Cost of base load ultra low and zero emissions electricity products using Compressed Air Energy Storage (CAES) in Western Canada

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Abstract: CAES can be scaled to very long duration without a significant capital cost increase making firm ultralow and zero emission renewable electricity products competitive with other forms of generation technologies. Alberta and Saskatchewan are the best locations globally to develop CAES and would employ thousands of people with all the pre-existing petroleum sector expertise required to develop, build and operate CAES facilities. As more wind and solar generation are added to the grid the required storage approaches the storage required for a system with only renewable generation and therefore provides a useful endpoint to study. Historical hourly data from Alberta wind farms was used to determine the storage attributes (storage duration and charge/discharge capacity) necessary to firm that wind farm's generation to firmly supply a 20MW base load. Based on the size of the wind farm and the storage asset the levelized cost of energy was calculated. Adiabatic CAES (ACAES) and DCAES as well as Lithium Ion batteries were considered as storage technologies. DCAES with wind generation was found to produce a base load product for $72-90/MWh CAD with 80% less emissions than a state of the art natural gas CCGT power plant. When including carbon emissions cost of $170/t the DCAES plus wind generation cost increases to $81 -102/MWh with the cost from the CCGT increasing my more than $55/MWh to a range of $104-153/MWh. ACAES with wind generation was found to be $91 - 114/MWh CAD with no natural gas cost exposure or emissions from generation based on a fixed price for wind of $30 - 45/MWh respectively. Advances in wind turbine technology enable projection of an ACAES product for less than $90/MWh in the near future making ACAES a technology of significant additional development. Li-Ion batteries were found to be too expensive due to the long duration requirement even at a price of $50/kWh installed cost. These numbers suggest that CAES with wind generation offer a competitive option compared to non-emitting (nuclear and hydro) and emitting firm generation with much lower or no emissions using current proven technology. Accelerated capital depreciation for energy storage may make this a significant opportunity for an existing company to defer taxes on current earnings, improving the corporate value of this project. All currency is in Canadian dollars.

[1] Employee of RMP Energy Storage Inc. RMP Energy Storage is a leading energy storage developer in Western Canada. RMP has focused on pumped hydro, CAES and Li-Ion battery storage opportunities within the Alberta, British Columbia, Montana and Saskatchewan markets for over a decade. RMP is actively seeking commercial support for CAES projects in Alberta and Saskatchewan.

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Background:

Electricity is a fundamental part of modern life in industrialized countries because of the cost and reliability of providing power on demand to an ever-increasing number of useful products. Worldwide emission of CO_2 from electricity and heat generation is 44% of the anthropogenic carbon emissions in 2018 [1] and therefore transition to lower emitting generation technologies is a key focus of climate change initiatives. Due in part to the policies surrounding climate change, renewable generation from solar and wind are now cost competitive

on a unit of energy basis with new thermal generation in many locations globally and, in some cases, lower cost than existing generation but, solar and wind are not available on demand [2]. Hydro and nuclear are other forms of non-emitting generation that have provided power to many globally. Each of these non-CO_2 emitting technologies have other environmental and societal impacts that need to be considered when selecting the best generation source for a given situation. As electrification of every type of technology drives up demand, locations with the most predictably affordable, reliable and most environmentally benign supply will be positioned to provide customers with superior power product.

In Canada, roughly 82% of electricity generation is CO_2 emissions free primarily from hydro and nuclear power [3]. The provinces of Alberta and Saskatchewan generate 44.9% and 46.6% of their electricity from coal respectively but this is being phased out under federal requirements by 2030 [3]. The coal generation in Alberta and Saskatchewan generated 39.75 TWh of electricity and 37.7 Mt of CO_2 in 2018 [4]. If this coal is replaced by CCGT the emissions reduction would be equivalent to 3.4% of Canada's total CO_2 equivalent emissions from the 2005 benchmark. Alberta in particular does not have ideal topography for hydro generation close to load centres. Alberta and Saskatchewan do have some of the best on shore wind potential in North America that is now being developed extensively by corporations selected through competitive bid processes or through participation in the spot market.

There are large projects in the electricity space that are in the development and construction process including additional large scale hydrogeneration in British Columbia (BC) and Newfoundland (NL) with additional potential in many other provinces. Nuclear is a significant generation source in New Brunswick and Ontario. Ontario is initiating a life extension program on a portion of its nuclear fleet to keep plants running until 2064 while New Brunswick completed a life extension to Point LePreau nuclear generation station in 2012. All of the projects completed to date have come in significantly over original budget estimates. Smaller, scalable projects determined through competitive purchasing processes are one way to reduce the risk of projects being over budget and adversely impacting either tax or rate payers.

Table 1 below outlines the cost of some of the projects providing non-CO2-emitting electricity in Canada as well as the estimated levelized costs for a new CCGT. The total cost of hydro does not include any reclamation costs at end of life and the cost of nuclear does not include the cost to safely dispose of the waste product. Neither hydro nor nuclear are as dispatchable as the CCGT asset as they must maintain river flows and are thermally constrained by ramping respectively. It is clear from recent wind and solar solicitations in Alberta and Saskatchewan that these sources on a unit of electricity generated are well below the alternatives listed in Table 1 but obviously this is not a fair comparison. Comparing dispatchable generation sources, emitting and non-emitting, to that of wind and solar energy directly does not capture that wind and solar are not available on demand and therefore must rely on other technologies to meet demand when the wind isn't blowing and the sun isn't shining.

Table 1: Cost of Dispatchable Generation

Generation Technology	$/MWh	Carbon Emissions (tCO_2/MWh)	Cost with $50/tonne CO_2	Cost with $170/tonne CO_2	Reference
BC Site C Hydro	82 – 112 [1]	0			[5]
ON Nuclear Refurbishment	80.7 – 87.9 [2]	0			[6]
New Combined Cycle Gas Turbine (CCGT)	49.4 – 97.5 [3]	0.325	65.7 – 113.8	104.7 – 152.8	[2]

[1] Estimated from $10.8B over 50 yr life, 5100 GWh/yr, 60/40 D/E, WACC 5.6%, and nominal operating cost assumptions. The higher value is considering a 30 yr economic cycle. Note that the 1100 MW asset is not fully dispatchable due to river flow constraints and 52.9% projected capacity factor. It is expected that this cost will increase due to recent quarterly BC Hydro report to BC Utilities Commission but it is unclear how much.

[2] The average Nuclear Price over the period from 2016-2064 is estimated at $80.7/MWh and if the refurbishment cost of all reactors increases 50% would go up to $87.9/MWh. The 50% increase is included as the FAO report notes that all other large life nuclear extension projects are nearly double the estimated cost. Note that there is nuclear waste associated with this and it is unclear if the

[3] Assumes capacity factor range of 55-70% and a natural gas price range of $3.18/GJ – $5.31/GJ CAD. Values are converted to CAD at 1.3 CAD/USD. No emissions cost is included in the first column numbers. Emissions cost are calculated with no allowance.

Issues with Wind and Solar Generation:

Wind and solar generation are not able to produce power on demand. This generation can be predicted a few hours in advance but needs additional backup generation that is capable of ramping with it and filling in to meet demand. More significantly, as the percentage of electricity from wind and solar on a grid increases, at certain times, they will generate more electricity than is demanded driving the electricity values to zero or negative prices as has been witnessed in many jurisdictions including Ontario, California, Texas and Germany. Excess generation is generally dealt with through curtailment and in many instances the curtailed energy is paid for by rate payers even though it is not produced. [7]. Curtailments hamper project economics, or drive up rate payer costs, and where curtailment compensation is not provided, reduces the potential installation of wind and solar generation. **Alternatively, excess electricity can be stored and used at a time when it is needed**. To demonstrate that renewable generation plus energy storage is a competitive alternative to the lowest cost dispatchable generation sources the attributes of the storage asset, the input variability and output generation profile must be described. As more wind and solar are added to the grid the required storage approaches the storage required for a system with only renewable generation. This study aims to determine the cost of such a system using currently available technology.

The cycle period for solar generation is well known for any given time during the day but intermittency primarily due to clouds that cause output variability and uncertainty. There is a significant reduction in potential solar generation from summer to winter across Canada that impacts solar generation ability to meet a significant percentage of demand. Alberta and Saskatchewan have some of the best on-shore wind resources in North America. However, the problem with wind and solar is not only that their production is volatile due to weather

patterns, but both are highly correlated across the provinces. For solar the sun rises and sets across Alberta and Saskatchewan within the window set by its East-West borders leading to near perfect correlation of solar generation less shading (clouds, buildings, etc.) across the province. Wind generation is also very well correlated across generating regions of r^2>0.85 on an hourly basis and r^2>0.89 on a daily basis [8]. Figure 1 illustrates the correlation between two specific wind farms used in this study and the value for all Alberta wind generation. This correlation of production causes significant excess generation when renewables come online and potential supply shortfalls when they are not. The duration of the periods with little wind generation on the system directly impacts the duration requirements of a dispatchable generation source to meet demand. Even though solar is more predictable than wind, because of the very low output from solar during winter periods in Canada, wind will likely be the preferential installation of renewable generation even as prices for solar on a unit of electricity generated basis go below that of wind generation. Therefore, the remainder of this paper deals primarily with wind generation combined with CAES.

With a small percentage of wind generation its intermittency can be addressed with dispatchable thermal generation but as the capacity of wind increases, the need to store excess energy becomes economically imperative and this duration requirement determines the storage duration requirements. This study aims to determine what the most economic storage asset and wind generation asset to firm wind energy in Alberta.

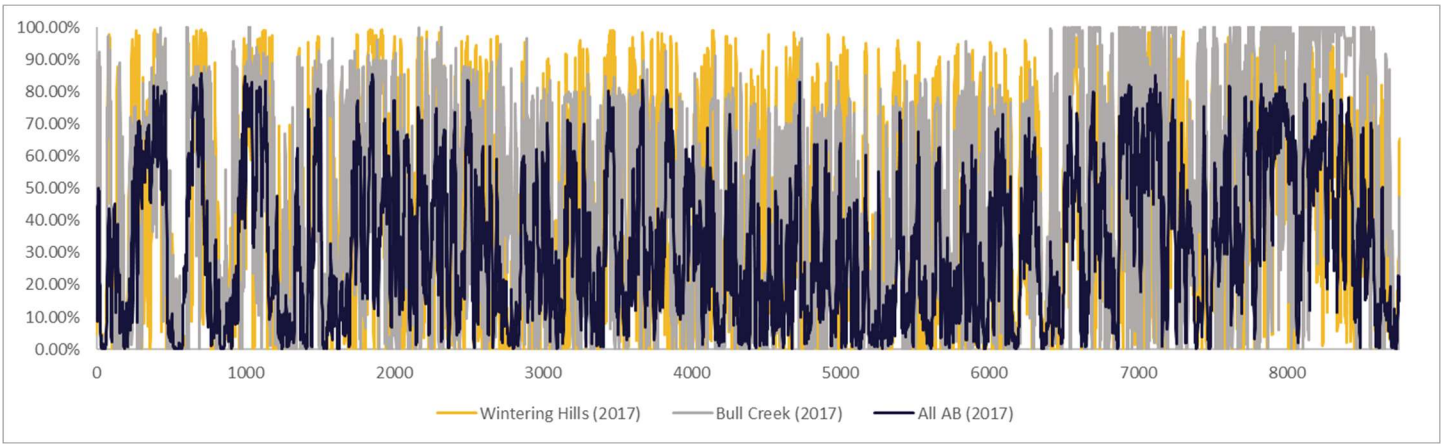

Figure 1: Wind Generator Hourly Capacity Factor over 2017 for Wintering Hills, Bull Creek and all Alberta wind generation.

Compressed Air Energy Storage Technology Overview:

CAES technology uses conventional equipment to store energy as pressurized air. Two operating plants exist using Diabatic cycles and having a combined life of over 70 years [9]. The process, illustrated in Figure 2 below, uses electrically driven compressors to compress ambient air to storage pressure, stores this pressurized air in purpose-built salt caverns, and generates electricity by allowing pressurized air to run a turbine. ACAES stores heat generated in the compression cycle to heat the expander air to increase power output and efficiency. DCAES combusts a fuel to heat the air during the expansion process to increase output of the unit. If the DCAES unit uses a hydrocarbon like natural gas then CO_2 is produced. Hydrogen is being explored as an alternative fuel for DCAES with no direct emissions.

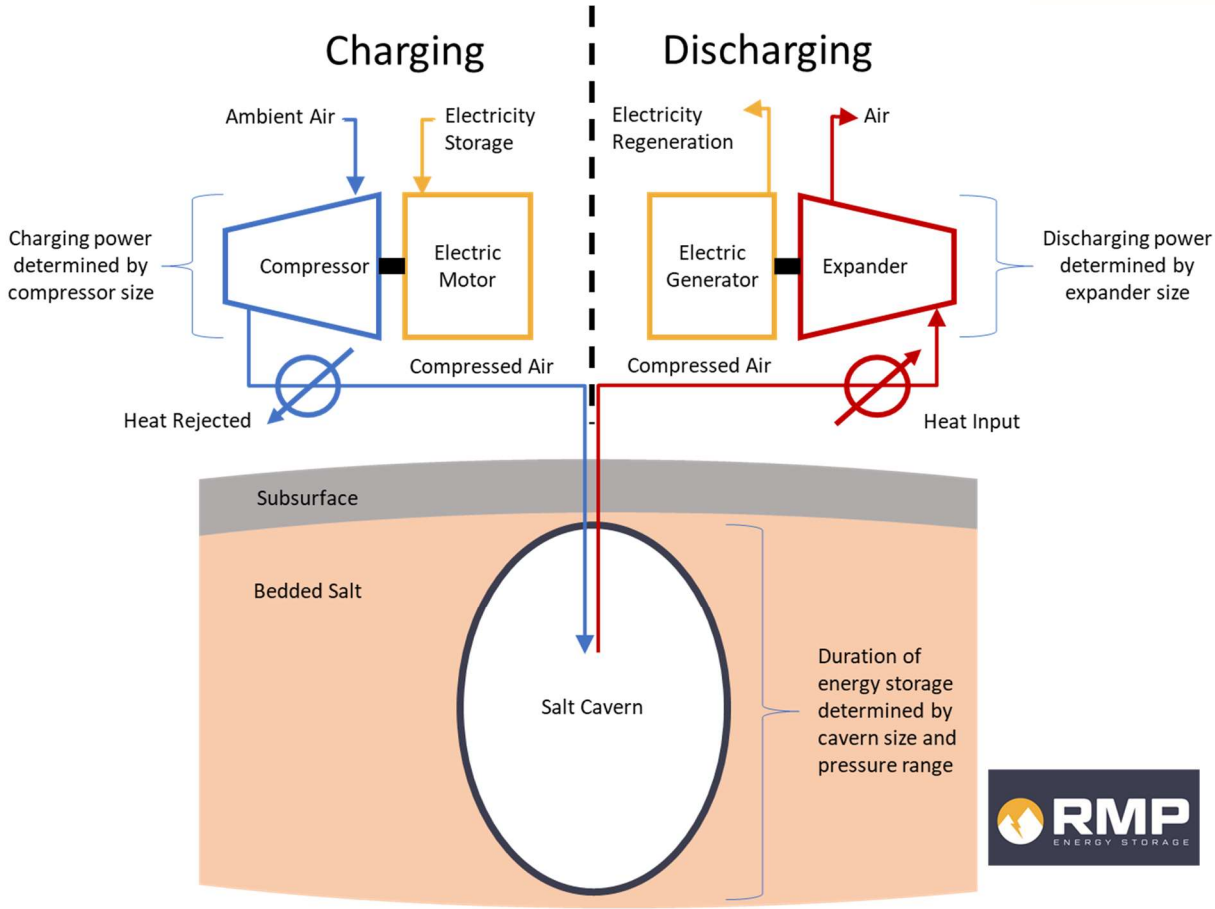

Figure 2: Schematic of CAES System. Heat input can be provided with fuel or stored rejected heat.

The efficiency of CAES technology is not well established as it depends on a number of parameters around the method of operation, cavern pressures, and thermal storage efficiency. ACAES can be demonstrated to be above 50% round trip efficiency with a potential to reach up to 65% in specific cases. DCAES is a hybrid storage and generation technology and therefore the fuel input must be considered along with the electricity. Different layouts of DCAES can result in different ratios of energy input from fuel and electricity per unit of electricity output. In this study, we have used a 1 to 1.45 electricity input to electricity energy output ratio.

Alberta and Saskatchewan are very well suited for CAES development due to the known geology and cavern building expertise that can be leveraged from the existing hydrocarbon industry. Very few locations globally have the ideal geology to create numerous caverns, dispose of the brine and publicly available data to prove it. The extent of the salt deposit is shown in Figure 3 below.

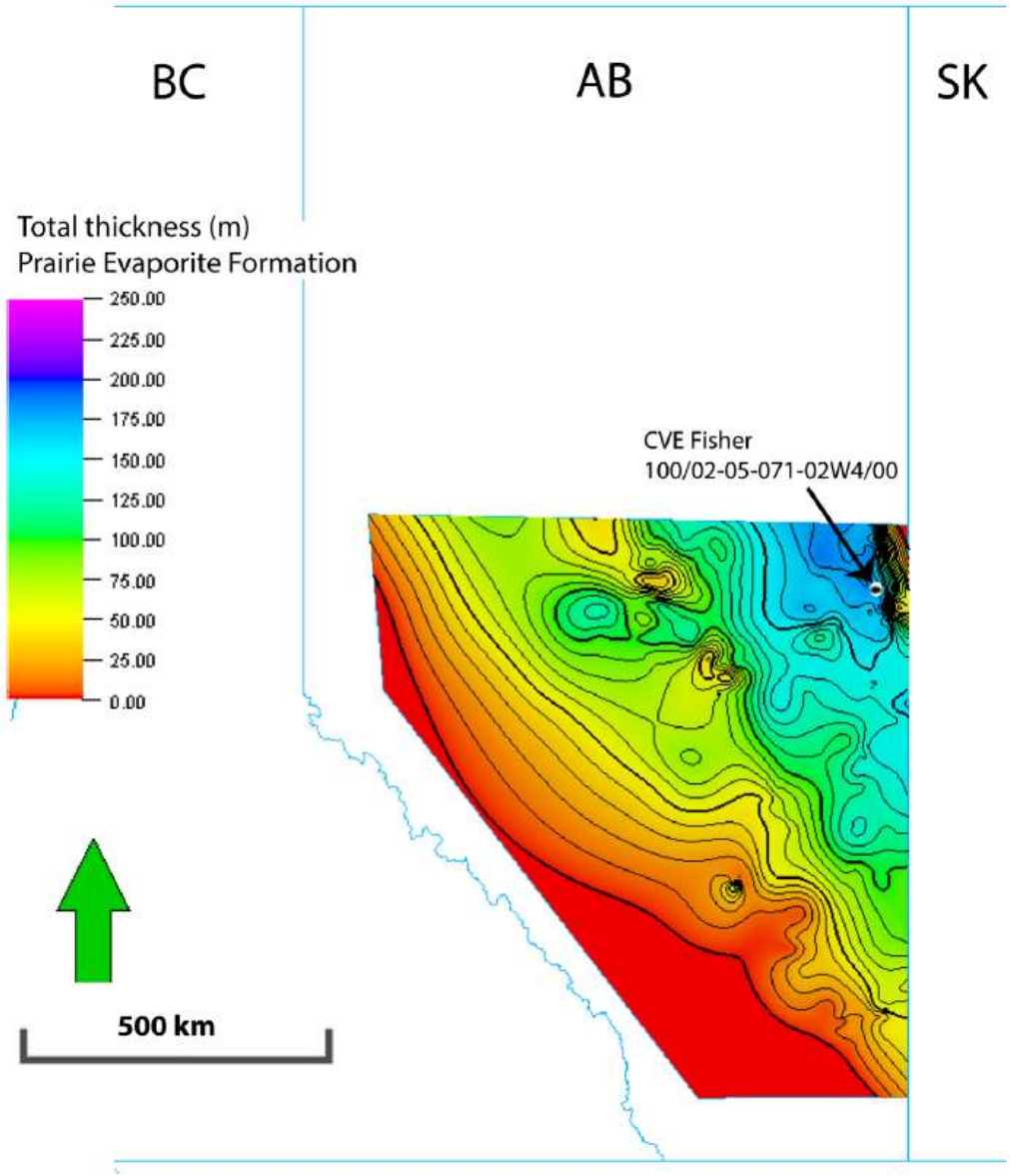

Figure 3: Prairie Evaporite salt deposit of the Western Canadian Sedimentary Basin [10]

Alberta and Saskatchewan are the best locations for CAES projects due to publicly available geological data, ideal geology, directly transferable oil and gas workforce expertise, and wind energy resources. Alberta has the additional advantage of being an open electrical market. In Alberta and Saskatchewan, all of the well logging and core data collected over decades of hydrocarbon production is a public asset except for a small sub-fraction near potash production in Saskatchewan. The volume of well data is higher than most other jurisdictions making access to this data a significant resource for CAES project developments. Many US states have significant number of wells but the data is not publicly available. The geology in Alberta and Saskatchewan is ideal for CAES with hundreds of square kilometers of salt underlying the province at the ideal depth and thickness for cavern development. Equally important is the availability of saline aquifers for solution mining the caverns and geology to dispose of the brine. This is supported by the hundreds of caverns that exist for hydrocarbon and waste

storage already operating in the province. The workforce available from a geology, engineering, construction and operation perspective are world class with skills directly transferable to CAES development.

Alberta and Saskatchewan have some of the best on shore wind resources in Canada which when coupled with low population density make them ideal for wind generation. The distributed nature of wind generation provide value to many stakeholders through lease payments, jobs and taxes to communities that are seeing reductions in revenue due to declining oil and gas activity.

After extensive research, it is clear that Alberta and Saskatchewan are among the best jurisdictions in North America to develop a firm renewable product. The size of the salt resource suggests that there is no realistic limit to the amount of load that could be supplied with firm renewable energy. The limit is first in the amount of load and a distant second the amount of potential wind generation.

RMP Energy Storage has spent years working on CAES project development with detailed thermodynamic models, cost estimation tools, project economics models and revenue generation models. This knowledge has been brought to bear in this paper to determine the cost of CAES with different durations. This goal of this paper is to determine the book end for a fully renewable system that is possible as a stand-alone product today.

RMP Energy storage has identified locations in New Brunswick, PEI and Nova Scotia where CAES assets of this size could be built but these are very small markets. Ontario has suitable geology but lacks a method of easily producing and disposing of the water required to build the caverns. US Gulf coast states of Louisiana and Texas are also well suited for CAES development but geological data is not necessarily publicly available making it more difficult to find suitable locations. Many other states including New Mexico, Arizona, New York and Michigan all have potential locations but less information is publicly available on the geology particularly related to water sourcing and brine disposal.

Method:

RMP's model uses hourly Alberta wind generation data from specific years. A 20 MW base load must be met by the combination of wind and storage in every hour of the year[1]. The model runs through every hour of the year and balances demand with supply. This is done stepwise starting with defining the wind generation for the hour from historical data. The storage asset state of charge is carried from the previous hour. If the wind generation exceeds the load value and there is capacity in storage, the storage asset charges. If there is insufficient hourly wind generation to meet the load and there is energy in storage the storage asset is dispatched to meet the load. If there is not enough wind generation and no energy in storage there is unserved load for that hour. If there is unserved load in any hour of the year, the model increments the wind generation capacity up and runs the yearly calculation again until there are no hours with unserved load. The model then increments the storage size and re-runs the wind size calculation. The levelized cost for each fleet that meets all load requirements throughout the year is then compared to determine the lowest cost fleet to deliver the power. The prices are calculated using three After Tax (AT) levered Internal Rate of Returns (IRR) for the energy storage asset to compare various potential contractual models.

[1] 20MW is an arbitrary number and is used simply for ease of calculations.

Inputs:

- One year of historical Alberta hourly wind generator output scaled to desired size. Three different wind asset and five outputs are used with different production profiles and ages as shown in Table 3.
- ACAES is modeled with 50% and 65% round trip efficiencies to capture potential range
- DCAES generates 1.45 MWh for every 1 MWh put into storage due to supplemental energy added to the system combusting 3.8 GJ/MWh of natural gas. Emissions from natural gas are calculated using 0.0503 tCO_2/GJ [11]
- Table 2 outlining costs associated with different durations of CAES for the different technologies
- Capital and operating costs fully calculated shown as a levelized cost with operational cost considerations included fixed maintenance cost 1.5%/yr of direct capital costs, insurance at 0.5%/yr of direct capital cost, land rights cost of 0.25%/yr of direct capital cost, municipal tax cost of 0.25%/yr of direct capital cost plus a 10% contingency.
- A variable operating cost of $5/MWh at an assumed 15% capacity factor.
- A natural gas price for the DCAES scenarios was assumed to be equal to $2.50/GJ
- A fixed price for wind generation of $45/MWh is also assumed for the base cases.
- Tax rate of 23% is used and the asset is assumed Canadian Capital Cost Allowance (CCA) class 43.2 with 100% accelerated capital available.
- Table 2 shows the input assumptions for cost of CAES and batteries under various equity return scenarios
- Table 3 shows some wind farm statistics summarizing the hourly data used in the modeling

Table 2: Asset Cost with 30 year life, Natural gas at $2.5/GJ, 60/40 debt/equity ratio, 20 year debt life at 4%

Technology	Duration (hr)	Efficiency (MWhout/MWhin)	Heat rate (GJ/MWh)	CAPEX ($k/MW)	Yearly Revenue Requirement ($k/MW/yr) for AT Levered IRR		
					8%	12%	15%
Li-Ion (1 hr) (25 yr)	1	90%		410	51	58	63
A-CAES	30	50 - 65%		3,001	332	386	427
A-CAES	60	50 - 65%		3,392	363	424	471
A-CAES	90	50 - 65%		3,784	394	463	517
D-CAES	30	145%	3.8	2,192	266	286	336
D-CAES	60	145%	3.8	2,323	277	298	351
D-CAES	120	145%	3.8	2,519	293	315	373

Table 3: Wind Farms description for scaling year of hourly data used is in brackets

	Actual size (MW)	Capacity Factor (%)	Installed (yr)
Wintering Hills (2012)	88	39.1%	2012
Wintering Hills (2017)	88	38.5%	2012
Bull Creek (2017)	13.6	45.0%	2015
Total Alberta Fleet (2017)	1445	31.9%	Various
Bull Creek/Wintering Hills (50/50)		41.8%	2012/15

Assumptions:

- *These assets do not have to be co-located but no grid losses or grid costs are included. This is a reasonable assumption because no grid losses and costs are assumed for competing generation technologies.*
- *CAES State Of Charge (SOC) at the beginning of year is matched to end of year*
- *The storage asset has enough flexibility that sub-hourly volatility is not meaningful for this level of analysis.*

Results:

The outcome from the model is multiple fleet descriptions that meet the load. All of these will provide the load with the same amount of power. The capital cost assumptions for the storage and size of the wind asset determine the cost of the service that is then divided by the number of MWh consumed by the load. All wind generation, even curtailed, is paid for and included in the price. Figure 4 below shows an example of the hourly output of the units under one sizing configuration over the model year. The gray line shows the hourly scaled wind farm output in MW. The blue line shows the hourly charging (negative) and discharging (positive) action of the ACAES asset to meet the 20 MW load. The yellow line uses the right hand side y-axis and shows the SOC of the CAES asset at the end of each hour. These align with the lowest cost scaled Bull Creek scenario described below of 90 MW wind generation, 20 MW ACAES with 90 hours duration of generation. The very long duration is required to match the wind volatility over multi day cycles in the lowest wind generation season as seen in Figure 4.

Figure 5 shows the requirements for a DCAES system also using scaled Bull Creek wind data to meet the same load to allow comparison between the ACAES and DCAES options. In both Figures 4 and 5, the lowest wind generation period of the year is what determines the CAES asset duration requirements.

The resulting levelized cost of output of wind and storage that meets electricity demand is shown in Table 4 with the best results from each wind generation location and resulting fleet description. The costs per MWh delivered are the complete capital and operating costs of the assets levelized over 30 years with no value for carbon (generated or credits), ancillary services, or other operations performed by the fleet. In all scenarios, excess generation is paid for at the price described in the model and assumed curtailed.

Under the baseline assumptions the lowest price for a base load product is $90/MWh delivered from a 53 MW wind farm with output modeled based on Bull Creek and a 20 MW, 180 hour DCAES unit. This product produced 0.061t/MWh delivered. The lowest cost ACAES system was $114/MWh delivered from a 73 MW blended capacity factor wind farm with 50% Bull Creek and 50% Wintering Hills, a 20 MW, 120 hour 65% efficient ACAES unit and no emissions. The lowest cost 50% efficient ACAES unit was $131/MWh delivered from a 79 MW capacity factor wind farm with 50% Bull Creek and 50% Wintering Hills, a 25 MW, 90 hour ACAES unit and no emissions.

Table 5 shows the lowest cost fleet price sensitivity to wind purchase price, natural gas price and shorter life at 8% energy storage AT IRR. Table 6 shows lowest cost delivered energy price sensitivity to various Li-Ion cost expected over the coming years with 60 hours duration and using 8% energy storage AT IRR.

Table 7 considers the impact of carbon prices for the DCAES system. Carbon costs are assumed without a baseline allowable emissions rate. They represent the lowest value from the model but do not necessarily come from the same scenario as the change in operating costs impacts the lowest fleet make up.

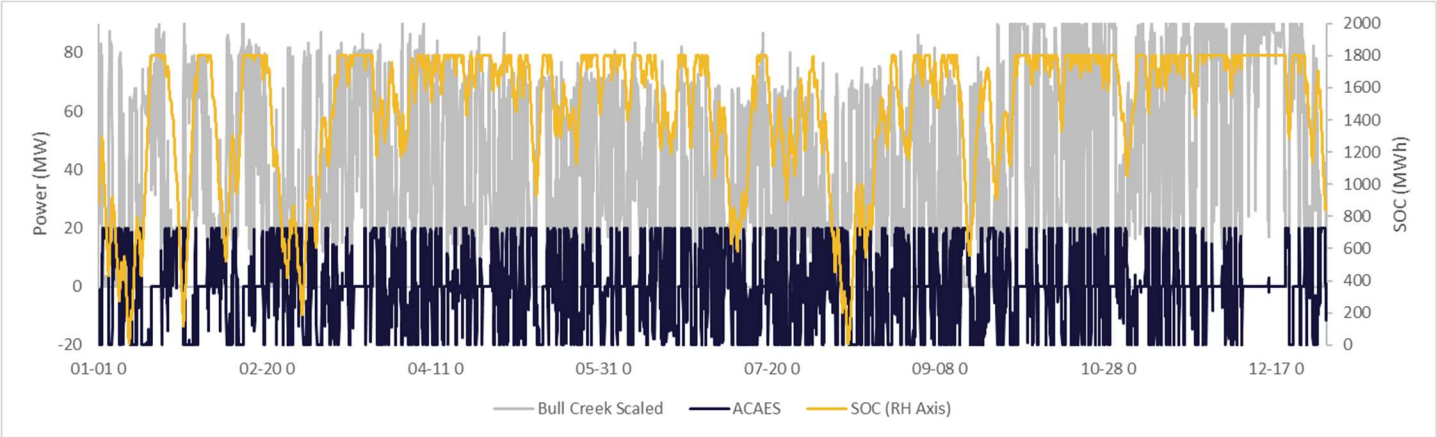

Figure 4: One year of scaled Bull Creek generation and ACAES(50% efficiency)firming to meet 20 MW load (90 MW wind, 20 MW ACAES, 90 hours duration) (ACAES charging is shown as negative MW)

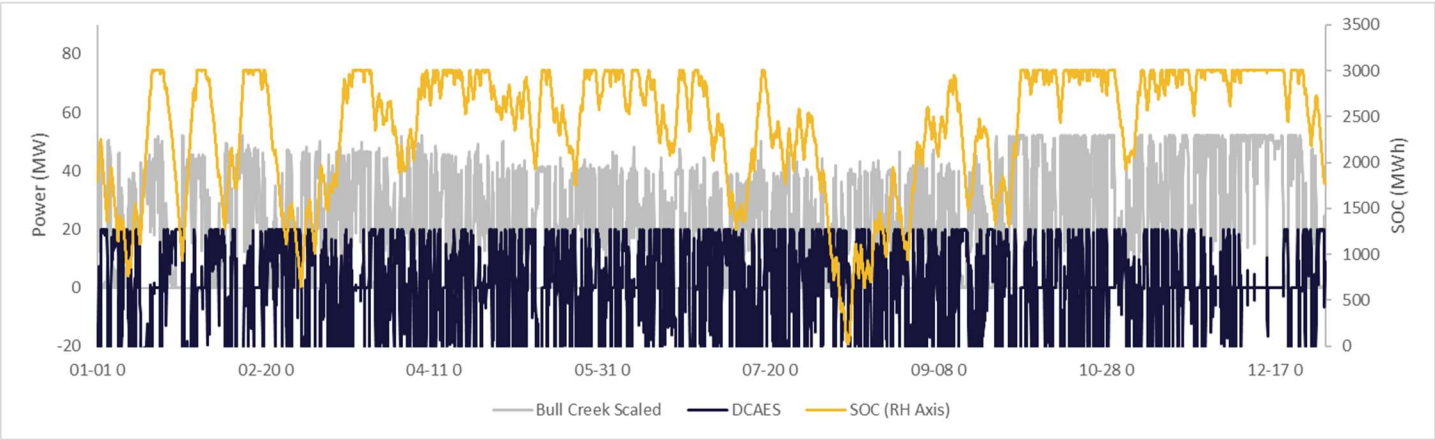

Figure 5: One year of scaled Bull Creek generation and DCAES firming to meet 20 MW load (52 MW wind, 25 MW DCAES, 120 hours duration) (DCAES charging is shown as negative MW)

Table 4: Lowest Cost Base Load Renewable Fleet by Wind Farm and CAES type using Wind at $45/MWh and a Natural Gas price of $2.5 GJ, lowest price highlighted in green.(updated Nov. 2021)

		Lowest cost fleet				CAES AT IRR Price per MWh delivered				
CAES Type	Wind Farm	Wind (MW)	ES Power (MW)	ES Duration (hr)	Excess Wind (MWh/yr)	8%	12%	15%	Natural Gas GJ/yr	Emissions tCO2/MWh delivered
DCAES	Wintering Hills (2012)	55	30	180	33617	101	104	112	239338	0.069
	Wintering Hills (2017)	65	25	180	62719	101	105	112	227824	0.065
	Bull Creek (2017)	53	20	180	51388	90	93	99	214106	0.061
	All AB (2017)	88	25	180	84315	105	108	114	152440	0.044
	Bull Creek/Wintering Hills (50/50)	59	20	180	54562	91	94	100	169480	0.049
	Wintering Hills (2012)	63	30	120	59861	107	111	119	227986	0.065
	Wintering Hills (2017)	64	30	120	59479	108	108	108	215975	0.062
	Bull Creek (2017)	52	25	120	47600	98	101	109	216030	0.062
	All AB (2017)	94	25	120	100422	112	115	122	156187	0.045
	Bull Creek/Wintering Hills (50/50)	62	20	120	65063	94	97	103	163618	0.047
	Wintering Hills (2012)	64	45	60	63158	131	131	131	237821	0.068
	Wintering Hills (2017)	65	40	60	62719	123	123	123	227824	0.065
	Bull Creek (2017)	58	35	60	70400	117	121	132	205357	0.059
	All AB (2017)	98	40	60	111204	134	138	149	141224	0.041
	Bull Creek/Wintering Hills (50/50)	66	35	60	79125	120	124	134	156555	0.045
ACAES (50%)	Wintering Hills (2012)	94	30	90	92822	150	162	171		
	Wintering Hills (2017)	104	25	90	127214	146	156	164		
	Bull Creek (2017)	90	20	90	135229	136	144	150		
	All AB (2017)	120	30	90	126427	151	161	169		
	Bull Creek/Wintering Hills (50/50)	79	25	90	77591	131	140	148		
	Wintering Hills (2012)	93	45	60	89180	175	191	203		
	Wintering Hills (2017)	95	40	60	94861	165	179	189		
	Bull Creek (2017)	89	30	60	131078	152	163	171		
	All AB (2017)	135	35	60	171385	169	182	191		
	Bull Creek/Wintering Hills (50/50)	80	35	60	81564	148	160	169		
ACAES (65%)	Wintering Hills (2012)	87	25	120	92681	131	141	149		
	Wintering Hills (2017)	88	25	120	93592	133	142	149		
	Bull Creek (2017)	74	20	120	90629	120	128	134		
	All AB (2017)	110	25	120	112828	133	140	147		
	Bull Creek/Wintering Hills (50/50)	73	20	120	71298	114	121	128		
	Wintering Hills (2012)	82	45	60	74849	162	179	192		
	Wintering Hills (2017)	85	40	60	83027	157	171	181		
	Bull Creek (2017)	81	30	60	119143	144	155	163		
	All AB (2017)	128	35	60	165372	163	173	181		
	Bull Creek/Wintering Hills (50/50)	74	35	60	75153	142	154	164		

Table 5: Price Sensitivities to Lowest Cost Fleet (Updated Nov. 2021)

Storage Technology (efficiency)	Baseline	Wind $30/MWh	Wind $60/MWh	Gas $5.31/GJ
	Price per MWh delivered			
DCAES (145%)	90	72	108	94
ACAES (50%)	131	106	155	
ACAES (65%)	114	91	137	
Li-Ion (90%)	482	438	527	

Table 6: Battery Price Reduction Impact on Delivered Electricity Cost (Updated Nov. 2021)

	$/kWh Installed				
	400	300	200	100	50
Wind Generator	Price per MWh delivered				
Wintering Hills (2012)	663	550	435	314	249
Wintering Hills (2017)	593	495	397	286	229
Bull Creek (2017)	482	409	334	249	200
All AB (2017)	629	516	401	286	229
Bull Creek/Wintering Hills (50/50)	557	460	362	263	207

Table 7: Carbon price impact on DCAES Delivered Electricity Cost (Updated Nov. 2021)

Price per MWh delivered							
CO2 $50/t	CO2 $170/t	CO2 $50/t Gas $5.31/GJ	CO2 $170/t Gas $5.31/GJ	Wind $30/MWh CO2 $50/t	Wind $30/MWh CO2 $170/t	Wind $30/MWh, Gas 5.31, CO2 $50/t	Wind $30/MWh, Gas 5.31, CO2 $170/t
93	100	96	102	75	81	78	84

Discussion:

Our analysis shows that DCAES and wind in Alberta can provide a base load energy profile for $90/MWh. Table 4 shows that a 53 MW wind farm with a blended output from Bull Creek, when coupled with at 20 MW DCAES system having storage capacity of 180 hours, could provide 20 MW for all hours in a year at a cost of $90/MWh when all wind output of the facility is purchased for $45/MWh. This price is within the range of the competing technologies outlined in Table 2. This scenario produces 0.061 tCO2/MWh delivered for wind plus DCAES compared to best CCGT 0.325 tCO2/MWh delivered greater than 80% reduction in emissions and much lower exposure to fuel price volatility.

Appling DCAES and wind broadly in Alberta and Saskatchewan to replace retiring coal instead of using CCGT would enable an additional emissions reduction of over 80%. This is equivalent to reducing Canada's emissions

4.8% below the 730 Mt CO_2 equivalent (Mt CO_2 eq) 2005 baseline compared to 3.4% if all coal was replaced with CCGT [4]. Using a DCAES plus wind product as a replacement for coal generation reduces Alberta and Saskatchewan coal fired power plant emissions from 37.7 Mt in 2018 to 2.4 Mt, a 93% reduction. Further reduction of emissions can be achieved through use of ACAES or using hydrogen from an emissions free source as part or all of the fuel. Using the ratio of load to storage to wind found in this paper means replacing 39.75 TWh of electricity would require roughly 5600 MW DCAES and 16.5 GW wind of generation. Transmission constraints would need to be considered through placement of storage and DCAES. Development of this magnitude would lead to significant economies of scale that would further reduce the cost of the product.

It is important to note that these results are not optimized and uses 5 MW steps in the sizing of the storage asset. Further refinement through optimization could be expected to yield lower prices. The CAPEX of the storage asset can be improved by optimizing the charging and discharging capacity to the wind asset and load size respectively. This analysis does show that these prices are an achievable price ceiling.

The analysis can be considered a stand-alone analysis without access to a larger grid or market. Significantly lower costs would occur if the excess wind generation was sold to alternative markets thereby reducing the revenue requirement for the base load product that comes about due to payments for curtailed wind generation. In addition, the storage asset could provide ancillary market services such as spinning and supplementary reserve generation while in generation and storage modes to reduce the revenue requirement coming from the base load product. Finally, newer, higher performance wind turbine models than those that produced the data used in this study are available. These should reduce cost of the generation significantly due to high capability factors and lower generation volatility further reducing the storage requirements and costs for the base load product. As shown in Table 5, if available wind can be produced/purchased for $30/MWh the cost of the combined DCAES/wind delivered energy could be as low as $72/MWh. This firm renewable product could be provided in Alberta or Saskatchewan to non-grid connected load customers such as data centre or mineral processing facility. Connected to the grid provides a level of additional resiliency and opportunity for revenue generation but also costs associated with the use of the grid.

The cost of wind generated power used in the baseline of this model ($45/MWh) is above the prices seen in the Alberta Renewable Energy Program (REP). This was done because the counter party in the REP is the Government of Alberta and prices of a corporate backed Power Purchase Agreement (PPA) would be expected to be higher. Government backed projects in locations like Saskatchewan could realize significantly lower costs for the wind generation and ultimately deliver these savings to the consumers. As wind turbine technology continues to improve it will undoubtedly increase capacity factors, reduce cost and therefore reducing storage requirements. This will enable an ACAES product to deliver a base load product below $100/MWh.

The natural gas price sensitivity analysis for DCAES aligns with the range used for CCGT in Table 1. It is noted that the change in gas price does not significantly impact the cost of delivered energy with wind and DCAES due to the low amount of fuel used. This low gas use is what leads to the very low emissions intensity. Furthermore, it can be seen that at the $5.31/GJ (US$3.45/MMBTU +25% used in [2]) used results in the DCAES and wind product being lower cost that the CCGT while having 80% lower emissions.

Batteries were considered as part of the generation/storage mix in a broader study not shown here but were found to not be included in the lowest cost option results due to near linear cost increase with increasing duration. This held true for all battery prices considered shown in Table 6. Current technology batteries are useful in many applications but not well suited to long duration requirements of firming wind. It is unlikely that batteries will ever be able to reach the cost of CAES storage capacity considered here. Under certain circumstances, batteries may be helpful for integration improvements such as controlling ramping events of a wind farm. As the percentage of renewable generation increases, the storage requirements approach that of a fully renewable grid similar to the product discussed here where the duration requirements dictate that CAES is superior to batteries. Wind farms looking to capture the highest revenue certainty for their future are best to contract with long duration storage to enable them to produce the product that consumers want, dispatchable power, for the life of the assets.

Considering the importance and cost of carbon dioxide emissions, the choice between ACAES and DCAES becomes less clear than the initial cost analysis alone. Table 7 considers two carbon prices along side the other variables for the DCAES fleets that can then be compared to zero emissions ACAES and batteries as well as the generation options with emissions cost in Table 1. The carbon price has a minor impact on price similar to natural gas price due to the low fuel consumption and therefore low emissions of the fleet compared to the CCGT in Table 1. At \$170/t of CO_2 the price range increases to \$81 -102/MWh. The comparison to ACAES becomes much tighter at this carbon price and warrants additional study. Should the ACAES cost estimate be reduced it may be possible to be in line with DCAES. It is critical to note that in the \$170/tCO_2 case, the estimated range for a CCGT in Table 1 spans the cost of a ACAES supported fleet even at low round trip efficiency. Also of note is that should emissions not be allowed for future generation, emissions free hydrogen fueled DCAES or ACAES would be the only CAES options.

Solar was initially considered in the model but did not provide additional value due to the cost of additional storage duration resulting from low solar capacity throughout the winter months. It is possible that some solar as part of the mix would provide additional value and this could be included in a future analysis. Similar analyses completed for jurisdictions further south having a smaller difference between summer and winter solar generation output could generate a different outcome. This should be considered when looking at locations further south with salt such as Texas, New Mexico and Mexico.

The revenue requirement for the energy storage assets uses CCA class 43.2 with 100% accelerated capital cost depreciation. This does make a material difference to the economics of the project but is not used until year 8 or later. An existing company with significant current tax burden could invest in a project of this nature and utilize the capital cost depreciation in earlier years, significantly improving the corporate value of this project.

A complete economic impact assessment has not been completed. However, based on previous work completed by an independent third party, a stand alone, 150 MW CAES asset creates 30 full time equivalent jobs and 1000 construction jobs (annualized). Additional jobs associated with wind generation and the load are not included. There is significant value here if the load is new to Alberta and requires highly skilled personnel such as data centres or high energy requirement manufacturing such as mineral processing. Export potential of electricity and expertise in these fields, leveraging oil and gas history, are significant.

Conclusion:

The possibility for affordable low carbon or carbon free power has been shown to be possible in Western Canada using CAES and wind today. This is a tremendous opportunity to leverage the existing expertise of thousands of Western Canadian oil and gas workers with no additional training towards the low carbon economy. An 80% reduction in CO_2 compared to CCGT using DCAES and wind for $72 - 90/MWh without including emissions cost is shown to be possible. When including CO_2 price of $170/t the price for DCAES and wind increases to $81 - 102/MWh. Using ACAES, $91 - 114/MWh may be achievable with no fuel cost, carbon cost or inflation exposure. With the potential of a zero emissions mandate for the power sector across Canada, this study shows the importance of additional consideration for ACAES. The modeling has not been rigorously optimized but shows realistic cases that are achievable today at these prices. Lower costs are possible with lower wind energy cost, fleet optimization, lower capital costs, lower cost of capital, if the excess generation is sold or additional services are provided by the storage assets to the grid. This base load low or zero carbon electrical product can be created within the current Alberta market today, enabling carbon conscious and cost volatility conscious loads to switch to a firm renewable product or move to Alberta without government intervention.

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