PEMBINA institute

Levelized cost of energy storage and operational GHG performance

CAES and zero emission storage compared to natural gas peaking plants

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Introduction

Electricity grids require a combination of generation resources with different characteristics to deliver reliable, affordable, low-carbon electricity. Wind and solar energy have significant potential in Alberta. As part of an integrated grid, renewable resources can provide valuable electricity at very low variable costs and emissions, and even further value can be unlocked with energy storage.

The ability to ramp electricity generation up or down in response to changes in demand or in the output of other generators on the grid is key to integrating variable renewables. Some generators, such as "baseload" coal plants or variable renewables like wind and solar, have limited ability to ramp up generation (newer wind turbines can ramp down). Traditionally, simple-cycle natural gas plants have been the main providers of this service, but technology developments are enabling more options like combined-cycle gas plants and many forms of energy storage. The relative greenhouse gas emission levels between fast ramping options are an important deciding factor when choosing which one to use.

On their own, renewables can provide valuable electricity to the grid, but pairing renewables with storage allows them to play an even bigger role. Alberta is in the process of phasing out coal-fired power, and in doing so will need additional generation capacity to replace that and meet Alberta's growing energy needs. At the same time, the province has a commitment to develop additional renewables, which will provide valuable low-cost electricity. By pairing the planned growth in renewables with storage, it will be possible to "firm" the capacity of renewables and reduce the need for other new generation.

What is energy storage?

Electricity can be stored in a variety of ways, and then be dispatched back to the grid as it is needed. There are many different technologies that can do this on a large scale; the two that are explored in this work are compressed air energy storage (CAES) and zero emission storage.

In a CAES plant, electricity is used to compress ambient air, which is stored under pressure in an underground cavern. When electricity is required, the pressurized air is heated and expanded to drive a generator that produces power. The heating process usually requires an input of energy.[1]

One example of zero emission storage is pumped hydro, where electricity is used to pump water to a dam at higher elevation. When needed, the water is released through turbines to generate electricity. Other zero emission technologies being explored include adiabatic compressed air and scaled-up battery resources.

Using energy storage to unlock additional value from renewables is particularly beneficial when we consider the deeper grid decarbonization trend beyond 2030. Deep decarbonization will require reducing natural gas generation and a further increase in renewable generation capacity.

As Alberta expands its renewable capacity, there is clearly a role for storage to help ensure greenhouse gas (GHG) emissions remain low without adding new emissions sources to the grid, putting Alberta on the path for future decarbonization.

This document describes our modelling and evaluation of results for the cost, operational greenhouse gas emissions, and firm capacity performance of compressed air energy storage and zero emission storage (such as pumped hydro storage), relative to fossil generation. Energy storage assets can provide additional benefits such as transmission constraint reduction, transmission upgrade deferral, frequency support, reactive power support, and improved black start and ramping capabilities that are beyond the scope of this work.

[1] Energy Storage Association, "Compressed Air Energy Storage (CAES)." http://energystorage.org/compressed-air-energy-storage-caes

Results

Costs

Results of the levelized cost of electricity (LCOE) analysis are shown in Figure 1. The LCOE for natural gas combusted in coal generators is included based on an increased interest in Alberta in continuing to use existing coal-fired power plants. Two additional scenarios for natural gas power generation are included in which the expected lifetime of these projects is shortened to 15 years. These scenarios are presented to illustrate the economics of new gas plants in light of the need for electricity systems to move toward zero-emitting power generation and the use of gas as a "bridge" fuel. This could ultimately shorten the lifetime of plants built today.

The two storage options (compressed air energy storage (CAES) and pumped hydro storage) were modelled with two different electricity sources used to charge the energy storage facility. The first, labelled *RE charge* in the graph, uses excess electricity from wind farms — a situation that is extremely rare today but could increase in the future when renewable generation supplies a very large portion of electricity in the province. In the second, labelled *spot charge* in the graph, electricity is purchased from the spot market where it would need to be replaced by additional generation.

The results show that storage is cost competitive with other options such as building new natural gas generation facilities. It should also be noted that costs for energy storage technologies are decreasing and this comparison will evolve over time.

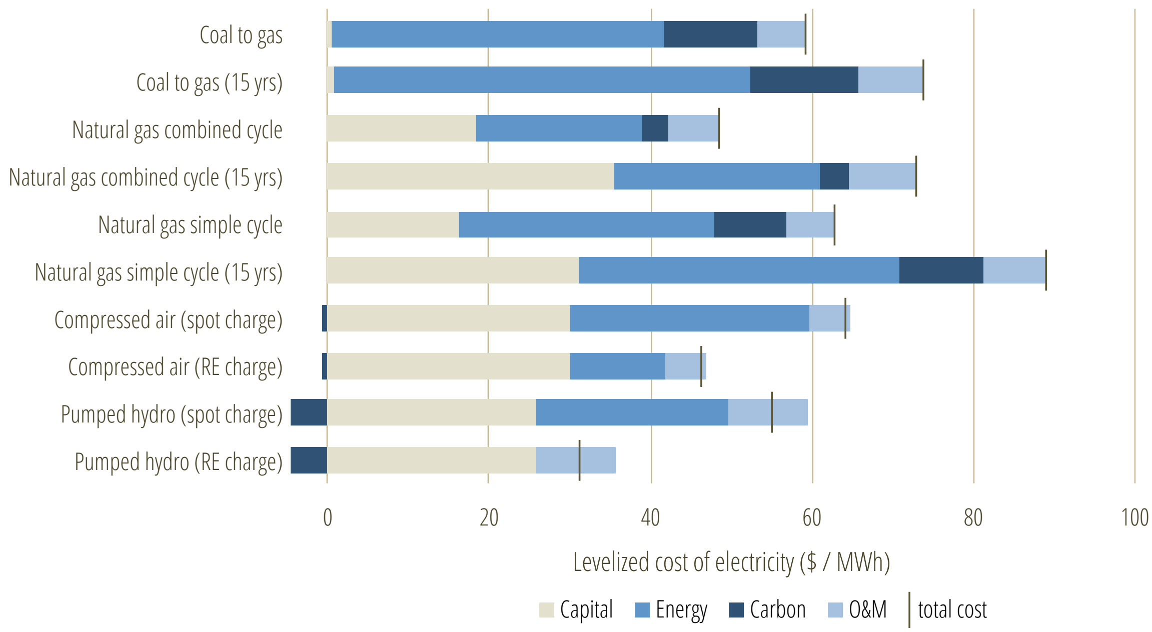

Figure 1. Levelized cost of electricity for different storage and generation options[2]

While the LCOE of pumped hydro storage is more favorable than that of CAES, pumped hydro storage is limited to suitable naturally occurring sites. Alberta has a limited number of such sites, but potentially many more sites for CAES.

Greenhouse gas emissions

Operational greenhouse gas emissions, those associated with power plant and storage facility operation, are shown in Figure 2. These emissions are broken down as charging and discharging cycles for storage, and generation emissions for natural gas power plants. The CAES and zero emission storage options using spot market electricity include charging emissions corresponding to Alberta electric grid emissions intensities.[3] To calculate levelized GHG emissions, the model assumes a declining emissions intensity corresponding to Alberta's Climate Leadership Plan objective to generate 30% of its electricity from clean energy sources by 2030. During the discharge cycles, GHG emissions reflect natural gas combustion for power generation and, in the case of CAES, heating the air as it expands (through a gas combustion and expansion turbine).

[2] Pumped hydro lifetime 50 years, all others 30 years except where noted. Storage efficiencies of 77% for hydro and 62% for CAES.

[3] Average value over the period 2016-2030.

As with the LCOE, the impact of storage on total emissions depends on the source of electricity used to charge the storage; the same two charge options (RE charge and spot charge) are used here.

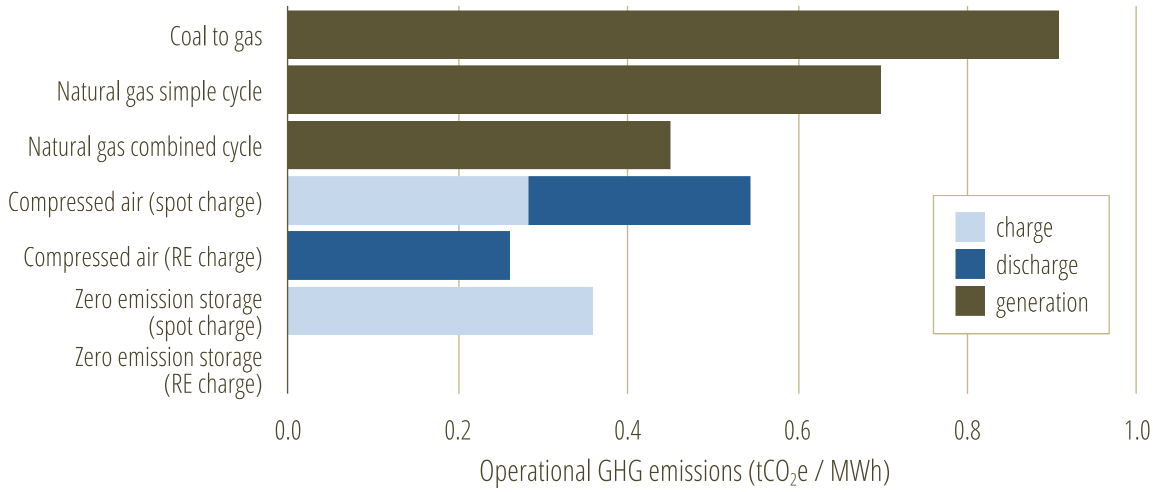

Figure 2. Comparing operational GHG emissions of generation technologies

In the case of zero emission storage, the emissions are always lower than the natural gas alternatives. For compressed air energy storage, emissions are lower in almost all situations with the exception of the highest efficiency natural gas generators.[4]

As Alberta moves forward with installation of renewables to meet the 30% target there is clearly a role for energy storage to help meet the target while further lowering overall emissions.

Firm capacity

The contribution of each individual generator to this margin is called the “firm capacity” (or “capacity credit”) and varies depending on the characteristic of the generator. Fossil generators typically have firm capacity in the range of 80-90%, which accounts for planned and unplanned maintenance. Renewables such as wind and solar can contribute to demand at peak times — for example, solar power is available during peak demand in the summer when air conditioning use is high because the sun is shining — but the firm capacity is typically lower. Energy storage can significantly

[4] Charging emissions are slightly higher for zero emission storage compared to CAES because of energy losses in the storage and discharge process; slightly more electricity must be stored in zero emissions storage vs. CAES in order to discharge the same amount.

increase the firm capacity for renewables by making it possible to store generated energy when it isn't needed and to use it later.

In light of the phase-out of coal power in Alberta there is a role for storage to increase the firm capacity for renewables and reduce the need to build additional fossil fuel generation. To evaluate this potential, we calculated the potential contribution to the firm generation capacity of storage paired with the renewables after the coal phase-out (Figure 3). The results show that a significant portion of the coal generation that will be removed can be replaced by adding storage to the electricity grid, greatly reducing the amount of natural gas generation needed compared to the AESO forecast.[5]

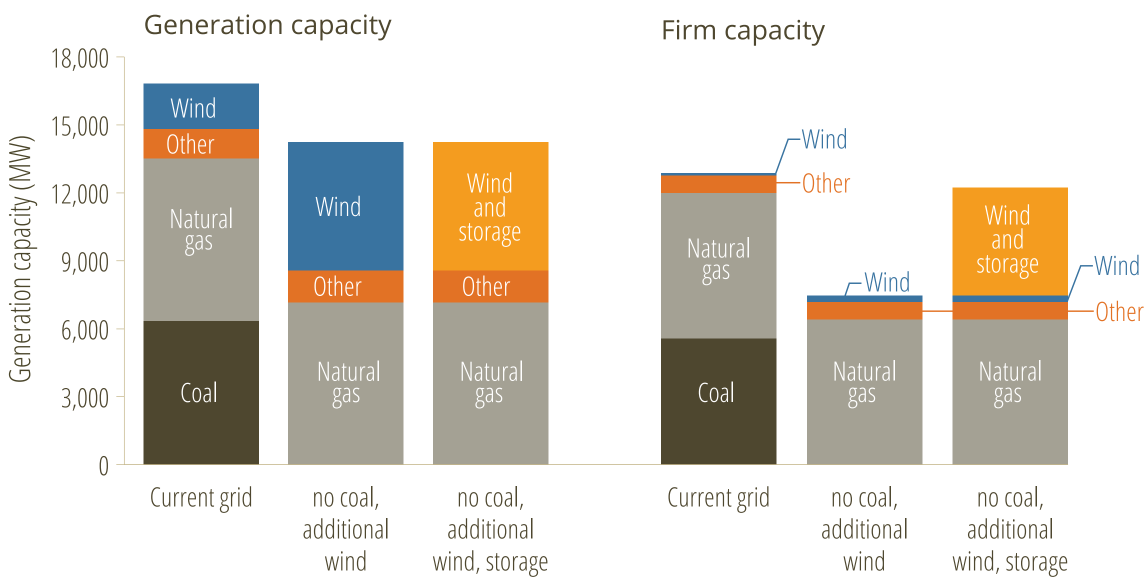

Figure 3. Generation capacity and firm capacity

[5] Alberta Electric System Operator, *2016 Long-term Outlook.* https://www.aeso.ca/grid/forecasting/

Methodology and assumptions

A model was developed to characterize LCOE and operational emissions performance of various electricity storage and generator technologies. The model also evaluates the firm capacity available in the Alberta electricity grid and the potential for storage to contribute to the firm capacity. CAES combined with wind-energy generation is compared to wind-energy combined with converted coal to gas plants, simple-cycle gas power plants, combined-cycle natural gas power plants, and pumped hydro storage.

Energy storage technology and cost information is based on literature research, including:

- Sandia National Laboratories, *Lessons from Iowa: Development of a 270 MW Compressed Air Energy Storage Project in Midwest Independent System Operator* (2012).
- *Lazard's Levelized Cost of Storage Analysis 1.0* (Lazard, 2015).
- OpenEI, *Transparent Cost Database* (2016).
- EIA, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (2013).

Key assumptions are outlined below, with detailed values in Table 1.

Capital, operations and maintenance costs — Sources include Lazard, EIA, pilot projects and academic studies. Salvage values are calculated as per assumption in Table 1. Costs are levelized over the lifetime of the asset.

Energy input costs for charging & discharging — Energy costs are calculated from electricity and natural gas input requirements. Electricity cost is based on an analysis of historic power pool prices during periods of the day when Alberta wind energy generators supply most of their power to the grid,[6] and natural gas prices are projected as per previous Pembina Institute analysis of natural gas power generation.[7] The natural gas power plants of all types are assumed to be operating at less than full load representing operation as peaker plants.

[6] Pembina Institute analyses show that this value ranges from $30 to $50 per MWh from 19h00 to 06h00 the following day.

[7] Pembina Institute, True price of wind and solar electricity generation (2016). https://www.pembina.org/pub/true-price-of-wind-and-solar.

Carbon costs — Alberta's electricity sector will be subjected to the province-wide carbon price using an output-based allocation approach. This means electricity generators will be allocated a specific carbon allowance per MWh electricity output. Generators who exceed this allowance will be subject to a carbon payment whereas those below receive credits. The starting allocation for electricity generators is being debated, but is expected to be near 0.375 tCO_2e per MWh. A ratcheting mechanism will reduce the allocation annually. As a result of this policy, electricity used to charge both pumped hydro and CAES will be subject to carbon costs or credits. This cost will be incorporated into the power pool price when the price-setting generator is subject to a carbon payment or credit. The model assumes that today's price-setting generator is approximated by the benchmark (0.375 tCO_2e per MWh). As the GHG emissions allocation declines, this generator will be subject to a carbon payment; this is incorporated into future spot market electricity prices used by CAES and pumped hydro storage.

Operational GHG emissions — The model calculates emissions for energy charging and discharging. CAES discharge emissions are calculated using a typical natural gas combustion emissions factor in Alberta — regardless of combustion in a gas turbine or boiler.[8] Charging emissions are based on the average Alberta grid emissions intensity for the given year of generation. As the mix will incorporate more clean generators, the intensity declines annually.

Firm capacity – The existing assets are based on AESO data with firm capacity factors from North American Electric Reliability Corporation data.[9]

[8] Typical GHG emissions from Alberta natural gas combustion are calculated from Canada's National Inventory Report (1,938 grams CO_2e per standard m^3 of natural gas, or 49.7 kg CO_2e per GJ). Source: Environment Canada, *National Inventory Report 1990-2014. Greenhouse Gas Sources and Sinks in Canada. Annex 6 Emission Factors* (2016), Tables A6-1 and A6-2. http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/9492.php

[9] AESO, "Annual market statistics reports." https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/ ; NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* (2011) http://www.nerc.com/files/ivgtf1-2.pdf

Table 1. Parameter values

	Parameter	Value
CAES project parameters	Rated power	160 MW[10]
	Energy capacity	9,600 MWh[11]
Electricity and carbon parameters	Power pool price	$35 / MWh[12]
	Carbon intensity benchmark	0.375 tCO_2e / MWh[13]
	Carbon intensity ratcheting	2% / yr
Financial parameters	Discount rate	5%
	Inflation rate	2%[14]
	Salvage value	2%[15]

This analysis uses the same project and financial parameters except for the 15-year lifetime scenarios for natural gas power plants. The capacity factor for each technology option is determined by the number of cycles and hours of operation at its rated power output. [16] For wind, this was calculated by looking at typical hours when wind farms are generating electricity; assuming one eight-hour cycle per day, and 300 wind days per year, produces a 30% capacity factor.

While pumped hydro requires no additional energy input during discharge, a commercial CAES option requires heat, initially lost during air compression while charging. All natural gas power plant options also consume natural gas in conventional gas turbines. Combined-cycle plants utilize a further steam cycle to increase discharge efficiency. In addition to energy inputs for the discharge cycles, the round-trip energy

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[10] Based on Rocky Mountain Power planned project

[11] Based on Rocky Mountain Power planned project, salt cavern capacity (first phase)

[12] Typical contract price (CAD)

[13] Likely benchmark for top quartile generators

[14] Average Consumer Price Index

[15] Conservative estimate for scrap metal and equipment, less decommissioning cost.

[16] Increasing the duration, number of cycles and operational days increases the capacity factor. Typical combined cycle power plants operate at 80% or more. Source: EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016 (2016)*, 7. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

conversion efficiencies of both pumped hydro and CAES are subject to system losses. Depending on mechanical and electrical system losses, in CAES options the efficiencies range from 41% to 80%[17] depending on use of heat recovery technology. Since the model calculates natural gas and electricity input per MWh discharged, and natural gas use during discharge generates electricity, the electricity (charging) input is scaled accordingly. This translates to 0.7 MWh of electricity input per 1 MWh discharged.

[17] Wenyii Liu, et al., A*nalysis and Optimization of a Compressed Air Energy Storage—Combined Cycle System* (2014), 11. www.mdpi.com/1099-4300/16/6/3103/pdf; Strategic Self-Management Institute, *Analysis of compressed air storage and electric batteries* (2010), 10. http://www.windenergy-in-the-bsr.net/download/17/SSI_Stasys_Paulauskas_2010_11_15.pdf