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Compressed air energy storage with waste heat export: An Alberta case study

Hossein Safaei [a,*], David W. Keith [a,b]

[a] School of Engineering and Applied Sciences, Harvard University, Pierce Hall, 29 Oxford Street, Cambridge, MA 02138, USA
[b] John F. Kennedy School of Government, Harvard University, 79 JFK Street, Cambridge, MA 02138, USA

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ABSTRACT

Interest in compressed air energy storage (CAES) technology has been renewed driven by the need to manage variability form rapidly growing wind and solar capacity. Distributed CAES (D-CAES) design aims to improve the efficiency of conventional CAES through locating the compressor near concentrated heating loads so capturing additional revenue through sales of compression waste heat. A pipeline transports compressed air to the storage facility and expander, co-located at some distance from the compressor. The economics of CAES are strongly dependant on electricity and gas markets in which they are embedded. As a case study, we evaluated the economics of two hypothetical merchant CAES and D-CAES facilities performing energy arbitrage in Alberta, Canada using market data from 2002 to 2011. The annual profit of the D-CAES plant was $1.3 million more on average at a distance of 50 km between the heat load and air storage sites. Superior economic and environmental performance of D-CAES led to a negative abatement cost of −$40/t$CO_2$e. We performed a suite of sensitivity analyses to evaluate the impact of size of heat load, size of air storage, ratio of expander to compressor size, and length of pipeline on the economic feasibility of D-CAES.

1. Introduction

Electric system operators dispatch the generation fleet in response to fluctuations in the load and to ensure grid reliability. Baseload power plants are characterized with low marginal costs, low ramp rates and high start up costs. Such inherent properties can lead to their part-load and less efficient operation and also depressed electricity prices during periods of low demand. On the other hand, peaking plants have low start up costs, fast dispatch, and high fuel costs. The variations in load and technical characteristics of the generation fleet cause fluctuations in electricity prices as well as inefficient and more polluting operation of the electricity sector. Penetration of intermittent renewable energies into the electric grid could worsen the volatility of prices. Low marginal cost of wind and solar-based electricity would depress price of off-peak electricity [1]. At the same time, forecast errors, uncertainty, and rapid changes in the output of these plants could increase the price of peak electricity [2,3].

Price volatility of electricity is a business opportunity for energy arbitrage by energy storage plants. In addition to direct financial gains for the plant itself, an energy storage unit may benefit the electric system (positive externalities) in numerous ways such as increasing the capacity factor of baseload plants and intermittent renewables [4–6] and reducing grid congestion [7,8]. Pumped hydro storage (PHS) and compressed air energy storage (CAES) are the two primary technologies for bulk storage of electric energy (hundreds of MW-hours) [9]. Development of PHS is constrained by factors such as the need for sufficient elevation difference between the two reservoirs, large footprint, relatively high capital costs, and environmental licensing [5,10].

CAES facilities buy electricity when prices are (relatively) low to run large compressors and store electricity in the form of compressed air which later is combusted to power modified gas turbines (air expanders) when prices are high. CAES plants can store air in both underground (e.g. salt caverns) and aboveground reservoirs (pressure vessels) and thus have more siting flexibility [5]. Furthermore, they have shorter construction time (around three years) and are less capital intensive compared to PHS projects [11]. There are currently two operating utility-scale CAES plants in the world. The first one is in Huntorf, Germany with an output of 290 MW over four hours, while the second plant is in McIntosh, Alabama and can generate 110 MW of electricity for 26 hours [5].

Efficiency and economics of CAES have been improved since the commission of the Huntorf plant in 1978. Recuperating heat from exhaust of the air expander in order to preheat air prior to entering the combustor reduced fuel requirements of the McIntosh plant by 25% [7]. Among various CAES designs, Adiabatic and Distributed

* Corresponding author. Tel.: +1 617 496 6196; fax: +1 617 496 0425.
E-mail addresses: safaei@seas.harvard.edu (H. Safaei), david_keith@harvard.edu (D.W. Keith).

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Nomenclature

CapEx	specific capital cost ($/MW)
CCR	capital charge rate (%)
D	diameter of pipeline (mm)
El	electric energy (MWh)
ER	energy ratio (non-dimensional)
f	friction factor of pipeline (non-dimensional)
FOM	fixed operating and maintenance cost ($/kW/year)
Heat	heating energy (MWh)
HR	heat rate (GJ/MWh)
L	length of pipeline (km)
P	pressure (kPa)
Q	flow rate (m^3/day)
T	temperature (K)
VOM	variable operating and maintenance cost ($/MWh)
Z	compressibility factor (non-dimensional)

Greek

η	efficiency (%)

Subscripts and superscripts

CAES	compressed air energy storage
Comp	compressor
Day	number of days in planning horizon
D-CAES	distributed compressed air energy storage
Down	downstream of pipeline
Exp	expander
Exp-Comp	portion of expander output used by compressor
h	hour
HOB	heat-only-boiler of district heating system
HRU	heat recovery unit
NG	natural gas
Pipe	air pipeline
Pur	electricity purchased from the market
Resv	depleted natural gas reservoir
Sold	electricity sold to the grid
Up	upstream of pipeline

CAES are of special interest. They both aim to address efficiency losses associated with waste heat of the compressor. In adiabatic CAES, air is adiabatically compressed to high pressures and temperatures and its heat is recovered prior to storage. The compression heat is stored in a thermal energy storage facility to reheat compressed air during the discharge phase. Utilization of compression heat can negate and even eliminate the need for combustion of fuel and consequently increase the efficiency of the plant [7]. However, this design is still in the research and development phase as its technical and economic feasibility is challenged by the need for high pressure and high temperature compressors and thermal energy storage facilities as well as high pressure expanders [12,13].

Distributed compressed air energy storage (D-CAES) aims to enhance efficiency and economics of CAES by utilizing the compression heat for space and water heating applications. The D-CAES concept was first proposed by the authors in an another paper [14] and a patent [15]. Energy used for municipal heating applications could be of low exergy content (low temperature) in contrast to the heating energy required for Adiabatic CAES which imposes technical difficulties to and cost burdens for this technology. The compressor of D-CAES is located near high heat load centers, such as downtown core. This configuration is in contrast to the conventional CAES in which the compressor is co-located with the expander and air storage. Compression heat would be recovered through a heat recovery unit (HRU) and sold to meet space and water heating loads with the aim of a district heating network. The downside of D-CAES is the need for a pipeline to transport compressed air from the compression facility (co-located with heat load) to the storage site located at favourable geological formations. Therefore, the capital cost of D-CAES is higher compared to conventional CAES despite its lower operational cost because of the revenue stream associated with waste heat recovery. Obviously, a D-CAES can be only economically feasible where the air storage site is in the vicinity of the heat load, otherwise the cost of pipeline would outweigh revenues from heat recovery. In some markets, the carbon emission reductions that occur when waste heat displaces gas may have a separate economic value such as a carbon credit, reduction in tax, or other instruments.

Our previous paper [14] evaluated the competitiveness of D-CAES with conventional CAES, simple cycle, and combined cycle gas turbines at a system level (i.e. minimizing the entire cost of electricity generation or maximizing the net social welfare) in a carbon-constrained world. Here we extend our earlier work to examine the performance of D-CAES under real-world market conditions. This paper compares the economics of CAES and D-CAES in a deregulated electricity market based on historical data. Both facilities are dispatched as stand-alone merchant plants performing energy arbitrage to maximize their own profitability. They are equipped with a 131 MW expander, a 105 MW compressor and a depleted gas reservoir with 1572 MWh of generation capacity in the base case scenario. The air storage site is located 50 km away from a concentrated heat load (five times larger than the University of Calgary, Canada). Price of natural gas, as a primary fuel for municipal heating would directly impact revenues associated with waste heat recovery. On the other hand, it can affect the price of electricity and thus the revenues of energy arbitrage. The main contribution of this paper is evaluating the effect of market conditions (gas and electricity prices) and design parameters (e.g. length of pipeline) on the economic competitiveness of D-CAES with conventional CAES system in energy arbitrage applications.

One should note the underlying assumption in this paper is that both facilities are price–takers. This implies the storage plants are not sufficiently large so that their operation could affect the dynamics of the market and change the price of electricity or gas. If the size of the compressor becomes comparable to the system load, then the price of off-peak electricity would likely rise (due to higher demand). This would be beneficial to the suppliers (higher sales and less cycling) while unfavourable to the consumers (including the storage plant itself due to higher prices). On the other hand, the ability of a large expander to deliver significant volumes would depress the price of peak electricity. This situation would indeed benefit the consumers (lower charges) and the grid (less need to dispatch less efficient peaking plants). However, this would hurt the profitability of the peaking plants, including the storage facility itself. Studying such possible effects are not in the scope of this paper. On the grounds that the size of the modeled compressor and expander are approximately 1% of the minimum annual load and the total installed generation capacity respectively, the authors have assumed that operation of the studied storage plants would not impact the dynamics of the market.

2. Methodology

This paper investigates potential financial gains associated with heat recovery for space and water heating applications from the

compression train of a CAES plant performing energy arbitrage. The Alberta electricity market is chosen as the financial market in which energy arbitrage is performed. The dispatch of two hypothetical CAES systems, with and without heat recovery ability, is optimized in various scenarios to maximize the profit of energy arbitrage and heat recovery. We use linear programming in MATLAB to optimize dispatch of the plants at an hourly resolution. A variety of scenarios are developed to assess the effect of different factors on economics performance of the CAES plants. These factors include: size of heat load, size of air storage, size of CAES turbomachinery, distance between heat load and air storage site, and variations in price of electricity and gas over a period of ten years in Alberta. The size of system components are fixed in each scenario while dispatch of the plants is optimized.

2.1. System of study

CAES can use a variety of geological formations for air storage. Both Huntorf and McIntosh plants store air in solution-mined salt caverns while Norton facility is to use an abandoned limestone mine [7] and the Iowa Stored Energy Park (ISEP) project was to store air in an aquifer [16]. Depleted gas reservoirs are also attractive for air storage because of their relatively low development costs [5,7].

A large concentrated heat load over a long time and at a short distance from the air storage site would be ideal for economic attractiveness of D-CAES. This is due to the trade-off between revenue stream of heat recovery and initial cost of the air pipeline. Because of the relatively cold winter climate of Calgary, Alberta, Canada [17] and abundance of gas reservoirs in its proximity [18], we assess the economics of CAES and D-CAES using depleted gas reservoirs in the vicinity of Calgary, as a case study. Both CAES and D-CAES plants would perform energy arbitrage in the Alberta electricity market while D-CAES would gain additional revenues through sales of its compression heat to a concentrated heat load in Calgary. We do not include capital cost of the base CAES plant and only take into account cost of the additional components required for waste heat recovery (i.e. air pipeline and heat recovery unit). This is because the main goal of this study is quantifying the net value of exporting the otherwise wasted heat of compression from CAES plants. This approach also allows us to avoid the current uncertainties in the true capital cost of conventional CAES technology as only two plants are so far deployed on a commercial scale. The underlying assumption in this paper is that building a merchant CAES facility for energy arbitrage is already justified and our focus is evaluating various circumstances under which heat recovery improves the economics of electric energy storage.

2.2. Electricity market of Alberta

Alberta's deregulated electricity market is managed by the Alberta Electric System Operator (AESO). The Alberta Power Pool is the spot (real time) market of wholesale electricity and there is no day-ahead market. Electricity price is capped at 999.99 $/MWh and negative prices are not allowed [19]. The generation units can voluntary modify their offers up to two hours before the delivery time. After this deadline, "Must Offer/Must Comply" (MOMC) rule is applied to all generators (except wind) implying that they will be penalized if cannot fulfill their commitment. Market participants are dispatched in real time by AESO. The price of the last dispatched unit sets the electricity price, known as system marginal price (SMP). The time-weighted average of SMP determines the wholesale settlement price for each hour, known as the pool price. One distinct characteristic of the Alberta market is lack of a capacity market; it is an "energy only" market. In other words, generators only get paid if they are dispatched. Another important characteristic is the relatively high ratio of average load to peak (load factor of approximately 80%) which is caused by the large share of industrial customers and consequently large market share of baseload plants. The fact that wholesale prices are set in real time, absence of a capacity market, and large market share of baseload plants inherently contribute to the high price of peak electricity in this market. In other words, price of peak electricity needs to be high enough so that the peaking plants (with low capacity factors) are able to recover both their operating and capital costs. Furthermore, wind farms are currently exempted from the MOMC rule and are treated as price takers. The fluctuations in the output of wind farms are managed through the power pool and the balancing services because of their low penetration level into this market (865 MW, 6% of installed capacity in 2011 [20]) without direct cost burdens on wind farms.

The dynamics of this electricity market and relatively high price fluctuations create favourable conditions for energy arbitrage. Therefore, the hypothetical CAES and D-CAES plants are assumed to directly buy and sell electricity from and to the Alberta Power Pool.[1] Natural gas is assumed as the fuel of both storage plants during the discharge phase and by the heat-only-boilers (HOB) of the district heating system. Our model uses historical wholesale electricity price reported by AESO [21] and the weighted average of gas prices traded on the Natural Gas Exchange (NGX) [22].

2.3. Heat load

Compression heat of D-CAES would be supplied to a municipal heat load through a district heating system. While a variety of heat loads can be serviced by district heating networks (single houses, office towers, etc.), a concentrated load would be the ideal candidate due to the relatively high initial and operating cost of long distribution systems. Examples of such ideal loads are downtown core, universities, and shopping malls. Since both the hot water and space heating demands of the University of Calgary are currently supplied through a district heating network, this load is used to represent a typical concentrated municipal heat load that would purchase waste heat from D-CAES. Thermal efficiency and hourly fuel consumption of the heating plant of this university in the year 2011 is used to determine its hourly heat load. This profile has a maximum and average value of 48.4 and 21.4 MW thermal, respectively. Analysis of the profile revealed strong correlation between the average hourly outside temperature and heat load ($R^2 = 0.88$). Therefore, we used the historical data for hourly temperature of Calgary reported by Environment Canada [23] to approximate the hourly load of the University of Calgary over the ten year simulation period. D-CAES plant is assumed to sell its waste heat to a load with the same profile as the University of Calgary but five times larger in the base case system. The effect of heat load size on the economics of D-CAES is examined through sensitivity analysis. The waste heat of D-CAES may satisfy a portion or the entire heat load, depending on its availability. The associated revenues are assumed equal to the market value of the fuel savings.

It is of note that a thermal energy storage (TES) unit could store the excess waste heat recovered during periods of low demand for use at a later time with high heating needs, improving the revenues of waste heat recovery. This is because periods of relatively inexpensive electricity price (when the compressor is likely operating) could coincide with periods of relatively low heating demands. TES systems can store heat over daily, weekly, and even seasonal time scales. In spite of potential economics gains through storage of thermal energy, no such a storage unit is considered in the base

[1] It bears mentioning that electricity can also be traded in forward markets or through bilateral agreements which are not in the scope of this work.

case scenario while the impact of daily storage of recovered heat is discussed in Section 3.2.

2.4. Compressed air pipeline

A pipeline would transport compressed air from the compressor to the storage site in the D-CAES configuration. Length of this pipeline is the key factor in economic viability of D-CAES as it impacts initial cost of the pipeline. Where the length of pipeline is zero (heat load and air storage are co-located), D-CAES would always be preferred over conventional CAES.

Although locating a suitable geological formation for air storage is not in the scope of this paper, we performed a preliminary screening of natural gas reservoirs to investigate the possible availability of such a geological formation in the vicinity of municipal heating loads in Alberta. We applied a set of geological screening criteria (Table 1) to a database compiled by an engineering firm for gas reservoirs within 100 km radius of Calgary and Edmonton, the two largest cities in Alberta. These criteria are pore volume, porosity, initial pressure, and pay thickness. Although permeability is an important geological characteristic too, it is not included in this screening practice due to the limited availability of rigorous data in the public domain. The authors emphasize that these criteria are only for high level screening and detailed core sampling, reservoir modeling, and air injection tests are required for final selection of a suitable reservoir. The minimum pore volume is set so that enough compressed air (known as cycled air) can be stored to support 12 hours of electricity generation at a rate of 131 MW (size of the expander in the base case system), assuming a ratio of 5 for the volume of total stored to cycled air.

The number of gas reservoirs within 100 km radius of Edmonton and Calgary that meet these geological criteria is tabulated in Table 2. As shown, pay thickness is the most limiting factor followed by storage capacity, pressure, and porosity of the reservoir and a total of 32 reservoirs met all the criteria. Although the injection and withdrawal rates in CAES facilities are generally higher compared to the rates seen in the natural gas industry, advanced techniques such as horizontal drilling and hydraulic fracturing could relax the possible constraints imposed by low permeability of gas reservoirs [16,27]. Therefore, there is a chance that at least one of these 32 identified reservoirs is suitable for storage of compressed air. Based on these results, the authors assumed a distance of 50 km between the compression and storage site in the base case analysis. The pipeline length is varied between 0 and 100 km in Section 3.5 to evaluate its impact on the economics of D-CAES.

The compression unit (located at the heat load site) would pressurize air enough to compensate the pressure losses along the pipeline. Eq. (1) is used to estimate the pipeline pressure drop (see nomenclature for definition of symbols) [28].

$$P_{\mathrm{Up}}^2 - P_{\mathrm{Down}}^2 = 9.36 \times 10^4 \times \frac{T \times L \times Z \times f \times Q^2}{D^5} \quad (1)$$

Through fixing the downstream pressure (P_{down}), maximum pressure drop per unit length of pipeline, and maximum flow rate of pipeline, Eq. (1) can be used to calculate the minimum diameter at each pipeline length. This value is then rounded up to the next commercial pipeline diameter. The downstream pressure (and hence the storage pressure) is set as 7400 kPa, the average storage pressure of the ISEP CAES project. The maximum pressure drop is set 25 kPa per km length of pipeline, a typical value for natural gas pipelines [29]. Maximum flow rate of pipeline is calculated based on the size of the compressor (105 MW) and storage pressure of 7400 kPa. The calculated values for the pipeline diameter are shown in Table 3.

2.5. Performance parameters

Turbo-machinery of CAES is composed of a compressor, expander, and combustor; similar to conventional gas turbines. While about half of energy generated by the expander is used to power the compressor of gas turbine, a CAES compressor is normally powered by electricity. CAES plants use both mechanical energy (electricity to power compressors) and fuel (to combust air) while gas turbines consume only fuel. Therefore, both the input fuel and electricity must be taken into account to quantify efficiency of a CAES plant. Heat rate represents the amount of fuel consumed per unit of electricity generated and sold. Because no energy is consumed by compressor during the discharge phase, heat rate of CAES is much lower (half to one third) of that for a similar sized gas turbine [7]. Energy ratio is the second performance index of CAES which expresses amount of electricity purchased to charge the cavern per unit of electricity sold back to the grid. See Table 4 for heat rate and energy ratio values used in this study. Energy ratio of D-CAES is higher compared to conventional CAES because of the pressure losses in the air pipeline. Table 3 shows values used for energy ratio of D-CAES. This parameter is modified for each pipeline length to take into account energy losses in the pipeline according to Eq. (1).

It is of note that a CAES plant can operate as a gas turbine when it runs short of stored air [30]. The compressor would consume a portion of the energy generated by expander in this case. Therefore, fuel consumption of CAES would increase from the optimal design point; close or even higher than values seen in gas turbines. A CAES plant is not likely to operate at these elevated heat rates unless high prices of peak electricity outweigh the increase in the fuel costs. Both plants are assumed to have such operational flexibility.

A thermal efficiency of 80% (higher heating value, HHV) is considered for the boilers and distribution pipes of the district heating network. This value is used along with the price of natural gas to estimate the financial revenues of heat recovery for D-CAES. We also used a heat recovery coefficient of 70% indicating that up to 70% of the compression energy can be recovered and supplied to the heat load in the D-CAES system.

2.6. Costing inputs

The underlying assumption in this study is that building a merchant CAES plant is already justified from technical and financial perspectives and the primary question addressed here is whether to build a D-CAES or a conventional CAES facility. Therefore, the

Table 1
Geological criteria for screening of natural gas reservoirs for air storage.

Criterion	Threshold	Notes	Reference
Storage volume	>900,000 m^3	Based on a volumetric ratio of 0.2 for cycled to total stored air	[24,25]
Porosity	>10%		[26]
Initial pressure	>5700 kPa	Inlet pressure of expander	[25]
Pay thickness	>15 m		[25]

Table 2
Number of natural gas pools within 100 km radius of Calgary and Edmonton that meet the geological requirements used in this study for air storage.

City	Total pools	Pay thickness	Storage volume	Initial pressure	Porosity	All criteria
Calgary	6726	187	1027	3788	3793	26
Edmonton	10,039	47	1625	4056	7273	8

Table 3
Diameter and capital cost of the pipeline and energy ratio of D-CAES at various pipeline lengths.

Length (km)	Diameter (mm)	Capital cost ($ million)	D-CAES energy ratio
25	743	17.0	0.759
50	743	30.6	0.766
75	743	43.3	0.772
100	743	55.4	0.777

Table 4
Performance characteristics of components of the CAES and D-CAES systems.

Parameter	Symbol	Value	Note
Expander heat rate	HR	4185 (MJ/MWh)	[31]
CAES energy ratio	ER	0.75	[31]
Boiler efficiency	η_{HOB}	80%	HHV
Heat recovery coefficient	η_{HRU}	70%	

capital cost (CapEx) and fixed operating and maintenance costs (FOM) of the base CAES plant are not included in our analysis. The base CAES facility is composed of a 131 MW expander, 105 MW compressor and a depleted gas reservoir with 1572 MWh of storage capacity (equivalent to 12 hours of generation at full capacity), in accordance with a recent study on the design and costing of CAES plants by the Electric Power Research Institute (EPRI) [31]. The variable operating and maintenance cost (VOM) as well as fuel and electricity charges are the costs associated with energy arbitrage. The major additional equipment in the D-CAES system is the air pipeline and heat recovery unit (HRU). Capital cost of the pipeline is estimated for each pipeline length and diameter with the aim of a regression model developed by Sean McCoy [32] (see Table 3). Capital cost of HRU is assumed negligible since air has to be cooled down prior to storage anyways, even if the heat is not to be used for heating applications. In other words, the capital cost of the heat exchanger is already included in the cost of the base CAES plant and no major additional costs are expected for the D-CAES facility.[2]

Costs associated with transmission lines to move electricity to/from the plants as well as cost of the gas pipeline required to deliver fuel to the expander are ignored since these components would be common between the two plants. One D-CAES configuration originally proposed by the authors in [15] considers moving both the compression and expansion trains from the storage site to the proximity of heat load. A single pipeline would transport air to the storage site and back to the expander for electricity generation. The advantage of this configuration is eliminating the need for gas pipelines and transmission lines at the storage site. Despite potential cost savings in this scenario, this paper assumes that expander of D-CAES is co-located with the air storage at some distance from the heat load.

Although CapEx and FOM of the base CAES system are excluded from our analysis, marginal capital and FOM cost of the expander, compressor, and air storage are considered in the sensitivity analysis section. These costs are used to evaluate how a different set of equipment size would alter economics of CAES and D-CAES compared to the base case scenario. Marginal costs are derived from a recent report on the design and costing of CAES by EPRI [31] and are shown in Table 5. All CapEx and FOM values are expressed in 2009 inflation adjusted US dollars according to the Chemical Engineering Plant Cost Index [33,34]. VOM and revenues of energy arbitrage and heat recovery are adjusted for inflation based on Customer Price Indices (CPI) of Alberta reported by Statistics Canada [35] and are reported in 2009 US dollars.

2.7. Optimization model

A linear programming model is developed in MATLAB to determine the optimal dispatch of the CAES and D-CAES plants. The optimal dispatch is defined as the operational strategy which maximizes the annual profit of the energy storage plant through energy arbitrage and heat recovery. The objective function is shown in Eq. (2). The first term expresses the financial gains through sales of electricity; the difference between payments from the electricity market and operating cost of the expander (fuel and VOM). The second and third terms represent the costs of running the compressor. The second term shows the cost of powering the compressor by the expander; the fuel consumed by the expander and VOM cost of expander and compressor. The third term calculates the cost of powering the compressor with electricity. The profits of waste heat recovery are calculated in the fourth term.

$$\begin{aligned}\text{maximize} \sum_{h=1}^{24\times\text{Day}} \Big\{ & [\text{El}_{\text{Sold}} \times (\text{Price}_{\text{El}} - \text{HR} \times \text{Prise}_{\text{NG}} - \text{VOM}_{\text{Exp}}] \\ & - [\text{El}_{\text{Exp\_Comp}} \times (\text{HR} \times \text{Price}_{\text{NG}} + \text{VOM}_{\text{Exp}} + \text{VOM}_{\text{Comp}})] \\ & - [\text{El}_{\text{Pur}} \times (\text{Price}_{\text{El}} + \text{VOM}_{\text{Comp}})] \\ & + \left[\text{Heat}_{\text{HRU}} \times \left(\frac{\text{Price}_{\text{NG}} \times 3.6}{\eta_{\text{HOB}}} - \text{VOM}_{\text{HRU}}\right)\right]\Big\} \end{aligned} \tag{2}$$

An hourly resolution is chosen for this study since energy arbitrage is the main application of the plants simulated. This approach is in agreement with other studies in the field of economic assessment of CAES systems dispatched for arbitrage of electric energy [4,8,9,30,37]. A bulk energy storage plant is normally dispatched based on its marginal operating cost and current and expected future price of electricity. This approach requires the plant operator

Table 5
Costing inputs for assessing the economics of CAES and D-CAES.

Parameter	Symbol	Value	Reference
Marginal CapEx of expander	$\text{CapEx}_{\text{Exp}}$	440 ($/kW)	[4,31]
Marginal FOM of expander	FOM_{Exp}	8.0 ($/kW/year)	[31]
VOM of expander	VOM_{Exp}	0.87 ($/kWh)	[31]
Marginal CapEx of compressor	$\text{CapEx}_{\text{Comp}}$	415 ($/kW)	[4,31]
Marginal FOM of compressor	FOM_{Comp}	8.0 ($/kW/year)	[31]
VOM of compressor	VOM_{Comp}	0.87 ($/kWh)	[31]
Marginal CapEx of air storage	$\text{CapEx}_{\text{Resv}}$	0.15 ($/kWh)	[7]
CapEx of HRU	$\text{CapEx}_{\text{HRU}}$	Negligible	
VOM of HRU	$\text{VOMEx}_{\text{HRU}}$	Negligible	
FOM of pipeline	$\text{VOMEx}_{\text{Pipe}}$	3820 ($/km/year)	[36]
Capital charge rate	CCR	10%	

[2] One should note that recovery of the compression heat might reduce the size (and consequently CapEx and FOM cost) of the boilers of the district heating system. A smaller boiler can be utilized since a portion of the heat load is supplied by HRU of D-CAES.

to forecast future price of fuel and electricity. Sioshansi et al. [37] evaluated the arbitrage profit of a hypothetical CAES facility in the PJM market with two different planning strategies. In both cases, the operational schedule for the following two weeks was set at the beginning of that period. Arbitrage profits were then summed to estimate the annual profits. The first planning strategy assumed that perfect foresight of market prices over the two week planning horizon was available. This case corresponds to the maximum theoretical profit because of perfect knowledge over future prices. On the contrary, the storage plant was dispatched solely based on the historical prices of the past two weeks in the second case (backcasting method). The simulation results over a period of six years revealed that the backcasting method was able to capture about 85% or more of the maximum theoretical value obtained in the first case. This phenomenon is mainly driven by the fact that the diurnal and weekly changes in the electricity prices are relatively predictable and repeated over time. The two scenarios modeled by Sioshansi et al. represent two extreme cases for dispatching energy storage plants in the real world. The arbitrage profits of real plants would be in between these extreme cases and sophisticated forecasting models and dispatch algorithms would reduce the gap between actual and the maximum theoretical profits. This paper; therefore, assumes perfect knowledge of electricity and gas prices in each planning period.

We choose a period of eight days as the planning horizon in order to take advantage of fluctuations in electricity prices driven by the diurnal (intra-day) and weekly (weekday and weekend effect) cycles in the demand and prices. This planning horizon is in accordance with sizing of the air storage and operational strategy of real world CAES plants. As a case in point, the geological formation of the ISEP CAES project could hold enough air to support 36 hours of electricity generation (week-long storage of energy). Furthermore, each planning period is overlapped one day with the next one to ensure smooth transition (rolling window optimization). This approach ensures that market signals over the next period are taken into account while the dispatch of the energy storage is optimized individually in each period. It is of note that our estimates for arbitrage revenues are more conservative (lower) compared to Sioshansi et al. since they used a two week planning horizon versus our 8 day period.

Maximizing profit of the energy storage plants in each eight-day planning horizon is subjected to the following constraints:

- Maximum heat recovered during each hour in the D-CAES configuration is equal to the product of heat recovery coefficient and the compression energy consumed during that hour.
- Heat supplied to the load during each hour is equal to or less than the hourly heat load. This constraint sets the upper bound for the financial gain from heat recovery.
- Output of the expander is less or equal to its size (fixed in each case).
- Energy stored in the air storage is less or equal to its capacity (fixed in each case).
- Energy consumption of the compressor in each hour cannot exceed its size (fixed in each case).
- Conservation of energy is honored for the air storage. The net energy injected in each hour should be equal to the increase in energy level of the cavern during that hour.
- Energy level of air storage at the beginning of each planning period is set based on plant's dispatch in the previous planning period.

Five parameters are determined by the optimization code for each hour: energy level of air storage, electricity purchased from the grid, electricity sold to the market, portion of expander output that is used by the compressor, and finally the amount of compression heat recovered. Fig. 1 illustrates a snapshot of optimized dispatch of D-CAES.

Arbitrage profits are calculated over a period of one full year to reflect seasonal changes in the price of electricity and gas as well as the heating load. In order to take the annual fluctuations into account as well, the profits are computed over a period of ten years (2002–2011). As illustrated in Fig. 2, this period embraces a wide range of market conditions. Mild prices in early years, significantly higher prices between years 2004 and 2008 (economic boom), depressed prices during the recent economic recession (years 2009 and 2010), and finally high electricity price and very low gas price in 2011 are observed in this decade. This figure also illustrates average of daily standard deviation of electricity prices for each year. As will be shown in next section, the daily fluctuations of electricity prices strongly impact the revenues of electricity arbitrage.

3. Results and discussions

3.1. Base case scenario

Annual operating (gross) profits of the CAES plant and the additional profits gained by the D-CAES system (profit of D-CAES minus profit of CAES, referred to "Additional profit of D-CAES" throughout the paper) are presented in Fig. 3. Only the operating costs (electricity, gas, and VOM) are subtracted from the arbitrage revenues to estimate operating profit of CAES. In addition to these, amortized capital and FOM cost of the air pipeline are considered in calculating profits of D-CAES.

The operating profit of CAES experiences large fluctuations with an average value of $28.2 million over the decade and a relative standard deviation of 36%. The D-CAES plant earns $1.3 million/year more than CAES on average, with a relative standard deviation of 119%. It is important to note this profit is after taking a 10% capital charge rate into account to reflect the cost of capital to the owner of the D-CAES plant. In next step, we look into the drivers for such annual fluctuations of the profits.

In a perfectly competitive market, all participants should offer electricity at their marginal cost of generation. This may not; however, be the case for real world electricity markets, especially for the Alberta market with a relatively small size (average load of 8.4 GW in 2011). Coal is the price setter for approximately 54% of the year while gas plants are marginal for almost the rest of the time. However, high electricity prices (when sales of stored energy is highly profitable) are weakly impacted by gas prices in this market ($R^2 = 0.03$ for correlation between daily price of electricity and gas over the study period). Periods with high electricity prices might be driven by various factors such as physical constraints or outage of generators and transmission lines as well as weather conditions. Lack of a capacity market and the ability of market participants to voluntarily modify their offers up to two hours before the delivery time may also contribute to high price of peak electricity. On the other hand, price of gas has a direct impact on the operating cost of the CAES and D-CAES plants and revenues of waste heat recovery. Therefore, variations in price of gas will not change the value of electricity arbitrage while it would directly affect operating cost of both plants and value of heat recovery.

Fig. 4 explores the impact of gas prices and fluctuations in electricity prices on the operating profit of CAES over the ten years of simulation. Since compressed air storage plants are sized and dispatched for short-term cycles, we use daily standard deviation of electricity prices, averaged over each year, to quantify volatility in electricity prices. The CAES profits are essentially uncorrelated with gas prices ($R^2 = 0.04$), but they have a strong correlation with

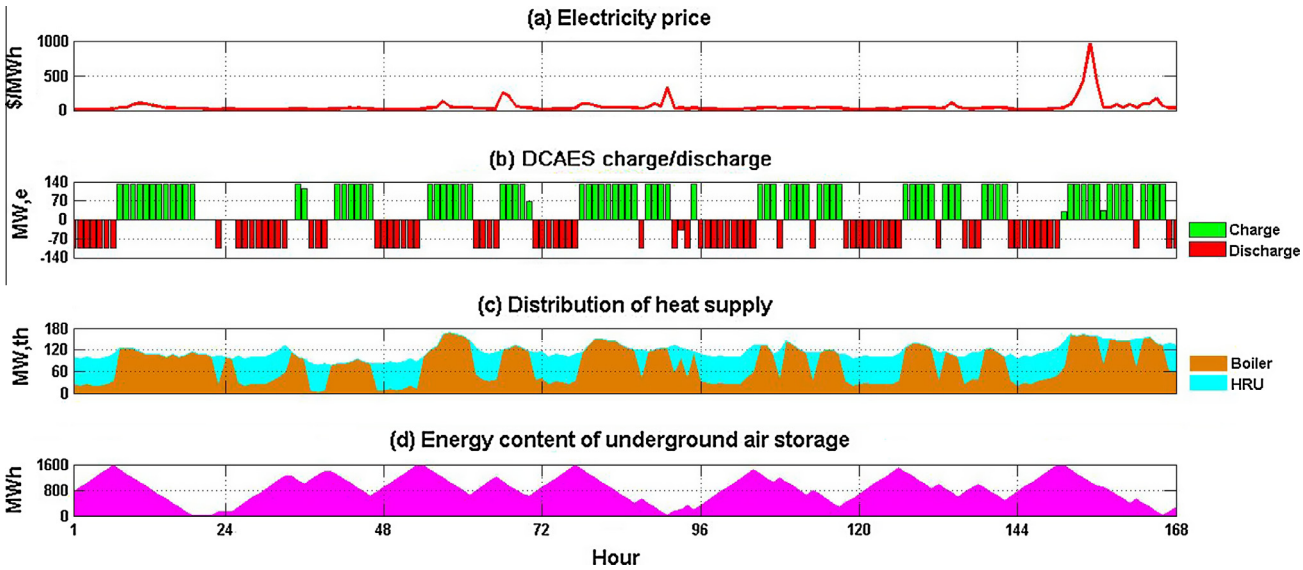

Fig. 1. Optimized dispatch of D-CAES system over an arbitrary time period (Saturday, October 29 to Friday, November 4, 2011). "Charge" and "Discharge" in subfigure b represent energy purchased and sold to the electricity market, respectively.

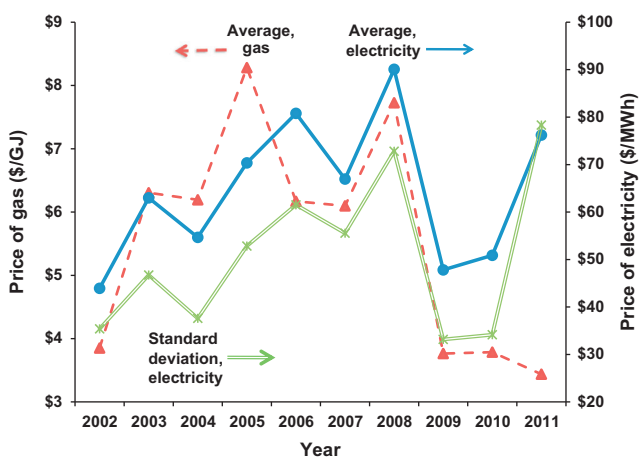

Fig. 2. Annual average of gas prices (left axis), electricity prices (right axis) and daily standard deviation of electricity prices (right axis) between 2002 and 2011 in Alberta.

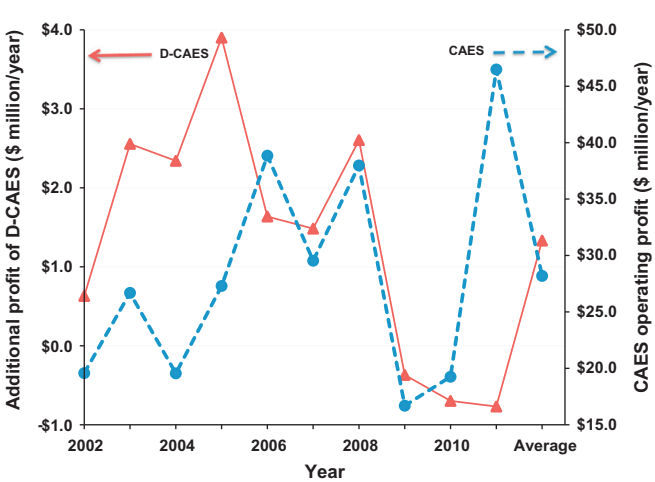

Fig. 3. Annual operating profit of the CAES plant (right) and the additional profit of D-CAES (left). Note large variations throughout the ten-year period.

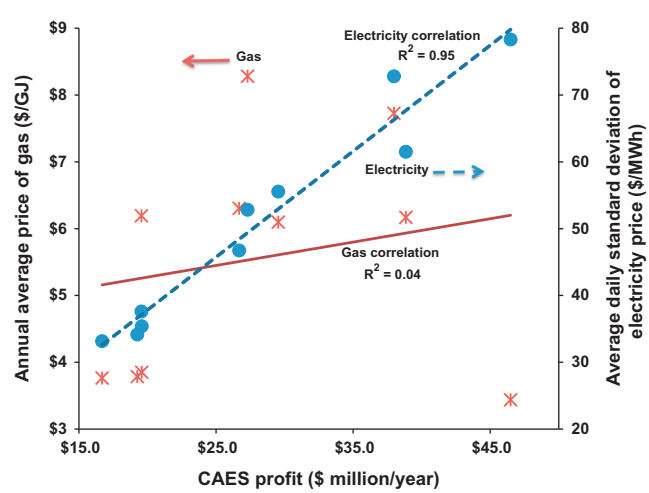

Fig. 4. Correlation of CAES operating profit with price of gas and volatility of electricity prices over the ten year simulation period. Profit of CAES is strongly correlated with standard deviation of electricity prices.

fluctuation in electricity prices ($R^2 = 0.95$). The relative importance of electricity and gas prices on economics of CAES can be further explored through studying their annual fluctuations (see Fig. 2). As a case in point, years 2010 and 2011 experienced similar gas prices ($3.8 and $3.4/GJ, respectively) while daily standard deviation of electricity prices was 130% higher in 2011. Arbitrage profits are 140% higher in 2011. On the other hand, years 2004 and 2010 are good examples of two years with similar daily volatility in electricity prices but wide spreads in gas prices. Gas prices were 64% higher in 2004 while CAES plant has similar arbitrage profits in those two years.

While a poor correlation between price of gas and arbitrage profits is observed, gas prices have a strong impact on the revenues of heat recovery. Fig. 5 shows the changes in profit difference of D-CAES and CAES with respect to the gad prices and fluctuations of electricity prices. The additional profit of D-CAES is strongly impacted by gas prices ($R^2 = 0.91$) and there is no notable dependence on electricity prices ($R^2 = 0.02$). Year 2005 experienced the highest profit difference (14%), highest price of gas, a moderate volatility in electricity prices and an intermediate profit for CAES. On the

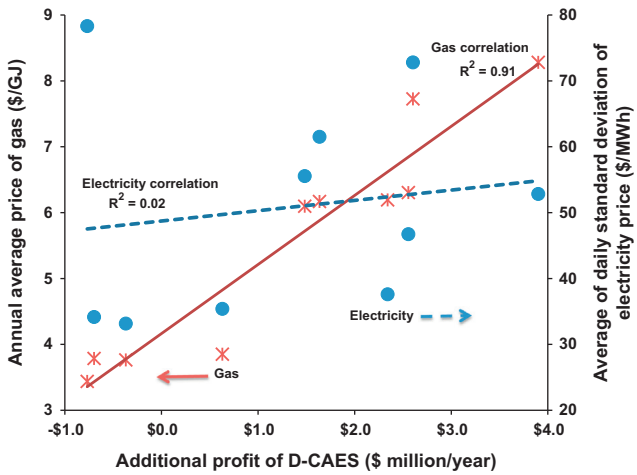

Fig. 5. Annual price of gas, price volatility of electricity, and additional profit of D-CAES (with respect to CAES) over the ten-year study period. Note the strong correlation between profit of D-CAES and gas prices.

contrary, year 2011 with the least additional D-CAES profit experienced the lowest gas price, the most volatile electricity prices, and the highest arbitrage profit for CAES.

D-CAES plant purchases 33% more electricity from the market each year on average indicating that revenues from waste heat recovery significantly alter the dispatch of the energy storage plant. The fact that compressor and consequently expander of D-CAES operate more often implies that D-CAES would consume more gas compared to CAES. On the other hand, heat recovery negates fuel consumption of the district heating system. To quantify these two opposite effects on the net fuel consumption and emissions, the GHG intensity of both plants are calculated. GHG intensity is defined as the net amount of greenhouse gases emitted per megawatt-hour of electricity sold. A value of 66 kg CO_2e[3]/GJ (lower heating value) is used for carbon content of natural gas (including the typical[4] upstream emissions) [4]. The fuel savings of the district heating system as a result of recovery of the compression heat is subtracted from the fuel consumption of the D-CAES plant to determine its net fuel consumption and GHG intensity. The annual average GHG intensity of D-CAES turned out 48% lower than CAES (144 and 273 kg CO_2e/MWh, respectively). Compressed air energy storage plants are considered as promising alternatives to gas turbines in providing cleaner peak electricity, especially if the off-peak electricity has a low GHG intensity, such as wind or nuclear. GHG intensity of a gas turbine with an efficiency of 35% would be 679 kg CO2e/MWh, a much higher value compared to CAES and D-CAES.[5] The superior environmental performance of D-CAES compared to conventional CAES and gas turbines could make this technology more attractive if aggressive measures for emission reduction are incorporated into the electricity market.

Carbon abatement cost is often used to inform policy making in identifying the most economic ways to reduce GHG emissions among alternative technologies. The fact that D-CAES facility has stronger economics and at the same time a lower GHG intensity, results in a negative abatement cost of −$40/t[6]$CO_2e$ over the study period. In other words, recovery of the otherwise wasted heat of compression would not only lower GHG intensity of the conventional CAES systems, but it also would provide a profit of $40 per ton of avoided CO_2e.

Finally, it is important to note that the energy storage plants modeled in this study are both stand-alone merchant facilities. This mode of ownership involves some positive externalities which could be captured by the plants themselves (especially D-CAES) if a utility co-owns such a storage plant with other generators. Following is two examples of scenarios where co-ownership might improve economics of energy storage:

- A utility could utilize either a conventional CAES or D-CAES facility to lower the cycling cost of its baseload assets. The energy storage plants would have almost the same effect on the operation of baseload units if they were individually operated; however, none of the financial benefits would be collected by the storage plants themselves. As the compressor of D-CAES has a higher capacity factor, the positive externalities would be higher for this plant.
- A utility can provide firming capacity for its wind assets through co-operating a compressed air energy storage plant with its wind farms.[7] If the MOMC rule is to be applied to wind farms, an independent wind farm would be penalized for shortage of delivery and would lose potential revenues if more wind becomes available. A D-CAES facility would have a higher desire to store the otherwise curtailed wind due to the revenues associated with heat recovery. From a public-policy perspective, wind energy currently has some negative externalities on the electricity market of Alberta since it is exempted from the MOMC rule. Co-operation of wind farms with CASE/D-CAES facilities can address this issue.

3.2. Optimal size of heat load

Higher needs for thermal energy would obviously improve the economics of waste heat recovery. The heat load used in this study experiences large variations (relative standard deviation of 42%). Therefore, revenues of heat recovery would fluctuate significantly unless the size of heat load is relatively large compared to the size of HRU. In other words, not all the available compression heat would earn revenue for D-CAES unless the size of HRU is comparable to the base (minimum) heating load. The size of HRU is set as 73.5 MW (70% of the size of compressor) while the minimum heating load is 35.8 MW thermal in the base case.

In order to evaluate the impact of heat load size on economics of D-CAES, we varied its value from 0.5 to 10 times the size of the University of Calgary's load. This ratio is set at 5 in the base case scenario. The profit difference between D-CAES and CAES systems is averaged over the ten year simulation period for each load size and it varies between −$2.6 million and $1.6 million, as shown in Fig. 6. A minimum value of 2.5 for the size of the load yields in positive net profits from heat recovery. A marginal increase in heat load has a significant impact on the profits of heat recovery at load sizes below 5. Fig. 6 also shows the percentage of available compression heat that is curtailed. This value is very high (73%) at a load size of 0.5 while it drops to 4% at a size of 5. One should note that a larger heat load generally translates to longer heating pipelines for the district heating network and consequently higher pressure and heat losses (higher operating costs). Therefore, the optimal size of the heat load paired with a D-CAES plant is project-specific and is determined based on the trade-off between

[3] GHG emissions are expressed in equivalent amounts of carbon dioxide (CO_2e) in this paper.

[4] Indirect GHG emissions (e.g. associated with manufacturing of equipments) are not included.

[5] One should note that net GHG intensity of energy storage plants will depend on the source of electricity used for charging if the round trip (life-cycle) GHG intensity is to be determined. Only "inside-the-fence" emissions are considered in this paper.

[6] One "*t*" indicates one metric ton (1000 kg).

[7] Wind farms are currently exempted from the MOMC rule in the Alberta market, mainly due to the low penetration of wind.

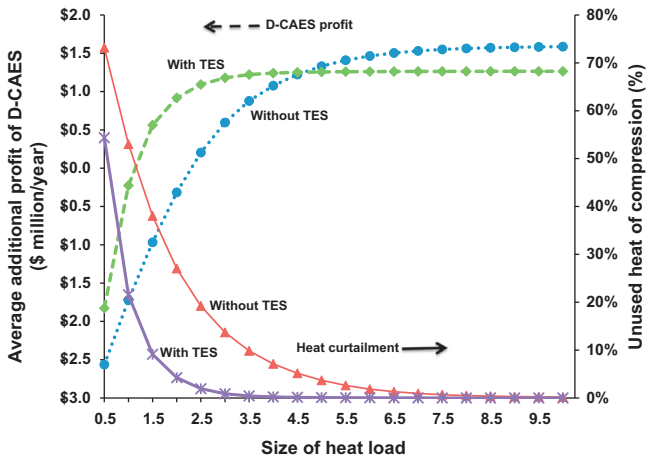

Fig. 6. Effect of size of heat load and storage of waste heat (day-long) on profit of D-CAES (left) and curtailment of compression waste heat (right). Size of heat load is expressed in relative terms compared to the University of Calgary (annual average of 21.4 MW thermal).

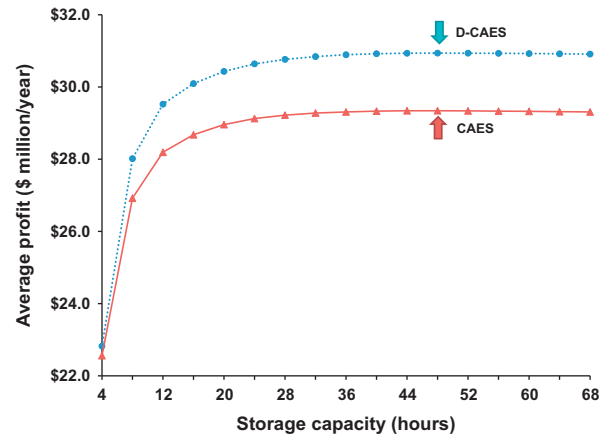

Fig. 7. Effect of the size of air storage on operating profits of CAES and D-CAES plants, averaged over the simulation period. Arrows indicate the optimal size of the storage facility.

revenues of waste heat recovery and capital and operating costs of the district heating network.

As discussed earlier, storing the surplus heat of compression for later use could improve both economic and environmental performance of D-CAES. In addition to the base case, we consider a scenario in which hot water tanks can store the excess recovered heat for the same day use. We use a value of $3.37 million for capital cost of such a thermal energy storage (TES) system in consultation with an engineering firm. The hot water tanks are sized to store heat of compression at HRU's full capacity for 12 hours. Fig. 6 illustrates the impact of utilizing such a TES system on the profit of D-CAES as well as portion of the available compression heat that is sold. As observed, the ability of storing the excess heat significantly improves profits of heat recovery up to a load size of 2.5. Effectiveness of TES weakens as the size of load increases and consequently there is a higher instantaneous need for the heat of compression.

3.3. Optimal size of air storage

As discussed in Section 3.1, revenues of heat recovery incentivize D-CAES plant to store more electricity. A larger reservoir would enable storing more energy during periods of high heating demand and low electricity price. A larger storage would also increase the arbitrage revenues of both plants as more electricity could be sold. On the other hand, a storage facility would be more capital intensive. In order to investigate this trade-off, the profit of CAES and D-CAES plants are compared in a range of storage capacities. The lower bound is a plant with a generation capacity of 4 hours (524 MWh) while the upper bound assumes 60 hours of energy discharge. The size of compressor and expander are fixed in all cases at 105 and 131 MW, respectively. It is important to note that our analysis presumes the capital cost of the air storage linearly increases with its size (at a slope of $1.5/MWh, see Table 5).

Fig. 7 shows the profits of CAES and D-CAES at various cavern capacities. Similar trends are observed for both plants: an incremental increase in the size of reservoir sharply enhances their profits up to a capacity of 12 hours while the rate of change is minimal past this point. Increasing the capacity of the air storage has a stronger impact on the profits of D-CAES since it improves revenues of both energy arbitrage and heat recovery. An increase in the storage size beyond 48 hours has even a negative impact on economics of D-CAES and CAES. This behaviour implies that increase in the initial cost of the reservoir overweighs the incremental revenues of energy arbitrage and heat recovery. It is of note that a larger cavern also translates to larger capital cost requirements and higher investment risks, especially due to the small financial gains at storage sizes larger than 12 hours. Therefore, a smaller reservoir might be chosen in real world projects compared to the optimal sizes shown in Fig. 7.

3.4. Optimal size of turbo-machinery

Size of compressor constraints the rate of electricity storage as well as the revenues of heat recovery. Similarly, size of the expander limits sales of stored electricity to the grid. Therefore, compressor and expander should ideally be sized for each electricity market. We vary ratio of the expander to compressor size in a wide range and calculate the profit of CAES and D-CAES plants (see Fig. 8). Size of the compressor, air storage, and heat load are kept same as the base case system. Size of the expander is changed between 52.5 MW and 1,050 MW, half and ten times the size of compressor, respectively.

Increasing the size ratio significantly improves economics of CAES and D-CAES at low ratios and profits of both plants peak at a size ratio of 5.5. As discussed in the methodology section, high market share of baseload plants and infrequent high prices are inherent characteristics of the Alberta electricity market. As a case

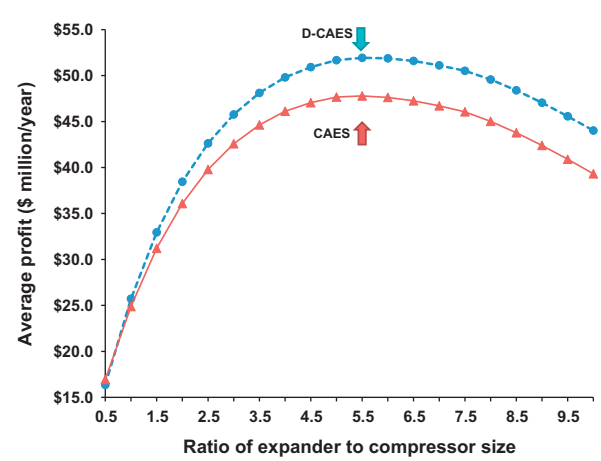

Fig. 8. Effect of size ratio of expander to compressor on profits of CAES and D-CAES, averaged over the ten years of study. Arrows indicate the optimal values. Size of compressor (105 MW) and air storage (1572 MWh) are fixed in all case.

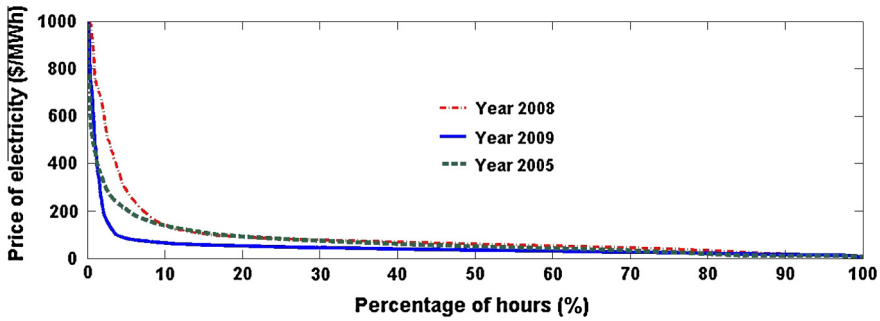

Fig. 9. Percentage of hours in various years during which the Alberta electricity prices were higher than a certain value (price duration curves).

in point, Fig. 9 shows the price duration curves for three years of the simulation period. A general observation is depressed prices for most of the time year. Therefore, a larger expander would enable the plant operator to take more advantage of limited periods with high prices. On the other hand, a larger expander would result in faster depletion of air storage and calls for increased capacity factor of compressor. Consequently, the revenues of waste heat recovery would also increase (profit of D-CAES rises faster compared to CAES in Fig. 8). Increasing this size ratio past 5.5 has a negative impact for both plants revealing that increased capital costs overweigh marginal revenues of arbitrage and heat recovery. Therefore, a ratio of approximately 5.5 for the size of expander to compressor would be the optimal ratio for the Alberta electricity market.

It bears mentioning that the optimal size ratio might be lower in real world caused by other factors not included in this study. As a case in point, a larger expander would necessitate a larger transmission line which may face technical or siting constraints. Higher initial cost of a larger plant might also present a higher investment risk. Moreover, adding too much peaking capacity would depress the price of peak electricity. A final note is that these results are very market specific and depend on the application of the storage facility. For instance, a CAES facility that is to provide firming capacity or energy arbitrage for a wind farm would likely have a larger compressor so that it can store as much wind energy when it becomes available.

3.5. Effect of pipeline length

While above-ground vessels can also be used for air storage, a utility-scale facility needs to store air in a geological reservoir due to their significantly lower capital cost. Availability of a suitable geological formation in vicinity of the heat load is crucial for economic viability of D-CAES. Fig. 10 shows the result of a sensitivity analysis on the distance between the air storage site and the heat load, as the main parameter impacting the capital cost of the D-CAES pipeline. The pipeline length is varied between 25 km and 100 km and the annual profit difference of D-CAES is calculated in each case. Besides, an unrealistic scenario in which the air storage and heat load are co-located (pipeline length of 0 km) is considered to further illustrate the effect of pipeline cost on economics of D-CAES.

Although the regression model used in this study takes into account the cost of material, labour, right of way, and some miscellaneous costs (e.g. surveying, and engineering), the exact cost of the air pipeline to a D-CAES plant would be affected by local parameters which are unique to each project. However, results of our simulation reveal promising economics of D-CAES with a break-even point of 75 km for pipeline length so that profits of CAES and D-CAES would become equal. Fig. 10 illustrates both the additional profit of D-CAES in each year and the average values over the ten-year simulation period at each pipeline length. The cost of very short pipelines might be higher in real world due to the fixed project costs (e.g. engineering, right of the way). Nevertheless, the authors are confident in the approximate location of the break-even point since it occurs at a relatively long length of 75 km. In other words, Fig. 10 might over estimate the economics of heat recovery at very short distances between heat load and air storage. However, D-CAES is very likely to be economically justified over conventional CAES in the current Alberta market, providing a suitable depleted gas reservoir exists within 75 km of the heat load.

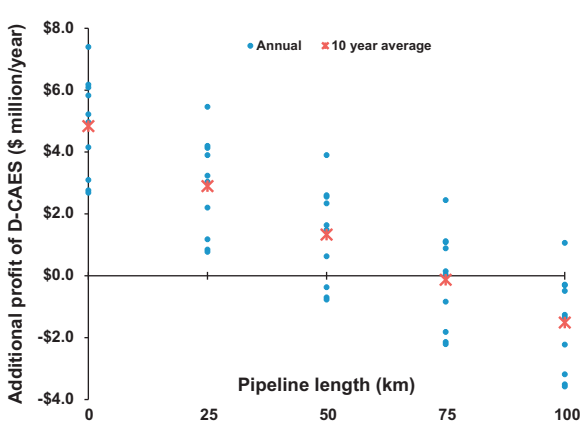

Fig. 10. Profit difference between D-CAES and CAES plants at various distances between heat load and air storage site (pipeline length). Note the relatively wide spread of annual profits over the ten years of study at each pipeline length.

4. Conclusions

We evaluated the possibility of enhancing the economic and environmental performance of CAES through recovery of compression heat for municipal heating applications. The compressor of the D-CAES system is co-located with a concentrated heat load inside the city in contrast to the conventional CAES configuration in which both compressor and expander are at the air storage site. We optimized the profit of two hypothetical merchant CAES and D-CAES plants performing energy arbitrage using ten years of historical data from the Alberta electricity market. Compression heat was recovered to supply a concentrated heat load with an annual average of 107 MW thermal. Size of expander and compressor were fixed at 131 and 105 MW in the base case scenario, respectively.

The D-CASE plant earned an additional profit of $1.3 million/year on average, after taking into account a 10% cost of capital. The profit difference of D-CAES and CAES varied between −$0.8 million and $3.9 million, with negative values in only 3 out of the ten years of simulation. Profits of D-CAES showed a strong

correlation with gas prices ($R^2 = 0.91$) because the economic advantage of D-CASE comes solely from reduction in gas demand for heating applications. Lower GHG intensity as well as higher profits led to a negative abatement cost of $-\$40/tCO_2e$ for the D-CAES compared to a CASE plant. Superior emission performance of D-CAES could further improve its viability if a policy frame is in place to support cleaner technologies. Larger capacity factor of the D-CAES compressor, motivated by revenues of heat recovery might also improve D-CAES attractiveness if the energy storage plant is to provide other services in addition to energy arbitrage, such as firming capacity for intermittent renewable energies.

Economics of both plants showed high sensitivity to the size of cavern at capacities below 12 hours of electricity generation with minor effects afterwards. The optimal turbo-machinery composition had a significantly larger (5.5 times) expander compared to the compressor for both plants. The authors highlight that this optimal size largely depends on the application and the market environment in which the plants are operating. In electricity markets like Alberta with high share of baseload electricity (load factor of 80%), a merchant stand-alone plant dispatched for energy arbitrage would have a very limited window to sell high value electricity and recover its capital and operating costs. Having a larger expander; therefore, facilitates sales of larger quantities of peak electricity during those short windows.

An essential requirement for economic attractiveness of D-CAES over CAES is availability of suitable geological formation in the vicinity of a concentrated heat load. Our case study for Alberta, with high heating loads and high price volatility, revealed that revenues from export of waste heat would breakeven with increased capital requirements at a pipeline length of 75 km. D-CAES can also be superior to conventional CAES in electricity markets with high peak prices and cooling loads in summer. Waste heat of compression can supply cooling energy with the aim of technologies such as absorption chilling, adding to financial and environmental profits of energy arbitrage. An example of such a location in North America could be Texas with outstanding wind resources, availability of aquifers and salt formations, and political support for wind energy.

A final remark that although our analysis revealed export of waste heat could be profitable, CAES technology is very unlikely to be economically viable unless the electricity market is carbon constrained [4,6,30]. We caution that waste heat recovery will not radically change this situation and some levels of emission policy will still be required for large-scale deployment of this technology.

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