Does wind need 'back-up' capacity?

Modelling the system integration costs of 'back-up' capacity for variable generation

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***Abstract*—A model of the Australian National Electricity Market (NEM) is used to explore the concept of 'back-up' capacity associated with the introduction of wind generation to an electricity market. Wind is found to primarily displace base-load capacity in the optimal (least cost) generation mix, shifting investment towards intermediate plant that operates more profitably at lower capacity factors. Rather than adding additional system costs to maintain resource adequacy, it is found that the introduction of wind produces significant cost *reductions* in the balance of system, partly due to avoided fuel and operational costs, and partly by allowing investment in less capital intensive plant. Savings may be as high as $2.9 billion pa (24% of total annual costs) with the introduction of 25GW of wind capacity to the NEM, in scenarios with high plant turnover (due to demand growth or large expected retirements). Thus, of the $4.9 billion pa invested in constructing the 25GW of wind capacity, 59% may be offset by the reduction in the balance of system costs. In scenarios where the installed capacity in the balance of system remains fixed due to sunk costs, savings are slightly smaller at $2.3 billion, or 19% of annual costs. Thus, the concept of 'back-up' capacity associated with wind generation appears to be flawed.**

I. Introduction

The question of wind integration costs has received much attention in the past several years [1]. The fundamental idea is to allow an estimation of the costs that are imposed on the power system by accommodating wind power, so that policy makers can be fully informed of the system-wide costs and benefits of introducing policy and regulatory mechanisms that support this particular technology. Similar attention is now being placed on solar integration costs as the deployment of photovoltaics grows rapidly.

While "integration costs" might initially appear to be a straightforward concept, it is becoming increasingly apparent that it is highly complex to calculate industry costs related to the "integration" of a new technology in isolation from the details of that system, and even more challenging to allocate costs incurred to a single resource type [1]. The industry-wide costs and benefits of a particular generation technology depend upon the integrated operation of the electricity industry as a whole, including its interaction with other generation sources in the system. Commonly used cost metrics such as the levelised cost of energy (LCOE) do not capture these dependencies.

For example, if wind generation is added to a power system composed of predominantly fossil-fuel plant it is likely to increase the cycling of that plant, adding to cycling costs. This is often referred to as part of the integration cost attributable to wind generation. However, adding a new base-load generator to this same system is *also* likely to increase the cycling of existing plant, by shifting them upwards in the merit order. Thus, *any* type of new entrant is likely to increase the costs of cycling for existing plant in the system. However, policy and regulatory focused discussions around integration costs generally don't consider such costs, or attempt to attribute them to the new entrant thermal unit [1].

The application of the "causer pays" principle is even more problematic in this case, since it is questionable whether the new entrant should be considered to "cause" these additional cycling costs. Cycling costs only arise because inflexible thermal plant have high costs associated with the cycling process; wind plant are highly flexible and do not suffer from the same problem. Therefore, it could equally be argued that the inflexible existing plant with high costs per cycle are responsible for imposing these additional costs on the system, due to their inflexibility. This could even be argued to be a preferable way to internalize system costs, since inflexible thermal units are presumably in the best position to make decisions around the upgrade of their plant to minimize such costs.

In reality, both points of view are reasonable. The costs are caused by the system *as a whole*, and cannot be attributed to any particular participant. Ideally, variable generators and loads that add net load fluctuations to a system would internalize the costs associated with that increased variability, encouraging smoother operation if economically efficient. Similarly, inflexible generators with high cycling costs should be exposed to those costs, encouraging upgrades and operational changes to minimize them, if economically efficient. Designing a market that achieves this is non-trivial.

An ideal electricity market will have prices that reflect all of the industry-wide costs and benefits that different participants bring to the market, and incentivize these participants to invest in and operate their generation in ways that maximize net system benefit. In practice, the fidelity of commercial arrangements to underlying industry economics varies greatly between jurisdictions. In many industries, a range of system-wide economic costs and benefits are not reflected in current market arrangements. Striving to improve the internalization of relevant costs is useful, but in order to avoid perverse consequences it is ideally introduced in a technology neutral manner that focuses on performance, rather than arbitrary distinctions.

Integration costs associated with variable renewable technologies are often considered to include a range of aspects, such as:

- The cost of additional operational/flexibility reserves to manage the variability and uncertainty of wind and solar generation.
- The costs of additional transmission and connection assets.
- 'back-up' capacity.

This paper focuses on 'back-up' capacity. The concept of 'back-up' capacity suggests that since wind and solar technologies have variable availability, they need to be matched by a quantity of firm capacity (such as open cycle gas turbines) when introduced to a power system. This kind of integration cost is most often considered when attempting to provide a "fair" economic comparison of the LCOE of variable and firm technologies.

In practice, the concept is problematic. In the shorter-term, when renewables are introduced into an electricity industry that has sufficient firm generation to meet demand, 'back-up' costs are very low or zero [2]. The system had sufficient firm capacity to begin with, and adding wind generation does not *increase* the firm capacity requirement[1].

In the long term the generation mix could be expected to change as old capacity retires and is replaced, and variable generation will optimally be partnered with some kind of firm capacity. It would be very expensive to compose a power system entirely of variable generation and meet a required reliability standard; a very large over capacity would be required, with substantial spilling of energy. It is likely to be much more cost effective to construct a power system with a mix of firm capacity and variable generation. Thus, wind capacity is optimally "matched" in some sense by a quantity of firm capacity.

However, note that it is also not optimal to compose a system entirely of base-load generation, such as nuclear power. This would be a very expensive way to meet a normal load profile, with some nuclear plant necessarily operating as peaking generation. This may not even be technically possible, given the inflexibility of most nuclear plant. Thus, it could be argued that nuclear plant similarly must be "matched" in a system with a quantity of peaking generation. Yet this is not typically considered an "integration" cost of introducing nuclear generation to a system.

This subtlety often is not recognized in studies comparing "system integration" costs of variable renewables and other generation types. For example, a 2012 OECD report on nuclear energy and renewables states [2, p. 31] that for longer-term studies of capacity adequacy, a suitable 'ex-ante' analysis approach "considers a country's energy system a clean slate, where the installed capacity of variable renewables needs to be matched by nearly equivalent amounts of dispatchable capacity", but an equivalent approach is not applied to nuclear generation.

This study calculated system integration costs for a range of technologies and found that "system costs for the dispatchable technologies are relatively modest and usually below USD 3/MWh. They are considerably higher for variable technologies and can reach up to USD 40/MWh for onshore wind…and up to USD 80/MWh for solar" [2]. In their analysis the majority of system integration costs related to variable renewable technologies fall within this category termed "'back-up' costs (adequacy)", which quantifies the cost of maintaining firm capacity to match the capacity of installed wind or solar generation. The implication is that to compare variable renewables and nuclear power on an equal footing, these additional 'back-up' costs (and other integration costs) must be added to the long run marginal costs of renewable technologies. The authors also propose that "regulatory frameworks to minimize system costs and favour their internalization" be prepared, with a particular focus on internalizing system costs for balancing (variability) and adequacy ('back-up' capacity). This appears to imply that the authors suggest variable renewable technologies should face additional "fees" or charges that internalize these system costs, including the cost of maintaining additional 'back-up' capacity to maintain system adequacy.

However, there are some significant questions regarding the concept, in both theory and practice. The limitations of using estimated LCOEs for particular technologies in electricity industry planning and investment are well appreciated. Adjusting these with some measure of additional system-related costs requires assumptions about the rest of the electricity generation mix. For longer-term studies, assuming a 'clean slate' electricity industry, the assumptions required are significant and must be made amidst high uncertainty.

There are also practical questions. For example, future electricity industries will likely see installed wind and solar capacity significantly higher than total system demand [3]. Does all of this capacity (minus some estimated capacity credit) still require 'back-up'? Also, would 'back-up' be provided through gas turbines as suggested in [2] or, instead, might demand-side options represent a lower cost future option? [4]

This paper aims to examine this particular aspect of system integration costs related to 'back-up' capacity by calculating changes in whole of system costs as wind is added, with a particular focus on the total system capacity, and the optimal mix of generation that would be partnered with wind generation. It applies conventional optimal generation mix

[1] Flexibility requirements such as additional reserves are ignored in this analysis.

techniques which, while relatively simple, remain a valuable method for exploring 'clean slate' future electricity industry options. It also, as we demonstrate, permits detailed consideration of the potential system costs of high renewable penetrations in terms of generation capacities (hence investment) without the need to consider highly abstracted and problematic concepts such as 'back-up'.

This paper does not address integration costs related to managing the variability and uncertainty of variable renewables. These aspects of renewable integration are typically managed via the maintenance of various kinds of operating reserves which ensure sufficient flexibility to respond to short term variations in wind, solar and demand. These system integration costs are usually quantified separately from 'back-up' integration costs, and are not the topic of this paper, but have been discussed elsewhere [5, 1].

II. Model Description

The model applied in this study uses conventional deterministic load duration curve methods to calculate the least cost installed mix of firm capacity technologies depending upon the cost profiles (capital and operating) of those plant, and a given demand profile.

The model calculates the total annual costs of each firm capacity technology available, as a function of the number of hours of the year that it operates, as illustrated in Figure IV.1 (A). This is then mapped onto the load duration curve, with the lowest cost technology selected to supply the load at each capacity factor, as illustrated in Figure IV.1 (B). The least cost optimal capacity installed for each technology was then calculated from the vertical axis representing demand (GW).

Unserved Energy (USE) was included as another "technology type", with zero fixed costs, and a short run marginal cost (SRMC) at the market price cap (MPC). The MPC was adjusted to set the amount of USE to the reliability standard of the system (in this study assumed to be 0.002% USE per annum, as currently applied in the Australian NEM).

Wind generation was modelled as an hourly aggregate generation trace, sourced from modelling results by Elliston et al. [3]. Generation was scaled to the appropriate amount for the relevant simulation. Total wind generation in the NEM in each hour was subtracted from the demand in the relevant hour, prior to calculation of the (net) residual demand duration curve. The total capacity of wind installed was iteratively adjusted by scaling the aggregate wind trace to minimize total system costs, or was set to the desired level of installed wind for the relevant scenario.

The model is broadly designed to represent the technology options and market design of the Australian NEM. However, the model does not capture many of the complexities of this market, and in particular does not attempt to represent plants with energy storage such as hydro, incumbent plant and operational constraints such as minimum operating levels, ramp rates or unit commitment timeframes and costs. It is entirely deterministic with no consideration of the uncertainties inherent in demand, plant performance or costs. Nor does it consider the full spectrum of technologies that may be available in future. Transmission and distribution networks are not modelled. Nevertheless, it does still provide a simple way to assess the validity of some of the 'back-up' cost methodologies being deployed in other studies.

III. Assumptions

The hourly demand profile in the NEM in the calendar year 2010 was applied as the load duration curve. Wind generation was based upon generation by existing wind farms in the NEM in 2010, to ensure realistic representation of the correlation with demand.

Technology costs were sourced from the Australian Government's 2012 Energy Technology Assessment (AETA) [6], applying a 5% discount rate (following [3]). The fixed operations and maintenance (FOM) costs for wind were updated with new values in the 2013 AETA report. Cost assumptions are listed in Table I. Short run marginal costs (SRMC) include variable operations and maintenance (VOM) costs, and fuel costs. Coal-fired plant is based upon a pulverized coal supercritical plant operating on bituminous coal. Combined cycle gas turbines (CCGT) are based upon a single F class turbine with 3 pressure reheat heat recovery steam generator. Open cycle gas turbines (OCGT) are based upon a 2F Class gas turbine. Wind technology is based upon a 100MW on-shore wind farm.

TABLE I. Cost Assumptions (unless otherwise stated)

	Capital + FOM ($/MW/yr)	**SRMC ($/MWh)**
Wind	197,080	0
Coal	253,721	26
CCGT	79,085	48
OCGT	51,032	84
USE (MPC)	-	4,300

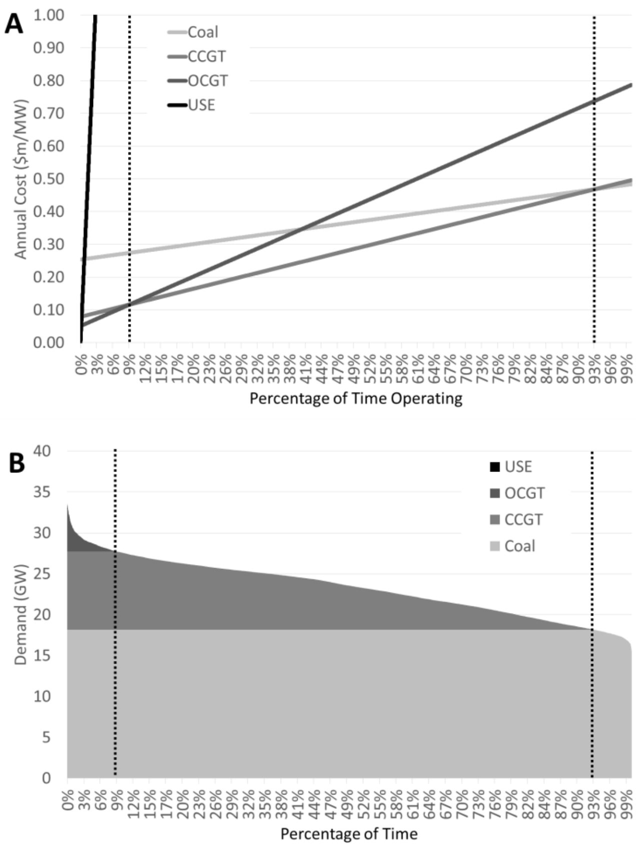
No carbon price was applied (unless otherwise stated), and the gas price was assumed to be $6/GJ, with a 20% uplift for the lower capacity factor OCGTs, representing their lower purchasing power. All costs are in real 2012 Australian dollars (AUD) throughout.

IV. Results

Figure IV.1 illustrates model results for the reference scenario with no wind generation. This is the least cost optimized generation mix based upon the assumptions listed in the previous section. In the absence of a carbon price, or pricing of other externalities, at present the inclusion of wind generation increases total system costs, due to the relatively higher cost of wind technology compared with fossil fuel technologies. The least cost generation mix to meet this demand profile includes 18 GW of coal-fired plant, 9.5 GW of CCGT, and 5.2 GW of OCGT. Note that uncertainty has not been taken into account in this analysis; in a real power system an additional reserve margin would be maintained to ensure adequate capacity in the event of higher than anticipated demands or generator forced outages. This reserve could be maintained in the form of additional OCGT plant which would be expected to operate very infrequently.

In many power systems, although wind generation (and other renewable technologies) are more expensive than other alternatives, they are being supported by additional subsidies and mechanisms to drive investment. Thus, the next scenario considers a situation where external mechanisms have supported the development of 12.5 GW of wind generation. In this scenario wind generation is providing 15% of annual energy. The optimal generation mix to meet the resulting net demand profile is illustrated in Figure IV.2. In this scenario, the optimal least cost capacity of coal-fired generation has reduced to 13.4 GW, while the least cost capacity of CCGT has *increased* to 12.3 GW. The capacity of OCGT plant has also increased slightly to 5.4 GW.

Figure IV.1 - Least cost optimized results for No Wind Scenario



The third scenario considers the situation where a larger quantity of wind is supported to enter the system. In this case, 25 GW of wind supplies 29% of annual energy. The least cost generation mix for the resulting net demand profile is illustrated in Figure IV.3. In this scenario, the optimal capacity of coal generation is reduced further to 7.5 GW, while the optimal capacity of CCGT plant has increased further to 17 GW. The capacity of OCGT plant has increased slightly to 5.9 GW. These results are summarized for each scenario in Table II, and illustrated in Figure IV.4.

Figure IV.2 - Least cost optimized results for Low Wind Scenario (12.5GW wind installed)

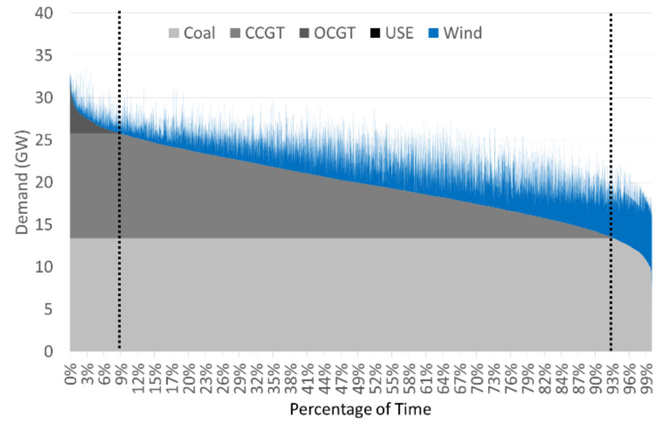
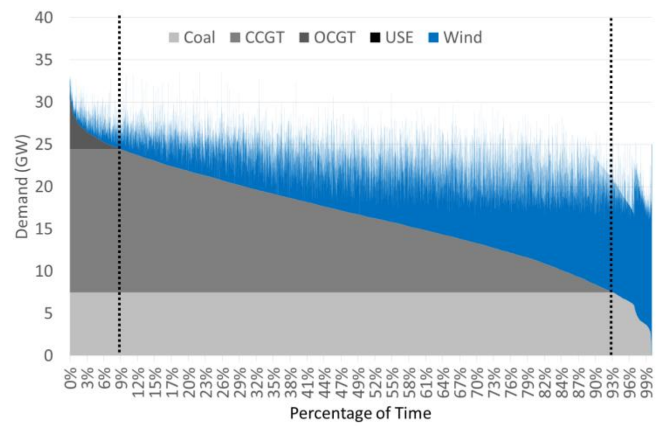


Figure IV.3 - Least cost optimized results for High Wind Scenario (25GW wind installed)

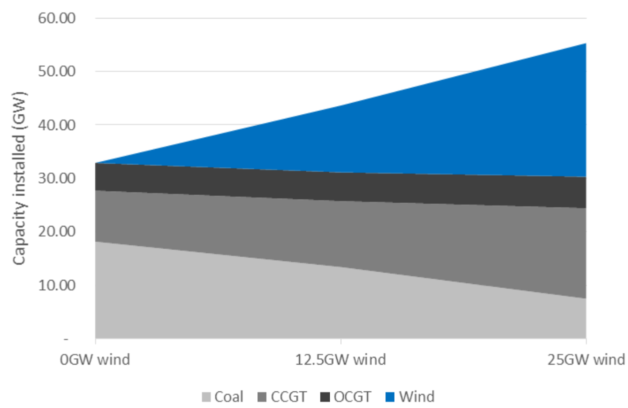


Note that anomalies in the right hand side of the wind generation curve are present in the original wind data collected from operating wind farms, and are thought to be due to curtailment during low demand periods.

TABLE II. LEAST COST OPTIMISED CAPACITIES BY SCENARIO (GW)

	No wind	**Low wind scenario**	**High wind scenario**
Wind	0.0	12.5	25.0
Coal	18.2	13.4	7.5
CCGT	9.5	12.3	16.9
OCGT	5.2	5.4	5.9
Total (incl. wind)	32.9	43.6	55.3
Total (excl. wind)	32.9	31.1	30.3

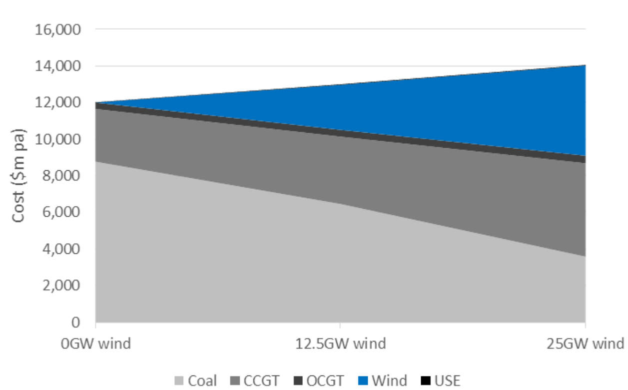
Figure IV.4 - Least cost optimized capacity of each technology installed in each wind scenario



The evolution of optimal least cost generation mix as more wind is introduced to the system is illustrated in Figure IV.4. As the capacity of wind increases, the primary effect is that base-load coal-fired generation is displaced by intermediate CCGT plant. The optimal capacity of peaking OCGT capacity remains relatively unchanged (demonstrating a slight increase). Thus, these results suggest that the primary effect of introducing variable renewable generation to a system is to shift the optimal generation mix away from base-load capacity, and towards intermediate type technologies that are more economical to operate at lower capacity factors.

The evolution of system costs as more wind generation is added to the system is illustrated in Figure IV.5. With no wind installed, the majority of system costs are in the capital repayments and operation of coal-fired plant. However, as more wind is installed, these costs shift to being primarily in the capital repayments and operating expenditure of operating CCGT plant. Total system costs (including capital repayments for wind capacity) grow as more wind is added to the system because at present wind generation is relatively more expensive than fossil fuel technologies (in the absence of pricing of environmental externalities such as greenhouse emissions).

Figure IV.5 – System costs in each wind scenario



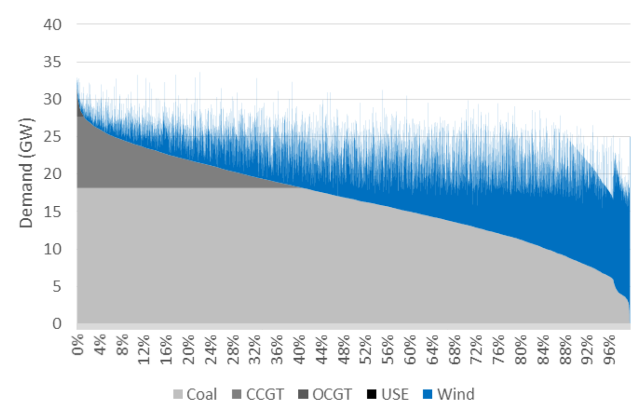
Wind generation acts to significantly reduce the balance of system costs (the total system costs, minus the costs related to the wind generation itself). Adding 12.5GW of wind reduces total system costs from $12 billion pa to $10.5 billion pa, a reduction of $1.5 billion, or 12%. Increasing the wind penetration further to 25GW reduces total system costs for the balance of system by $2.9 billion, a reduction of 24%. Thus, of the $4.9 billion pa invested in constructing the 25GW of wind capacity, 59% is offset by the reduction in the balance of system costs.

A. *Sunk costs of existing assets*

Note that the previous analysis does not take into account the sunk costs in the existing power system. Where generating assets already exist, these sunk costs act as a barrier to exit and entry, and slow the movement to a new equilibrium least cost generation mix. Thus, the savings would be lower in the case of adding wind to an existing system, and would be related to the displacement of fossil fuel operating costs.

The savings in this case have been calculated by assuming that the installed capacities in the balance of system remain constant as wind is added. This is illustrated in Figure IV.6 for the case with 25GW of wind added. This can be compared with Figure IV.3, where the installed capacities in the balance of system are allowed to freely move to the new least cost generation mix.

Figure IV.6 – Dispatch in High Wind Scenario (25 GW of wind installed), assuming the installed capacity of the balance of system remains fixed as wind is added



The evolution of system costs are illustrated in Figure IV.7, showing how system costs change as more wind is added to the system, if the installed capacity in the balance of system is not allowed to change. This can be compared with Figure IV.5, where the capacities were allowed to move to the new least cost equilibrium generation mix.

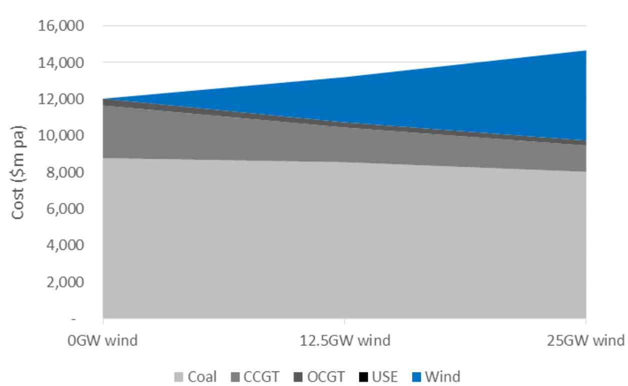
It is apparent in the comparison of Figure IV.7 and Figure IV.5 that the savings in the balance of system are somewhat lower in this case, because the benefit of reducing capital expenditure on capital intensive base-load plant is not available. However, the costs do still reduce in the balance of system as more wind is added, due to reduced operating and fuel costs for the balance of system.

When the installed capacities in the balance of system are held fixed, the costs for the balance of system reduce by 11% with 12.5GW wind installed and by 19% with 25GW wind installed. Thus, of the $4.9 billion pa invested in constructing the 25GW of wind capacity, 46% is offset by the reduction in the balance of system costs, even when the installed capacity in the balance of system remains fixed.

Note that in this situation the savings are primarily due to reduced operation of CCGT plant, which has a relatively high short run marginal cost of $48/MWh (at a $6/GJ gas price). While coal generation produces 18% less energy when 25GW of wind is introduced, CCGT is much more strongly affected, producing 68% less energy. This is unlike the previous case where coal-fired plant produced 59% less energy upon the introduction of 25GW of wind, and CCGT plant produced 77% *more* energy (since a significantly larger capacity of CCGT plant was installed).

OCGTs are also strongly affected, producing 88% less energy when 25GW of wind is added (if the installed capacities remain fixed). In a real market peaking plant such as OCGTs would generally receive the majority of revenues via the sale of cap contracts. If the incidence of price spikes is reduced, the value of these cap contracts would be reduced over the medium term, reducing the profitability of OCGT plant. Over the long term the market might be expected to adjust with retirements, causing the return of the incidence of price spikes to close to the previous equilibrium level, and the value of cap contracts might be expected to return to close to previous levels.

Figure IV.7 – System costs in each wind scenario, with installed capacity of balance of system remaining fixed as more wind is added



There will be additional savings in a power system with expected demand growth (or retirement of generating capacity), due to the changed decisions on the type of new capacity to be installed. If it is know that wind capacity has been or will be installed, it is possible to install lower capital cost intermediate or peaking generation (rather than high capital cost base-load plant), creating a higher saving for the balance of system. The magnitude of this saving could be calculated in net present value terms by discounting it over the number of years before new capacity investment would have been required. Savings will be higher in high demand growth systems.

Thus, the savings for the balance of system for a particular system of interest will be between these two extremes illustrated in Figure IV.5 (maximum savings, assuming the system can fully move to new equilibrium least cost generation mix) and Figure IV.7 (minimum savings, assuming the system cannot move at all to new equilibrium least cost generation mix, and there is no demand growth or retirements).

B. Capacity Value (credit) of Wind

This analysis uses a net demand profile, such that wind generation is taken into account in the calculation of the balance of system capacity required to meet the reliability standard. Thus, if wind generation is contributing meaningful amounts of generation at times of high demand, the model will install a correspondingly smaller amount of firm capacity. The amount by which the firm capacity requirement is reduced could be interpreted as the "capacity value" of the wind generation, since it has reduced the system capacity requirement by that amount.

In this modelling, when 12.5GW of wind generation was added to the system, the capacity requirement for the balance of system was found to be reduced by 1.8 GW. Thus, the wind generation was found to have a capacity value of 14% of its nameplate capacity. When 25GW of wind was installed, the balance of system capacity requirement was reduced by 2.6GW, or 10% of the nameplate capacity of the installed wind. These values are consistent with those found in previous studies [7]. It is also consistent with previous analysis to find that the capacity value of wind reduces as larger quantities of wind are installed.

Best practice methodologies for determining the capacity value of wind and examining issues related to power system reliability dictate the necessity of considering multiple years of data. This analysis considers data from only a single year (2010) and therefore is not adequate for assessing long term power system capacity requirements or for accurately determining the capacity value of wind over the long term.

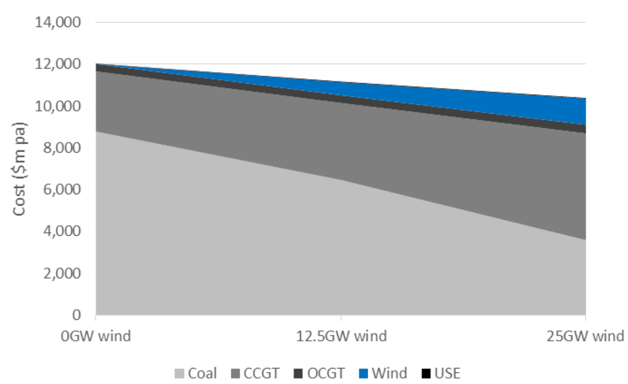
To explore a more conservative approach, the analysis can be repeated by considering the capacity value of wind to be zero, and including a larger quantity of peaking OCGT reserve plant. In the Low Wind Scenario (with 12.5GW of wind installed) an additional reserve of 1.8GW of OCGT plant would be required, and in the High Wind Scenario (with 25GW of wind installed) an additional reserve of 2.6GW of OCGT plant would be required. This maintains the total system capacity of "firm" plant at 33GW, as in the scenario with no wind installed. This is found to add capital repayments of $90 million pa in the Low Wind Scenario, and $132 million pa in the High Wind Scenario. This increases total system costs by 0.7% and 0.9% respectively. Thus, consumers in this system could expect retail tariffs to increase by a correspondingly small amount if this additional reserve plant was considered to be required by a conservative system operator. Also note that this amount is far smaller than the balance of system cost savings created by the introduction of wind generation. Wind generation reduces the balance of system costs by $1.5 billion and $2.9 billion in the Low and High Wind Scenarios respectively. Thus, even if additional reserves are considered to be required to maintain the original system firm capacity, the cost of maintaining these reserves would only erode the savings from introducing wind by 5-6%. Therefore, even in this conservative case, of the $4.9 billion invested in installing wind generation, 56% of that cost is saved by reduced fuel and operating expenditure, and reduced capital cost for the balance of system.

V. Sensitivities

A. *Systems with cheaper wind generation*

Due to the higher cost of wind generation at present, a system without a carbon price or other subsidies to support renewable development would not include wind in the least cost generation mix. Thus, the scenarios above assumed an external subsidy of some type that supported the entry of wind generation to the prescribed amounts in each scenario.

Figure V.1 – System costs in each wind scenario with wind generation available at $50,000/MW/yr



Alternatively, it is possible to envision a future system where wind costs have fallen such that wind would be included in the least cost generation mix. For example, consider a scenario where wind generation is available at a total fixed cost of $50,000/MW/year (as opposed to $197,080/MW/year as modelled in the previous scenarios). In this case, total system costs decline as more wind is installed (at the quantities considered here), as illustrated in Figure V.1.

With the parameters defined in this modelling, 25GW of wind is the optimal (least cost) capacity when wind technology has a fixed cost of $112,000/MW/year, and 12.5GW of wind is the optimal (least cost) capacity at a fixed cost of $114,000/MW/year. At any cost more than $132,000/MW/year, no wind is included in the least cost generation mix (assuming no carbon price is applied). Thus, substantial cost reductions are required for wind technology before it will be competitive in the absence of a meaningful carbon price.

B. *Systems without coal-fired generation*

This sensitivity considers a hypothetical situation where there is no coal-fired generation available. All energy is supplied from a combination of CCGT, OCGT and wind generation. Cost assumptions are identical to the above scenarios.

In this sensitivity, the entry of wind generation displaces CCGT plant, shifting it to OCGT capacity. As 25GW of wind is added to the system, the least cost capacity of CCGT decreases by 3.3GW, while the least cost capacity of OCGT increases by 1.1GW.

Thus, the entry of wind generation will not always act to increase the least cost capacity of CCGT included in the system, as observed in the previous scenarios. Rather, *wind acts to displace base-load capacity*, and increases the amount of intermediate and peaking plant in the least cost generation mix.

Figure V.2 – Capacity installed in a sensitivity with no coal-fired generation

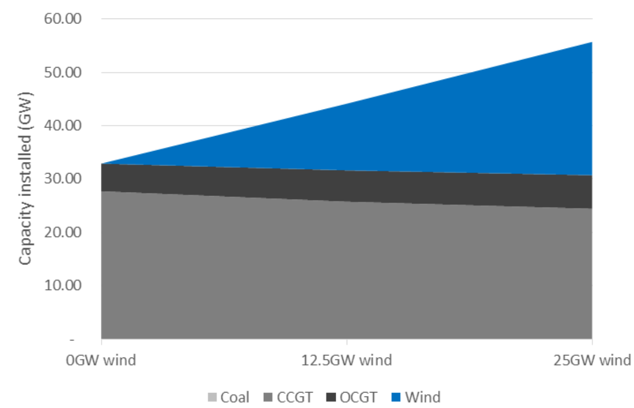
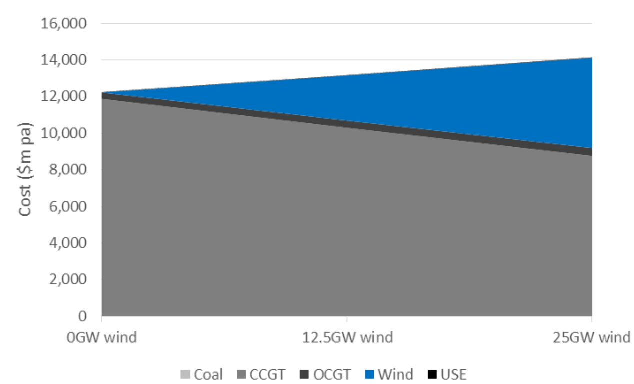


Figure V.3 – System costs in a sensitivity with no coal-fired generation



C. *Systems with higher gas prices and carbon pricing*

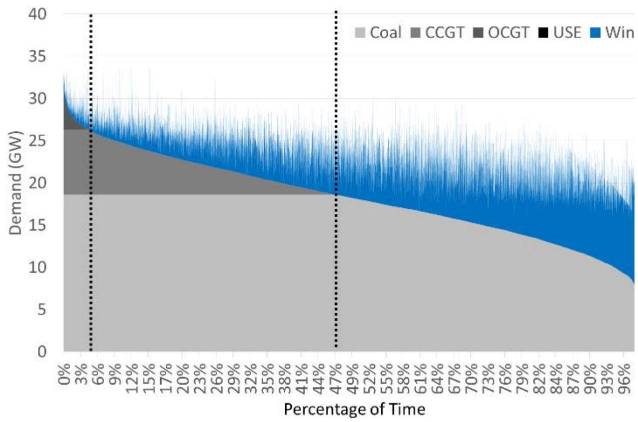
All scenarios thus far have assumed a gas price of $6/GJ. However, the east coast of Australia is rapidly developing major liquefied natural gas (LNG) export facilities that are likely to cause the domestic price of gas to rise to international parity in the near future [8]. Thus, gas prices are projected to rise to around $12/GJ by 2030, or possibly to as high as $16/GJ [6].

Australia has a national carbon pricing scheme, although the present Government has pledged to repeal the relevant legislation [9]. It remains unclear when or if this may happen. Thus, the future of carbon pricing remains highly uncertain in Australia. Over the long term it is assumed that some mechanism to significantly reduce greenhouse emissions from the electricity sector is likely.

To explore the impacts of higher gas prices and carbon pricing on the least cost generation mix, a gas price of $12/GJ was applied with a carbon price of $55/t$CO_2$-e. All other cost assumptions are identical the previous scenarios in this paper for ease of comparison.

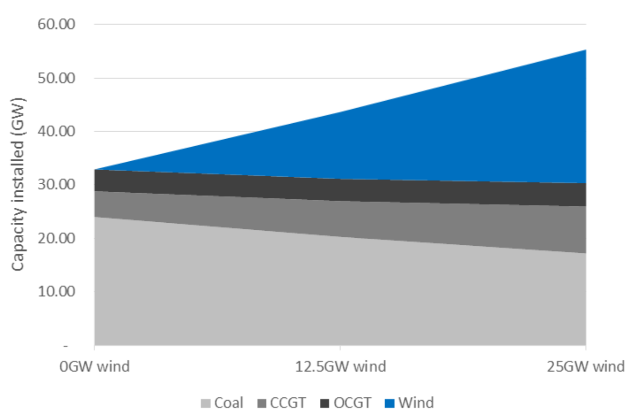
In this sensitivity, wind generation enters the least cost generation mix without additional subsidies, with 19GW being included. The least cost generation mix also includes 18.6GW of coal-fired generation, 7.8GW of CCGT, and 4.4 GW of peaking OCGT generation, as illustrated in Figure V.4.

Figure V.4 – Least cost generation mix with \$12/GJ gas price and \$55/tCO_2-e carbon price



With these cost assumptions, as the level of wind penetration increases to 25GW, 6.8 GW of coal-fired generation is displaced. This is partially replaced with an increase of 4GW of CCGT and 300MW of OCGT plant, as illustrated in Figure V.5. The least cost optimized capacities of each technology at various wind penetrations are listed in Table III. Due to the relatively high cost of gas, coal-fired generation is favored (compared to the previous scenarios depicted in Table II), despite the moderate carbon price.

Figure V.5 – Least cost generation mix at various wind penetration levels with \$12/GJ gas price and \$55/tCO_2-e carbon price

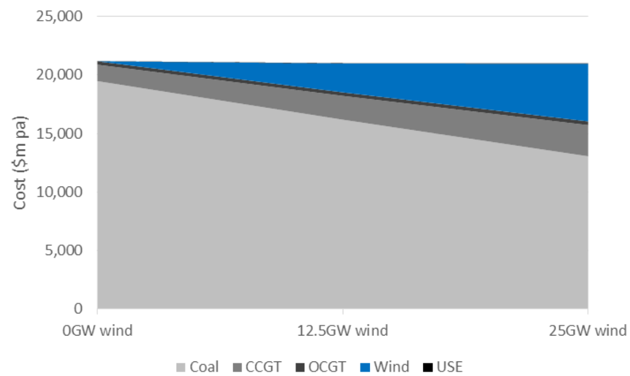


Total system costs decline with the introduction of wind (at the levels considered) as illustrated in Figure V.6. With the high gas price and moderate carbon price in this scenario, wind generation is an economically attractive alternative that reduces total system costs. Similarly to previous scenarios, wind acts to displace base-load coal-fired capacity, shifting investment towards intermediate CCGT plant.

TABLE III. LEAST COST OPTIMISED CAPACITIES BY SCENARIO (GW), WITH \$12/GJ GAS PRICE AND \$55/tCO_2 CARBON PRICE

	No wind	**Low wind scenario**	**High wind scenario**
Wind	-	12.5	25.0
Coal	24.0	20.3	17.2
CCGT	4.8	6.7	8.8
OCGT	4.1	4.2	4.4
Total (incl. wind)	32.9	43.6	55.3
Total (excl. wind)	32.9	31.1	30.3

Figure V.6 – System costs at various wind penetration levels with \$12/GJ gas price and \$55/tCO_2-e carbon price



VI. DISCUSSION

This analysis suggests that it is not meaningful to attempt to ascribe the cost of "'back-up' capacity" to wind generation entering a system in the manner suggested by some researchers. If a system has sufficient capacity at present, adding wind does not create a requirement for *additional* capacity[2]. In such cases, any capacity requirement of the system cannot be considered to be related to the entry of wind generation.

In the longer-term, all existing capacity will eventually need to be replaced. However, the key question of how wind and solar might best contribute to future 'clean slate' electricity industries is best answered through analysis of system-wide generation portfolios, not methods that attempt to establish integration costs for particular technologies. Such costs are challenging to measure, and will depend upon the other generation technologies making up the overall generation mix (whose own integration costs depend upon the other plants in the system as well). Integration costs are even more challenging to allocate to individual technologies or market participants, requiring non-obvious judgments about who has "caused" a problem that is innately related to the system as a whole.

It may be a more sensible framework to consider the capacity and energy requirements of a system to be properties of the demand profile. Thus, the requirement for capacity is created by the *demand* in a system, not by the addition of wind. Various technology combinations to meet that demand profile

[2] As discussed in the introduction, flexibility requirements are not dealt with in this paper.

to a sufficient reliability standard can then be compared, and the generation mix that best meets customer requirements (including costs) can be selected with holistic consideration of all system costs and benefits involved. Since customers ultimately create the requirement for both capacity and energy, customers should be responsible for paying the costs of supplying those services. Adding the cost of one type of technology (such as OCGTs) to another (such as wind) does not helpfully "internalize" any system relevant effects.

As opposed to increasing system costs, this analysis demonstrates that adding wind generation to a power system acts to significantly *reduce* the balance of system costs in two ways:

- Reducing fuel costs and operating costs (since the balance of system operates less), and
- Reducing capital expenditure by allowing less capital intensive intermediate plant to be installed (rather than highly capital intensive base-load plant).

Even if wind is conservatively considered to have a zero capacity value and additional peaking reserve plant is maintained to ensure that the total firm capacity remains as it was before the introduction of wind generation, the savings from introducing wind far exceed the cost of maintaining additional reserves. More than half of the cost of the wind itself is found to be offset by reductions in costs in the balance of system.

Savings are smaller in a power system with existing generating assets, since the sunk costs in these assets inhibit rapid transition to the least cost generating mix. However, there are still significant savings related to reduced fuel and operating costs. Also, further savings will be available in systems with demand growth, or where retirement of firm capacity is anticipated, since future capital repayments can be reduced by the installation of less capital intensive plant to partner optimally with the energy supplied by variable renewables.

When entering a power system, this analysis shows that wind generation acts primarily to displace base-load capacity, shifting a larger proportion of capacity into the intermediate category. This suggests that investors should cautiously assess any perceived need for development of new base-load capacity, and examine the risk of scenarios where that plant may operate at lower than expected capacity factors. It also suggests that policy makers should not have cause for alarm if the capacity of base-load generation appears to be decreasing over time; this analysis suggests that this is an appropriate market response to the introduction of variable generation.

VII. Conclusions

This analysis brings into question the concept of 'back-up' capacity as a system integration cost associated with introducing variable renewables to a power system. Applying an additional "fee" to wind plants related to 'back-up' capacity does not appear to be an effective way of internalizing system costs, since wind generation is acting to significantly *reduce* the costs of the remaining power system (as opposed to increasing costs). A better approach involves a whole-of-system analysis, examining the implications of various technology mixtures for meeting the required demand profile. Attempts to define a single "integration cost" associated with 'back-up' capacity to allow direct comparison of firm technologies (such as nuclear) and variable technologies (such as wind) oversimplify the many complex issues involved.

VIII. Acknowledgment

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