renewable generators receive revenue from both the wholesale market and from the sale of Renewable Energy Certificates (RECs) or an equivalent, which quantify the amount of renewable energy generated. Typically, a prescribed quantity of these certificates must be purchased each year by consumers.

In contrast, a carbon price charges generators for producing emissions. The government can either set the price of emissions or set a limit on emissions and let the price of emissions permits be set by a market. A key difference with an RPS is that a carbon price charges higher emitting fossil plant more than lower emitting plant, whereas a RPS only rewards renewable generators. In Australia, an RPS scheme named the Renewable Energy Target (RET) is currently in place, which requires 33,000GWh/yr of renewable energy generation in 2020 [3], whilst a carbon price was introduced in 2012 and repealed in 2014 [4].

There is now a large body of literature on the technical challenges in wholesale electricity markets with increasing VRG, e.g. [5–13]. Considerations such as thermal plants' start-up times, minimum stable generation and ramping constraints, along with VRG forecast uncertainty, non-synchronicity and often not providing ancillary services combine to pose challenging problems for unit commitment and dispatch. Such issues are even being considered in the planning problem. For example, Palmintier & Webster [14] examined an ERCOT-like system under abatement policy (RPS & carbon), finding that generation expansion fleets that did not consider operational flexibility constraints could not simultaneously meet both demand and the abatement policies when these constraints were later applied. Shortt et al. [7] compared dispatch only versus full unit commitment models for the Irish, Finnish and Texan markets with a range of wind penetration levels. They concluded that full unit commitment may be important, but this was to some extent market dependent. It was also found that the cost penalty associated with full unit commitment increased with increasing wind penetration.

However, the challenges for wholesale electricity markets with increasing VRG are not only technical. In Australia, as in some other jurisdictions, electricity is provided by independent companies which compete in an energy-only, wholesale market [15]. Operational and investment decisions are primarily based on price signals arising from this market. In Australia, the origins of this marketplace go back about 25 years, when some state-owned generation and network assets were privatised and the National Energy Market (NEM) was formed [16]. In such a system, abatement policy usually uses market incentives, rather than prescribing particular operational or investment decisions. Since VRG has very low short run costs and receives revenue from the RET, they can often bid at or below zero price. This inevitably depresses wholesale market prices [17, 18], and, it has been suggested, might lead to issues of revenue insufficiency, e.g. [19, 20].

It has been shown theoretically that competitive short-run marginal pricing will guide investors to build the socially optimal capacity mix without the need for capacity payments under certain conditions [21–25]. Put simply, if the electricity price a generating technology expects to receive were to fall below its long-run costs, investment in new capacity would stall and prices rise. On the other hand, if prices are higher than its long-run costs, further investment would be profitable, thereby reducing prices to the optimal level. However, this result requires convex costs and constraints. Electricity markets feature non-convexities, in particular for unit commitment constraints, start-up costs and the lumpiness of investment, which may be exacerbated by increasing forecast uncertainty due to increasing VRG [26].

Declining revenue to incumbent generators with increasing VRG market share has been observed in some studies e.g. [20, 27, 28] though these do not allow existing units to exit so that the market is not in a true equilibrium. Riesz et al. [29] and Simshauser [30] did include optimal mixes, though non-convex effects such as unit commitment constraints were not included. Hirth et al. [31] use the marginal value of VRG generation to define VRG integration costs, quantifying these costs as i) balancing costs to accommodate forecast errors, ii) differences in demand and VRG profiles, and iii) locational constraints. Work by De Sisternes et al. [32] modelled commitment and expansion decisions, finding that revenue insufficiency due to a non-optimal capacity mix outweighs the increase in uplift from a large share of VRG - however de Sisternes et al. [32] did not include forecast uncertainty of VRG. Similarly, Levin et al. [33] modelled the impacts of several VRG or emissions policies on market outcomes, including revenue sufficiency for a least-cost optimal fleet, but again did not consider forecast uncertainty in VRG.

This paper therefore examines the performance of a market that includes full unit commitment and reserves constraints and realistic operational uncertainty under increasing wind penetration. We then investigate the technical and financial performance of the market and of individual generators, determining when revenue sufficiency is achieved. We also examine the effectiveness of an RPS and a carbon price in achieving abatement at least cost to consumers.

2. Method

The model has three sub-models, each of which is a linear program that determines one of planning, unit commitment or dispatch decisions (Figure 1). The generation expansion (i.e. planning) sub-model determines plant capacities at each policy price to meet a demand profile at least cost. These capacities are then fed into the unit commitment sub-model. The commitment schedule is then used to determine the unit dispatch, and the associated prices for energy and reserves in the economic dispatch sub-model. This modelling process shares some similarities with that of Levin et al. [33]. Four generating technologies are used: coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), along with wind, and the option to not serve demand (charged at the market price cap, P^{MPC}).

2.1. Generation Expansion Model

The generation expansion sub-model determines the number of units of each plant type for a given level of VRG or abatement. A mixed-integer linear program minimizes costs to serve a year of demand at a given carbon price or REC price. Investment decisions are integers, thereby representing the lumpiness of investment in capacity. We use a 10% real discount rate to annualise plant capital expenditure. The objective function is the cost of building and operating units to serve a year of electricity demand,

$$\begin{aligned} C^{\text{GE}}_{\text{Total}} = \sum_{st} \pi_s (C^{\text{GE}}_{\text{Build},st} + C^{\text{GE}}_{\text{FOM},st} + C^{\text{GE}}_{\text{Var},st} \\ + C^{\text{GE}}_{\text{CP},st} - C^{\text{GE}}_{\text{REC},st}) + \sum_{s} \pi_s C^{\text{GE}}_{\text{Uns},s}. \end{aligned} \tag{1}$$

Here, $C^{\text{GE}}_{\text{Total}}$ is the total cost, and the terms on the right hand side are the annualised build cost, fixed operating costs, variable operating costs, carbon costs, REC value and unserved energy costs. A full formulation is provided in Appendix Appendix B.1.

2.1.1. Fixed & Optimised Fleets

We analyse two fleets termed the *Fixed Fleet* and the *Optimised Fleet* (Figures 5 & 12). These fleets represent two plausible limits to the response of the thermal system to a given RPS or carbon policy.

1. The Fixed Thermal Fleet begins with the least cost thermal fleet with no VRG, and this thermal capacity remains unchanged as either the REC or carbon price is increased, driving new VRG capacity.
2. The Optimised Thermal Fleet re-optimises the fleet using the generation expansion model for each carbon or REC price. Thermal plant can therefore both be built and retired along with new build VRG.

This is consistent with the method used by de Sisternes et al. [32]. It is noted that the fleets studied in this paper have reserve margins that are lower than those of real power systems, (e.g. the NEM [34] and the ERCOT market [35]). This is because, in practice, reserve margins are used to manage system contingencies, i.e. when an element of the system fails. Since we do not model contingencies in this paper, our capacity expansion model finds that smaller reserve margins achieve acceptable levels of reliability. Correspondingly higher system costs (and therefore prices) and higher revenues to generators will result if contingencies are included in our modelling, but this will have no effect on the conclusions made by this paper.

2.2. Stochastic Unit Commitment Model

Unit commitment decisions need to be made ahead of time because of thermal plants' start up times. Whilst units are usually turned on in order

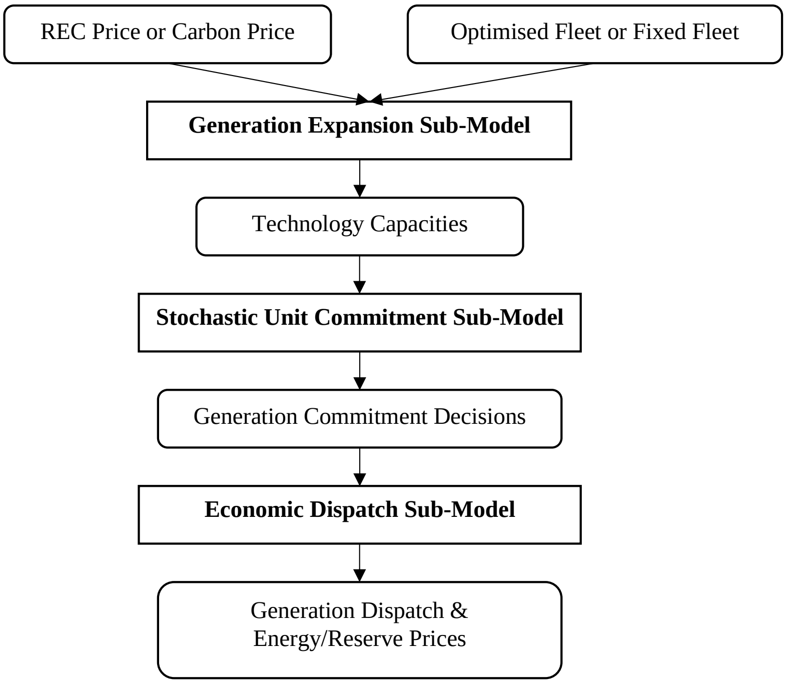

Figure 1: Model overview. Bold text indicates an optimization model, whilst regular text are model inputs and outputs.

of their short run production cost, this is complicated by constraints such as minimum up and down times and minimum stable generation, as well the need for various types of reserves. Because these decisions are made ahead of real time, there is also uncertainty in the demand for thermal generation due to variations in both load and VRG.

We solve the unit commitment problem using a mixed-integer linear program which minimises costs in meeting demand associated with production costs, start-up and shut-down costs and unserved energy and reserve costs. This problem is stochastic and the commitment decisions must minimize the cost over ten different realisations of VRG and demand (Figure 2). The objective function is

$$C^{\text{UC}}_{\text{Total}} = \sum_{sg} \pi_s (C^{\text{UC}}_{\text{Var},sg} + C^{\text{UC}}_{\text{SU},sg} + C^{\text{UC}}_{\text{SD},sg} + C^{\text{UC}}_{\text{CP},sg} - C^{\text{UC}}_{\text{REC},sg}) + \sum_{s} \pi_s C^{\text{UC}}_{\text{Uns},s}. \tag{2}$$

Here, $C^{\text{UC}}_{\text{SU},sg}$ and $C^{\text{UC}}_{\text{SD},sg}$ are the start up and shut down costs respectively, with other terms defined similarly to Equation (1). The unit commitment sub-model was formulated using Carrion & Arroyo's method [36] and a reserves formulation similar to that of Palmintier & Webster [37]. A full formulation is provided in Appendix Appendix B.2.

We model primary, secondary and tertiary reserves which correspond to response times of 5-15s, 90s-5min and 5min-20min respectively [38]. Each thermal plant type is able to provide different quantities of each reserve type according to its technical characteristics (Table 1). Primary and secondary reserves may only be provided by units which are already committed. The unit commitment sub-model uses a horizon of 48 hours, with the first 24 hours being kept as the commitment solution, and the state of the system at the end of those 24 hours used as the input state for the following 48 hours. This mimics the day-ahead commitment that is a feature of several electricity markets. The extra day is solved to negate end-effects of only optimising one day at a time.

2.2.1. *Generation of Demand and Wind Forecast Scenarios*

We use an Autoregressive Moving Average (ARMA) [39] model to estimate VRG and demand errors, i.e.

$$E_i = \alpha E_{i-1} + Z_i + \beta Z_{i-1}. \tag{3}$$

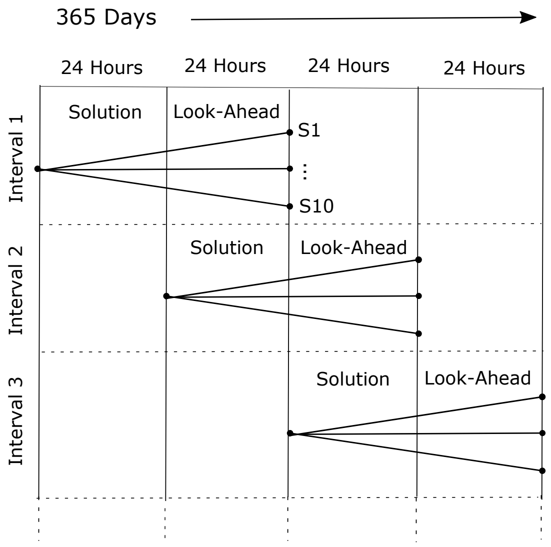

Figure 2: Scenario trees in the unit commitment model.

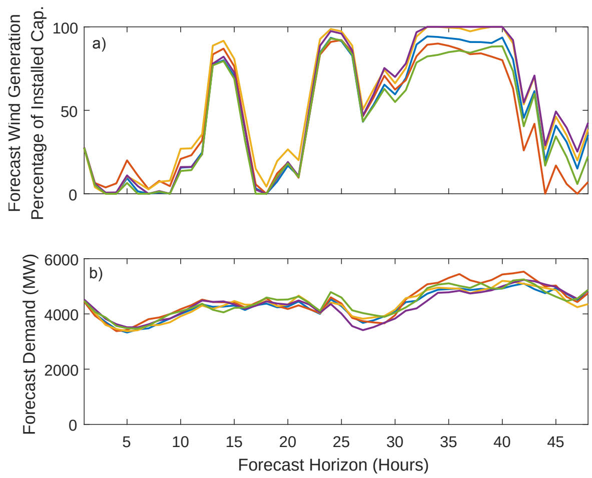

Figure 3: Example of the 48 hour ahead forecasts of a) wind generation as a percentage of capacity and b) demand used for unit commitment decisions. Five scenarios are shown.

Here, E_i is the forecast error at hour h, with $E_0 = 0$, Z_i is a random Gaussian variable with zero mean and standard deviation σ_z, whilst α, β and σ_z are model parameters, shown in Table 2. Examples of wind and demand forecasts are shown in Figure 3. The magnitude of the demand forecast errors at each forecast time horizon was calculated from pre-dispatch demand forecasts published by the Australian Energy Market Operator (AEMO) [40]. The magnitude of the wind forecast errors was calculated from figures taken from AEMO's Wind Energy Forecasting System (AWEFS) [41]. We assume that over and under forecast errors have the same distribution.

2.3. Economic Dispatch And Pricing

Once a fleet is built and committed, all dispatch decisions are determined in the economic dispatch (ED) sub-model. It is also used to calculate the price of energy and reserves, from the shadow prices of the demand and reserve constraints. All generators bid at their Short-Run Marginal Cost (SRMC) which is defined later, and the associated objective function is

$$C^{\mathrm{ED}}_{\mathrm{Total}} = \sum_{sg} \pi_s \left(C^{\mathrm{ED}}_{\mathrm{Var},sg} + C^{\mathrm{ED}}_{\mathrm{CP},sg} - C^{\mathrm{ED}}_{\mathrm{REC},sg} \right) + \sum_{s} \pi_s C^{\mathrm{ED}}_{\mathrm{Uns},s}. \tag{4}$$

These terms are defined similarly to Equation (1) and a full formulation is shown in Appendix Appendix B.3.

Once prices and generator dispatch are known, we calculate quantities such as each unit's capacity factor and other performance metrics. We present the average performance of each plant type and also the average over the ten scenarios, i.e. we run an economic dispatch for each scenario.

2.4. Abatement Policies

The simulations include either a REC or a carbon price. Typically, a given level of either abatement or renewable energy is determined by government, and then the market sets the price required to achieve this outcome. The REC price or carbon price is calculated for a given level of VRG or carbon abatement in the generation expansion sub-model. Under a RPS scheme, we assume that VRG producers subtract the REC price from their bid, and receive REC revenue separately from consumers. Under a carbon price, we assume that thermal units add this to their bid (adjusted for their emissions intensity) which is passed on to consumers. As the government receives this revenue, we therefore assume it is refunded to consumers. Although the carbon price revenue is fully refunded, consumers will still pay higher prices because of higher production costs e.g. if a cleaner CCGT unit is run instead of a coal unit.

2.5. Implementation

The model is written in the GAMS [42] optimisation language and run with the CPLEX solver [43]. Solution time for a single year is up to 140 hours in the unit commitment sub-model, with the generation expansion and economic dispatch sub-models being much faster. All three programs are resolved at an hourly resolution, and we use a optimality criterion of 0.5% due to the integer nature of the generation expansion and unit commitment programs. With this optimality criterion and a realistic value of the market price cap MPC = $13,000/MWh [44], there may be times when a small amount of demand could go unserved, whilst not exceeding this criterion. However, as small amounts of unserved demand have large effects on the energy price we use very high values for the MPC $10M/MWh) when solving the unit commitment sub-model, replacing these with the actual value in the economic dispatch sub-model. This is similar to an issue with using a 'large' duality gap of 1% in Tuohy et al. [45].

2.6. System Model & Input Data

We model a hypothetical, islanded electricity system with approximately 10GW maximum demand and no annual demand growth with increasing REC Price of carbon price. Generator data was taken from the Australian Energy Technological Assessment 2012 [46] and from the WILMAR All Island Planning Tool [38].

All relevant parameters are shown in Table 1. Using the parameters in this table, we provide approximate short-run and average costs (which includes capital and fixed costs) of each technology. For wind, assuming a capacity factor of 32%, the average cost of energy is $109/MWh, (and near-zero short-run marginal cost). For coal, assuming a 95% capacity factor, the average cost is $63/MWh, and the short-run cost is $19/MWh. For CCGT and OCGT with capacity factors of 50% and 3.5%, the average cost is $77/MWh and $343/MWh, and the short-run marginal costs are $50/MWh and $80/MWh respectively. These costs are exclusive of any carbon price or REC price effects.

The underlying wind and demand traces, to which the forecast errors are added, were taken from Victoria's historical load profile in 2014. The summation of the production of all Victorian wind farms over the same period was used, to preserve a representative relationship between system load and the wind. An example of the outputs of our model for a 48 hour period is shown in Figure 4. Three cases are shown: a case with no wind, and both the Fixed and Optimised Fleets (see Section 2.1) under a RPS for 30% wind (i.e. 5300MW installed capacity).

3. Results & Discussion

We begin by comparing the results of the Fixed and Optimised Fleets under the RPS scheme in Section 3.1. Then, in Section 3.2, we compare the results under a RPS to those of a carbon price. We quantify results in Section 3.1 by the total wind energy available, which is defined as the amount of wind that could be generated if it were never curtailed, as a percentage of total demand, i.e.

$$W_{\%} = \sum_{s} \left[\pi_s \frac{\sum_{hg \in \mathcal{G}_W} \overline{w}_{shg} \overline{P_g}}{\sum_h D_{sh}} \right]. \tag{5}$$

Here, $\overline{w}_{shg}$ is the wind available in hour h and scenario s as a fraction of capacity $\overline{P_g}$, D_{sh} is the demand in hour h, scenario s. We then use abatement to compare the RPS and carbon price policies in Section 3.2, which is defined as the percentage decrease in total carbon emissions relative to the emissions with no abatement policy M_{s00}, i.e.

$$\mathrm{Ab}_{pf} = \sum_{s} \left[\pi_s \frac{M_{s00} - M_{spf}}{M_{s00}} \right]. \tag{6}$$

Here, the subscript p indicates the policy type (RPS or carbon price) and the subscript f indicates the fleet of that policy (Figures 5 & 12).

Whilst we have modelled individual generating units, we present the results averaged over all units of a given type. We have also averaged results over all wind and demand scenarios, which is equivalent to running simulations over multiple years.

3.1. Renewable Portfolio Standard

3.1.1. Technical Performance

The capacity of each technology calculated by the generation expansion sub-model is shown in Figure 5. Each successive fleet has an increase in wind capacity equivalent to a 10% increase in the amount of unspilt wind available $W_{\%}$, up to 60%. We define the long-run (LRMC) and short-run (SRMC) marginal costs. The SRMC of unit g is the cost that must be paid to produce an extra MWh of electricity,

$$\mathrm{SRMC}_g = 3.6 c_g^{\mathrm{Fuel}} / \eta_{\mathrm{th},g} + c_g^{\mathrm{VOM}} + P^{\mathrm{CP}} \mathrm{e}_g \qquad g \in \{\mathrm{Coal}, \mathrm{CCGT}, \mathrm{OCGT}\}, \tag{7a}$$

$$\mathrm{SRMC}_g = c_g^{\mathrm{VOM}} - P^{\mathrm{REC}} \qquad g = \mathrm{Wind}. \tag{7b}$$

Here, c_g^{Fuel} and c_g^{VOM} are the fuel and variable operating costs, e_g is the emissions intensity, and P^{CP}

Parameter	**Units**	**Wind**	**Coal**	**CCGT**	**OCGT**
Capacity	MW	345	200	100	50
Annualised Capex	\$/MW	278725	315084	108599	76695
Fixed Operations & Maintenance Cost (FOM)	\$/MW	22562	50500	10000	4000
Variable Operations & Maintenance Cost (VOM)	\$/MWh	1.926	7	4	10
Fuel Price	\$/GJ	0	1.4	6.3	6.8
Thermal Efficiency	NA	1	0.419	0.495	0.35
Minimum Stable Generation	/MW	0	0.5	0.3	0.1
Emissions	kg CO_2e/MWh	0	773	368	519
Minimum Up Time	Hours	0	6	4	0
Minimum Down Time	Hours	0	4	1	0
Start Up Fuel Use	GJ/MW	0	61.6	1.3	0.016
Shut Down Fuel Use	GJ/MW	0	6.16	0.13	0.0016
Primary Reserve Capability	/MW	0	.065	0.0325	0.1
Secondary Reserve Capability	/MW	0	0.13	0.0925	0.2
Tertiary Reserve Capability	/MW	0	0	0	0.2

Table 1: Generating technology parameters.

Parameter	**Wind**	**Demand**
α	0.936	0.391
β	-0.168	0.761
σ_z	0.0376	0.0299

Table 2: ARMA Parameters for wind and demand forecast errors.

and P^{REC} are the carbon and REC prices respectively. The Long-Run Marginal Cost (LRMC) of unit g is the average total cost of production, including capital expenditure,

$$\text{LRMC}_g = \sum_s \left[\left(\frac{\pi_s}{\sum_h p^*_{shg}} \right) \left(\text{SRMC}_g \sum_h p^*_{shg} + C^{*\text{UC}}_{\text{SU},sg} + C^{*\text{UC}}_{\text{SD},sg} + (c^{\text{Capex}}_g + c^{\text{FOM}}_g)\overline{P_g} \right) \right]. \quad (8)$$

Here, c^{Capex}_g is the annualised capital cost (a discount rate of 10% was used).

It is the LRMC that must be considered when deciding whether or not to build a plant. However, once built, the fixed costs (last term on the RHS of Eq. 8) do not influence commitment decisions. Similarly, once a unit is committed, start up costs are no longer relevant, and units are dispatched on SRMC.

Figure 5 shows that there is no change in thermal capacity for the Fixed Fleet as wind is introduced. However, thermal capacity can vary with increasing wind in the Optimised Fleet. By 40% wind available (Fleet B4), coal is no longer present. With more wind however, more dispatchable generation is required, which is provided by CCGT.

Figure 6 shows the number of hours where reserves or demand have gone unserved from the solution of the economic dispatch sub-model. Even up to 60% wind, we find reasonable levels of unserved demand and reserve with our unit commitment and dispatch schedule. In the Fixed Fleet, as wind increases and no thermal capacity is removed, the system indeed becomes *more* reliable. In the Optimised Fleet, thermal capacity decreases slightly as more wind is introduced, meaning that the reliability stays approximately at the optimal level of 7 hours per year (calculated from the MPC and the cost of building an OCGT unit).

Figure 7 shows the percentage of load fulfilled by each technology, and Figure 8 shows the annual capacity factor of each technology. Three features are worth noting. First, in the Fixed Fleet it is mainly CCGT that loses market share to new wind. This is because CCGT has higher short run costs than coal, and so is displaced by wind. Given that coal is the highest emitting form of thermal generation, and CCGT the lowest, this has obvious implications for emissions reduction. However, in the Optimised fleet, as coal and wind compete on LRMC in the generation expansion problem, coal is removed and

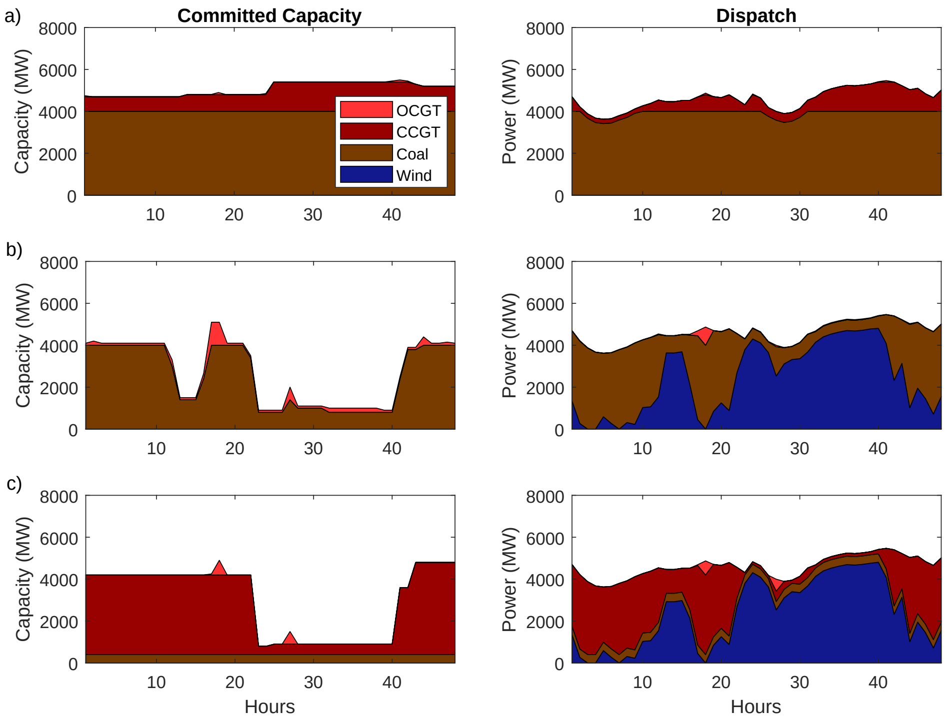

Figure 4: An example of the commitment and dispatch schedule over a forty-eight hour period for a) 0MW installed wind capacity, b) 5300MW wind (30% of annual demand) - Fixed Fleet and c) 5300MW wind (30%) - Optimised Fleet.

the CCGT capacity factor remains reasonable.

Second, past about 30% wind, each successive unit of installed wind capacity has decreasing utility, as curtailing is necessary during times of high wind and low demand. This is a manifestation of the 'profile effect' (e.g. [31, 47]), which occurs because VRG does not perfectly correlate with load. Interestingly, the capacity factor of wind is very similar in both the Fixed and Optimised cases, suggesting that the unit commitment constraints of the coal-dominated Fixed Fleet do not substantially inhibit wind dispatch. Finally, in both fleets, there is increasing generation by OCGT at higher levels of wind, due to its flexibility and ability to cost-effectively provide reserves. These effects may also be seen in the commitment and dispatch schedules shown in Figure 4.

3.1.2. Financial Performance

We now look at the financial performance of both the wholesale market and individual generators. Figure 9 shows a breakdown of the cost of providing electricity, and the price paid by consumers for energy, both per MWh. The former - the *average system cost* (ASC) - represents the average cost of all supplied electricity and is defined as

$$\begin{aligned}\text{ASC} = \sum_s \Bigg[\pi_s \sum_g \Bigg((3.6 c_g^{\text{Fuel}}/\eta_{\text{th},g} + c_g^{\text{VOM}}) \sum_h p^*_{shg} \\ + C^{*\text{UC}}_{\text{SU},sg} + C^{*\text{UC}}_{\text{SD},sg} + (c_g^{\text{Capex}} + c_g^{\text{FOM}})\overline{P_g} \Bigg) \Bigg/ \sum_h D_{sh} \Bigg] \\ + \sum_s \Bigg[\pi_s \left(P^{\text{MPC}} \sum_h (u^{*\text{En}}_{sh} + \sum_r u^{*\text{Re}}_{shr}) \right) \Bigg/ \sum_h D_{sh} \Bigg].\end{aligned} \tag{9}$$

The latter - the *energy price* - is made up of two components: the average price paid for energy in the wholesale market (i.e. the *market price*) and the cost of purchasing RECs (i.e. the *average REC cost*), both per MWh of energy consumeed.

As discussed in Section 1, in a competitive, optimised market without significant non-convexities, the total paid for electricity will match the total costs of providing it. This result can be seen in both the Fixed and Optimised Fleets with no wind, where both the average energy price and average system cost are equal to approximately \$70/MWh. As more wind is introduced in Figure 9 the average

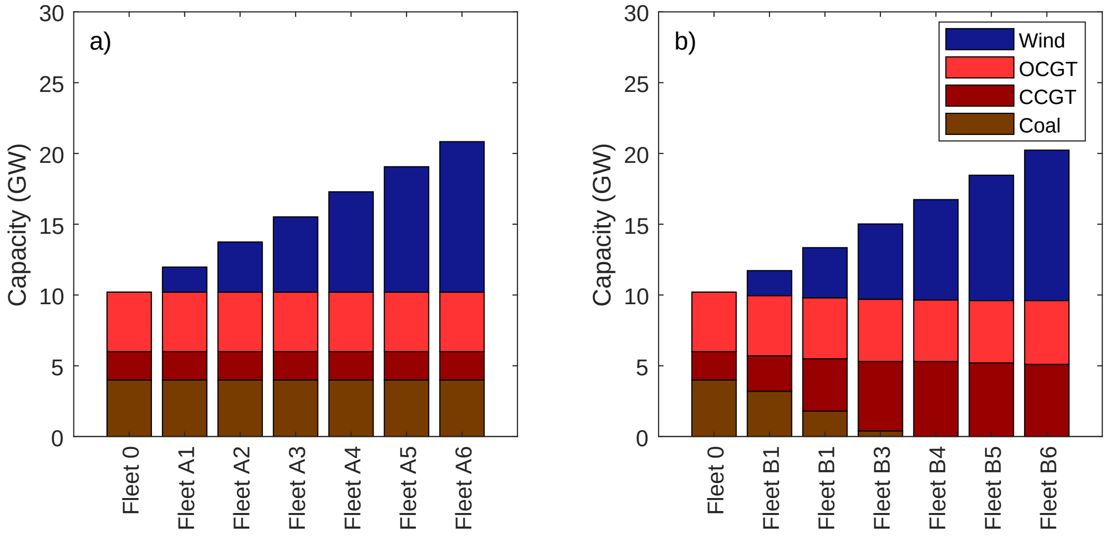

Figure 5: Least cost installed capacities for a) the Fixed Fleet, and b) the Optimised Fleet under a Renewable Portfolio Standard. Groups of 10 units are shown for coal, CCGT, and 20 units for OCGT. The REC price increases from the left to right, starting from \$0/MWh.

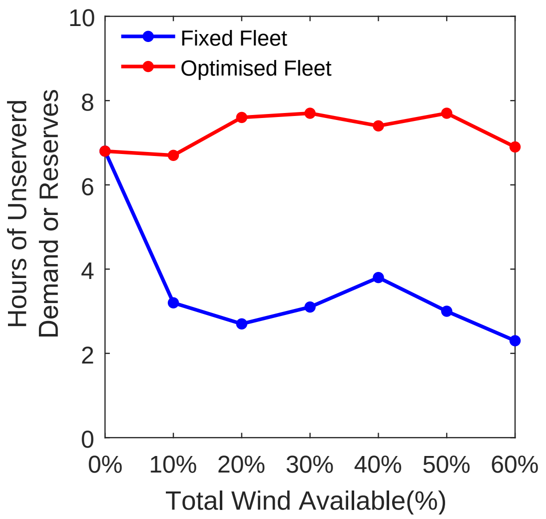

Figure 6: Number of hours where some demand or reserves is unserved for increasing wind penetration.

market price decreases because wind lowers the fleet averaged SRMC. At the same time, both the average REC cost and the average system cost both increase due to wind's high LRMC relative to other plant. In the Fixed Fleet the average energy price falls below the average system cost due to over-capacity. But in the Optimised Fleet, the average system cost is matched by the average energy price, indicating a well-functioning market where costs are covered by prices. At very high wind penetrations (i.e. $\geq 50\%$) the average system cost and average energy price begin to diverge slightly, and this will be discussed below.

Investors in a market of course expect to make a reasonable return on their investment. The return should be 10% in this study since we have used that discount rate in calculating the annualised capital expenditure for each technology in the capacity expansion sub-model. The generator operating revenue is

$$\mathrm{Rev}_{\mathrm{sg}} = \sum_h p^*_{shg}\mu^{\mathrm{En}}_{sh} + \sum_{h,r} \mu^{\mathrm{Re}}_{shr}\rho^*_{shgr} + P^{\mathrm{REC}} \sum_h p^*_{shg}. \tag{10}$$

Here, μ^{En}_{sh} is the energy price in hour h, μ^{Re}_{shr} is the price of reserve type r in hour h, while ρ^{UC}_{sigr} is the reserves provided by unit g. Again, the REC revenue in the final term is only included for wind units. Total operating costs are

$$\begin{aligned}\mathrm{Op.Costs}_{\mathrm{sg}} = (3.6c^{\mathrm{Fuel}}_g/\eta_{\mathrm{th},g} + c^{\mathrm{VOM}}_g + P^{\mathrm{CP}}\mathrm{e}_g) \sum_h p^*_{shg} \\ + C^*_{\mathrm{SU+SD},sg} + \overline{P_g} \cdot c^{\mathrm{FOM}}_g,\end{aligned} \tag{11}$$

and the free cash flow is the difference between the

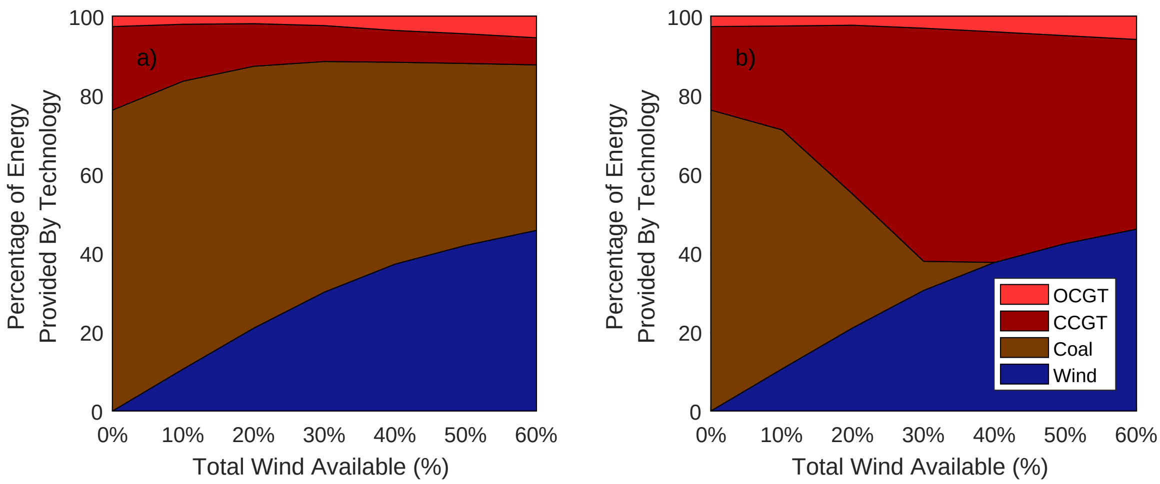

Figure 7: Percentage of load fulfilled by each technology for increasing wind penetration for a) the Fixed Fleet and b) the Optimised Fleet.

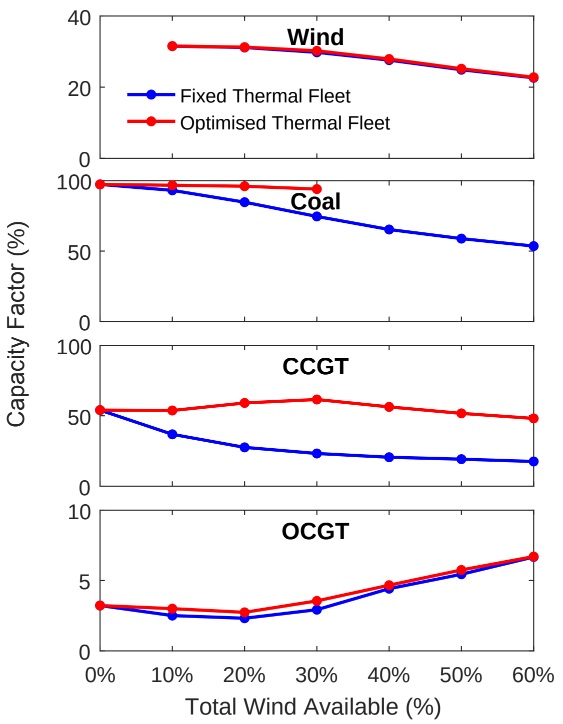

Figure 8: Change in average capacity factors for each technology for increasing wind penetration.

revenue and operating costs,

$$\mathrm{FCF}_g = \sum_s \left[\pi_s(\mathrm{Rev}_{\mathrm{sg}} - \mathrm{Op.Costs}_{\mathrm{sg}})\right]. \qquad (12)$$

As we only look at one year per fleet, we assume that this year repeats over the lifetime of each unit. The net present value (NPV) is then

$$\mathrm{NPV}_g = \sum_{\mathrm{y}=1}^{\mathrm{L}_g} \frac{\mathrm{FCF}_g}{(1+d)^{\mathrm{y}}} - \overline{P_g} \cdot c_g^{\mathrm{Capex}}, \qquad (13)$$

where L_g is the life of the unit and the internal rate of return (IRR) is the value of d that sets NPV_g to zero .

The resulting free cash flow and IRR of each plant type are shown in Figure 10. Because the simulations with no wind capacity have least-cost optimised capacities, each technology meets its 10% IRR. As wind generators are introduced, they always achieve a 10% IRR at all penetrations in both fleets, as the REC price has been chosen to ensure this. However, in the Fixed Fleet, all three of the thermal technologies perform increasingly poorly as wind penetration increases. This is simply because the additional wind capacity has depressed energy prices. Interestingly, gas plants perform worse than coal in the Fixed Fleet, and this is because CCGT is further up the merit order than coal.

In contrast, thermal units in the Optimised Fleet receive normal economic returns with the exception of OCGT at high levels of wind penetration. This suggests that the market, when optimised, has adequate economic performance. The decline of the OCGT financial performance at high levels of wind is due to OCGTs being chosen by the optimiser as the

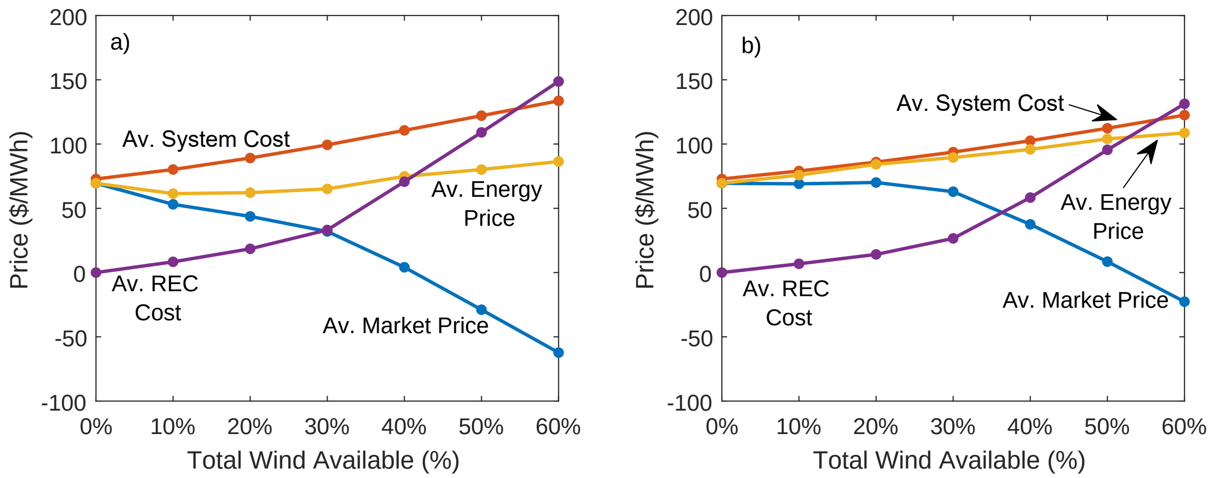

Figure 9: Comparison of costs of providing energy and the price paid for energy by consumers for a) the Fixed Fleet and b) the Optimised Fleet for increasing wind penetration.

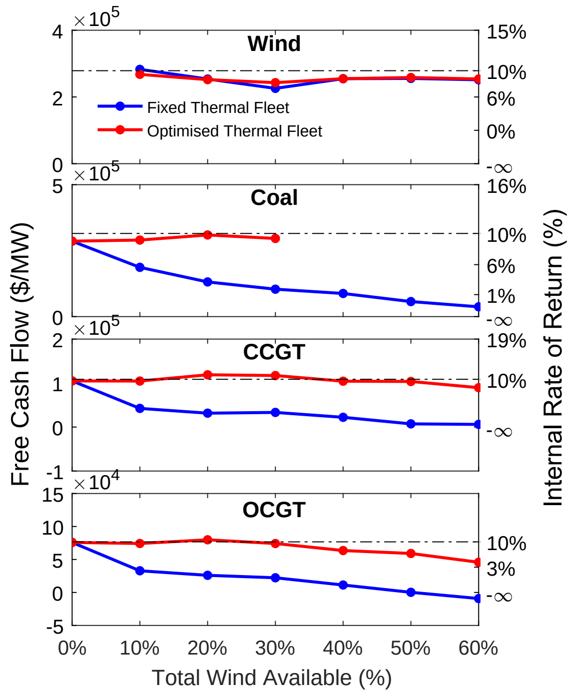

Figure 10: Plant free cash flow and corresponding Internal Rate of Return, for increasing wind penetration.

cheapest way to provide reserves. When wind generation is high, the energy price is well below their SRMC, but they have to be turned on at their minimum stable generation in order to provide primary and secondary reserves. This indicates the need for increased uplift payments, because the marginal price does not allow OCGT plants to completely recover their costs. This effect is small relative to the over-capacity in the Fixed Fleet, and is not noticeable unless wind penetration is greater than 40% of annual load. Make-whole payments could be used to cover the operating costs of the OCGT plant, increasing their profit. However, the need for this shows that the reserve prices do not provide the incentives for the desired amount of reserves, and increases the need for both system operator directions, and out-of-market payments.

3.2. Carbon Price

We now consider the performance of the Fixed and Optimised Fleets under a carbon price and compare these results with those of the RPS policy. Figure 11 shows the REC and carbon prices used for each fleet and the corresponding abatement they produced.

Unlike a RPS scheme, a carbon price promotes lower emission thermal plants over higher emission plants. As the carbon price increases the coal SRMC increases more than that of CCGT and OCGT, meaning that merit-order switching can occur. This switching produces discontinuities in abatement since all units in a given class have identical characteristics. For example, in the optimised

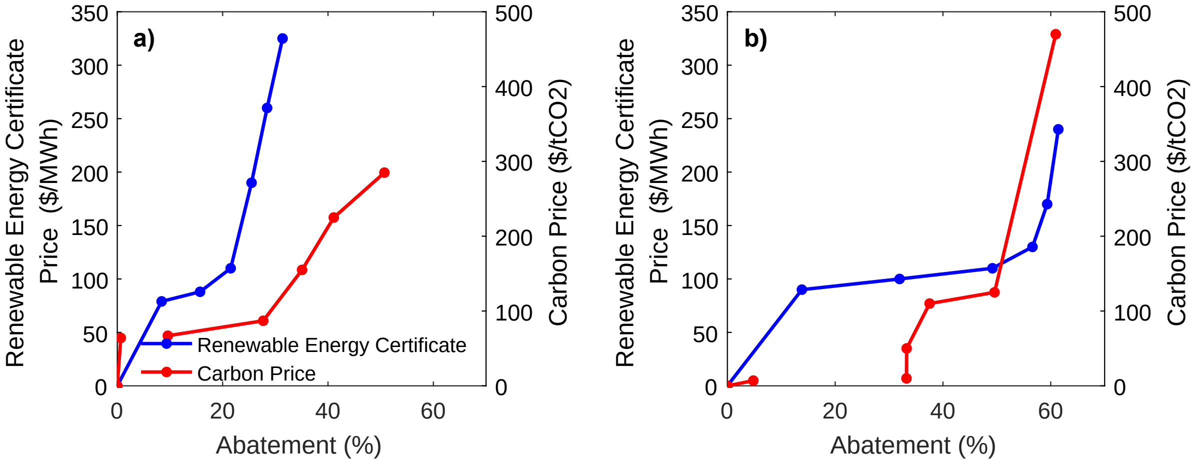

Figure 11: Prices of Renewable Energy Certificates or carbon prices versus the abatement achieved in a least-cost optimisation for a) the Fixed Fleet and b) the Optimised Fleet. For the carbon price, the discontinuities discussed in Section 3.2 are represented by not joining some points.

fleet the LRMC of coal becomes higher than the LRMC of CCGT at a carbon price of approximately $7/t$CO_2$, and therefore is no longer present in the technology mix. Additionally in the Fixed Fleet, at a carbon price of approximately $90/t$CO_2$, coal's SRMC becomes higher than CCGT's SRMC, so that CCGT becomes baseload and coal becomes mid-merit.

Plant capacities for the Fixed and Optimised Fleets are shown in Figure 12. Figure 13 shows the average system cost for each case. Under a carbon price, far less wind is installed in comparison with the RPS scheme for a given level of abatement as the carbon price lowers emissions by running more CCGT and less coal. In the Fixed Fleet, significantly more abatement is achieved under the carbon price by moving coal further up the merit order. Indeed, 35% abatement occurs at an average cost of $116/t with the carbon price, compared with 31% abatement at a cost of $254/t with the RPS. In the Optimised Fleet, coal is ultimately removed from the supply mix as it is unable to compete with CCGT, allowing significant abatement before any wind has been installed. This result shows the benefit of the carbon price over the RPS, as it directly targets emissions reduction, and is consistent with Park & Baldick [48].

However, though the carbon price initially achieves abatement at much lower cost, at higher abatement the performance of the two policies is closer. For example, the carbon price produces 50% abatement at a cost of $43/t, compared to 49% at $56/t for the RPS. This convergence on costs is thought to be because wind becomes the dominant technology at deeper abatement since it is the sole, zero emission generator considered in this work. Fleets with several near-zero and zero-emission generators competing for market share are not expected to show this behaviour, although further analysis is required to test this.

3.2.1. Technical Performance

As with the RPS policy, no significant reliability or security issues were encountered by our model with carbon pricing as the hours of unserved energy or reserves in Figure 14 shows. This is not surprising since the carbon price installs less wind than the RPS scheme. Figure 15 shows capacity factors for each technology in the Fixed and Optimised Fleets. The merit order switching that occurs as the carbon price is increased can again be clearly seen. In the Fixed Fleet, the coal capacity factor declines as it moves up the merit order, meaning that its utilisation is even lower than it was under the RPS scheme. Conversely, CCGT moves up to almost 100% utilisation after switching with coal, and then decreases slightly as more wind is introduced. OCGT also starts to increase in capacity factor at higher carbon prices. This is because the coal SRMC starts to move closer to the OCGT SRMC, and combined with the OCGT's more flexible dynamics, it is dispatched more frequently.

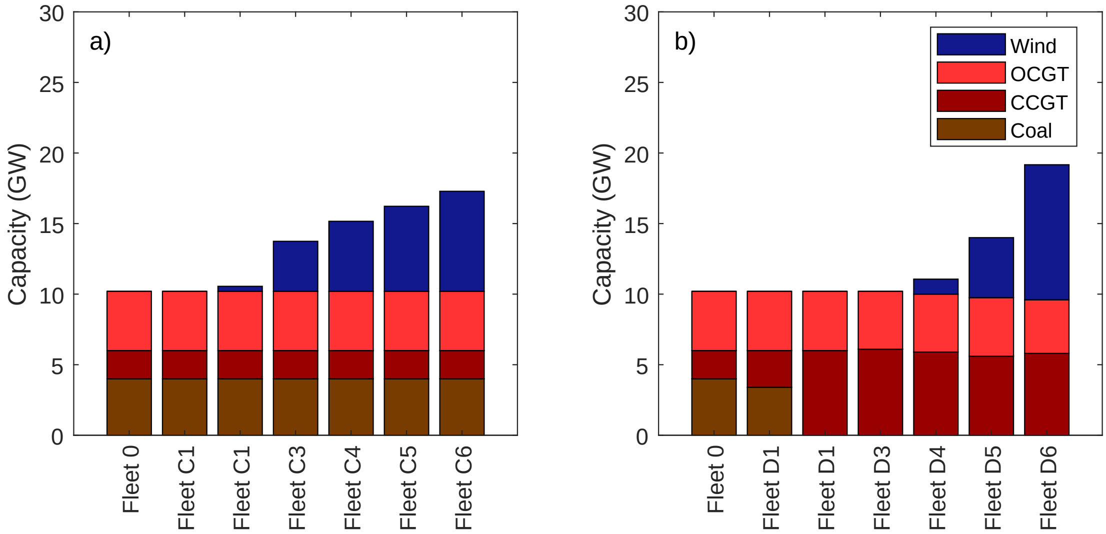

Figure 12: Least cost installed capacities for a) the Fixed Fleet, and b) the Optimised Fleet under a carbon price. Groups of 10 units are shown for coal, CCGT, and 20 units for OCGT. The carbon price increases from the left to right, starting from \$0/tCO_2.

3.2.2. *Financial Performance*

Figure 16 shows the breakdown of costs against prices. In theory, the carbon price revenue received by government could be refunded to consumers, so that the net amount paid for electricity (average energy price) by consumers is the average market price less the average carbon cost. Like the RPS scheme, the average system cost increases under increasing carbon price, though the increase is higher in the Fixed Fleet than the Optimised Fleet, as capacity cannot be retired. Also, like the RPS, the total paid by consumers after the carbon price refund in the Fixed Fleet is significantly less than the System LRMC, due to over-capacity. This represents a wealth transfer from generators to consumers that must negatively impact returns to generators.

Additionally, carbon prices below approximately \$60/MWh have minimal abatement in the Fixed Fleet (Figure 11). This is because the carbon price is not high enough to introduce wind or switch coal and CCGT in the merit order. This money would then get refunded causing no net wealth transfer in this regime. Figure 11 shows that the carbon price needs to be at least \$90/MWh in the Fixed Fleet to produce any appreciable abatement in these simulations.

Figure 16 also shows that the average system cost and the total price paid by consumers in the Optimised Fleet are similar up until high levels of abatement, as seen previously in the RPS case, meaning that efficient competitive prices are being produced. Prices drop below average average cost at approximately 50% abatement.

Figure 17 shows the financial performance for each technology under the carbon price for both fleets. In the Fixed Fleet, the IRR for wind is close to the required 10%. The strength of the carbon price over the RPS in the Fixed Fleet can be seen, as it provides a signal for coal to shut down and for more CCGT to be built - i.e. the fixed capacity constraints result in a revenue *surplus* to CCGT, while coal and OCGT still receive a deficit as in the RPS Fixed Fleet. In the Optimised Fleet, all plants achieve approximately a 10% IRR, indicating again that once optimised, the market produces efficient returns to all generators. As with the RPS, the only exception to this is with OCGT plants at high levels of abatement, where the need for some form of uplift payment for cost recovery can be seen.

3.3. *Implications for Market Design & System Planning*

We return now to the result that competitive spot pricing should induce investors to build the socially optimal capacity mix under certain conditions [21, 25]. As discussed in the Introduction, it is not clear whether this result holds in electricity markets

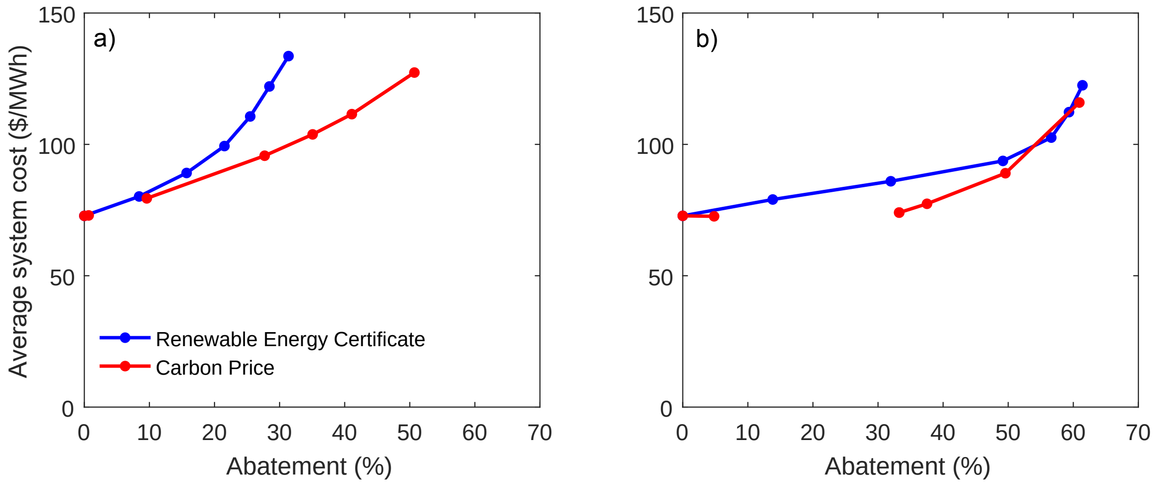

Figure 13: Average system cost versus abatement under a RPS and a carbon price for a) the Fixed Fleet and b) the Optimised Fleet. For the carbon price, the discontinuities discussed in Section 3.2 are represented by not joining some points.

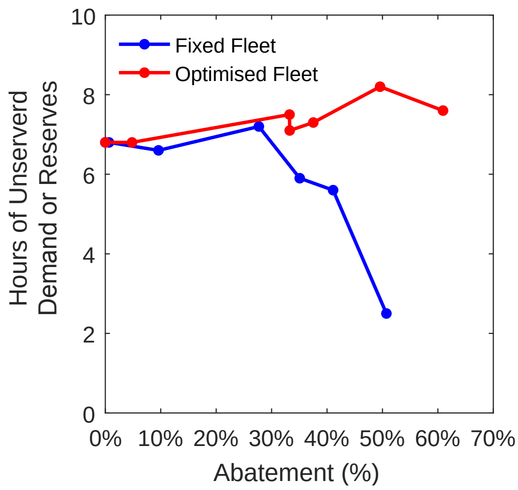

Figure 14: Number of hours where some demand or reserves is unserved under a carbon price.

with, amongst other things, unit commitment and uncertainty in demand and renewable generation. These considerations - which violate the conditions for cost recovery via marginal pricing - should become more significant with increasing proportions of VRG.

However, the results presented in this paper have shown that unit commitment and forecast uncertainty did not cause significant departure from this result, *provided that the generator fleet was optimal*. 'Optimality' in this sense was determined in a capacity expansion problem that did not feature unit commitment, *and which allowed thermal generators to be built or retired as greater renewable generation or abatement was mandated.* Wholesale system prices and costs were closely matched, and all generators received their desired rate of return. It was not until very high wind penetration ($\geq 50\%$) that the need for increased out-of-market payments to OCGT plant was observed.

In contrast, the wholesale market with fixed generator fleets experienced a progressively larger difference between system prices and costs as the levels of renewable generation and/or abatement increased. Rates of return for individual plant also declined. Given the prior result for the optimal fleets, this result for the fixed fleet is not evidence of any form of variability-related market failure. Rather, it is a consequence of over-capacity, with the RPS or carbon price subsidising new build which, in turn, depresses wholesale market prices for all generators when the now non-optimal incumbents do not exit the market. This occurs due to the inclusion of the fixed capacity constraints in the generation expansion model, and the revenue deficit (or surplus in the case of CCGT under a Carbon Price) is consistent with the effect of imposing technology capacity constraints in Perez-Arriaga & Meseguer [25].

The requirement that the fleet must be 'optimal' in order for generators to receive adequate returns on investment from the wholesale market also has implications for studies of generation expansion/planning.

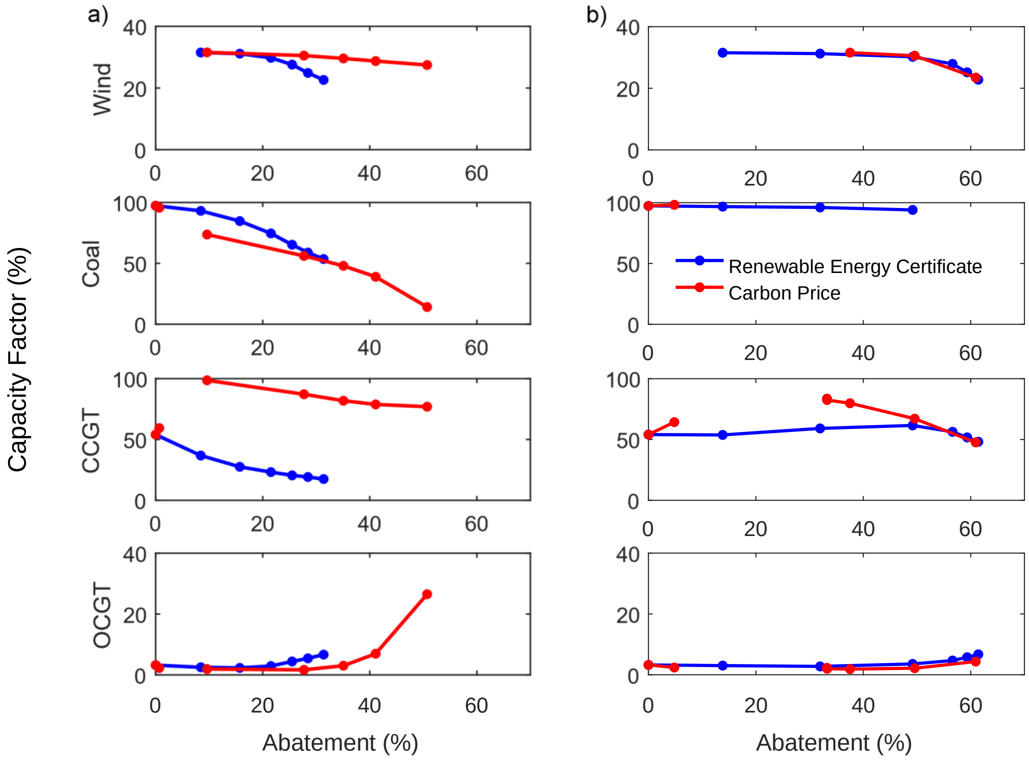

Figure 15: Capacity factors for a) the Fixed Fleet and b) the Optimised Fleet for each technology under increasing abatement.

Such studies typically annualise plants' capital expenditure with a discount rate that is set to a reasonable cost of capital, as in the present work, before calculating the required capacity of each resource. This paper shows that such methods implicitly assume optimality of the fleet across the planning period, i.e. market prices generate returns at the discount rate only if over-capacity leaves at no cost to the market. It is reasonable to question this assumption in any planning study, particularly since it is common for ageing plant to remain in operation well beyond their initially estimated plant life. It also suggests that incentives or mandates to leave the market may be required if a greenhouse gas objective is sought whilst demand for thermal plant is flat or falling, so that an investible market for the remaining participants is maintained.

Finally, there may be challenges with evolving existing fleets towards this optimum. Namely, the simulations show that the RPS and a carbon price policies produce different signals for the exit of thermal generators. The carbon price clearly signals for more CCGT and the removal of coal generators, and always has similar or lower cost of abatement than the RPS policy. The RPS drives more VRG capacity, but does not differentiate between thermal generators. Therefore, the primary affect upon thermal generators is being moved up the merit order - which tends to impact the financial performance of gas rather than coal, as the former is more dependent upon scarcity pricing to cover its fixed costs.

4. Conclusion and Policy Implications

This paper examined the impact of progressively deeper levels of wind generation and/or abatement on the performance of both a wholesale electricity market and of individual, participating generators. Comparison is made to the result that competitive marginal pricing should induce investors to build the socially optimal capacity mix, since it is not clear that this result will hold in renewable-rich systems. The impact of both a Renewable Portfolio Standard and a carbon price is first considered in the capacity expansion (i.e. the planning) problem. The resulting fleets were then subjected to stochastic unit commitment, followed by conventional economic dispatch of the committed units.

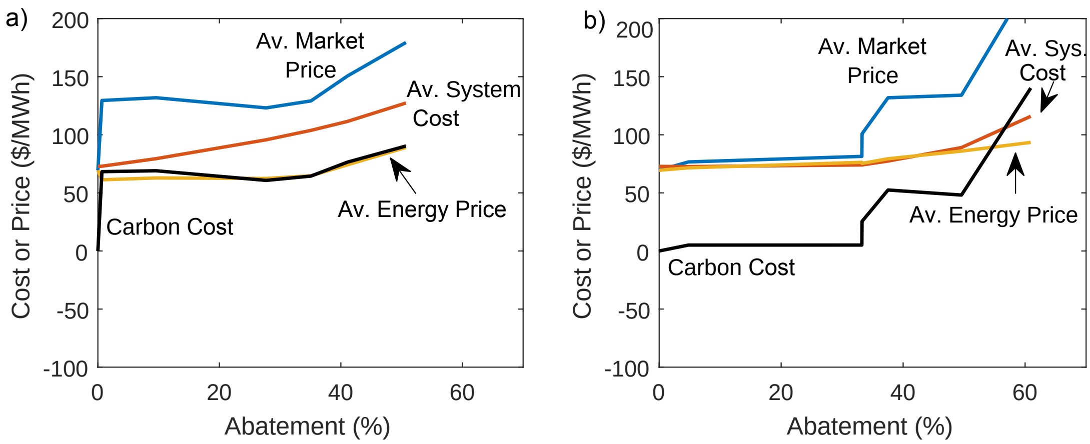

Figure 16: System costs, system wholesale energy price, and carbon price or REC costs for a) the Fixed Fleet and b) the Optimised Fleet.

It was found that unit commitment and renewable generation forecast uncertainty do not cause significant departure from this result when the generator fleet was optimal. 'Optimality' in this sense was determined in the capacity expansion problem that did not feature unit commitment, and which allowed thermal generators to be built or retired as greater renewable generation or abatement was mandated. In contrast, the wholesale market with a fixed thermal fleet experienced a progressively larger difference between total system prices and costs, as well as low rates of returns to thermal generators, as the level of renewable generation and/or abatement increased. This was simply because of over-capacity, with subsidised new build (and lack of capacity exit) depressing wholesale market prices for all thermal generators, and is consistent with conclusions drawn in other works.

Finally, the requirement that the fleet must be optimal in order for generators to receive adequate returns on investment from the wholesale market has implications for planning studies. This paper showed that such methods implicitly assume optimality of the fleet across the planning period, i.e. market prices result in adequate returns only if over-capacity leaves at no cost to the market. This suggests that incentives or even mandates for some plant to exit may be necessary if an emissions target is sought in a liberalised electricity market.

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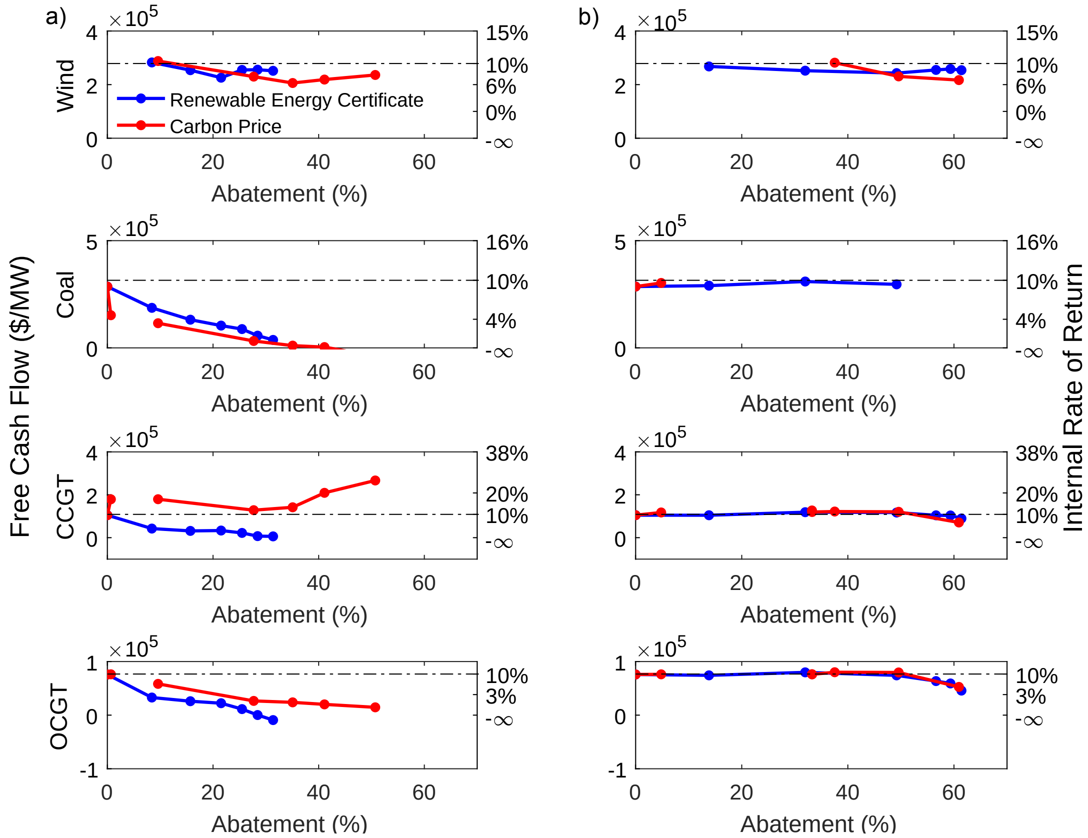

Figure 17: Plant free cash flow and corresponding Internal Rate of Return, for a) the Fixed Fleet and b) the Optimised Fleet for increasing abatement.

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Appendix A. Selected Nomenclature

Sets

$t \in \mathcal{T}$	Technologies.
$g \in \mathcal{G}$	Generators.
$w \in \mathcal{G}_W$	Wind generators.
$d \in \mathcal{G}_D$	Dispatchable generators.
$r \in \mathcal{R}$	Reserve types; primary up & down (pu,pd), secondary up & down (su,sd), tertiary up (tu).
$h \in \mathcal{H}$	Time (hours); 1,...,8760.
$i \in \mathcal{I}$	Time (hours); 1,...,48.
$s \in \mathcal{S}$	Scenarios.
$p \in \mathcal{P}$	Type of abatement polices (RPS or Carbon Price).
$x \in \mathcal{X}$	Level of abatement policy.

Parameters

E_i	Forecast error at hour i.
α	ARMA model parameter.
β	ARMA model parameter.
σ_z	ARMA model parameter.
Z_i	Random Gaussian variable.
$D_{sh},\ D'_{si}$	Electricity demand in hour h or i, in scenario s (MW).
$\overline{w}_{sh},\ \overline{w'}_{sig}$	Wind available in hour h or i for technology t or unit g, in scenario s, fraction of installed capacity.

P^{CP}	Carbon Price (\$/t$_{\mathrm{CO_2e}}$).
P^{REC}	Renewable Energy Certificate Price (\$/MWh).
P^{MPC}	Value of Lost Load (\$/MW).
d	Discount rate (%).
π_s	Probability of scenario s.
f^{QS}	Proportion of secondary reserves that may be provided by quick start reserves.
R_r	Quantity of reserves of type r that must be obtained (MW).
$W_{\%}$	Total wind available, as a percentage of total demand, assuming no curtailment (%).
Ab_{pf}	Abatement of a simulation, relative to the case with no climate policy (%).
M_s	Total yearly emissions ($\mathrm{t_{CO2}}$).
$\overline{P'_t}$, $\overline{P_g}$	Capacity of technology t or unit g (MW).
$c_t'^{\mathrm{Fuel}}$, c_g^{Fuel}	Fuel cost of technology t or unit g (\$/GJ).
$c_t'^{\mathrm{VOM}}$, c_g^{VOM}	Variable operating cost of technology t or unit g (\$/MWh).
$c_t'^{\mathrm{Capex}}$, c_g^{Capex}	Annualised capital expenditure for unit g (\$/MW).
c_g^{SU}	Cost of starting up for unit g (\$).
c_g^{SD}	Cost of shutting down for unit g (\$).
$c_t'^{\mathrm{FOM}}$, c_g^{FOM}	Yearly fixed operating costs for unit g (\$/MW).
$\eta'_{\mathrm{th},t}$, $\eta_{\mathrm{th},g}$	Thermal efficiency of technology t or unit g.
$\underline{P_g}$	Minimum stable generation of unit g (MW).
Q'_t, Q_g	Ramp rate of technology t or unit g (fraction of capacity per hour).
M_g^{up}	Minimum up time for unit g (hours).
M_g^{do}	Minimum down time for unit g (hours).
N_g^{up}	Initial number of hours that unit g must be online at the start of a commitment interval (hours).
N_g^{do}	Initial number of hours that unit g must be offline at the start of a commitment interval (hours).
$\overline{R'}_{tr}$, $\overline{R}_{gr}$	Reserve capability for reserve type r from technology t or unit g (MW).
e'_t, e_g	Emissions intensity of technology t or unit g ($\mathrm{t_{CO2}}$/MWh).
L_g	Operating life of unit g (years).
SRMC_g	Short-run marginal cost of producing electricity by unit g (\$/MWh).
LRMC_g	Long-run marginal cost of producing electricity by unit g (\$/MWh).
ASC	Long-run marginal cost of electricity production for entire system (\$/MWh).
$\mathrm{Rev_{sg}}$	Total revenue to generator g in a year (\$).
$\mathrm{Op.Costs_{sg}}$	Yearly operating costs for unit g (\$).
FCF_g	Yearly free cashflow for unit g (\$).
NPV_g	Net present value for unit g (\$)

Variables

$C^{\mathrm{GE}}_{\mathrm{Total}}$, $C^{\mathrm{UC}}_{\mathrm{Total}}$, $C^{\mathrm{ED}}_{\mathrm{Total}}$	Total cost in the generation expansion model, unit commitment and economic dispatch models (\$).
$C^{\mathrm{GE}}_{\mathrm{Build},st}$	Total annualised cost of building generating units of technology t in scenario s (\$).
$C^{\mathrm{GE}}_{\mathrm{FOM},st}$	Total fixed operating and maintenance costs for technology t, in scenarios s (\$).
$C^{\mathrm{GE}}_{\mathrm{Var},st}$, $C^{\mathrm{UC}}_{\mathrm{Var},sg}$, $C^{\mathrm{ED}}_{\mathrm{Var},sg}$	Total short run cost of producing electricity, for technology t or unit g in scenario s (\$).
$C^{\mathrm{GE}}_{\mathrm{Uns},s}$, $C^{\mathrm{UC}}_{\mathrm{Uns},s}$, $C^{\mathrm{ED}}_{\mathrm{Uns},s}$	Total cost of unserved energy and reserves in scenario s (\$).
$C^{\mathrm{GE}}_{\mathrm{CP},st}$, $C^{\mathrm{UC}}_{\mathrm{CP},sg}$, $C^{\mathrm{ED}}_{\mathrm{CP},sg}$	Total cost of carbon emissions produced by technology t or generator g in scenario s (\$).
$C^{\mathrm{GE}}_{\mathrm{REC},st}$, $C^{\mathrm{UC}}_{\mathrm{REC},sg}$, $C^{\mathrm{ED}}_{\mathrm{REC},sg}$	Total cost of purchasing RECs produced by technology t or generator g in scenario s (\$).
$C^{\mathrm{UC}}_{\mathrm{SU},sg}$	Total start up costs for generator g in scenario s.
$C^{\mathrm{UC}}_{\mathrm{SD},sg}$	Total shut down costs for generator g in scenario s.
$u^{\mathrm{GE,En}}_{sh}$, $u^{\mathrm{UC,En}}_{si}$, $u^{\mathrm{ED,En}}_{sh}$	Unserved energy in hour h or i, scenario s (MW).
$\hat{C}_{\mathrm{SU},shg}$	Start up cost incurred in hour i by unit g, in scenario s.
$\hat{C}_{\mathrm{SD},shg}$	Shut down cost incurred in hour i by unit g, in scenario s.
$u^{\mathrm{GE,Re}}_{shr}$, $u^{\mathrm{UC,Re}}_{sir}$, $u^{\mathrm{ED,Re}}_{shr}$	Unserved reserve of type ρ, in hour h or i, scenario s (MW).
I_t	Number of units of technology t built.
p^{GE}_{sht}, p^{UC}_{sig}, p^{ED}_{shg}	Power generated by technology t or unit g in hour h or i in scenario s (MW).
ρ^{GE}_{shtr}, ρ^{UC}_{sigr}, ρ^{ED}_{shgr}	Reserves of type r provided by technology t or unit g in hour h or i in scenario s (MW).
$p_{\mathrm{curt},shw}$, $p_{\mathrm{curt},siw}$	Wind power curtailed by technology t or unit g in hour h or i in scenario s.
U_{sig}	Commitment of unit g in hour i in scenario s (0 is off, 1 is off).
$\hat{U}_{ig}$	Commitment of inflexible unit g in hour i (0 is off, 1 is off).
μ^{En}_{sh}	Price of energy in hour h, scenario s (dual variable) (\$/MWh).
μ^{Re}_{shr}	Price of reserves of type r in hour h, scenario s (dual variable) (\$/M)

A star (*) on a variable denotes that this is optimal value of that variable in the solved program.

Appendix B. Formulation

Appendix B.1. Generation Expansion Sub-Model

The generation expansion sub-model decides the number of units of each plant type to be built and is based on the simple screening curve method. However, we include the time sequential nature of demand and intermittent renewables to allow for investment decisions, as well as reserves and generator ramping constraints. The objective function to be minimised is the total cost of building and operating generating units to meet demand, including the cost of any unserved energy or unserved reserves. Start up and shut down costs are not modelled, and unit commitment constraints are not included. The total cost is

$$C^{\mathrm{GE}}_{\mathrm{Total}} = \sum_{st} \pi_s (C^{\mathrm{GE}}_{\mathrm{Build},st} + C^{\mathrm{GE}}_{\mathrm{FOM},st} + C^{\mathrm{GE}}_{\mathrm{Var},st} + C^{\mathrm{GE}}_{\mathrm{CP},st} - C^{\mathrm{GE}}_{\mathrm{REC},st}) + \sum_s \pi_s C^{\mathrm{GE}}_{\mathrm{Uns},s}. \tag{B.1}$$

The build cost is

$$C^{\mathrm{GE}}_{\mathrm{Build},st} = c'^{\mathrm{Capex}}_t I_t \overline{P'_t}. \tag{B.2}$$

Similarly the Fixed Operating and Maintenance Cost is

$$C^{\mathrm{GE}}_{\mathrm{FOM},st} = c'^{\mathrm{FOM}}_t I_t \overline{P'_t}. \tag{B.3}$$

The production cost is

$$C^{\mathrm{GE}}_{\mathrm{Var},st} = \sum_h p^{GE}_{sht} (3.6 c'^{\mathrm{Fuel}}_t / \eta'_{\mathrm{th},t} + c'^{\mathrm{VOM}}_t). \tag{B.4}$$

The cost of unserved energy and unserved reserves is

$$C^{\mathrm{GE}}_{\mathrm{Uns},s} = P^{\mathrm{MPC}} \left[\sum_h u^{\mathrm{GE,En}}_{sh} + \sum_{hr} u^{\mathrm{GE,Re}}_{shr} \right]. \tag{B.5}$$

The carbon cost and value of renewable energy certificates are, respectively

$$C^{\mathrm{GE}}_{\mathrm{CP},st} = P^{\mathrm{CP}} \mathrm{e}'_t \sum_h p^{GE}_{sht}, \tag{B.6}$$

$$C^{\mathrm{GE}}_{\mathrm{REC},st} = 0 \qquad t \neq \text{wind}, \tag{B.7}$$

$$C^{\mathrm{GE}}_{\mathrm{REC},st} = P^{\mathrm{REC}} \sum_h p^{GE}_{sht} \qquad t = \text{wind}. \tag{B.8}$$

This cost function is minimized subject to the following constraints.

1) Generation plus any unserved energy must equal demand at all times,

$$\sum_t p^{GE}_{sht} + u^{\mathrm{GE,En}}_{sh} = D_{sh}, \tag{B.9}$$

2) Reserve requirements for the five types of reserves (primary up and down, secondary up and down, and quickstart/tertiary up) must be met:

$$\sum_t \rho^{GE}_{shtr} + u^{\mathrm{GE,Re}}_{shr} \geq R_r \qquad r \in \{\mathrm{pu, pd, sd}\}, \tag{B.10}$$

$$\sum_t \rho^{GE}_{shtr} + u^{\mathrm{GE,Re}}_{shr} \geq R_r (1 - f^{\mathrm{QS}}) \qquad r \in \{\mathrm{su}\}, \tag{B.11}$$

$$\sum_{r \in \{\mathrm{su,tu}\}} \left(\sum_t \rho^{GE}_{shtr} + u^{\mathrm{GE,Re}}_{shr} \right) \geq \sum_{r \in \{\mathrm{su,tu}\}} R_r. \tag{B.12}$$

3) The power from all units must be less than their capacity less any up reserves provided, and greater than any down reserve provided, wind units cannot produce more than the wind trace $\overline{w}_{sh}$.

$$p^{GE}_{sht} \leq \overline{P'_t} I_t - \sum_r \rho^{GE}_{shtr} \qquad r \in \{\mathrm{pu, su, tu}\} \qquad \forall t \in \mathcal{T}_D, \tag{B.13}$$

$$p^{GE}_{sht} \geq \sum_r \rho^{GE}_{shtr} \qquad r \in \{\mathrm{pd, sd}\} \qquad \forall t \in \mathcal{T}_D, \tag{B.14}$$

$$p^{GE}_{sht} \leq \overline{w}_{sh} \overline{P'_t} I_t \qquad t = \text{wind}. \tag{B.15}$$

4) Ramp rate constraints,

$$p^{GE}_{sht} \leq p^{GE}_{s(h-1)t} + \mathrm{Q}'_t, \tag{B.16}$$

$$p^{GE}_{sht} \geq p^{GE}_{s(h-1)t} - \mathrm{Q}'_t. \tag{B.17}$$

5) Limits on the amount of reserves that can be provided by technologies,

$$\rho^{GE}_{shtr} \leq \overline{R'}_{tr} \qquad . \tag{B.18}$$

Appendix B.2. Unit Commitment Sub-Model

The unit commitment sub-model determines the on/off status of generating units a day ahead of real time. It requires a binary 'commitment' variable, U_{sig} ($U_{sig} = 1$ indicates that unit g is online in hour h) for each dispatchable unit in each hour, and is therefore computationally challenging. Our formulation is based on Carrion & Arroyo, [36] and the reserves equations of Palmintier & Webster [37]. The cost function to be minimised is

$$C^{\mathrm{UC}}_{\mathrm{Total}} = \sum_{sg} \pi_s (C^{\mathrm{UC}}_{\mathrm{Var},sg} + C^{\mathrm{UC}}_{\mathrm{SU},sg} + C^{\mathrm{UC}}_{\mathrm{SD},sg} + C^{\mathrm{UC}}_{\mathrm{CP},sg} - C^{\mathrm{UC}}_{\mathrm{REC},sg}) + \sum_s \pi_s C^{\mathrm{UC}}_{\mathrm{Uns},s}, \tag{B.19}$$

with the components of this equation similar to Eqs. B.4 - B.8. Total start up and shut down costs are the sum of the respective costs incurred in each hour,

$$C^{\mathrm{UC}}_{\mathrm{SU},sg} = \sum_i \hat{C}_{\mathrm{SU},shg}, \tag{B.20}$$

$$C^{\mathrm{UC}}_{\mathrm{SD},sg} = \sum_i \hat{C}_{\mathrm{SD},shg}, \tag{B.21}$$

where

$$\hat{C}_{\mathrm{SU},shg} \geq c^{\mathrm{SU}}_g (U_{sig} - U_{s(i-1)g}) \tag{B.22}$$

and

$$\hat{C}_{\mathrm{SD},shg} \geq c^{\mathrm{SD}}_g (U_{s(i-1)g} - U_{sig}). \tag{B.23}$$

The cost equation is minimised subject to the following constraints:

1) Inflexible units (i.e. coal and CCGT) must have the same commitment in each scenario,

$$U_{sig} = \hat{U}_{ig} \qquad g \in \{\mathrm{coal, ccgt}\}. \tag{B.24}$$

2) Load must be met by generation plus any unserved energy

$$\sum_g p^{UC}_{sig} + u^{\mathrm{UC,En}}_{si} = D'_{si}. \tag{B.25}$$

Similarly, reserve requirements for the five types of reserves (primary up and down, secondary up and down, and quick-start/tertiary up) must be met:

$$\sum_g \rho^{UC}_{sigr} + u^{\mathrm{UC,Re}}_{sir} \geq R_r \qquad r \in \{\mathrm{pu, pd, sd}\}, \tag{B.26}$$

$$\sum_g \rho^{UC}_{sigr} + u^{\mathrm{UC,Re}}_{sir} \geq R_r(1 - f^{\mathrm{QS}}) \qquad r \in \{\mathrm{su}\}, \tag{B.27}$$

$$\sum_{r\in\{\mathrm{su,tu}\}} \left(\sum_g \rho^{UC}_{sigr} + u^{\mathrm{UC,Re}}_{sir} \right) \geq \sum_{r\in\{\mathrm{su,tu}\}} R_r. \tag{B.28}$$

3) Generator output constraints i.e. the power generated is less than capacity and greater than the minimum stable generation if a unit is committed and zero otherwise.

$$p^{UC}_{sig} + \sum_r \rho^{UC}_{sigr} \leq U_{sig}\overline{P_g} \qquad r \in \{\mathrm{pu,\ su,\ tu}\}, \tag{B.29}$$

$$p^{UC}_{sig} - \sum_r \rho^{UC}_{sigr} \geq U_{sig}\underline{P_g} \qquad r \in \{\mathrm{pd,\ sd}\}. \tag{B.30}$$

Equations (B.29) and (B.30) include headroom for reserves.

4) Ramp rate constraints

$$\begin{aligned} p^{UC}_{sig} \leq\, & p_{s(i-1)g} + Q_g U_{s(i-1)g} \\ & + \overline{P_g}(1 - U_{s(i-1)g}), \end{aligned} \tag{B.31}$$

$$\begin{aligned} p^{UC}_{sig} \geq\, & p_{s(i-1)g} - Q_g U_{s(i-1)g} \\ & - \overline{P_g}(1 - U_{sig}). \end{aligned} \tag{B.32}$$

5) Minimum up and down times for the start (B.33) - (B.34), middle (B.35)-(B.36) and end (B.37)-(B.38) of the optimization time interval:

$$\sum_{i=1}^{N^{\mathrm{up}}_g} U_{sig} \geq N^{\mathrm{up}}_g, \tag{B.33}$$

$$\sum_{i=1}^{N^{\mathrm{do}}_g} (1 - U_{sig}) \geq N^{\mathrm{do}}_g, \tag{B.34}$$

$$\sum_{j=i}^{i+M^{\mathrm{up}}_g-1} U_{sjg} \geq M^{\mathrm{up}}_g (U_{sig} - U_{s(i-1)g}) \qquad \forall ist.\ N^{\mathrm{up}}_g < i \leq |I| - M^{\mathrm{up}}_g + 1, \tag{B.35}$$

$$\sum_{j=i}^{i+M^{\mathrm{do}}_g-1} (1 - U_{sig}) \geq M^{\mathrm{do}}_g (U_{s(i-1)g} - U_{sig}) \qquad \forall i\ st.\ N^{\mathrm{do}}_g < i \leq |I| - M^{\mathrm{do}}_g + 1, \tag{B.36}$$

$$\sum_{j=i}^{|I|} (U_{sjg} - [U_{sig} - U_{s(i-1)g}]) \geq 0 \qquad \forall i\ st.\ i > |I| - M^{\mathrm{up}}_g + 1, \tag{B.37}$$

$$\sum_{j=i}^{|I|} ([1 - U_{sig}] - [U_{s(i-1)g} - U_{sig}]) \geq 0 \qquad \forall i\ st.\ i > |I| - M^{\mathrm{do}}_g + 1. \tag{B.38}$$

6) For wind plants, generation must be less than or equal to their available generation,

$$p^{UC}_{sig} \leq \overline{w'}_{sig}\overline{P_g} \qquad \forall g \in \mathcal{G}_W. \tag{B.39}$$

7) Units may not produce more reserves than their reserve capability:

$$\rho^{UC}_{sigr} \leq \overline{R}_{gr} U_{sig} \qquad r \in \{\mathrm{pu, pd, su, sd}\}, \tag{B.40}$$

$$\rho^{UC}_{sigr} \leq \overline{R}_{gr}(1 - U_{sig}) \qquad r \in \{\mathrm{tu}\}. \tag{B.41}$$

Appendix B.3. Economic Dispatch Sub-Model

The Economic Dispatch sub-model is used to obtain prices for energy and reserves. It is a linear re-formulation of the UC program with the commitment decisions U^*_{shg} are fixed. The objective function is

$$C^{\mathrm{ED}}_{\mathrm{Total}} = \sum_{sg} \pi_s \left(C^{\mathrm{ED}}_{\mathrm{Var},sg} + C^{\mathrm{ED}}_{\mathrm{CP},sg} - C^{\mathrm{ED}}_{\mathrm{REC},sg} \right) + \sum_s \pi_s C^{\mathrm{ED}}_{\mathrm{Uns},s}, \tag{B.42}$$

with the components defined similarly to Equations B.4 - B.8. The dual of the constraint requiring supply to equal demand (Eq. B.43) determines the energy price μ^{En}_{sh}, and the five reserve prices μ^{Re}_{shr} are determined by the duals of Eqs. B.44 - B.46.

1) Demand and reserve constraints,

$$\sum_g p^{ED}_{shg} + u^{\mathrm{ED,En}}_{sh} = D_{sh} \qquad (\mu^{\mathrm{En}}_{sh}), \tag{B.43}$$

$$\sum_g \rho^{ED}_{shgr} + u^{\mathrm{ED,Re}}_{shr} \geq R_r \qquad (\mu^{\mathrm{Re}}_{shr}) \qquad r \in \{\mathrm{pu,\ pd,\ sd}\}, \tag{B.44}$$

$$\sum_g \rho^{ED}_{shgr} + u^{\mathrm{ED,Re}}_{shr} \geq R_r(1 - f^{\mathrm{QS}}) \qquad (\mu^{\mathrm{Re}}_{shr}) \qquad r \in \{\mathrm{su}\}, \tag{B.45}$$

$$\sum_{r\in\{\mathrm{su,tu}\}} \left(\sum_g \rho^{ED}_{shgr} + u^{\mathrm{ED,Re}}_{shr} \right) \geq \sum_{r\in\{\mathrm{su,tu}\}} R_r \qquad (\mu^{\mathrm{Re}}_{sh(\mathrm{tu})}). \tag{B.46}$$

2) Generator output constraints,

$$p^{ED}_{shg} + \sum_r \rho^{ED}_{shgr} \leq U^*_{shg}\overline{P_g} \qquad r \in \{\mathrm{pu,\ su,\ tu}\}, \tag{B.47}$$

$$p^{ED}_{shg} - \sum_r \rho^{ED}_{shgr} \geq U^*_{shg}\underline{P_g} \qquad r \in \{\mathrm{pd,\ sd}\}. \tag{B.48}$$

3) Ramp rate limits,

$$\begin{aligned} p^{ED}_{shg} \leq\, & p^{ED}_{s(h-1)g} + Q_g U^*_{s(h-1)g} \\ & + \overline{P_g}(1 - U^*_{s(h-1)g}), \end{aligned} \tag{B.49}$$

$$\begin{aligned} p^{ED}_{shg} \geq\, & p^{ED}_{s(h-1)g} - Q_g U^*_{s(h-1)g} \\ & - \overline{P_g}(1 - U^*_{shg}). \end{aligned} \tag{B.50}$$

4) For wind plants, generation must be less than or equal to their available generation,

$$p^{ED}_{shg} \leq \overline{w}_{shg}\overline{P_g} \qquad \forall g \in \mathcal{G}_W, \tag{B.51}$$

5) Units may not produce more reserves than their reserve capability,

$$\rho^{ED}_{shgr} \leq \overline{R}_{gr} U^*_{shg} \qquad r \in \{\mathrm{pu, pd, su, sd}\}, \tag{B.52}$$

$$\rho^{ED}_{shgr} \leq \overline{R}_{gr}(1 - U^*_{shg}) \qquad r \in \{\mathrm{tu}\}. \tag{B.53}$$