Applied Energy 103 (2013) 165–179

Contents lists available at SciVerse ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Compressed air energy storage (CAES) with compressors distributed at heat loads to enable waste heat utilization

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HIGHLIGHTS

- ▶ Novel form of CAES is proposed in which the heat of compression is used for space and water heating demands.
- ▶ Economic analysis of waste heat recovery from a CAES facility was performed.
- ▶ The distance between the heat load and storage site has a critical impact on economic favorability of waste heat recovery.
- ▶ Minimum gas price of $7.0/GJ makes heat recovery economically favorable at a 25 km distance.
- ▶ Minimum gas price of $7.6/GJ makes heat recovery economically favorable at a 50 km distance.

ARTICLE INFO

Article history:
Received 9 February 2012
Received in revised form 10 September 2012
Accepted 15 September 2012
Available online 12 December 2012

Keywords:
Compressed air energy storage
Waste heat recovery
District heating
Economic analysis
Emission tax
Optimization

ABSTRACT

Large scale penetration of renewable energies such as wind and solar into the electric grid is complicated by their intermittency. Energy storage systems can mitigate these fluctuations by storing off-peak energy for use at peak-demand times. Compressed air energy storage (CAES) is one of the most promising storage technologies due to the large amount of energy that can be stored at an economical cost. We evaluate the feasibility of improving the economics of CAES by distributing compressors near heat loads to enable recovery of the heat of compression to supply low-grade heating needs such as district heating. Distributed CAES (DCAES) is more efficient; however, it has higher capital costs due to the compressed air pipeline required between distributed compressors and the storage site. We evaluate the project economics of DCAES in a hypothetical scenario with a variable electric and heat load. The size and dispatch of a generation fleet composed of a wind farm, CAES or DCAES plant and conventional gas turbines are optimized to satisfy the annual electricity load at an hourly resolution at the lowest total cost. We find that the total cost of supplying heat and electric loads is less expensive with DCAES given a 50 km pipeline when fuel prices exceed $7.6/GJ. The cross-over fuel price depends on the distance as it drives the capital cost of the pipeline. The minimum effective fuel price required for economic superiority of the DCAES system is $7.0/GJ and $8.3/GJ at pipeline lengths of 25 and 100 km, respectively.

1. Introduction

Electricity demand has substantial hourly, daily, and seasonal variations, resulting in the need for peaking plants that operate only during peak-demand periods, and base load power plants that operate below their optimum output during low-demand periods. These effects lead to a reduction in overall system efficiency, shortened plant lifespans, greater requirements of financial investment, and higher greenhouse gas (GHG) emissions.

Renewable energies, especially solar and wind, have the potential to provide substantial fractions of electricity supply and to reduce GHG emissions and air pollution from the electricity sector at large scale. Although GHG emissions of nuclear plants and hydroelectric dams are also low, large-scale expansion of these energies is facing difficulty. US and Canada have not built a new nuclear plant for more than 15 years [1,2] and hydroelectric dams are challenged by environmental and siting concerns [3]. Renewable energies in general, and wind energy in particular, have experienced significant expansion in the past decade. The installed wind capacity in the USA by the end of 2010 (40.2 GW) was approximately 15 times higher than its value at the beginning of the year 2000 [4]. Similarly, the installed wind capacity in Canada

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http://dx.doi.org/10.1016/j.apenergy.2012.09.027

Nomenclature

CapEx	specific capital cost ($/MW)
CCR	capital charge rate (%)
GHG_{NG}	Greenhouse gas intensity of natural gas (tCO_2e/GJ)
COE	levelized cost of electricity ($/MWh)
D	diameter of pipeline (mm)
El	electricity generated during each hour (MWh)
ER	energy ratio of energy storage plant (MWh energy stored/MWh generated)
f	friction factor of the pipeline (dimensionless)
FOM	fixed operating and maintenance cost ($/MW/year)
HL	hourly heat load (MW thermal)
HR	heat rate (GJ/MWh)
L	length of pipeline (km)
P	pressure (kPa)
Price	price of fuel ($/GJ)
Q	flow rate of pipeline (m^3/day)
Size	optimal size (MWh or MW)
T	temperature (K)
Tax	emission tax ($/$tCO_2e$)
VOM	variable operating and maintenance cost ($/MWh)
Z	compressibility factor of compressed air (dimensionless)

Greek

η	thermal efficiency (%)

Subscripts and Superscripts

Cav	cavern of energy storage plant
CCGT	combined cycle gas turbine
Comp	compressor of energy storage plant
Down	downstream of pipeline
Exp	expander of energy storage plant
h	hour
HOB	heat-only-boiler
HRU	heat recovery unit
NG	natural gas
Pipe	pipeline
SCGT	simple cycle gas turbine
Up	upstream of pipeline
Wind	wind farm

has increased more than 30-fold at the end of 2010 (4.0 GW) compared to its levels at the beginning of the year 2000 [5]. In spite of this impressive growth, wind energy still composes a small portion of the total installed capacity in these countries. Integration of wind energy into the electric grid is complicated by the additional costs raised by its intermittent nature, the challenge that periods of high production do not necessarily coincide with periods of high demand, and sometimes the far distances between sites with good wind resources and high electric loads that mandate construction of capital intensive transmission lines. As a case in point, Denmark can generate up to 30% of its electric power by offshore wind farms; nevertheless, almost all of its excess wind-based electricity is sold to its neighboring countries with hydroelectric capacities for virtual storage as a means to cope with wind intermittency [3,6]. Even if periods of peak production and demand coincide, grid congestion may prevent delivery of wind-based electricity to the customers of the grid. In fact, the uncertain production of wind-based electricity has the potential to create or worsen grid congestion problems and grid stability issues [7].

The grid operator can choose any of the following approaches to deal with the intermittency of wind energy and to provide reliable and dispatchable wind-based electricity and thus facilitate higher wind penetration into the grid. These include utilization of fast-response thermal plants, geographically dispersed production sites, and bulk energy storage.

(a) Fast-ramping thermal plants: these plants, such as gas turbines and diesel generators, can engage as necessary to fill the gap between the generation and demand of electricity. They can quickly ramp up and down to accommodate changes in electricity production and consumption; however, their intermittent (as needed) operation causes them to have a relatively low capacity factor. Therefore, their capital, maintenance, and operating costs should be compensated by their limited operational period leading to an increase in the overall cost of wind-based electricity. The transient and partial-load operation of these plants also leads to lower thermal efficiencies and higher emission of pollutants. In recent years, some new gas turbine designs have been introduced to the market that are claimed to be able to "chase-wind" without significant performance degradation when operated at partial load (e.g. Langage CCGT plant in the UK [8]). Therefore, compensating inherent fluctuations in wind-based electricity through fast-response thermal plants involves the associated cost of cycling fast ramping thermal plants and/or building specially designed fast ramping thermal plants.

(b) Spatial distribution of generation sites: Another option to cope with intermittency of wind energy is to geographically disperse wind farms over a large area, overcoming localized wind patterns and resulting in smoother overall energy production [9]. However, this arrangement has the disadvantage of increased overall capital cost due to the need for longer transmission lines between distributed production centers and the load and it may not be feasible for some wind projects. Furthermore, this approach may necessitate large-scale planning over a large area which may include different utility owners and electricity markets, further complicating the market dynamics of wind-based electricity.

(c) Bulk Energy Storage: Bulk Energy Storage (BES) systems can partially mitigate the fluctuations in supply and demand of electricity by storing excess energy generated during off-peak periods or during periods that electricity cannot be transmitted because of grid congestion for later use (peak-demand times with higher electricity prices). BES can improve operation of conventional power plants, e.g., coal and nuclear, by allowing them to operate closer to their optimal design points. More importantly, energy storage systems can convert intermittent wind energy into a firm capacity that can be dispatched based on the market price of electricity and the requirements of the grid operator. They can also avoid or reduce grid congestion and prevent or delay the need for new transmission lines. Furthermore, some of the BES facilities can provide ancillary services to the grid (e.g. frequency control) and hence generate additional revenues [10]. BES systems are characterized based on their discharge duration and power production capacity. Only compressed air energy storage (CAES) and pumped hydro storage (PHS) can provide utility- scale storage capacities (hundreds of MW-hours) required for large scale

penetration of wind energy into the electric grid. Although PHS has approximately 40 and 20 GW of installed capacity in Europe and US respectively [3], development of PHS projects is geographically limited due to the necessity for two large natural or artificial water reservoirs with sufficient elevation difference. Environmental licensing and long construction time (in 10 years scale) are among other factors limiting large expansion of PHS capacities [10,11].

On the other hand, CAES technology can use a variety of both underground and aboveground storage facilities and CAES plants can be constructed in a relatively short time (around 3 years). CAES systems use inexpensive off-peak electricity to compress air into underground or aboveground storage reservoirs, which are later used to power modified gas turbines and generate electricity. CAES technology was extensively investigated in the 1970s to provide load following services and to gain a high capacity factor for base load power plants (especially nuclear) by storing off-peak electricity. The first CAES plant was commissioned in Huntorf, Germany in 1978 to provide black-start services to nuclear plants as well as provide relatively inexpensive peak power [12]. The Huntorf plant, which is still in operation, stores up to 310,000 m^3 of compressed air at a pressure range of 44–70 bar in two salt caverns and can produce up to 290 MW of electricity at full capacity for 4 h at an air discharge flow rate of 417 kg/s.

The second utility scale CAES plant was commissioned in 1991 in McIntosh, Alabama and is still in operation as well. The McIntosh plant can generate 110 MW of electricity at full capacity for 26 h at an air discharge rate of 154 kg/s. It stores up to 540,000 m^3 of compressed air at a pressure range of 45–74 bar in a salt cavern [13]. The Alabama plant consumes up to 25% less natural gas than the Huntorf plant as waste heat from the exhaust of the low pressure expander is recuperated to preheat discharge air from the cavern prior to entering the high pressure combustor [13].

Despite the successful operation of these two CAES plants, a series of events caused the development of CAES technology to slow down during the late 1980s and the 1990s. These events included the loss of momentum in the nuclear industry, the development of efficient and low capital intensive single and combined cycle gas turbines, a drop in natural gas prices, and an overbuilt generation capacity [3,11]. However, the desire for higher penetration of clean but intermittent wind and solar energy sources into the electric grid has renewed interest in CAES as a method to overcome their intermittency and thus lower the GHG emissions from electricity generation [11].

CAES plants are not pure energy storage facilities since their operation requires the combustion of fuel during the generation cycle (the only exception is the Adiabatic CAES configuration which is still in the research and development phase). Compressed air is heated during the generation cycle (to prevent water vapor from freezing) and then electricity is generated through expansion of heated compressed air in expanders. As a case in point, the Huntorf plant uses 5800 kJ of natural gas per kWh of peak electricity that it generates[1] [13]. A variety of newer CAES designs have been proposed in the past few decades to improve the storage efficiency of conventional CAES plants. One design introduced by Energy Storage and Power Corporation in the 1990s is based on pairing CAES plants with conventional gas turbines. The main idea of this approach is eliminating the combustor in the CAES facility and utilizing the exhaust stream from the gas turbine instead of the combustor to heat the compressed air and thus improving the overall efficiency [10,14].

In contrast to this approach which focuses on waste heat recovery during the discharging process, the Adiabatic CAES design is based on storing the heat of compression in a thermal energy storage facility. This stored heat then would be utilized to heat the compressed air during the generation process and thus lower (or even eliminate) the fuel consumption of the CAES plant [15]. This concept was introduced in the 1980s and the interest in this concept is recently renewed both in Europe and the United States [10,16]. However, this concept is still in the research and development phase and its development is challenged by few major technical issues including design of high pressure, high temperature, large scale and economically attractive thermal energy storage systems, high pressure and high temperature compressors, and high pressure expanders [17,18].

This paper introduces and evaluates a different approach to improve the efficiency of conventional CAES plants. This approach focuses on utilizing the otherwise wasted heat of compression for heating needs and thus improving the overall thermal efficiency of the CAES plant. This new configuration, which is called Distributed CAES (DCAES), is realized by distributing air-compression stations near heat loads such as district heating facilities instead of siting the compression train at the storage facility (as the case for a conventional CAES plant). An integrated compressed air pipeline network, supplied by these distributed compressors located near high heat-load facilities (e.g. hospitals and office towers), would use off-peak electricity to compress air. The heat produced by air-compression would then be utilized or stored for heating needs, and thus lower the overall cost of the DCAES system by negating the demand for heating fuel usage within these high heat-load regions. The compressed air from this system would be pipelined to favorable geological sites for underground storage. The expander of the DCAES system located at the storage site would generate electricity via combustion and expansion of stored compressed air, similar to the conventional CAES designs. Further details on different variations of the DCAES concept may be found in Hugo et al. [19].

The DCAES concept is based on improving the economics of the conventional CAES facilities through the use of the low quality heat of compression for space and water heating demands. Waste heat recovery from industrial compressors is a mature technology and therefore introduces less technical complexity compared to the Adiabatic CAES design which requires heat recovery and storage at high pressures and temperatures. On the other hand, the DCAES design requires a pipeline between the compression site (region with high density of heat load) and the storage site (e.g. cavern). In the admittedly unrealistic case where the heat load and the CASE storage facility are co-located, then D-CASE would always be preferred to CASE since it provides heat "for free". The essence of our analysis is to explore how the relative competitiveness of CAES and D-CASE depends on pipeline length. The tradeoff between the increased capital cost of the DCAES system compared to conventional CAES (mainly due to the air pipeline) and savings on fuel (used for heating purposes) can make the DCAES system cheaper compared to the conventional CAES in certain situations.

The intensity and fluctuations of the heat load, size and fluctuations of the electric load, distance between the heat load and storage facility, and the fuel and construction costs are the major players in this tradeoff. As mentioned earlier, ambitious plans for higher penetration of wind energy into the electric grid is one of the main drivers for the renewed interest in the CAES systems in the twenty first century. Therefore, this paper focuses on economic evaluation of DCAES concept, as an alternative to conventional CAES systems, to provide economic and dispatchable wind-based

[1] Each kWh of energy equals to 3600 kJ. Therefore, the thermal efficiency of the Huntorf plant would be 62% solely based on its "inside-the-fence" fuel consumption. This CAES plant also uses 0.82 kWh of electricity during the compression cycle for each kWh of electricity that it delivers during the generation cycle (energy ratio of 0.82).

electricity. To the knowledge of the authors this idea has not been discussed in literature before and this paper is the first to investigate the opportunities in enhancing the economics of CAES through recovery of the otherwise wasted heat of compression from CAES plants to satisfy heating loads (instead of wasting the heat to the ambient in conventional CAES plants or storing it to later heat the compressed air during the power generation cycle as proposed in the Adiabatic CAES design). The primary contribution of this paper is providing insight into the potential financial gains through waste heat recovery from the compression trains of CAES for municipal heating applications in order to facilitate R&D work on detailed engineering design of such plants.

It bears mentioning that a different the concept of distributed (decentralized) compressed air energy storage has been introduced and discussed in the literature which is based on replacing the generator of individual wind turbines with compressors to directly store mechanical energy of wind in the form of potential energy of compressed air [20,21]. The main advantage of this concept is eliminating the energy losses during the process of converting mechanical energy of wind to electricity and then to potential energy of compressed air. Nevertheless, distributing the compressors near heat loads to enable the use of compression heat for space and water heating applications, as proposed in the DCAES configuration, has not been studied before.

2. Methodology

Although the economic performance of CAES plants depends on the nature of the electricity market that they participate in, some recent studies have shown that conventional CAES plants may not be able to compete economically with other alternatives, especially conventional gas turbines, in support of wind-based electricity [12,22,23]. This fact is due to the relatively high capital cost of the CAES facility in comparison to gas turbines. However, at elevated fuel prices or in the case of high emission taxes, CAES technology would become more attractive because of its better fuel economy compared to conventional gas turbines. In a carbon-constrained world, technologies with high carbon footprints would be phased out and the electricity generation mix would move towards cleaner technologies which would make the already complicated market dynamics more difficult and uncertain to model. Moreover, compressed air energy storage plants should ideally be designed and operated as independent entities in the electricity market to maximize their economic performance [24]. These plants would buy and store off-peak electricity from a variety of sources and sell electricity back to the grid during periods of peak demand and also provide ancillary services to the grid to maximize their competitiveness and profit in the electricity market.

However, because of the complexities associated with forecasting and modeling this real world scenario with higher fuel costs, we study a simplified system to investigate the economics of DCAES and CAES plants in supporting wind-based electricity. In order to avoid the complex dynamics of the electricity market but at the same time provide insight into the performance of the DCAES configuration in a close-to-real world scenario, a hypothetical scenario which represents a high-level policy making approach was used in this study. This hypothetical scenario represents a planning firm designing the electricity and heating infrastructure of a portion of a city in a carbon-constrained world. It is assumed that good wind resources are available; therefore the planning firm is considering harnessing this clean energy resource to satisfy a portion of the electric load. Natural gas-based power plants (simple cycle gas turbine, SCGT, and combined cycle gas turbine, CCGT) and natural gas-based compressed air energy storage plants (either conventional CAES or DCAES) are also considered as candidates for electricity generation because of their relatively low GHG emissions. In addition, the firm plans to utilize district heating technology to satisfy the heat load of a portion of the city with a high load intensity (e.g. downtown core) because of the potential of the district heating technology in supplying cleaner and more efficient heating energy compared to individual heating facilities. The heating energy of this district heating facility could be supplied through either direct combustion of natural gas in heat-only-boilers (HOB) or heat recovery from the DCAES plant. The overall objective of the planner is to satisfy both the electric and heat load at the lowest levelized cost (or maximizing the net social welfare). It is also assumed that the electric load of the city has to be satisfied by its own generation fleet and import and export of electricity are ignored. One should note that in the real world, cities are not normally isolated from the electric grid and can buy/sell electricity from/to other grids. The authors acknowledge this simplification in the model presented but decide to use this assumption for the sake of simplicity and to evaluate the conditions under which the DCAES design might be economically preferable to CAES at a high level policy making approach.

The performance of the DCAES configuration depends most strongly on the size and diurnal and seasonal fluctuations of the heat load profile. In other words, if the heat load is too small then the economic gains from waste heat recovery for heating purposes would not be sufficient to justify the DCAES system (mainly due to the requirement for capital intensive compressed-air pipelines and the effect of economy of scale on this cost). However, in the real world the magnitude of heat load supplied by district heating networks is limited by increased heat losses in geographically-dispersed networks. In order to build a close to real world scenario, the size of the heat load connected to the district heating network was chosen so that it represented a concentrated municipal heat demand center. It should be noted that the DCAES system might only be chosen over the conventional CAES configuration when it is possible to pair with a district heating network. Therefore, instead of modeling the heat demand of an entire city, the authors only focused on satisfying a concentrated heat load (a portion of the city) supplied by a district heating network.

2.1. System of study

As mentioned, two different configurations can be considered to evaluate the performance of conventional CAES and DCAES systems in meeting the electric and heat loads.

2.1.1. System with a conventional CAES plant

As shown in Fig. 1, a wind farm, a conventional CAES plant located outside a city at a favorable geological storage site, and conventional gas turbine plants (SCGT and CCGT) could be utilized to meet the electric demand. The heat load would be satisfied by large scale boilers connected to district heating networks. Since this study focuses on providing reliable and dispatchable wind-based electricity, it is assumed that the CAES facility can only be charged by the wind farm while SCGT and CCGT can only provide electricity for instantaneous use and not for compression in the CAES plant.

2.1.2. System with a DCAES plant

The major difference between this configuration (Fig. 2) and the previous system is that the compressor of the compressed air storage facility is located within the city and close to a concentrated heat load. A heat recovery unit (HRU) is utilized to recover the heat of compression, thereby negating the fuel consumption of the heat-only-boiler (HOB) of the district heating system. The generated compressed air is transported via a pipeline network to a suitable geological storage site outside of the city for storage. The expander of the compressed air storage plant is located at this site

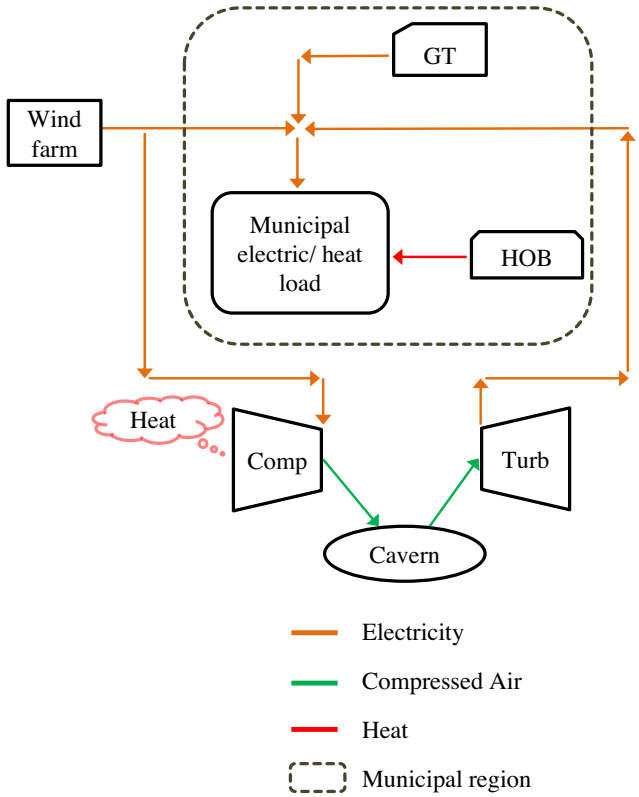

Fig. 1. CAES configuration: Conventional CAES, wind farm, and combined and simple cycle gas turbines are utilized to meet the electricity demand. Heat-only-boilers (HOB) satisfy the heat load of a district heating network. Wind-based electricity is the sole energy source to charge the underground compressed air storage facility.

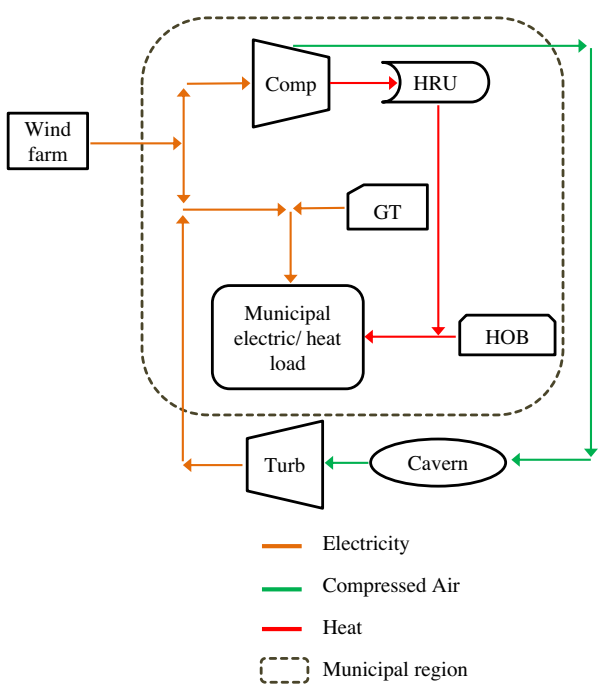

Fig. 2. DCAES configuration: the compression train of the compressed air energy storage facility is located within the city. Compressed air is pipelined to the storage facility outside the city where both the underground storage and expansion train are located. The heat of compression is recovered by a heat recovery unit (HRU) to satisfy the concentrated heat load in conjunction with the heat-only-boilers (HOB) of the district heating network.

similar to the conventional system. One should note that a low pressure, low temperature thermal energy storage (TES) unit can also be used to store the excess compression heat for later use. However, this additional component is not considered in this paper for the sake of simplicity.

2.2. Inputs and simulation model

We model a planner who aims to minimize the levelized (capital and fuel) cost of satisfying a variable electric and heat load over the period of one full year (or maximizing net social welfare). Following is a description of various inputs and assumptions made to establish this optimization problem.

2.2.1. Simulation resolution and period

High penetration of intermittent wind energy affects the electric grid in three different time scales: minute-to-minute, intra-hour, and hour- to day-ahead [22]. Since the primary application of compressed air energy storage plants is bulk energy storage (arbitrage and load leveling applications), an hourly resolution was chosen for this study. This approach is in agreement with some of other studies in the field of economic assessment of compressed air energy storage systems to support wind energy [12,22,23]. One should note that CAES plants can provide a range of ancillary services in electricity markets in addition to the primary duty of energy arbitrage and load leveling. CAES plants can provide frequency and voltage control services (in seconds time scale) and ramping services (in minutes time scale) in addition to the load following application considered in this study [25]. However, the economic value of these services highly depends on the market in which they are offered; therefore, these services were not included in this study and only energy arbitrage was considered as the primary role of energy storage plants.

In order to capture the diurnal, weekly, and seasonal changes in wind energy, electric load, and heat load, the system was modeled over a period of one full year. Both the heat and electric loads are to be satisfied at each hour over the entire simulation period.

2.2.2. Heat load

District heating networks have the ability to supply heat to different types of heat loads (single houses, office towers, hospitals, etc.). However, an ideal heat load for district heating networks would be a concentrated load (e.g. downtown core) because of the relatively high capital costs associated with heating pipelines in district heating systems with low heat intensity. Therefore, a large concentrated heat load (three times as the heat load of the University of Calgary, Alberta, Canada) was chosen for this study. The heat load of this university experienced a peak and average hourly value of 48.4 and 21.4 MW thermal in the year 2011. Since the heat load of the University of Calgary is currently satisfied with a district heating network, this load can be a good representation of a concentrated municipal heat load supplied by a district heating network.

2.2.3. Electric load

The electric load profile used in this study is based on the peak electric load profile of the province of Alberta in the year 2011 reported by the Alberta Electric System Operator (AESO) [26]. Alberta's hourly peak load was scaled down to simulate a large electric load with an hourly peak and average load of 1000 MW and 516 MW, respectively. The size of the electric load was chosen arbitrary to represent a real world load. The system planner would choose the optimal size and dispatch strategy of the plants to supply the electric load throughout the simulated period. One should note that system of study was assumed to be "congestion free" and the only geographical constraint in the model was the distance

between the heat load and the geological formation for storage of compressed air.

2.2.4. Wind resources

Hourly generation data from existing wind farms in Alberta reported by AESO [26] for the period of 2008–2011 were used in this study. The hourly capacity factor of wind (ratio of the hourly generation to the name plate capacity of the wind farm) was calculated to represent the quality of wind resources to be exploited for electricity generation during the simulation period.

2.2.5. Compressed air pipeline

A pipeline is required to transport the generated compressed air from the compressor/heat-load site to the underground storage facility. The economics of DCAES are strongly dependent on the capital cost of the pipeline. A pipeline length of 50 km was used in the base case system and the sensitivity of the results to this value was then performed through running the simulation with 25 and 100 km lengths for the air pipeline. Furthermore, an unrealistic scenario with a pipeline length of 0 km is considered to provide better insight into the tradeoff between the capital cost of the pipeline and revenues generated from waste heat recovery. One should note that this study focuses on Calgary, Alberta as a case study. Calgary is in close proximity of depleted gas reservoirs that could be used for underground storage of compressed air.

Due to the relatively short length of the pipeline (50 km) and to maximize waste heat recovery benefits in the DCAES configuration, no boosting compression stations were considered. In other words, the maximum downstream pressure of the pipeline was fixed (equal to the maximum cavern pressure, 74 bar) and the upstream compression facility was sized to be able to compensate for the pressure drop along the pipeline. At the same time, the upstream pressure was set to a value lower than the Maximum Allowable Operating Pressure (MAOP) of the pipeline (set as 100 bar).

Eq. (1) relates the flow rate of the compressed air to the pipe diameter and length and the upstream and downstream pressures (see nomenclature for definition of symbols) [27].

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

The maximum allowable pressure drop along the compressed air pipeline was set to 35 kPa per km, a typical value for natural gas pipelines [28]. By fixing downstream pressure (P_{Down}) and knowing the maximum air flow rate in the pipeline given compressor size, Eq. (1) was used to calculate the pipe diameter. Once the pipe diameter was determined, its length and diameter were used to estimate the capital cost of the pipeline based on regression models for industrial pipelines [29].

2.2.6. Storage facility

Compressed air energy storage facilities can use both above- and underground storage [30–32]. Both high pressure storage tanks and pipelines can be utilized in aboveground CAES systems; however, aboveground CAES systems are not economically feasible for utility scale (bulk) storage due to the significantly higher capital costs associated with aboveground compared to underground storage [10]. Underground CAES can utilize a variety of geological formations (naturally formed or man-made salt caverns, hard rock and porous rock formations, and depleted gas reservoirs) to store compressed air in large quantities [11]. The selection of the proper formation is subject to various factors such as its availability, geological characteristics, and development costs. Porous rock formations were considered as the storage for this study since Calgary is in the proximity of porous rock geological formations. As explained in the previous section, this formation was assumed to be located at a distance of 50 km from the heat load (equal to the length of the air pipeline) in the base case analysis.

2.2.7. Operation of CAES and DCAES

A compressed air storage facility is very similar to a conventional gas turbine power plant with the major difference that the air compression and expansion processes do not happen at the same time. However, in principle a CAES plant can run as a simple cycle gas turbine during the periods that the cavern is depleted [12]. This capability was considered in the optimization model such that the expander could receive compressed air required for its operation from both the cavern (running as a pure CAES) and the compressor (running as a pure SCGT).

2.2.8. Fuel price

A series of recent studies [12,22,23] have shown that the capital intensive conventional CAES facilities would not be economically favorable over conventional gas turbines to support wind-based electricity under the current low natural gas prices (as the primary fuel for CAES and gas turbine plants). However, CAES would become superior in a carbon-constrained world due to its lower emissions compared to conventional gas turbines. Therefore, a variable emission tax is considered in the natural gas price in this study and the effective fuel price (combination of market price of the natural gas, fixed at \$5.0/GJ,[2] and associated emission taxes) was calculated based on Eq. (2). The effective fuel price concept incorporates both the fluctuations in the market price of fuel and the associated emission taxes due to the GHG emissions from the combustion of the fuel. A value of 66 kg CO_2e[3]/GJ was considered as GHG emissions associated with burning natural gas (including the typical[4] upstream emissions) [23]. As a case in point, a market price of \$5.0/GJ for natural gas and an emission tax of \$30/tCO_2e[5] would translate to an effective natural gas price of \$7.0/GJ. At low levels of tax, neither a CAES nor a DCAES system is expected to be superior to gas turbines. However, as the effective fuel price increases, CAES becomes more favorable and finally at higher effective fuel prices, a DCAES system is expected to become superior.

$$\mathrm{Price}_{\mathrm{NG}}^{\mathrm{Eff}} = \mathrm{Price}_{\mathrm{NG}}^{\mathrm{Market}} + \mathrm{Tax} \times \mathrm{GHG}_{\mathrm{NG}} \tag{2}$$

2.2.9. Capital cost

Table 1 illustrates the inputs used in evaluating the associated cost of various components of the two systems. All costs were converted to 2009 inflation adjusted US dollars according to the Chemical Engineering Plant Cost Index [33,34]. The capital cost of the heat recovery unit was assumed negligible since this heat has to be removed during inter-stage cooling between compression stages and from the compressed air prior to underground storage anyways (whether it is utilized for heating applications or dumped to the ambient). Similarly, the associated capital costs with the district heating network (excluding the boilers) were ignored in the analysis since this network would exist in both CAES and DCAES configurations. In other words, the district heating system would be utilized to satisfy the heat load, regardless the source of the heating energy (HOB or HRU). One should note that recovering the heat of compression would shave the peak heating load and

[2] All heating values in this paper are expressed in terms of lower heating value (LHV). Higher heating value (HHV) energy content of natural gas is about 11% higher than its LHV. Therefore, a natural gas price of \$5.0/GJ (LHV) corresponds to approximately \$4.5/GJ (HHV).

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

[4] The GHG emissions associated with manufacturing of the components were not included.

[5] One t indicates one metric ton (1000 kg).

Table 1
Economic inputs for the optimization.

Parameter	Base value	Reference
$CapEx_{Wind}$ ($/MW)	1.67×10^6	[35]
$CapEx_{SCGT}$ ($/MW)	5.92×10^5	[35]
$CapEx_{CCGT}$ ($/MW)	8.50×0^5	[35]
$CapEx_{Exp}$ ($/MW)	5.15×10^5	[25][a]
$CapEx_{Comp}$ ($/MW)	4.76×10^5	[25][a]
$CapEx_{Cav}^{Marginal}$ ($/MWh)	1.5×10^2	[13]
$CapEx_{Cav}^{Base}$ ($)[b]	12.22×10^6	[36]
$CapEx_{HOB}^{Marginal}$ ($/MW)	5.0×10^4	[37]
$CapEx_{HRU}$ ($/MW)	Negligible	
CCR (%)	10	[23]
$CapEx_{Pipe}$ ($) ($L$ = 50 km and $250 < D < 700$ mm)	$41{,}457 \times D - 1{,}449{,}340$	[29][c]
VOM cost of all components	Negligible	
FOM cost of all components	Negligible	

[a] The estimates for the specific capital cost of compressor and expander are based on the capital cost of the McIntosh CAES plant estimated by the Electric Power Research Institute (EPRI) [25]. This cost was adjusted for the cost of the salt cavern [13] and the cost ratio of expander and compressor to estimate the costs of expander and compressor separately. The ratio of the specific cost of expander to compressor is assumed 1.08, average of the values used by Fertig and Apt [12] and Greenblatt et al. [23].

[b] The base case for the cavern represents a depleted natural gas reservoir capable of storing enough air for 12 h of continuous electricity generation at a rate of 131 MW, as estimated by Electric Power Research Institute [36].

[c] The estimates for capital cost of the pipelines are based on a regression model developed by Sean McCoy [29] for 263 on-shore natural gas pipeline projects in US. The values used in this study are for 25, 50, and 100 km pipelines in the Central Region of the United States, as classified by the US Energy Information Administration for natural gas pipeline regions.

a smaller boiler would be required to meet the heat load. Consequently, the value used to calculate this savings in the capital cost of the boiler was chosen to reflect this effect (marginal capital cost). In addition, all fixed and variable operating costs were ignored because of the fact that at the high carbon prices which would be necessary to justify building capital intensive CAES and DCAES plants, these operating costs would be negligible compared to the much higher fuel costs.[6] Therefore, only the capital and associated fuel costs of various system components were considered in the economic analysis.

Another simplification in this study is the capital cost of the transmission lines. These lines are required to transmit electricity from the wind farm to the electric load and to the compression train, and from the expansion train to the electric load. Since our scope was to only model electric load of a portion of a city instead of an entire city, it was rational to assume that large transmission lines would already be built between the wind farm, municipal region, and the geological formation to integrate the valuable wind energy into the electric grid for the entire city. Therefore, it is assumed that these lines would exist anyway regardless of the specific CAES and DCAES facilities modeled. The authors acknowledge the possible inaccuracies associated with this intentional simplification. The alternative to this approach was considering the capital cost of these transmission lines in the economic analysis; however, the authors believe the former approach would be a closer and more accurate approximation of the real world case. Moreover, the associated costs with transmission lines between the gas turbine plants and the city were also ignored since these facilities are normally built in close proximities to the load.

2.2.10. Performance characteristics

Table 2 shows the technical data used to characterize the performance of various components in the simulation. The storage efficiency of compressed air storage facilities can be expressed using two parameters: energy ratio and heat rate. Energy ratio indicates the amount of energy (off-peak electricity) that the compressor of the plant consumes per unit of energy that the expander generates during the peak hours. Heat rate expresses the amount of fuel burned per unit of peak electricity generated by the expander, similar to conventional gas turbines. The values used for heat rate and energy ratio are for a typical CAES facility as reported Electric Power Research Institute (EPRI) [13]. It is of note that these parameters may vary based on the design and operation of the storage facility in real world. Heat rate of compressed air storage facilities is much lower compared to SCGT and CCGT since all the energy generated by the expander is converted to electricity in a CAES plant while up to two thirds of this energy is consumed by the compressor in conventional gas turbines.

It was assumed that up to 70% of the input energy into the compressor of the DCAES plant could be recovered and utilized to satisfy the heat load. The authors acknowledge that this value might change the capital cost of the HRU; the higher this value, the more sophisticated HRU required and the higher the capital cost. Therefore, a conservative value of 70% was used as the heat recovery efficiency of the HRU. In addition, the economics of DCAES might be enhanced if a thermal energy storage facility is utilized to store the excess waste heat for later use; however, this opportunity is not considered in this study for the sake of simplicity. A value of 80% (higher heating value) was used for the thermal efficiency of the boilers of the district energy system.

2.2.11. Optimization model

A mixed integer linear optimization code was developed in MATLAB to minimize the levelized cost of satisfying the hourly electric and heat loads over the one year simulation period. Both the size and dispatch of the various system components (wind farm, compressor, expander, cavern, SCGT, CCGT, compressed air pipeline, HRU, and HOB) were optimized to minimize the value of the objective function shown in Eq. (3). This equation shows the total cost to satisfy the annual electric and heat loads at an hourly resolution. The terms in the first set of curly brackets show the levelized capital cost of various components of the system while the terms in the second set of curly brackets show the summation of the associated hourly fuel cost. Only the savings in fuel cost of the boiler as a result of the operation of the heat recovery is included in the objective function. At each effective fuel price, the optimization code finds the optimal size for various components and their optimal dispatch strategy to satisfy the electric and heat load at the minimal cost over the one year period of

[6] As a case in point, the variable and fixed operating and maintenance costs (VOM and FOM) for a combined cycle gas turbine plant is $1.3/MWh and $10.8/kW year as reported by Greenblatt et al. [23]. Assuming a capacity factor of 80%, heat rate of 7170 kJ/kWh and a natural gas price of $5.0/GJ, the levelized VOM, FOM and fuel costs of this plant would be $1.30, $1.54 and $35.85 per MWh of electricity generated, respectively. The VOM and FOM costs of the plant would not vary with market price of natural gas while the fuel cost would. Therefore, the authors do not expect excluding the VOM and FOM costs would introduce major inaccuracies in the results of the simulations performed, especially at high fuel prices or associated emission taxes required for economic superiority of CAES and DCAES plants over conventional gas turbines.

Table 2
Performance characteristics of various components of the CAES and DCAES systems.

Parameter	Value	Reference
HR_{CCGT} (GJ/MWh)	7.17	[35]
HR_{SCGT} (GJ/MWh)	11.02	[35]
HR_{Exp} (GJ/MWh)	4.19	[13]
ER	0.75	[13]
η_{HOB}	80%	
η_{HOB}	70%	

simulation. Then the associated capital and fuel costs are used to calculate the average cost of electricity (COE) in \$/MWh of electricity for the simulation period. The capital and fuel cost of the boiler would be lower in the DCAES system compared to the CAES configuration (due to waste heat recovery). The difference between these values in the DCAES and CAES configurations would be considered as a negative cost (savings) in calculation of COE of the DCAES system. In addition, the carbon intensity of natural gas (66.0 kg CO_2e/GJ was used to calculate the average carbon intensity of electricity generation (kg CO_2e/MWh electricity) in the two systems.

$$\begin{aligned}
&\mathrm{CCR} \times \{(\mathrm{Size}_{\mathrm{CCGT}} \times \mathrm{CapEx}_{\mathrm{CCGT}}) + (\mathrm{Size}_{\mathrm{SCGT}} \times \mathrm{CapEx}_{\mathrm{SCGT}}) \\
&+(\mathrm{Size}_{\mathrm{Exp}} \times \mathrm{CapEx}_{\mathrm{Exp}}) + (\mathrm{Size}_{\mathrm{Comp}} \times \mathrm{CapEx}_{\mathrm{Comp}}) \\
&+(\mathrm{Size}_{\mathrm{Wind}} \times \mathrm{CapEx}_{\mathrm{Wind}}) + (\mathrm{Size}_{\mathrm{Cav}} \times \mathrm{CapEx}_{\mathrm{Cav}}) \\
&+(D \times \mathrm{CapEx}_{\mathrm{Pipe}}) - \mathrm{CapEx}^{\mathrm{Marginal}}_{\mathrm{HOB}} \times (\mathrm{HL}_{\mathrm{Max}} - \mathrm{Size}_{\mathrm{HOB}}) \\
&+(\mathrm{Size}_{\mathrm{HRU}} \times \mathrm{CapEx}_{\mathrm{HRU}})\} + \sum_{h=1}^{365\times 24} \mathrm{Price}^{\mathrm{Eff}}_{\mathrm{NG}} \times \left\{ \left(\mathrm{El}^{h}_{\mathrm{CCGT}} \times \mathrm{HR}_{\mathrm{CCGT}}\right) \right. \\
&\left. +\left(\mathrm{El}^{h}_{\mathrm{SCGT}} \times \mathrm{HR}_{\mathrm{SCGT}}\right) + \left(\mathrm{El}^{h}_{\mathrm{Exp}} \times \mathrm{HR}_{\mathrm{Exp}}\right) - \left(\mathrm{Heat}^{h}_{\mathrm{HRU}} \times \frac{3.6}{\eta_{\mathrm{HOB}}}\right) \right\} \qquad (3)
\end{aligned}$$

The major constraints in this optimization are the following:

- Hourly electricity generated by the wind farm, simple and combined cycle gas turbines and the expander of the storage facility should be equal to the hourly electric load.
- Heat provided by the HOB and HRU at each hour should be equal to the hourly heat load.
- Hourly generation of each component of the system should be less or equal to its optimal size.
- Hourly heat provided by the HRU should be less or equal to the compression energy at that hour multiplied by the efficiency of the HRU.
- Summation of the hourly wind-based electricity provided to the electric load and to the compressor of the energy storage plant should be less or equal to the optimal size of the wind farm multiplied by its capacity factor at that hour.
- Conservation of energy should be honored for the energy storage plant at each hour; change in energy level of the cavern should be equal to the difference between energy stored and generated by the plant during that hour.
- The minimum size of SSCGT, CCGT, compressor, expander, and wind farm is set to either 10 MW or 0 MW to simulate a close to real world scenario. This constraint is imposed to avoid the small size of this equipment (e.g. a 0.2 MW gas turbine) which would have a high specific cost (\$/kW) due to economies of scale.
- The air storage facility would be sized for a week-long storage period and it is assumed to be depleted by midnight Friday each week. Since the electric load and thus its price would be lower on the weekend compared to weekdays, the cavern would most probably be generating electricity during the weekdays and storing energy during the weekend.

3. Results and discussion

In order to compare the performance of the DCAES system with the CAES system, a base fuel price of \$5.0/GJ was assumed while the emission tax was varied from 0 to 80 \$/tCO_2e at \$10/tCO_2e intervals. Each \$10/tCO_2e increase in the emission tax corresponds to approximately \$0.66 increase in the effective fuel price. At each effective fuel price, the optimal size and dispatch strategy of various components were determined by the mixed integer linear optimization code developed in MATLAB. The following is a description of the results.

Prior to detailed presentation of results at various emission taxes and pipeline lengths, it is beneficial to better understand how the objective function and constraints of the optimization impact the simulation. As a case in point, Fig. 3 illustrates the distribution of electricity supply, distribution of available wind energy, distribution of energy supplied to compressor for storage, distribution of heat supply, and the energy level of the cavern over a 7 day period at an emission tax of \$60/tCO_2e in the DCAES scenario. The time frame is arbitrary chosen as the 48th week of the year (Saturday, November 26 to Friday, December 2, 2011) and as expected, electric load is lower over the weekend. Most of the available wind energy is directly used by the electric load and expander of DCAES is mainly dispatched during hours with low availability of wind. Not surprisingly, less efficient SCGT is poorly competitive with other three types of generators at such a high emission tax and only dispatched for very few hours. Furthermore, waste heat of compression supplies a high portion of the heat load during hours with high availability of wind energy (charging period of cavern). Wind energy is only curtailed when it exceeds the electric load and the storage of this energy is limited by the capacity of the compressor. Finally, the cavern is depleted at the end of week to simulate a weekly cycle of energy storage.

3.1. Optimal size of components

An important aspect in determining the average COE is the size of various system components of the CAES and DCAES configurations. Fig. 4 illustrates the optimal size of the single and combined cycle gas turbines, expander, compressor and wind farm as well as the maximum hourly electric load (for comparison) at various values of emission tax in the CAES configuration. As shown, the generation fleet is only composed of gas turbines in the absence of any emission tax (effective fuel price of \$5.0/GJ). The optimal size of wind farm increases as emission tax is introduced while the optimal size of the CAES facility remains zero until a tax of \$40/tCO_2e. This observation implies that better environmental performance and fuel economy of CAES are not strong enough to justify investing in this capital intensive technology at low levels of emission penalties. As the tax (and thus effective fuel price) increases from zero, the size of SCGT (with higher fuel costs but a lower specific capital cost) decreases while the size of the more efficient but more expensive CCGT increases at a mild rate. However, as CAES enters the picture at \$40/tCO_2e, the optimal size of gas turbines declines at a sharp rate while the optimal size of wind farm increases rapidly. Therefore, relatively high emission taxes would be required for economic competitiveness of the more expensive but less polluting wind farms and CAES facilities with conventional gas turbines. Another interesting observation is the relatively large size of the combined cycle gas turbines even at high emission tax levels. As a case in point, the size of CCGT is 409 MW while the size of the wind farm and expander reach 1160 and 397 MW at a high emission tax of \$80/tCO_2e. This behavior can be explained by the good thermal efficiency of CCGT technology and low GHG intensity of natural gas as its fuel.

Not surprisingly, the size of the energy storage facility remains zero at tax levels below \$40/tCO_2e in the DCAES scenario as well (Fig. 5). Utilizing less efficient gas turbines would result in lower levelized cost of electricity (objective of optimization) at low tax levels compared to building more efficient but capital intensive DCAES plants. The overall trend is similar to the CAES configuration: rapid increase in the size of the wind farm and expander of DCAES and decline in the size of the gas turbines at emission tax of \$40/tCO_2 and higher. Nevertheless, comparing Figs. 4 and 5 leads to an interesting observation: the size of the wind farm, expander, compressor, and simple cycle gas turbines are larger in the DCAES system compared to the CAES configuration at the same levels of

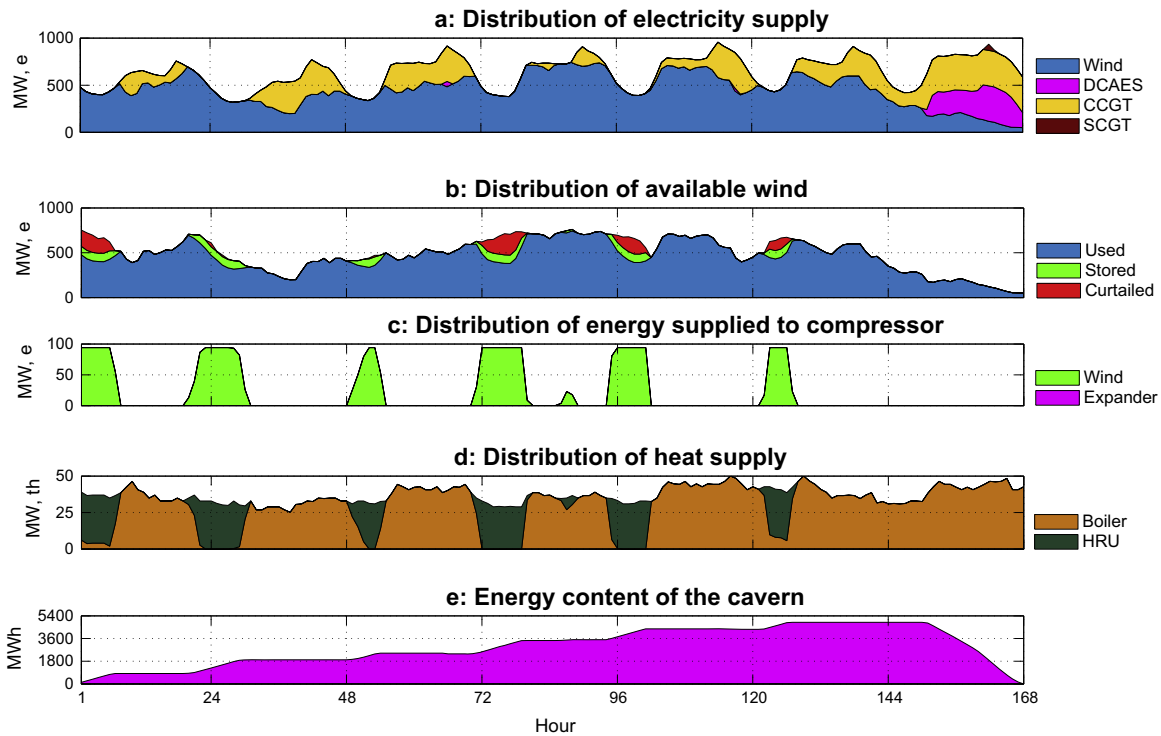

Fig. 3. Performance of various components of the DCAES system over an arbitrary period at an emission tax of \$60/tCO_2e. Horizontal axis shows the period between Saturday, November 26 and Friday, December 2, 2011. "Used" and "Stored" in subfigure b represent the amount of wind energy that is used by the electric load and by the compressor of DCAES, respectively. Note wind energy is curtailed only when it exceeds the electric load and its storage is constrained by the capacity of the compressor (94 MW). "MW, e" and "MW, th" stand for MW electric and MW thermal respectively.

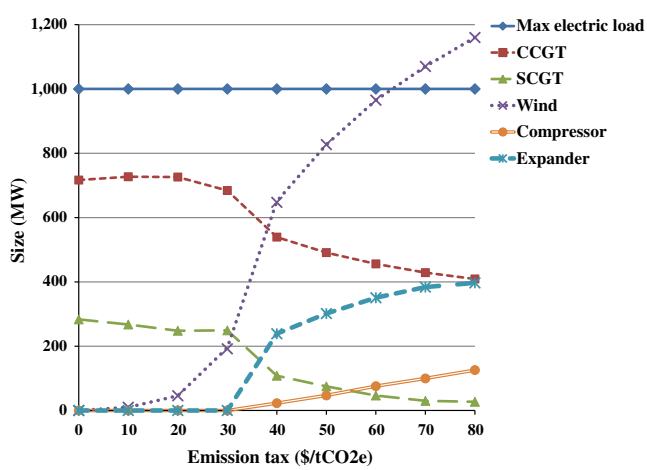

Fig. 4. Maximum electric load and the optimal size of electricity generation fleet in the CAES configuration at various levels of emission tax. Wind and CAES do not enter the electricity market until emission tax of \$10 and \$40/tCO_2e, respectively.

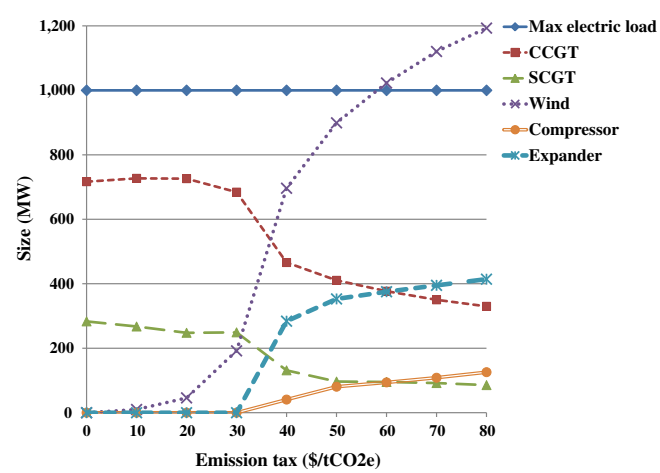

Fig. 5. Maximum electric load and the optimal size of electricity generation fleet in the DCAES configuration at various levels of emission tax. Wind and DCAES do not enter the electricity market until emission tax of \$10 and \$40/tCO_2e, respectively.

emission taxes. On the other hand, the optimal size of the combined cycle gas turbine is smaller in the DCAES system. As a case in point, Table 3 compares these values for the two systems at a emission tax of \$60/tCO_2e. The larger sizes of the wind farm and energy storage plant (compressor, expander, and cavern) in the DCAES configuration can be explained by the revenues associated with heat recovery from the DCAES facility used to satisfy a portion of the heat load, especially at high emission taxes. However, the larger size of the less efficient SCGT and smaller size of the more efficient CCGT fleet in the DCAES system may look strange at the first glance. As will be discusses later in Section 3.2, SCGT has a low capacity factor (dispatched infrequently) at high emission taxes; therefore, its lower capital cost would favor it over more efficient but more expensive CCGT.

Table 3
Optimal size of various system components for the CAES and DCAES configurations at an emission tax of \$60/tCO_2e. All values are in MW.

	CCGT	SCGT	Wind farm	Expander	Compressor
CAES configuration	456	47	965	351	76
DCAES configuration	377	95	1023	375	94

3.2. Distribution of electricity generation

Figs. 6 and 7 respectively show the share of the generation fleet in supplying electricity at different values of emission tax over the simulation period in the CAES and DCAES configurations.

In the absence of any emission tax, all the electric load is supplied by the combined and simple cycle gas turbines (98.0% and 2.0%, respectively). As emission tax increase to \$30/tCO_2e, wind share increases to 12.1% while the share of CCGT and SCGT decrease to 86.4% and 1.5% in both systems. However, this level of tax is still not high enough to justify building capital intensive compressed air energy storage plants and large wind farms. Nevertheless, as more aggressive emission taxes are enforced, the share of gas turbines decreases sharply because of their less efficient operation and consequently higher emission intensity compared to CAES, DCAES and wind. Interestingly, the share of wind energy in the annual electricity generation increases very fast, the share of the expander of the CAES facility remains relatively small, and the share of the CCGT remains intermediate (although declining) at higher emission taxes. These results reveal that even high emission taxes would not significantly increase the market share of the CAES facilities and most of the wind energy would be directly supplied to the grid rather than stored in the CAES facility due to its high capital costs and the requirement for burning fuel during its electricity generation cycle (heat rate of 4.19 GJ/MWh in this study).

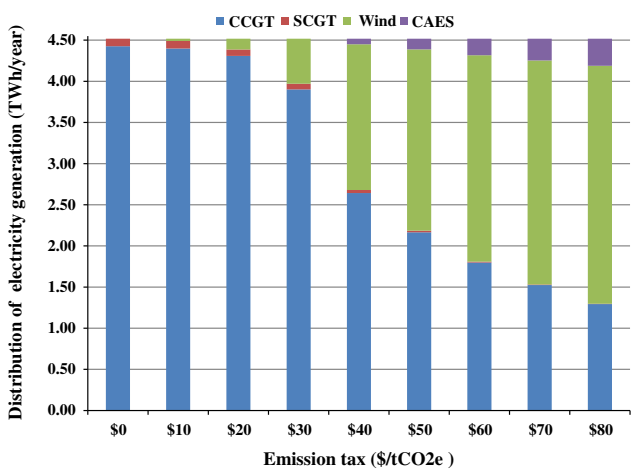

Fig. 6. Distribution of annual electricity generation in the CAES configuration at various levels of emission tax.

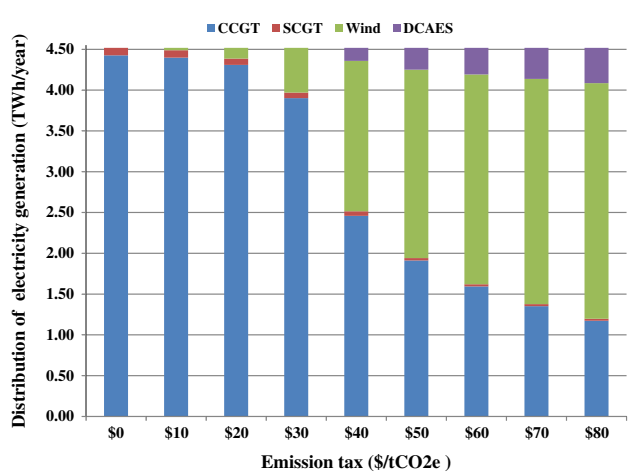

Fig. 7. Distribution of annual electricity generation in the DCAES configuration at various levels of emission tax.

Table 4
Share of electricity generation of various components in the CAES and DCAES configurations at a tax level of \$60/tCO_2e. All values are expressed as percentage of the annual electric load.

	CCGT	SCGT	Wind farm	Expander
CAES configuration	39.8	0.2	55.5	4.4
DCAES configuration	35.3	0.6	56.9	7.2

Similar results are observed for the DCAES system as electric load is supplied solely by gas turbines and wind farm at emission tax below \$40/tCO_2e. Nevertheless, a major difference between the DCAES system and the CAES system is the lower share of CCGT and higher share of wind, expander and SCGT in the annual electricity supply. As tabulated in Table 4, the expander of DCAES supplies 7.2% of the annual electric load while this value is 4.4% in the CAES configuration at an emission tax of \$60/tCO_2e. In addition, the CCGT share is 35.3% in this configuration while it is 39.8% for the CAES system. This observation is in agreement with the trend of equipment size in Figs. 4 and 5 with wind farm and expander replacing a larger market share of the CCGT in the DCAES system due to revenues gained through waste heat recovery from the compressor. Another observation is the small share of the SSGT in the annual electricity generation. Only 0.6% of the annual load is supplied by the simple cycle gas turbine because of its low thermal efficiency and thus high associated fuel costs at high emission taxes. As discussed in Section 3.1, the size of the SCGT plant is larger in the DCAES system at high emission taxes compared to the CAES system in spite of its low thermal efficiency. However, SCGT has a very low capacity factor (annual electricity generation/maximum possible annual electricity generation) of 3.3% in the DCAES system; therefore, its lower specific capital cost would justify building a larger SCGT plant in the DCAES system despite its higher fuel cost per MWh of electricity generated. The capacity factor of each plants with a specific size is driven by its dispatch cost (fuel and emission tax). In other words, the optimization code sizes and dispatches the generation fleet so that the electric load is satisfied at the least cost.

3.3. Distribution of wind energy

Although higher emission taxes justify building larger wind farms, the fact that periods with large availability of wind do not necessarily coincide with periods of high electric load necessitates existence of gas turbines and/or compressed air energy storage facilities to fill the gap between the electric load and wind-based electricity generation. Despite the fact that compressed air energy storage plants have a lower heat rate compared to gas turbines, they still burn fuel during the generation phase which translates to high fuel costs for these plants at high levels of emission tax. To further investigate the role of wind energy in meeting the electric demand, the distribution of the available wind energy (sold to the grid for instantaneous use, stored by the compressed air energy storage plant, or curtailed) at various levels of emission taxes in the CAES and DCAES scenarios are illustrated in Figs. 8 and 9, respectively.

The availability of wind energy is very limited in both systems below emission taxes of \$40/tCO_2e; nevertheless, it increases rapidly beyond this point as compressed air energy storage enters the electricity market. Interestingly, only a small portion of the available wind energy is stored by the compressor of the energy storage facility while a much higher portion is supplied to the grid for instantaneous consumption. This observation is in agreement with

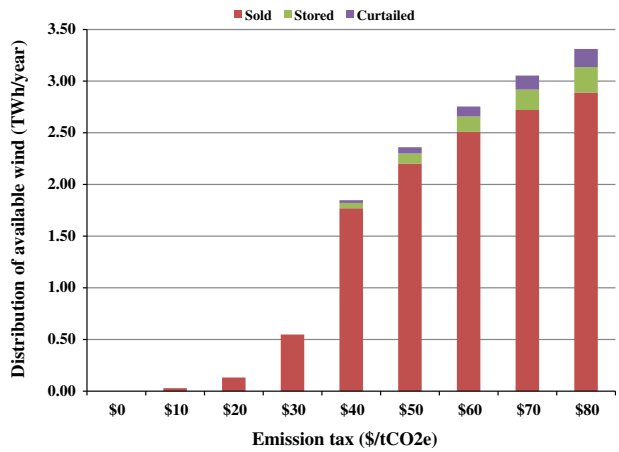

Fig. 8. Distribution of available wind energy in the CAES configuration at various levels of emission tax. Sold category represents the portion of available wind that is utilized to satisfy the instantaneous electric load. A much smaller portion of the available wind energy is stored by the compressor of the CAES facility for later use (stored category). Note the absolute amount of wind energy that is curtailed increases at larger emission tax due to the increased size of the wind farm.

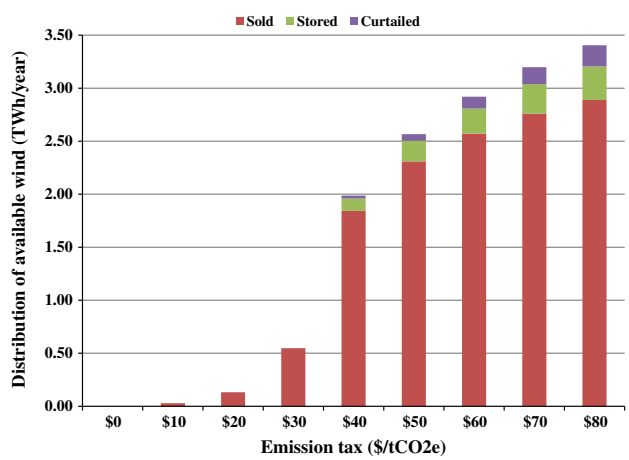

Fig. 9. Distribution of available wind energy in the DCAES configuration at various levels of emission tax. Note higher penetration of wind energy in this scenario compared to the CAES scenario.

the small compressor size in both systems as shown in Figs. 4 and 5 and is due to the high operating cost of the storage facilities at high emission tax. Another observation is the higher availability of wind energy and the portion of it that is stored by the compressor of the energy storage facility in the DCAES scenario which is driven by revenues gained through waste heat recovery from the compressor of the DCAES plant.

3.4. Distribution of heat supply

As discussed in Section 3.3, relatively higher compression energy in the DCAES system is an indication of the contribution of the heat recovery unit in supplying the heating load. The entire heat load is supplied by the conventional boilers at tax levels below \$40/tCO_2e since the size of the compressor and heat recovery unit are zero. As illustrated in Fig. 10, waste heat recovery from the compressor of the DCAES system negates fuel consumption of the boilers past this point and consequently reduces their share of annual heat supply so that 16.4% and 35.5% of the annual heat load is supplied by HRU at an emission tax of \$40 and \$80/tCO_2e,

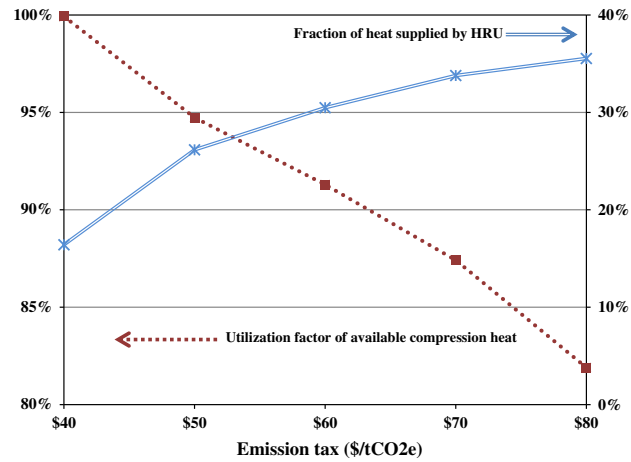

Fig. 10. Fraction of annual heat load supplied by the heat recovery unit (right axis) and percentage of recoverable heat of compression that is utilized by the heat load (left axis) in the DCAES configuration at various levels of emission tax. Note that the utilization factor of compression heat decreases at higher emission taxes since the size of the compressor (and therefore the available waste heat) increases while the size of heat load is fixed.

respectively. Furthermore, this figure illustrates the percentage of available heat from the compression train of the DCAES plant that is utilized by the heat load (called utilization factor of compression heat). Recovery of waste heat of compression negates consumption of fuel for heating purposes and brings additional revenues for DCAES. Interestingly, this value remains very high (above 80%) as the size of compressor increases as more aggressive emission taxes are introduced (see Figs. 5 and 10).

One should note that the level of contribution of the HRU to the heat supply is subject to the magnitude and fluctuations of both the electric and heat loads. In the system analyzed, the size of the electric load (maximum load of 1000 MW and average annual load of 516 MW electric) is relatively large compared to the heat load (maximum and average hourly heat load of 145.2 and 64.1 MW thermal, respectively). These values inherently make heat recovery from the DCAES system more economic due to the relatively larger size of the electric load. This setting is in agreement with real world systems in which the typical size of power plants are in the range of a few hundred MWs while the size of centralized municipal heat loads are usually in the range of a few tens of MWs. Moreover, a thermal energy storage facility (short- and long-term) might increase the share of HRU in the annual heat supply (or at least lead to a smaller HRU and better economics for the DCAES system) which is not studied in this paper.

3.5. Cost of electricity

Knowing the size and the hourly dispatch of the system components, the average cost of electricity at each effective fuel price was calculated for the two generation fleets considered in this study (one with the conventional CAES and one with the proposed DCAES system). This cost can be used to determine the cross-over point of emission tax: the tax level above which the DCAES system is economically superior to the conventional CAES configuration. The average COE of the DCAES system becomes less than the cost of the CAES system (\$73.73 and \$73.80/MWh, respectively) at an emission tax of \$40/tCO_2e (cross-over point with a pipeline length of 50 km) while the generation fleet is solely composed of wind farm and gas turbine prior to this point in both CAES and DCAES scenarios. The cost of electricity in the DCAES system remains lower than the CAES system past this level of emission tax while their difference grows as the share of wind and energy storage facilities

in the annual electricity supply increases. The annual cost of electricity in DCAES and CAES scenarios respectively reaches \$81.72 and \$82.60/MWh at emission tax of \$80/tCO_2e.

The primary drivers in the trade-off analysis between a DCAES and a CAES plant are the capital cost of the pipeline and the revenues gained through waste heat recovery in the DCAES scenario. Furthermore, the HRU of the DCAES system would replace some capacity of the boilers of the district heating plant which could be considered as an extra financial profit at a system level analysis. In order to obtain better insight to this trade-off analysis, the size and associated capital fuel costs of various components of the DCAES system are shown at the cross-over carbon price of \$40/tCO_2e in Table 5. It should be noted that the capital and fuel cost of the heat recovery unit are negative since they represent the savings in the capital cost (shaving of peak load of the boilers due to the existence of the HRU) as well as the fuel cost of the boilers of the heating system. As shown, the levelized capital cost of the air pipeline is approximately 8.5% of the total capital cost of the DCAES plant (expander, compressor, cavern, and pipeline). However, the annual fuel savings from the heat recovery unit is \$2.86 million per year, more than 50% of the annual fuel consumption of the expander.

One should note that the exact location of the cross-over point would obviously depend on various system parameters such as the nature of the heat and electricity markets (composition of the generation fleet, value of ancillary services, etc.). The main contribution of this paper is to introduce and investigate the opportunity of the DCAES system to economically compensate for fluctuations of wind-based electricity in niche markets. Recovery of the low-quality waste heat of compression form a compressed air energy storage facility for heating applications instead of using it to lower fuel consumption of the plant itself (i.e. adiabatic design) is a new approach that could be valuable in a carbon-constrained economy. The authors acknowledge that this system does require further evaluation prior to industrial development; however, believe that this model illustrates the potential benefits of DCAES over conventional CAES technology.

3.6. Sensitivity analysis on pipeline length

As discussed, the cross-over point is sensitive to the inputs and assumptions made in the simulation. Since the major difference between the conventional CAES and DCAES systems is the air pipeline, the possible effects of the length of the pipeline on the cross-over point and thus the minimum effective fuel price required for economic competitiveness of DCAES with CAES is evaluated in this section. In order to investigate the effect of the capital cost of the pipeline in this tradeoff analysis, the simulations were run again with two different pipeline lengths to evaluate the change in the cross-over point. Two new systems were simulated, one with an increased pipeline length of 100 km and another with a decreased length of 25 km.

DCAES system with a pipeline length of 100 km: this increased length would not have any impact on the optimal configuration of the CAES system. However, it is expected to increase the COE for the DCAES system since it would require a longer and more expensive pipeline. The cross-over emission tax in this scenario is \$50/tCO_2e as compared to the base case with a threshold tax of \$40/tCO_2e. The optimal values of the system components for the two DCAES systems with 50 and 100 km pipelines are tabulated in Table 6. As shown, an increase in the length of the pipeline makes wind energy and compressed air storage less favorable and results in lower sizes for the wind farm, expander, compressor, cavern and air pipeline. Since a smaller compressor and wind farm are used, there are fewer opportunities for waste heat recovery and a smaller HRU and larger HOB are required in the DCAES system with a 100 km long pipeline. A longer pipeline, smaller wind farm, smaller HRU, and thus higher demand for fuel to meet the electric and heat load would cause an increase of \$0.33/MWh in the average annual cost of electricity in the DCAES scenario with a 100 km long pipeline (a value of \$76.57/MWh). Although this change in COE may not seem very high, it indicates that DCAES systems could compete with conventional CAES systems effectively only under certain circumstances (niche markets) and highlights the importance of custom designing these facilities in accordance to the local parameters and local energy market conditions.

Simulation with 25 km pipeline: the cross-over emission tax for the system with a shorter pipeline length of 25 km is \$30/tCO_2e corresponding to an effective fuel price of \$7.0/GJ (at a base natural gas price of \$5.0/GJ). These values are \$40/tCO_2e and \$7.6/GJ in the base-case system with a pipeline length of 50 km. The optimal size of various components of the two DCAES systems at the carbon price of \$30/tCO_2e are tabulated in Table 7. As shown, high capital costs associated with a 50 km long pipeline leads to the superiority of conventional gas turbines so that the optimal system configuration only includes gas turbines and wind farms in this scenario. In other words, revenues from waste heat recovery from the compressor would not be high enough to justify building a 50 km pipeline between the compression unit (heat load) and the cavern of the energy storage plant at low emission taxes. However, these revenues are high enough to justify building a 25 km pipeline. The optimal design of the system with a 25 km distance between the heat load and the cavern includes a DCAES facility with a 193 MW expander and a 23 MW compressor. Size of the energy storage plant and wind farms sharply increase past this point and the cost of electricity remains lower in this system compared to the configuration with the pipeline length of 50 km.

3.7. Emission tax and emission reduction

This study optimizes both the size and the dispatch of the gas turbines, wind farm, and CAES and DCAES facilities to satisfy a variable electric load at variable emission taxes. This approach provides insight into the opportunity of reducing the carbon intensity of the electric sector, a major contributor to GHG emissions but relatively easier to be managed, through the introduction of emission taxes. The interesting question is how much of an emission tax would be required to justify investing in more capital intensive but cleaner technologies (wind and energy storage in this case) and drive the overall emissions associated with electricity generation below a certain level. The carbon intensity of satisfying the electric load considered in this study at the base-case natural

Table 5
Optimal size, fuel consumption and associated costs of the DCAES plant at a tax level of \$40/tCO_2e (at the cross-over point for the scenario with a 50 km long pipeline).

	Size	Fuel consumption (TJ/year)	Capital cost (\$ million/year)	Fuel cost (\$ million/year)
Expander	284 (MW)	734.7	14.62	5.61
Compressor	41 (MW)	NA	1.94	NA
Cavern	4106 (MWh)	NA	1.26	NA
Pipeline	437 (mm)	NA	1.65	NA
HRU	29 (MW)	−374.1	−0.04	−2.86

Table 6
The effect of pipeline length on the optimal size of system components and cost of electricity of the DCAES configuration at an emission tax of \$50/tCO_2e (cross-over point for the DCAES system with 100 km long pipeline).

L (km)	50	100
$Size_{CCGT}$ (MW)	411	416
$Size_{SCGT}$ (MW)	97	107
$Size_{Wind}$ (MW)	899	887
$Size_{Exp}$ (MW)	353	339
$Size_{Comp}$ (MW)	81	70
$Size_{Cav}$ (MWh)	7316	6362
D (mm)	575	520
$Size_{HRU}$ (MW)	56	49
$Size_{HOB}$ (MW)	138	138

Table 7
The effect of pipeline length on the optimal size of system components and cost of electricity of the DCAES configuration at an emission tax of \$30/tCO_2e (cross-over point for DCAES with 25 km long pipeline).

L (km)	50	25
$Size_{CCGT}$ (MW)	684	618
$Size_{SCGT}$ (MW)	249	114
$Size_{Wind}$ (MW)	192	273
$Size_{Exp}$ (MW)	0	193
$Size_{Comp}$ (MW)	0	23
$Size_{Cav}$ (MWh)	0	2314
D (mm)	0	357
$Size_{HRU}$ (MW)	0	16
$Size_{HOB}$ (MW)	145	134

gas price of \$5.0/GJ (and no emission tax) where the generation fleet is only composed of gas turbines is 507 kg CO_2e/MWh. As higher emission taxes are introduced and the effective price of natural gas increases accordingly, this value declines while the average cost of electricity increases.

Fig. 11 illustrates the minimum emission tax (vertical axis on the left) required to lower the emission intensity from the base case value of 507 kg CO_2e/MWh in the conventional CAES scenario as well as DCAES scenario with 25, 50, and 100 km long pipelines. This graph also shows the results for an unrealistic scenario of co-located underground storage facility and heat load for the DCAES system (0 km pipeline), as the most favorable scenario ("free heat" due to the possibility of waste heat recovery at no additional capital costs compared to the CAES system). Although this scenario is unrealistic, it is presented for the sake of argument and to show the maximum benefits from heat recovery in the DCAES configuration (ideal conditions for the economic superiority of the DCAES configuration, i.e. a pipeline length of 0 km). Moreover, the effective price of fuel at each level of emission tax (based on a fixed market fuel price of \$5.0/GJ) is demonstrated on the vertical axis on the right hand side. These values are calculated according to Eq. (2) and represent the total price paid by the plant owner for each GJ of natural gas consumed (summation of actual market price and the associated emission taxes).

The GHG intensity of all systems is the same at emission tax of \$0 and \$10/tCO_2e (absolute values of 507 and 503 kg CO_2e/MWh, respectively) since fuel costs are not high enough to justify investing in neither CAES nor DCAES. However, at an emission tax of \$20/tCO_2e, DCAES with 0 km pipeline enters the generation fleet and consequently lowers the GHG intensity of electricity generation (a value of 468 compared to a value of 491 kg CO_2e/MWh for all other scenarios). Similarly, DCAES with 25 km pipeline, CAES, DCAES with 50 km pipeline, and DCAES with 100 km pipeline enter the electricity market at an emission tax of \$30, \$40, \$40, and \$50/tCO_2e, respectively. As expected, the DCAES system with a longer pipeline has a higher emission intensity compared to the DCAES

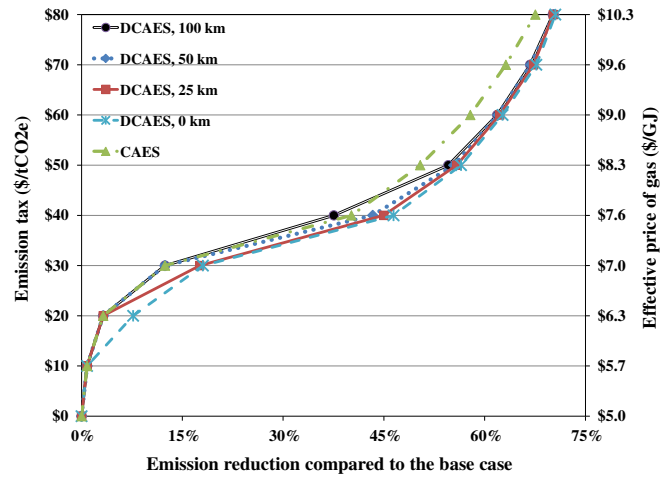

Fig. 11. Emission taxes and corresponding effective fuel prices required to reduce the carbon intensity of the electricity generation fleet compared to the base case of no emission tax (\$5.0/GJ effective fuel price and an average emission intensity of 507 kg CO_2e/MWh).

system with a shorter pipeline but lower than the CAES scenario. In other words, the same level of emission reduction would be achieved with the aim of a lower emission tax for the system with a shorter pipeline compared to a system with a longer pipeline (or CAES system). Interestingly, the emission intensity of all DCAES systems become similar at very aggressive emission tax measures so that the difference between GHG intensity of DCAES systems with 0 km and 100 km pipeline becomes less than 2 kg CO_2e/MWh at an emission tax of \$80/tCO_2e (values of 149 and 151 kg CO_2e/MWh, respectively). This can be explained by the fact that the capital costs associated with wind farm, expander, compressor, and cavern become much higher compared to the capital cost of the pipeline at such high emission taxes and thus the total cost and emission intensities are similar for different pipeline lengths. In other words, the optimal configuration and dispatch of the generation fleet with the DCAES system for 0, 25, 50, and 100 km pipelines are less affected by the capital cost of the pipelines at aggressive taxes on GHG emissions.

4. Conclusions

The potential financial and GHG emission savings through waste heat recovery in CAES plants to meet heating loads were evaluated in this study. The major additions to the compressed air energy storage facility equipped with waste heat recovery (a DCAES plant) compared to a conventional CAES plant are a heat recovery unit and a pipeline to transport the generated compressed air from the heat load site to the storage site. A series of hypothetical scenarios with an electricity generation fleet composed of conventional gas turbines (CCGT and SCGT), a wind farm, a conventional CAES or a new DCAES plant were analyzed. The electricity generation fleet were optimally sized and dispatched at minimal levelized cost (or maximized social welfare) over a period of 1 year at an hourly resolution. A district heating network equipped with conventional boilers and the heat recovery unit of the DCAES plant was used to meet a concentrated heat load over the same 1 year period. The distance between the heat load (compression unit of the DCAES system) and the underground air storage facility was set as 50 km in the base case.

At emission tax levels below 40 \$/tCO_2e, the optimal size of the wind farm and compressed air storage facility were small compared to the size of conventional gas turbines in both CAES and DCAES configurations. However, both their size and share of an-

nual electricity generation rapidly increased as more aggressive emission taxes were introduced. This behavior shows that, in order to be competitive, relatively high taxes on GHG emissions would be required for compressed air energy storage plants (conventional CAES and new DCAES) with conventional gas turbines to be used to compensate for fluctuating electricity output from wind farms. Both the size and share of the wind farm and storage facility were larger in the DCAES configuration compared to the CAES system revealing the economic gains associated with the use of otherwise wasted heat of compression for heating applications. In other words, fuel savings gained from waste heat recovery in the DCAES system could justify building larger capital intensive but cleaner wind farms and storage facilities to support wind-based electricity. As a result, the emissions associated with a generation fleet equipped with DCAES instead of conventional CAES plants would be lower. The financial gains from the recovery of the otherwise wasted heat of compression outweighed the increased capital cost of the DCAES system past the cross-over point of \$40/tCO_2e. The fact that the average cost of electricity in both systems remained close revealed that a DCAES system could compete economically with conventional CAES plants in certain niche markets but the exact performance would depend on the nature of the electricity market under investigation. It bears mentioning the wide development of DCAES systems is likely to be firstly limited by the availability of suitable geological formations in proximity of concentrated heat loads. Considering the size of the electric load (peak of 1 GW), size of simulated heat load (three times the size of University of Calgary), and optimal size of the expander of DCAES (28% of the peak electric load at an emission tax of \$40/tCO_2e), the size of electric load rather than heat load is expected to be the second limiting factor.

The authors also evaluated the sensitivity of the results to pipeline length. The cross-over emission tax price for economic superiority of the DCAES system with a 100 km pipeline instead of the base-case length of 50 km was increased to the value of \$50/tCO_2e. This \$10/tCO_2e increase translates to an increase of \$0.7/GJ of natural gas price. However, the DCAES system becomes more competitive with the conventional CAES at shorter distances between the heat load (compression facility of the DCAES plant) and the storage site. The cross-over emission tax in a system with a shorter pipeline length of 25 km is \$30/tCO_2e, corresponding to an effective natural gas price of \$7.0/GJ at a base natural gas price of \$5.0/GJ.

Although the complex dynamics of the real world electricity markets were ignored in this study, the authors believe this assessment provides a high level insight into the possible economic gains from waste heat recovery for heating applications from compressed air storage plants. Due to the higher capital cost intensity of these facilities compared to conventional gas turbines, CAES and DCAES would not be able to compete economically with gas turbines under normal conditions in the real world. Aggressive GHG taxes or other economic incentives are required to compensate their higher capital costs which would obviously affect the already complicated market dynamics. Therefore, this simplified approach is not expected to cause significantly higher errors compared to the case in which future market dynamics were forecasted. A macro-level approach was chosen in this paper, as the first study to introduce and evaluate DCAES design, to inform the policy makers and assess the potential of DCAES in supporting higher penetration of wind energy into the electric grid in a carbon constraint world. The authors acknowledge the importance of detail engineering and design of DCAES plants based on the local policies and nature of electricity market to maximize the profit of the plant. In addition, a thermal energy storage unit was not considered in the DCAES configuration for the sake of simplicity. As a result, the heat of compression could only be used to satisfy the instantaneous heat load. The economics of heat recovery from compressed air energy storage facilities may improve if such thermal energy storage facilities are considered, especially for seasonal storage of waste heat.[7] Finally, a generation fleet with lower pollution levels (e.g. NOx emissions) would benefit the neighboring communities through improved air quality, another benefit of the DCAES plants that could enhance their competitiveness with conventional CAES systems.

Acknowledgements

The authors would like to thank Eduard Cubi Monyanya from the Catalonia Institute for Energy Research (IREC, Spain) and Murray Sloan and Jim Sawers from the University of Calgary (Canada) for their valuable comments and help with heat load calculations. They also acknowledge useful technical discussions with Sean McCoy from the Carnegie Mellon University (USA) and Kenton Heidel from Carbon Engineering Ltd. (Canada) regarding capital cost estimates of pipelines and boilers, respectively. Hossein Safaei gratefully acknowledges financial support from Natural Sciences and Engineering Research Council of Canada (NSERC) under a graduate scholarship program.

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