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# Comparing Coal IGCC with CCS and Wind-CAES Baseload Power Options in a Carbon-Constrained World

Samir Succar, Jeffery B. Greenblatt, Robert H. Williams

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# Abstract

Coal integrated gasification combined cycle (IGCC) with carbon capture and storage (CCS) has emerged as a potentially cost-effective carbon mitigation strategy. However carbon policies that make energy systems such as IGCC with CCS competitive with conventional fossil power generators will also bring other low carbon technologies into play.

In particular, two strategies for generating baseload power from wind are investigated: pairing wind with dedicated natural gas generation and coupling wind energy to compressed air energy storage (CAES). The costs and performance of these options are analyzed in comparison to coal IGCC with and without CCS.

We find that wind with natural gas backup faces significant challenges in economic dispatch competition due to high fuel prices. However CAES, a commercially ready technology, makes it possible to transform wind power into a baseload power option with the low short-run marginal cost needed to compete in baseload markets. Moreover, geologies suitable for CAES seem to be reasonably well distributed in wind-rich regions of the United States (e.g., Great Plains) where much of the new capacity for coal power generation is being planned. An economic analysis indicates that costs and greenhouse gas emission levels of wind-CAES systems fired with natural gas will be comparable to those of coal IGCC with CCS, and could be strong competitors for coal IGCC with CCS in providing baseload electricity in a carbon-constrained world.

# Introduction

The integrated gasification combined cycle (IGCC) facilitates the production of electricity from coal with low greenhouse gas (GHG) emission rates via pre-combustion capture of $CO_2$ and $CO_2$ storage in geological media [1]. A coal IGCC plant with carbon capture and storage (CCS) typically becomes competive with a coal IGCC plant with $CO_2$ vented when GHG emissions are valued at a price ~ \$100 per tC [2]. However when the greenhouse gas emissions price ($p_{GHG}$) reaches this level, other low carbon generation technologies may be competitive as well. The future of coal IGCC with CCS will depend on how the performance and economics of this technology compare with other low-carbon generation options and how well it is able to compete in economic dispatch.

Wind energy offers lower production costs than most other sources of renewable, low carbon energy. However, due to the intermittency of wind, it is not possible to make a direct comparison between wind generation costs and those of coal IGCC, which will serve as baseload plants. But a baseload power system made up of wind power plus dispatchable backup generation can be compared to a coal IGCC plant.

Two options for backing wind are utilizing dedicated stand-alone generation capacity and energy storage. Natural gas generation is chosen as the stand-alone backup generation technology due to its low capital costs and its fast ramping rates that are well suited to balancing rapid fluctuations in wind power output. CAES is chosen as the energy storage technologies due to its low cost at large scale and potential widespread availability. A wind/CAES system would store excess wind electricity by using it to run compressors that store high-pressure air in underground geologic formations such as saline aquifers or salt domes. This mechanical energy can be retrieved by burning a suitable fuel (e.g., natural gas) in the high pressure air recovered from storage and expanding the combustion products in a gas turbine expander to make electricity. In this way, a wind farm coupled to CAES (or wind/CAES) can store excess wind energy and use it to generate electricity at later times when wind speeds diminish.

While many studies have looked more broadly at the issues associated with integrating wind and energy storage [3-5], a number of studies have also focused on wind specifically with CAES [6, 7] including studies focused on system costs [8-11] and emissions [12]. Although both CAES and pumped hydroelectric storage meet the cost requirements for long-duration storage (> 8 hrs) [13], pumped storage offers limited availability since its economic viability depends on utilizing preexisting reservoirs suitable for storage. CAES however can be implemented in a wide variety of formations that appear to be readily available in the wind-rich Great Plains [14-16]. This is also the same region where most of the capacity for new coal generation is currently being planned.

# Methodology

Costs are analyzed for four low-carbon baseload power generation options: coal IGCC with $CO_2$ vented (IGCC-V), coal IGCC with CCS (IGCC-C), wind coupled to compressed air energy storage (wind/CAES) and wind energy with dedicated natural gas generation (wind/gas).

Cost estimates are for plants with an 85% capacity factor using the financing model in the EPRI Techincal Assessment Guide. The assumed financing parameters are 55% debt (4.4%/y real cost) and 45% equity (14.2%/y real cost), a 30-year (20-year) plant (tax) life, a 38.2% corporate income tax rate, a 2%/y property tax/insurance rate, and an owner's cost of 5.5% of the total installed capital cost. Under these conditions the discount rate (real weighted after-tax cost of capital) is 7.9%/year, and the levelized annual capital charge rate is 15.0%/year. Plant construction requires four years, with the capital investment committed in four equal payments, so that interest during construction factor (IDCF) is 1.124 with Base Case financing.[1] All costs are expressed in 2002 inflation-adjusted U.S. dollars.

Table 1: **Coal IGCC System Parameters** [17]

| | **IGCC-V** | **IGCC-C** |
|---|---|---|
| Fate of $CO_2$ | Vented | Captured |
| Capacity Factor (%) | 85 | |
| Levelized Annual Capital Charge Rate (%) | 15 | |
| Installed capacity $MW_e$ | 826.5 | 730.3 |
| $CO_2$ Storage Rate ($tCO_2$/hour) | 0 | 626.6 |
| Greenhouse Gas Emissions ($gC_{equiv}$/kWh) | 237 | 52.7 |
| Efficiency, LHV | 0.380 | 0.315 |
| $CO_2$ Transport/Storage \$/$tCO_2$ (100km pipeline) | 0 | 6.82 |
| $CO_2$ Transport/Storage \$/$tCO_2$ (200km pipeline) | 0 | 11.1 |
| Overnight Construction Cost, \$/$kW_e$ | 1135 | 1428 |

Table 2: **Wind System Parameters [10]**

| | **Wind/CAES** | **Wind/Gas** |
|---|---|---|
| Capacity Factor (%) | 85 | |
| Installed capacity $MW_e$ | 2000 | |
| Levelized Annual Capital Charge Rate (%) | 15 | |
| Wind Farm Rated Power $MW_e$ | 3090 | 2000 |
| CAES Expander Capacity $MW_e$ | 2000 | 0 |
| CAES Compressor Capacity $MW_e$ | 1090 | 0 |
| Natural Gas Backup Capacity $MW_e$ [2] | 0 | 336(SC)/1597(CC) |
| Hours of Storage at CAES Exp Capacity | 73 | 0 |
| Wind Turbine Specific Rating [19] | 1.19 | 1.34 |
| Transmission Line Voltage (kV) | 751 | 569 |
| Transmission Loss % (500km) | 2.72 | 4.20 |
| Transmission Line Load Factor After Losses | 0.85 | 0.43 |
| Wind Energy Transmitted Directly (TWh/y) | 12.2 | 8.91 |
| Wind Energy Input to CAES (TWh/y) | 3.46 | 0 |
| Natural Gas Output (TWh/y) [2] | 0 | 0.879(SC)/6.45(CC) |
| Greenhouse Gas Emissions ($gC_{equiv}$/kWh) | 23.2 | 61.8 |
| Backup System Heat Rate (kJ/kWh)[2] | 4220 | 9350(SC) / 6670(CC) |
| Wind Capital Cost at Nominal Rating \$/$kW_e$ | 923 | 923 |
| Backup System Capital Costs \$/$kW_e$[2] | 453 | 234(SC)/571(CC) |
| CAES Storage Volume Cost \$/kWh | 1.75 | 0 |

Energy quantities are expressed on a lower heating value (LHV) basis, except energy prices are on a higher heating value (HHV) basis—the norm for US energy pricing. Energy prices of \$1.31/GJ for coal and \$5.05/GJ for natural gas are based on a 30-year levelized 2010 price (EIA 2006). The GHG fuel emissions include the $CO_2$-equivalent upstream GHG emissions (estimated in the GREET model of Argonne National Laboratory as 1.00 $kgC_{equiv}$ per GJ of coal and 2.84 $kgC_{equiv}$ per GJ of natural gas) resulting in a total GHG emissions rate of 25.0 $kgC_{equiv.}$ and 18.0 $kgC_{equivv.}$ per GJ of coal and natural gas, respectively.

Coal IGCC plant performances, capital costs, and O&M costs[3] are derived from a 2003 study on coal IGCC by Foster Wheeler Energy carried out for the International Energy Agency's Greenhouse Gas R&D Programme [17].

[1] LACCR*(total installed capital cost—including interest charges accumulated during construction) = the annual capital charge. Alternatively, the annual capital charge = IDCF*LACCR*OCC (where OCC = overnight construction cost), so that IDCF*LACCR is the OCC multiplier

[2] Natural Gas Backup generation is comprised of a combination of natural gas combined cycle (CC) and simple cycle gas turbine (SC) systems.

Cost modeling of wind energy systems and transmission as well as optimization methodology for variable scaling of wind turbine components (i.e. derating) are as described in previous studies unless otherwise noted [10, 18, 19].

# Findings

Disaggregated costs for the four baseload power systems are presented in Table 3. The generation costs are compared at three stages by adding GHG emissions and transmission costs incrementally. The GHG costs scale with the emissions levels for each of the technologies. While the IGCC-V system has the largest emissions rate (237 $gC_{equiv}$/kWh) it is found that IGCC-C and wind/gas have very similar emissions (53 and 62 $gC_{equiv}$/kWh respectively). The wind/CAES system has the lowest GHG emission rate of 23 $gC_{equiv}$/kWh. In part this is due to the larger fraction of power delivered directly from wind relative to wind/gas system (see Table 2). This is largely a function of optimizing both the sizing the wind farm and the wind turbine specific rating [10, 19]. The low heat rate for CAES electricity (4220 kJ/kWh) also contributes to the low emissions profile for the wind/CAES system.

When GHG emissions are valued at $100/tC, the wind/CAES system is competitive with the coal IGCC options at the busbar. However, if the wind resource being exploited is 500 km more remote from the electricity market being served than the coal IGCC options, then the coal IGCC-C option becomes the least costly (see bottom of Table 3). The effect of these factors on the relative economics of these systems underscores the sensitivity of the results to climate policy strength and wind resource remoteness.

Table 3: **Disaggregated Generation Costs for Coal IGCC and Baseload Wind, $/MWh (class 5 winds, $923/kW wind capital)**

| | IGCC Vent | IGCC w/CCS | Wind/CAES | Wind/Gas |
|---|---|---|---|---|
| Fixed Costs | | | | |
| Capital | 25.70 | 32.32 | 52.95 | 32.86 |
| Fixed Operations and Maintenance | 3.39 | 4.96 | 3.75 | 3.76 |
| Dispatch Costs | | | | |
| Variable Operations and Maintenance | 4.49 | 4.76 | 8.29 | 4.88 |
| Fuel (NG = $5.05/GJ HHV, Coal = $1.31/GJ HHV) | 13.07 | 15.77 | 7.23 | 19.31 |
| $CO_2$ Transport and Storage Cost[4] | 0.00 | 5.86 | 0.00 | 0.00 |
| *Total Dispatch Cost* | *17.56* | *26.39* | *15.52* | *24.19* |
| **Total Generation Cost** | **46.64** | **63.67** | **72.22** | **60.81** |
| | | | | |
| GHG emissions costs, $p_{GHG}$=$100/tC | 23.68 | 5.27 | 2.32 | 6.18 |
| *Total Dispatch Cost +* $p_{GHG}$ | *41.24* | *31.66* | *17.83* | *30.38* |
| **Total Generation Cost +** $p_{GHG}$ | **70.32** | **68.94** | **74.54** | **67.00** |
| | | | | |
| Cost of 500km Dedicated TL for Remote Wind | 0.00 | 0.00 | 4.09 | 3.25 |
| **Total Generation Cost +** $p_{GHG}$ **+ TL** | **70.32** | **68.94** | **78.63** | **70.25** |

Table 3 also shows that the dispatch costs (i.e. the sum of all short-run marginal costs: fuel + variable operations and maintenance + GHG emissions cost) are larger for wind/gas than for wind/CAES despite a lower overall COE. This has important implications for the viability of wind/gas as a baseload generation option, as discussed in the next section.

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[3] In the original FWE study property taxes and insurance (PTI) were included in O&M costs. With the assumed EPRI TAG financing model, PTI is accounted for in the levelized annual capital charge rate instead.

[4] Assuming CO2 is transported by pipeline 100 km for storage in an aquifer and that the maximum injection rate is 1000 t/d per well

## Dispatch Cost Concerns

### Capacity Factors Assumptions

In the above discussion of generation costs it is assumed all competing options are baseload systems operating at 85% capacity factor. This assumption must be examined more closely with respect to the relative dispatch costs for competing technologies. The capacity factor for each option depends on how well it can compete in economic dispatch on the grid. For a given set of power generating systems, the grid operator determines the capacity factors of these systems by calling first on the system with the least dispatch cost. Under this condition, deployment in sufficient quantity of the technology with the least dispatch cost can lead to a reduction of the capacity factors and thus an increase in the COE of the competing options on the system.

As a result of the recent increases in natural gas prices in the U.S. this phenomenon has resulted in reducing capacity factors for natural gas combined cycle plants originally designed for baseload operation to average utilization rates in the range 30-50% where coal plants are available to compete in dispatch [20].

In principle this downward pressure on capacity factors for options with high dispatch costs could be avoided with "take-or-pay" contracts that require the generator to provide a specified fixed amount of electricity annually. But uncertainties about future fuel prices, technological change, and future electricity demand make such contracts rare.

### Variable Dispatch Costs

Since dispatch costs determine the relative suitability of different options for baseload operation, it is necessary to examine closely the dynamics of dispatch for both wind options. Furthermore, although we can treat the dispatch costs from coal IGCC as approximately constant in this context, the dispatch costs from wind cannot be treated as a simple average. Wind/gas and wind/CAES will operate at the lowest dispatch costs when all the electricity is being provided directly by wind, when fuel expenditures are zero. But dispatch costs will increase significantly as backup generation comes on line to balance shortfalls in wind output. Thus it is important to analyze the variations in dispatch costs for these options, not simply their average value as reported in Table 3.

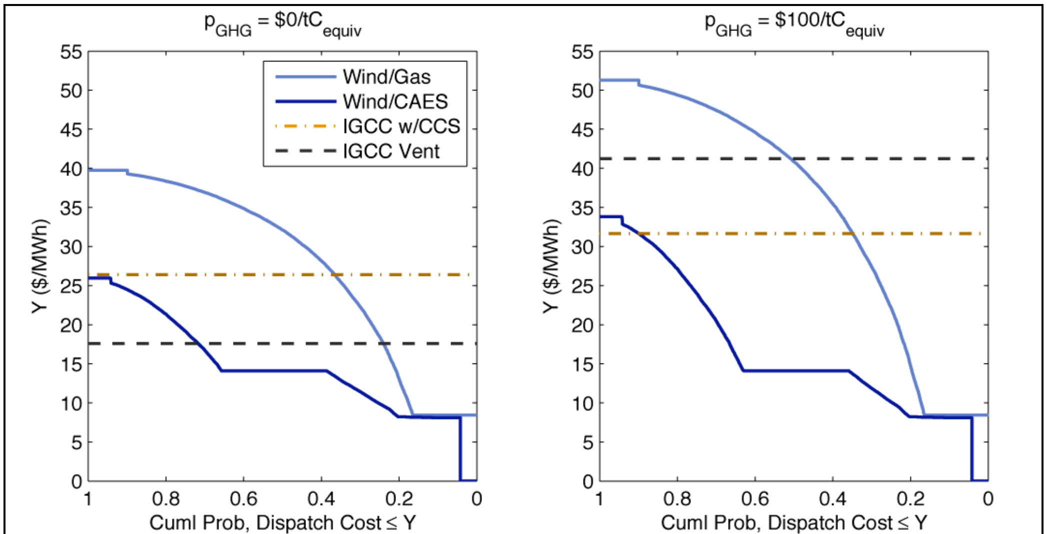


Figure 1 Variable dispatch costs for wind/gas and wind/CAES in comparison with coal IGCC costs at two different GHG emissions prices

The dispatch cost of the wind/gas and wind/CAES systems will vary with the wind input according to whether wind is transmitting power directly or whether the backup system is deployed. Figure 1 shows the variation in dispatch costs in a manner similar to a "load-duration" curve or, more precisely, as an inverse cumulative probability curve counting from the top end of the distribution. The choice of horizontal axis (in reverse order from 1 to 0) can be useful since horizontal axis values at the intersection of the wind curves with each constant-cost IGCC line indicate the percent of time that it can deliver power at a lower dispatch cost. These dispatch cost curves are evaluated at both $p_{GHG}$=$0/tC and $100/tC.

Dispatch costs are the same lowest value for both the wind/gas and wind/CAES systems when all power comes directly from the wind array (right portion of each plot in Figure 1) but that dispatch costs rise at very different rates as the fraction of power coming from the backup system increases (left portion of each plot). In addition, the wind/CAES system has an intermediate dispatch cost regime where CAES compressors are running to store wind energy that cannot be transmitted; this appears as a step in intermediate ranges on the wind/CAES line.

Figure 1 shows that wind/gas has the highest dispatch cost of all the options when natural gas generation is dispatched in significant quantities to balance wind output. This is true in both panels of Figure 1 regardless of the price on GHG emissions. At $0/tC wind/gas cannot compete in economic dispatch relative to the lowest cost coal technology for more than 30% of the time and even at $100/tC it will be competitive less than 40% of the time. Hence a baseload-level capacity factor cannot be sustained with wind/gas where coal or wind/CAES capacity is available and thus given current natural price projections it is unlikely that wind/gas will be a viable baseload strategy for the foreseeable future.

This does not mean however that wind backed by existing reserve capacity cannot serve intermediate load applications. In fact, if diurnal variations in wind speed are positively correlated with demand for electricity, it is likely that the economics of wind backed by supplemental capacity could be quite favorable for serving intermediate loads even at very high penetrations, but such an analysis is outside the scope of this paper.

On the other hand, the wind/CAES system, because of its low heat rate (4220 kJ/kWh) and higher utilization rate of wind (see Table 2), is able to run at a lower dispatch cost than both coal options more than 70% of the time without a GHG price and more than 90% of the time for $p_{GHG}$=$100/tC. Thus from the point of view of dispatch costs, wind/CAES has the potential to be a competitive baseload technology with respect to coal IGCC. Consequently the analysis that follows will focus on the competition between wind/CAES and coal IGCC systems. The wind/gas technology, although capable of delivering electricity at a competitive cost, is not a viable baseload strategy for the reasons stated above and will not be considered further.

## *Total Generation Cost*

The costs of energy of three base load power plants were analyzed as a function of GHG price.

Costs for IGCC-C are presented as a band showing the upper and lower bounds for $CO_2$ pipeline costs. Costs for $CO_2$ transport and for aquifer storage are based on a model developed by Ogden [21], assuming that the maximum $CO_2$ injection rate per well is 1000 t/day (a typical value for mid-continental aquifers) and that $CO_2$ is transported by pipeline 100 km to 200km (corresponding to a total cost for $CO_2$ transport and storage of $6.8 to 11.1 per tonne of $CO_2$, respectively).

Cost bands for wind/CAES reflect 0 to 500km of dedicated high voltage transmission. Since equal transmission costs applied to both systems appear only as equal offsets (and thus would not affect the relationship between systems) the lower bound for wind (0 km transmission) can be interpreted more generically as the case of equal transmission costs between wind and coal. Likewise the upper bound reflects a 500km transmission distance differential of wind relative to coal.

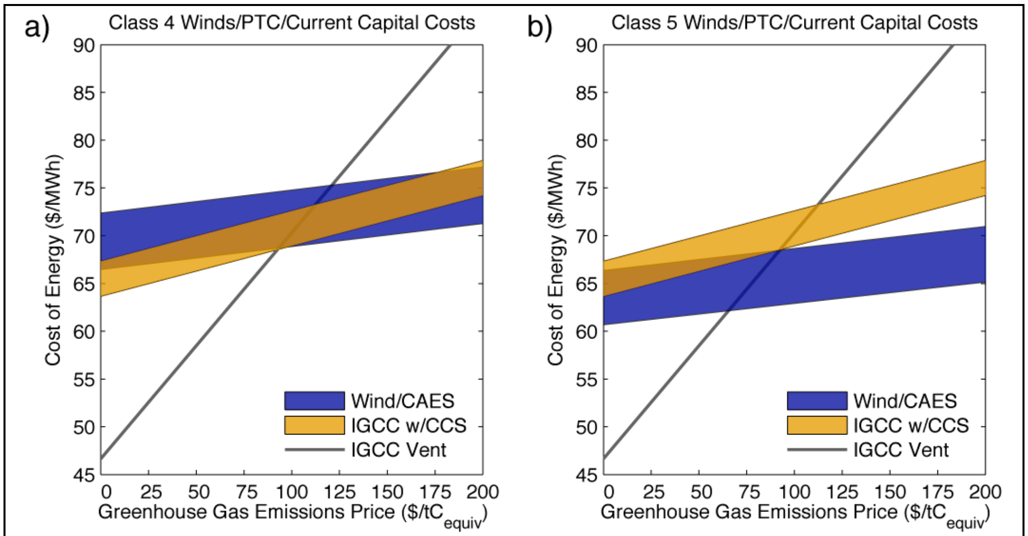


Figure 2 System cost dynamics under a GHG emissions price with current capital costs with a 1.9¢/kWh production tax credit (PTC) for wind.

The generation costs ($/MWh) of all four systems are analyzed as a function of greenhouse gas emissions costs with variations in three principle variables: wind resource strength, wind production tax credit (PTC), and capital costs for wind and CAES.

Wind resources of class 4 (8.23 m/s mean wind speed and 650 W/m$^2$ mean wind power density at a hub height of 119 meters) and class 5 (8.8 m/s, 800 W/m$^2$) were explored. While current wind development takes place predominantly in regions with resources of class 5 and above, future capital cost reductions and wind turbine technology improvements may make class 4 winds economically viable thus significantly enhancing wind energy potential worldwide (especially in North America, Europe and Middle East/Africa [22]). Therefore this range captures both current conditions and projected frontiers for wind development.

Figure 2 shows the cost competition between IGCC-C and wind/CAES under both wind resource conditions with current capital costs for wind [23] and CAES [13, 24] as well as a production tax credit (PTC) of 1.9 cents per kWh applicable to the first 10 years of plant life—the current situation in the United States.

This figure shows that wind resource strength and location has a profound effect on the cost effectiveness of wind/CAES. Moving from a Class 4 remote wind site (the upper edge of the blue band in Figure 2a) to a Class 5 local wind site (the lower edge of the blue band in Figure 2b), wind/CAES goes from lying entirely above the IGCC-C cost band to entirely below it. This also shows the coupled tradeoff of wind resource strength and remoteness: the cost of exploiting a remote class 5 resource is nearly equivalent to that of developing a local class 4 site.

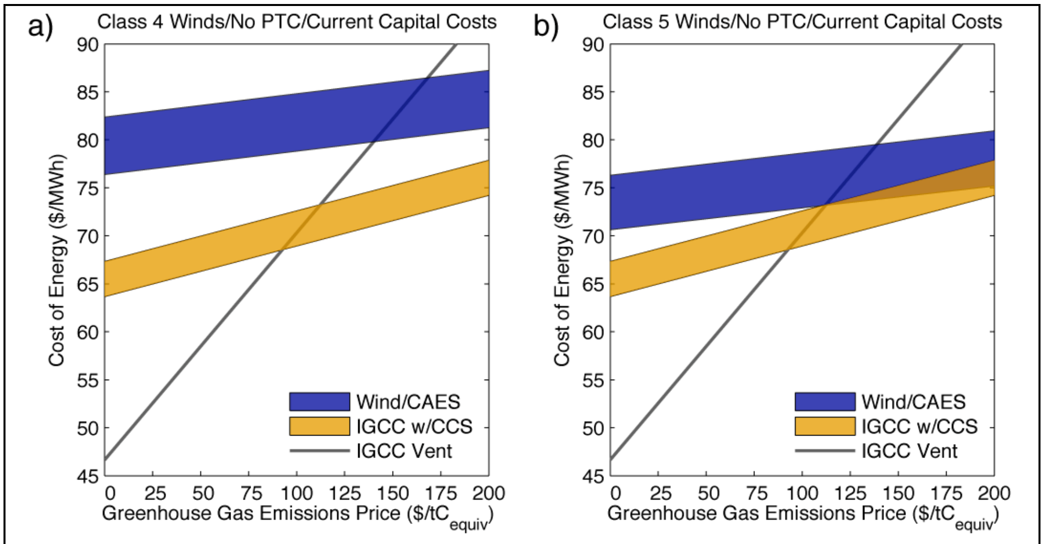


Figure 3 System cost dynamics under a GHG emissions price with current capital costs and no PTC

Nevertheless we see that in the absence of a price on GHG emissions, IGCC with $CO_2$ vented is clearly the least costly option in both cases. But the wind/CAES and IGCC-C technologies begin to compete with the IGCC-V option at comparable GHG emission prices.

An analysis of systems costs in the absence of a PTC (Figure 3), shows that wind/CAES will be competitive with IGCC-C only under the most favorable combination of conditions. For the systems we have modeled, only a class 5 wind resource without additional transmission costs can come in near the $100/tC price at which we expect to see IGCC-C becoming competitive with IGCC-V. Furthermore, it is only because of its low emissions rate that wind/CAES can compete at all; the shallow slope of the cost line allows wind/CAES to enter at high GHG emissions prices despite relatively high fixed costs. Therefore under current capital conditions and with $p_{GHG}$ = $100/tC wind/CAES can only compete if class 5 winds are available at no greater transmission distance than coal IGCC-C and if CCS costs exceed $11/tCO_2 (i.e. the $CO_2$ pipeline distances is greater than 200 km).

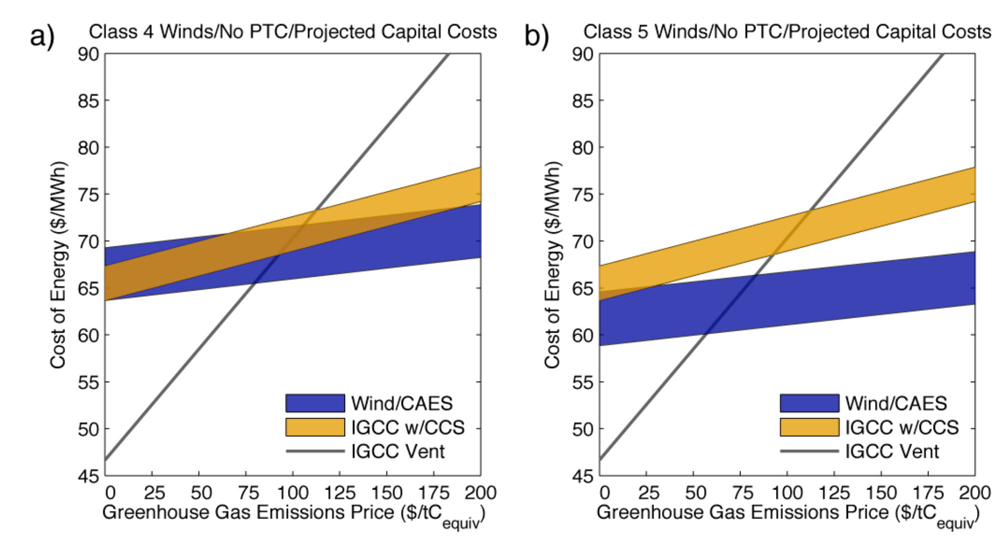


Figure 4 System cost dynamics under a GHG emissions price with 24% projected capital cost reductions for wind turbine and CAES turbomachinery (no PTC)

The potential for capital cost reduction is significant for both wind and CAES technologies. There have been large sustained growth rates in global wind capacity in recent years: 29.3% average annual global capacity growth over the past ten years and 27.9% over the past five years [25]. If these trends continue, they will likely drive significant cost buy-downs for wind capital in coming years. Assuming a somewhat reduced 20% annual growth rate, and using average progress ratios for wind of 0.81-0.95 [26, 27], the 24% capital cost reductions assumed for Figure 4 could be realized within a 5-20 year timeframe.

In addition, the small scale of current CAES deployment suggests that significant cost reductions could be realized with very modest capacity additions.

The capital costs for IGCC could likewise see significant reductions, however the near-term costs reported by Foster Wheeler Energy used here (total plant costs of $1135/kW$_e$ and $1428/kW$_e$ for $CO_2$ vented and stored respectively) already reflect some cost reductions relative to IGCC plants that would be built today. As a result IGCC costs are regarded as already incorporating some learning and thus have not been modified for the analysis of projected capital costs in Figure 4.

Capital cost reductions would not only make class 5 resources more broadly viable for wind/CAES without subsidy, but under a wide range of conditions they would make class 4 wind resources economical as well. This in turn could significantly extend the range of sites available for wind/CAES and ease the need for additional transmission costs for wind as less remote sites become viable. This is significant since the bottom edge of the class 4 wind/CAES band corresponding to a zero transmission distance differential is competitive with respect to IGCC-C at all GHG prices without a PTC. Thus if capital cost buy-downs over the next 5-20 years can make class 4 wind resources viable, this has the potential to not only reduce the capital costs of the turbines themselves, but to reduce the infrastructure costs associated with wind and to make wind/CAES viable over a broader geographical area.

Over the longer term, of course, it will be desirable to exploit remote Class 4 wind as well because so doing would greatly magnify the exploitable wind resources. On a global basis, the exploitable Class 5+ wind resource is estimated at 80.5 PWh/y compared to 185.0 PWh/y for Class4+ [28]. These figures exceed the global consumption of electricity in 2002 by factors of 5.7 (for classes 5 and above) and 13.0 (for classes 4 and above) [29].

# Conclusions

The viability of wind and coal IGCC baseload electricity options will depend on a handful of critical factors. While IGCC-V is the least-costly baseload power option investigated without a price on GHG emissions, climate policies equivalent to a carbon price ~ $100/tC could bring several low-carbon technologies to the table. While wind with dedicated natural gas backup generation can operate at competitive total costs, it is unlikely that it will be able compete under economic dispatch in baseload markets for the foreseeable future. Wind with CAES storage however can operate at much lower short-run marginal costs with total costs very similar to IGCC-C under several credible scenarios. The relative economics of these systems will depend largely on the quality and remoteness of wind resource available for wind/CAES systems. Furthermore, the competitiveness of wind/CAES may be enhanced as growth rates in wind buy down capital costs making less remote sites economically viable in the near future.

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