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Compressed Air Energy Storage: Theory, Resources, And Applications For Wind Power

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Preface

This report reviews the literature on compressed air energy storage (CAES) and synthesizes the information in the context of electricity production for a carbon constrained world.

CAES has historically been used for grid management applications such as load shifting and regulation control. Although this continues to be the dominant near-term market opportunity for CAES, future climate policies may present a new application: the production of baseload electricity from wind turbine arrays coupled to CAES.

Previous studies on the combination of wind and CAES have focused on economics and emissions [1-10]. This report highlights these aspects of baseload wind/CAES systems, but focuses on the technical and geologic requirements for widespread deployment of CAES, with special attention to relevant geologies in wind-rich regions of North America.

Large penetrations of wind/CAES could make substantial contributions in providing electricity with near-zero GHG emissions if several issues can be adequately addressed. Drawing on the results of previous field tests and feasibility studies as well as the existing literature on energy storage and CAES, this report outlines these issues and frames the need for further studies to provide the basis for estimating the true potential of wind/CAES.

Executive Summary

Compressed Air Energy Storage (CAES) is a commercial, utility-scale technology suitable for providing long-duration energy storage with fast ramp rates and good part-load operation. CAES works by using electricity to compress air, which is subsequently stored in a large reservoir (typically in an underground geologic formation). Electricity is regenerated by recovering compressed air from storage, burning in this air a small amount of fuel (typically natural gas), and expanding the combustion products through a turbine (see section 1.2, page 15).

This report is intended to analyze the potential of CAES for balancing large penetrations of wind energy. The economic analysis of wind coupled with CAES for providing baseload power indicates that it will likely be competitive in economic dispatch under the same range of greenhouse gas (GHG) emissions price needed to make carbon capture and storage (CCS) economic for new coal integrated gasification combined cycle (IGCC) systems (~\$30/tCO_2). However the potential for wind/CAES is contingent on the availability of geologies suitable for CAES in windy regions. Thus the central focus of the report is on the geologic and technical requirements for CAES as they relate to the potential for large-scale deployment of this technology.

The CAES storage reservoir can often be constructed in pre-existing formations (e.g. a salt cavern, aquifer or abandoned mine). As a result, the capital cost of adding an incremental amount of storage capacity can be much lower than for other comparable storage technologies. This makes CAES especially well suited for bulk storage applications.

The total capital cost of a CAES unit tends to be dominated by the cost of the turbomachinery. The low total capital cost can be understood by noting that the turbomachinery is essentially a gas turbine for which the compression and expansion functions are separated in time—and gas turbines are characterized by relatively low capital costs.

In the 1970s, CAES began to attract attention as a way to store inexpensive baseload power produced during off-peak periods for use later when demand is higher and electricity is more valuable.

Shifts in market conditions led to diminished interest in CAES. However, the sustained rapid growth of wind power has catalyzed a renewed interest in this technology as an option for making wind power dispatchable (see section 1.1, page 12). Additionally, because CAES consumes significantly less fuel than a conventional gas turbine per unit of energy delivered, the GHG emissions from wind/CAES systems can be quite low.

Although the global wind resource can theoretically satisfy the demand for electricity several times over, the variability of wind and the typical remoteness of high-quality wind resources from major electricity demand centers (e.g. in the U.S.) must be addressed for wind to serve a large percentage of electricity consumption (>20-30%). CAES offers the potential for overcoming these challenges by both smoothing the output from wind and enabling the cost-effective operation of high capacity, high-voltage transmission lines carrying this power at high capacity factors.

The ultimate potential of wind in satisfying electricity needs via wind/CAES depends on the availability of geologies suitable for CAES in regions with high-quality wind resources (for a description of geologic options for CAES reservoirs see section 1.3, page 17). In the continental US, high-quality wind resources overlap more closely with porous rock geology than any other storage geology (see Figure i). Thus, in this region at least, widespread deployment of CAES in connection with wind power implies a considerable role for aquifers.

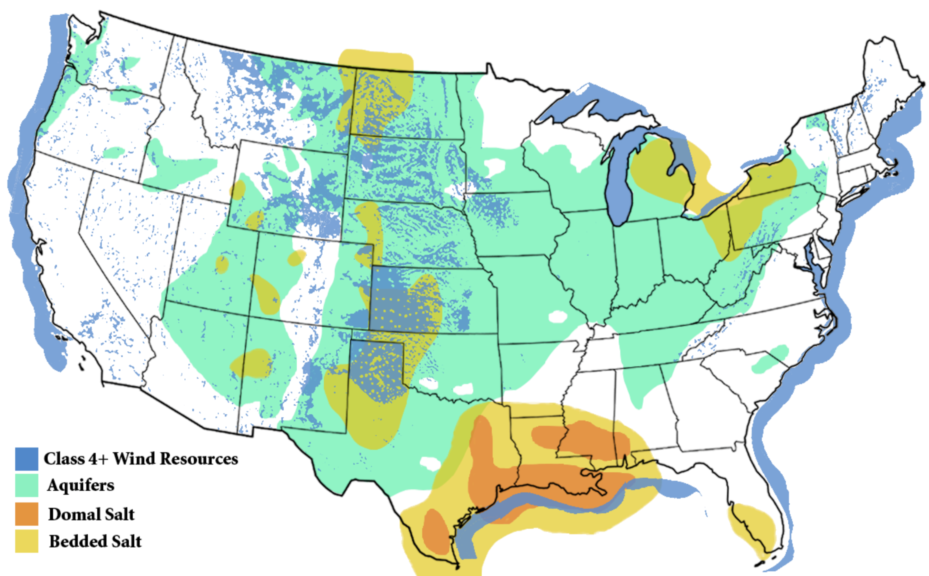


Figure i Areas with geologies favorable for CAES and class 4+ winds (see Section 3, "Aquifer CAES Geology and Operation" on page 42)

Although two commercial CAES plants have been built, neither uses aquifers as the storage reservoir (see section 1.4 "Existing and Proposed CAES Plants" on page 22). However, previous studies and field tests have confirmed that air can be successfully stored and withdrawn using a saline aquifer as a storage reservoir. Furthermore, a recently announced wind/CAES plant in Iowa will use an aquifer [a porous sandstone formation (see Figure ii)]. Once built, this project will provide important information about these systems in terms of both the utilization of aquifers for air storage and coupling of CAES to wind. The system is being designed to enable wind power to be dispatched in electric load-following transmission support applications, which is likely to be the most important near-term use of wind/CAES systems.

Although there has been no commercial experience with aquifer CAES, much can be gleaned from what is already known about natural gas storage in aquifers. The natural gas storage industry has vast experience with porous rock formations under conditions similar to those for CAES (see section 3.2.2, page 44). As such, the theory of natural gas storage provides a useful point of departure for understanding CAES, and many of the methodologies and data amassed for identifying natural gas storage opportunities may well prove useful for assessing CAES sites.

Relative to methane however, air has both different physical properties (e.g., air has a higher viscosity than methane) and different chemical properties (e.g., introducing oxygen underground can lead to various oxidation reactions, corrosion mechanisms, and the promotion of bacteria) that could pose challenges for air storage (see sections 3.4 and 3.5 on page 53). While it is expected to be often feasible to mitigate the effects of these factors, it will be essential to test the viability of aquifer CAES under a wide variety of geologic conditions and to carefully determine the impact of local geology on CAES system planning and design.

The use of CAES in an intermediate load application such as that envisioned for the Iowa wind/CAES plant will provide a valuable demonstration of wind/CAES integration. However, demonstration of much more closely coupled systems capable of serving baseload power markets is also needed to understand better the potential of wind/CAES, because although bulk storage may be valuable for serving a broad range of grid management applications, ultimately the role of wind as a tool for climate change mitigation will depend on the extent to which it will be able to supplant new baseload coal-fired capacity.

Figure ii The wind/CAES system scheduled to begin operation in 2011 near Des Moines, Iowa (IAMU, 2006)

A dispatch cost analysis suggests that a natural gas-fired wind/CAES system would often be able to compete against coal and other baseload power options, especially under a climate change mitigation policy sufficiently stringent to make CO_2 capture and storage cost-effective for coal power (see section 4, "Wind/CAES Systems in Baseload Power Markets" on page 58). Thus, the wind/CAES hybrid could give both wind and natural gas entry into baseload markets in which they would otherwise not be able to compete.

The storage capacity of CAES systems designed to deliver baseload power would typically be several times that for other grid management applications, but even so the "footprint" of a 10-m thick aquifer capable of providing baseload wind/CAES power would occupy a much smaller (~14%) land area than that of the corresponding wind farm under typical conditions (see section 2.3 on page 30).

A better understanding is needed of the performance of CAES over a wide range of conditions. In particular, use of CAES for wind balancing will require CAES to adjust output more frequently and to switch between compression and generation modes more quickly than has been required of CAES in applications such as storing off-peak power at night and generating peak electricity during the day (see section 2.1, page 27). Understanding well the impacts of these operational demands requires further study.

Determining the ultimate potential of baseload wind/CAES as a climate change mitigation option also requires knowledge of the prevalence of suitable geologies. Although porous rock formations seem to be prevalent in high wind areas, understanding the full potential of this technology will require in-depth assessments of the extent of formations with anticlines suitable for containment and, for promising structures, their geochemical and geophysical suitability for CAES. Data on local geology from US and state geological surveys including natural gas storage candidate site evaluations might aid in further characterizing these areas, but new data will also be needed, especially in regions where natural gas storage is not commonplace (see section 3.3 "Geologic Requirements" on page 47).

CAES appears to have many of the characteristics necessary to transform wind into a mainstay of global electricity generation. The storage of energy through air compression may enable wind to meet a large fraction of the world's electricity needs competitively in a carbon constrained world. If the needed steps are taken soon, it should quickly become evident just how large this fraction might be.

1. Background

Compressed Air Energy Storage (CAES) is a low cost technology for storing large quantities of electrical energy in the form of high-pressure air. It is one of the few energy storage technologies suitable for long duration (tens of hours), utility scale (100's to 1000's of MW) applications. Several other energy storage technologies such as flywheels and ultracapacitors have the capability to provide short duration services related to power quality and stabilization but are not cost effective options for load shifting and wind generation support [11, 12].

The only technologies capable of delivering several hours of output at a plant-level power output scale at attractive system costs are CAES and pumped hydroelectric storage (PHS) [13-17]. Although some emerging battery technologies may provide wind-balancing services as well, typical system capacities and storage sizes are an order of magnitude smaller than CAES and PHS systems (~10 MW, <10 hours) with significantly higher capital costs (see Table 1).

PHS does not require fuel combustion and has a greater degree of field experience relative to CAES, but it is only economically viable on sites where reservoirs at differential elevations are available or can be constructed. Furthermore, the environmental impact of large-scale PHS facilities is becoming more of an issue, especially where preexisting reservoirs are not available and sites with large, naturally occurring reservoirs at large differential elevations where environmentally benign, inexpensive PHS can be built are increasingly rare.

Table 1 Capital Costs for Energy Storage Options [11, 12, 18]

Technology	Capital Cost: Capacity ($/kW)	Capital Cost: Energy ($/kWh)	Hours of Storage	Total Capital Cost ($/kW)
CAES (300MW)	580	1.75	40	650
Pumped Hydroelectric (1,000MW)	600	37.5	10	975
Sodium Sulfur Battery (10MW)	1720-1860	180-210	6-9	3100-3400
Vanadium Redox Battery (10MW)	2410-2550	240-340	5-8	4300-4500

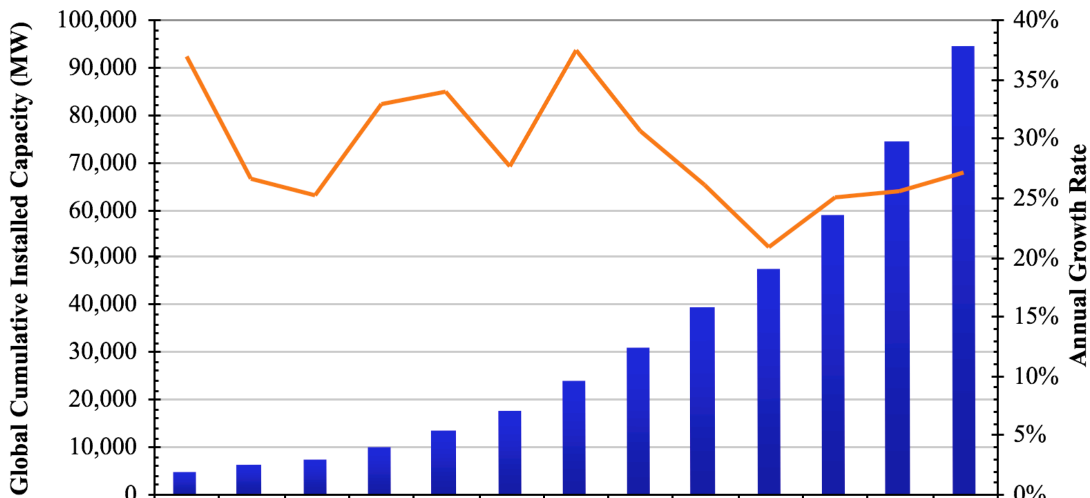
In contrast, CAES can use a broad range of reservoirs for air storage and has a more modest surface footprint giving it greater siting flexibility relative to PHS. High-pressure air can be stored in surface piping, but for large-scale applications, developing a storage reservoir in an underground geologic formation such as solution mined salt, saline aquifer, abandoned mine, or mined hard rock are typically more cost effective. The widespread availability of geologies suitable for CAES in the continental US suggests that this technology faces far fewer siting constraints than PHS, which is especially important for the prospect of deploying CAES for wind balancing.

One of the central applications for CAES is for the storage of wind energy during times of transmission curtailment and generation onto the grid during times of shortfalls in wind output. Such wind balancing applications require not only large-scale, long duration storage, but also fast output response times and siting availability in wind-rich regions. Prior studies indicate that suitable CAES geologies are widely available in the wind-rich US Great Plains. Furthermore, CAES is able to ramp output quickly and operate efficiently under partial load conditions making it well suited to balance the fluctuations in wind energy output. Finally, the low greenhouse gas (GHG) emissions rate of CAES makes it a good candidate for balancing wind in a carbon constrained world.

Among the geologic options for air storage, porous rock formations offer the most widespread availability and potentially the lowest cost. Moreover, geographical distributions of aquifers and good wind resources are strongly correlated in the US. Therefore the potential for CAES to play a major role in balancing wind output and producing low greenhouse gas (GHG) emitting power will depend to a large degree on the availability of aquifer structures suitable for CAES.

1.1. Evolving Motivations for Bulk Energy Storage

CAES emerged in the 1970s as a promising peak shaving option [19]. High oil prices together with an expanding nuclear power industry sparked an interest in energy storage technologies such as CAES to be used in load following applications. The high price of peak power and the perceived potential for inexpensive baseload nuclear power made attractive the option of storing inexpensive off-peak electricity and selling this electricity during peak demand periods [20, 21].



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
MW	4,800	6,100	7,600	10,200	13,600	17,400	23,900	31,100	39,431	47,620	59,091	74,133	94,112
% Growth	36.8%	26.6%	25.2%	32.8%	33.9%	27.6%	37.4%	30.5%	26.0%	20.8%	24.9%	25.5%	27.0%

Figure 1 Global Wind Capacity 1995-2007 (GWEC, 2008)

These conditions initially fueled a strong interest in CAES among many utilities, but as the nuclear power industry lost momentum and oil prices retreated from their peaks, the market conditions for CAES began to change. During the 1980s the gas turbine and combined cycle generation emerged as the leading low cost options for peaking and load-following markets. This together with overbuilt generating capacity on the grid and the perception that domestic natural gas supplies were abundant led to erosion of market interest in energy storage.

Recent trends in gas price and wind power development have fostered new interest in energy storage, not as a way to convert baseload power into peak power, but as a way mitigate the variability of wind energy [8, 10]. Global wind power capacity has grown rapidly in recent years from 4.8 GW in 1995 to 94 GW by the end of 2007 (see Figure 1). The variability of wind output requires additional standby reserve capacity to ensure output during times of peak demand. Gas turbines can respond quickly to shortfalls in wind output and so gas fired spinning reserve units are good candidates for dispatch to meet the challenge of balancing this growing wind segment of the power mix.

Energy storage represents an alternative wind balancing strategy, and the low fuel consumption of CAES makes it especially relevant in the face of high gas prices. Although wind balancing has long been acknowledged as a potential application for bulk energy storage [22], it is only recently that wind penetrations have reached levels that require additional balancing measures for maintaining system stability [23]. However recent studies have shown that bulk storage can reduce the integration costs for wind energy even at relatively low penetration levels [24].[1] The use of storage for balancing wind and for serving other grid management applications will be especially valuable where the supply of flexible generating capacity (e.g. hydroelectric) is limited [10, 25]. The continued increase of wind penetration on the grid and the need to reduce greenhouse gas emissions may create an incentive to use storage systems directly coupled with wind to produce baseload power rather than as independent entities to provide grid support services (see below). Further, because the fuel consumption of CAES is less than half of that of a simple cycle gas turbine, using CAES would provide a hedge against natural gas price volatility [26].

A further reason for considering wind farms coupled to CAES storage (henceforth referred to as wind/CAES) stems from the fact that most high quality onshore wind resources are often remote from load centers. The exploitable onshore wind potential in classes 4 and above in North America is huge—equivalent to more than 12 times total electricity generation in 2004 [27, 28].[2,3] However the resources in the US are concentrated in the sparsely populated Great Plains and Midwest States (see Figure 2) which account for over half of the exploitable US wind generation potential in class 4+ [29]. Bringing electricity cost-effectively from the Great Plains to major urban electricity

[1] The cited report indicates that removal of bulk storage (pumped hydroelectric storage in this case) increases integration costs for wind by approximately 50% for a wind penetration level of 10%. Also, doubling of storage capacity lowered integration cost by ~$1.34/MWh in the 20% penetration case.

[2] The Greenblatt (2005) estimate is based on the assumption that various land use constraints limit the technical potential for wind to what can be produced on 50% of the land on which class 4+ wind resources are available.

[3] The technical wind power potential at the global level is also huge. Considering only class 4+ winds exploited on 50% of the land on which these resources are available, as in the North American case, Greenblatt (2007) estimated that the global technical wind energy potential is 185,000 TWh/y on land plus 49,400 TWh.year offshore. For comparision the global electricity generation rate in 2004 was 17,400 TWh/year.

demand centers requires that it be transmitted via GW-scale high-voltage transmission lines that are baseloaded. CAES systems coupled to multi-GW-scale wind farms could provide such baseload power.

As will be shown, wind/CAES systems have good prospects of being able to compete in a carbon constrained world directly with other low carbon *baseload* power options such as the coal integrated gasification combined cycle (IGCC) with carbon capture and storage (CCS) (see Section 4).

Because the incremental capital cost for increasing CAES storage volume capacity is relatively low, it is well suited for providing long-duration storage (>80 hours) needed to produce baseload power. Although seasonal storage of wind is also possible, it would require much larger storage volumes [30].

Wind/CAES also gives natural gas a role in baseload power markets that are often out of reach due to the relatively high dispatch costs of natural gas generation. Thus, wind/CAES gives both wind and natural gas an entry into large baseload power markets

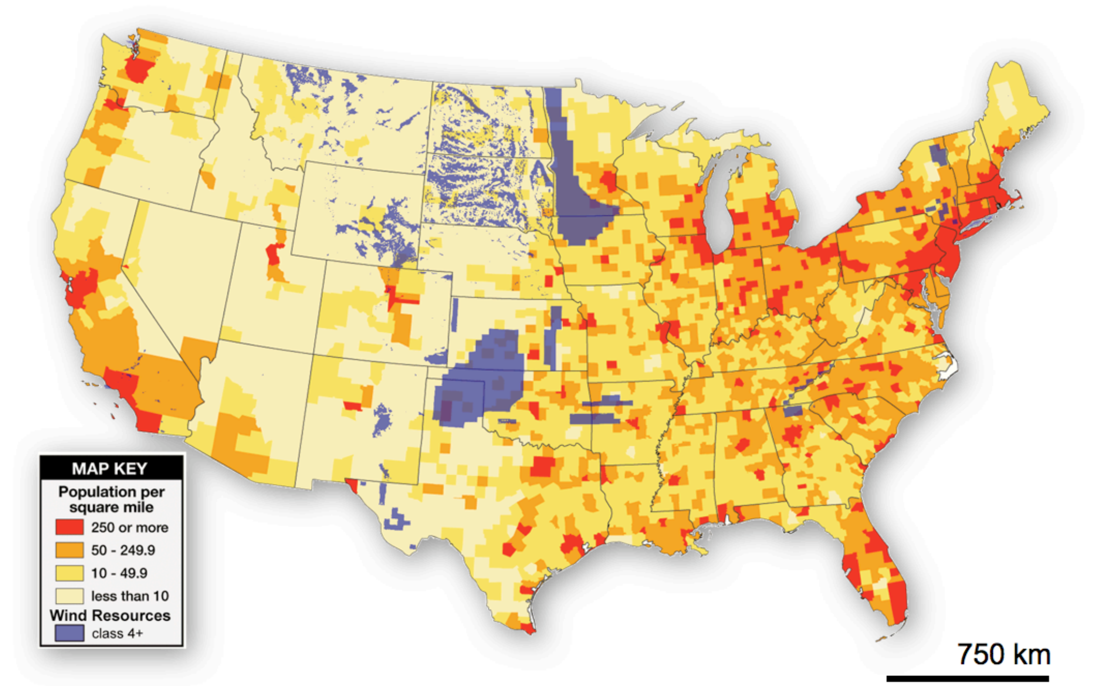


Figure 2 Onshore wind resources and population density in the continental US (US Census 2000; NREL, 2001, 2002, 2006)

to which they would not otherwise have access.

While typical capacity factors for wind farms are approximately 30-40% [31], wind/CAES systems can achieve capacity factors[4] of 80-90% typical of baseload plants.

[4] Capacity factor in this case is on the basis of a constant demand level. The rated capacity of the wind park will be "oversized" relative to this demand level and the CAES turboexpander capacity matched to it such

Therefore, the coupling of wind to energy storage enhances utilization of both existing transmission lines and dedicated new lines for wind. This can alleviate transmission bottlenecks or obviate transmission additions and upgrades.

In the case that transmission capacity is limited, it will be advantageous to site the storage reservoir and wind turbine array as closely as possible to exploit the benefits described above. If this is not the case however, there is no need to co-locate the storage system and wind array. Independently siting these components would allow added flexibility for simultaneously matching facilities to the ideal wind resource, storage reservoir geology and the required natural gas supplies.

1.2. CAES Operation

CAES systems operate much in the same way as a conventional gas turbine except that compression and expansion operations occur independently and at different times (see Figure 3). Because compression energy is supplied separately, the full output of the turbine can be used to generate electricity during expansion, whereas conventional gas turbines typically use two thirds of the output power from the expansion stage to run the compressor.

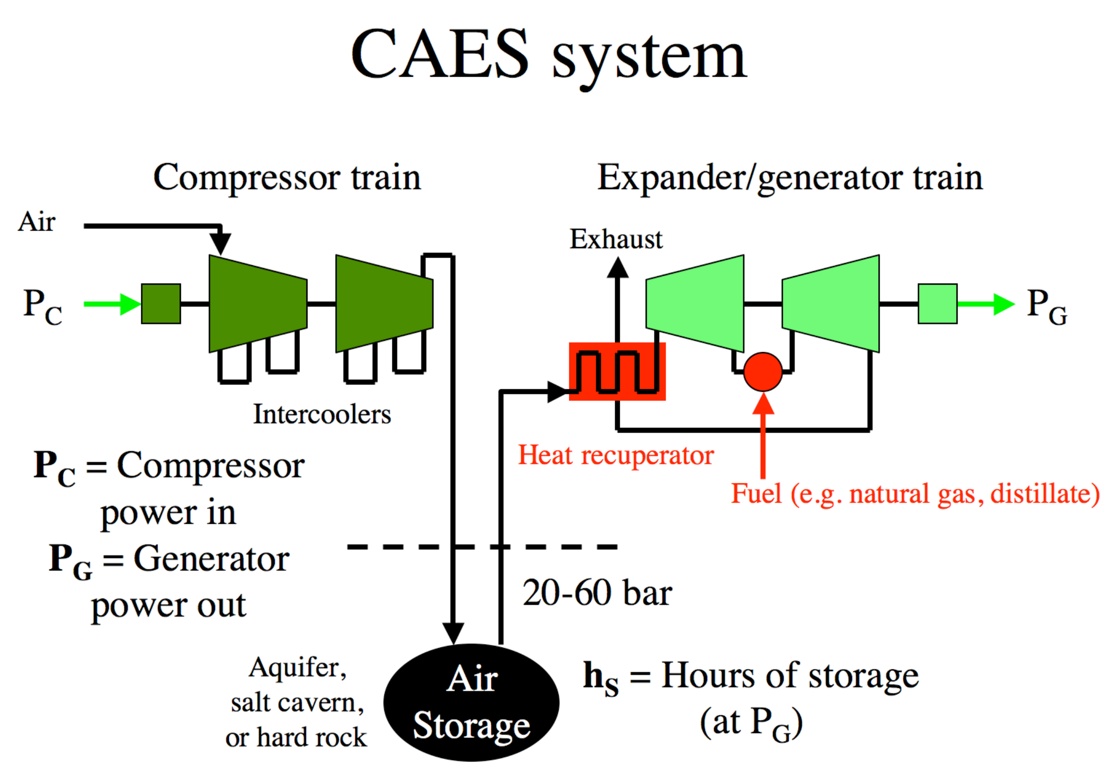


Figure 3 CAES System Configuration

that excess wind can be stored to balance subsequent shortfalls. While it is possible to produce constant output (i.e. 100% capacity factor) from a wind/CAES plant, it would require a significantly larger storage volume capacity.

During the compression (storage) mode operation, electricity is used to run a chain of compressors that inject air into an uninsulated storage reservoir, thus storing the air at high pressure and at the temperature of the surrounding formation. The compression chain makes use of intercoolers and an aftercooler to reduce the temperature of the injected air thereby enhancing the compression efficiency, reducing the storage volume requirement and minimizing thermal stress on the storage volume walls.

Despite the loss of heat via compression chain intercoolers, the theoretical efficiency for storage at formation temperatures in a system with a large number of compressor stages and intercooling can approach that for a system with adiabatic compression and air storage in an insulated cavern (see the discussion of compression efficiency in Appendix A).[5]

During the expansion (generation) operation mode, air is withdrawn from storage and fuel (typically natural gas) is combusted in the pressurized air. The combustion products are then expanded (typically in two stages), thus re-generating electricity

Fuel is combusted during generation for capacity, efficiency and operational considerations. Expanding air at the wall temperature of the reservoir would necessitate much higher air flow in order to achieve the same turbine output – thus increasing the compressor energy input requirements to the extent that the charging energy ratio would be reduced by roughly a factor of four [32]. Furthermore, in the absence of fuel combustion the low temperatures at the turbine outlet[6] would pose a significant icing risk for the blades because of the large airflow through the turbine, despite the small specific moisture content for air at high pressure. There is also the possibility that the turbine materials and seals might become brittle during low temperature operation.

[5] Adiabatic CAES designs capture the heat of compression in thermal energy storage units (see discussion of AA-CAES in section 5, Advanced Technology Options)

[6] For example assuming air recovered from storage at 20°C, adiabatic expansion, and a 45x compression ratio, T=-174°C at the turbine exhaust

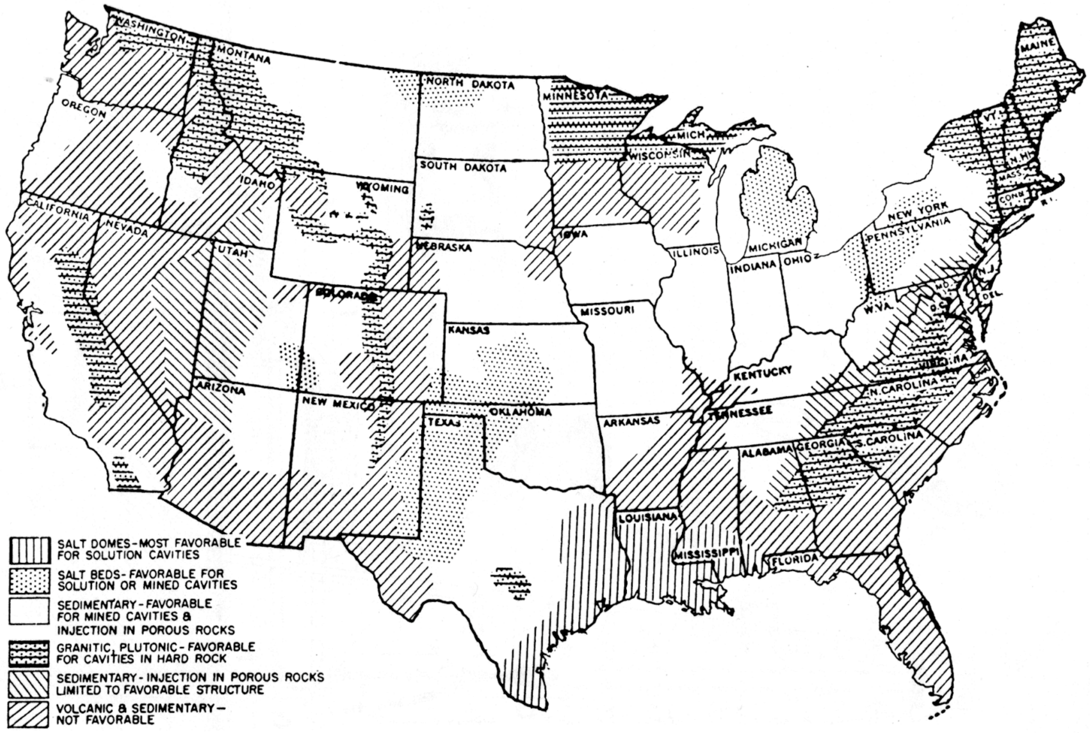


Figure 4 Areas classified for subsurface storage of fluids. From the National Petroleum Council Report of the Committee on Underground Storage for Petroleum, April 22, 1952; updated in Oct 1962 b C.T. Brandt, Underground Storage and Mining Consultant, Bartesville, OK; additional changes reflect comments in Katz and Lady, 1976.

1.3. Suitable Geologies for CAES

Geologies suitable for CAES storage reservoirs can be classified into three categories: salt, hard rock, and porous rock. Taken together, the areas that have these geologies account for a significant fraction of the continental United States (see Figure 4). Prior studies indicate that over 75% of the U.S. has geologic conditions that are potentially favorable for underground air storage [33, 34].

However, those studies carried out only macro scale analyses that did not evaluate areas according to the detailed characteristics necessary to fully estimate their suitability for CAES. While the large fractions of land possessing favorable geologies is encouraging, broad surveys such as the data presented in Figure 4 can only serve as a template for identifying candidate areas for further inquiry and detailed regional and site-specific data will be necessary to determine the true geologic resource base for CAES.

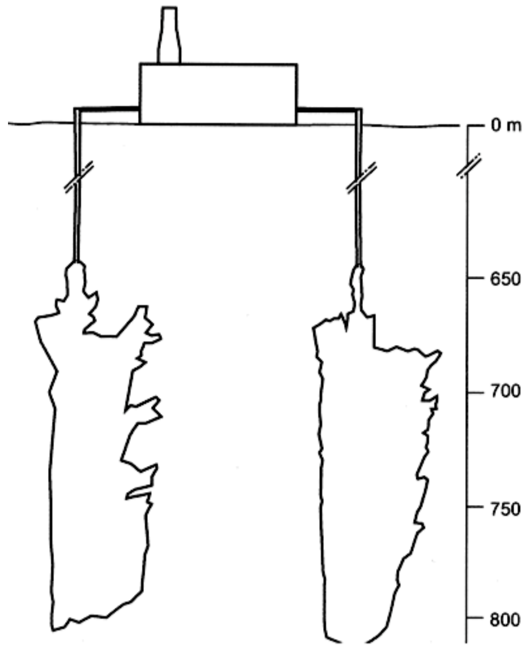


Figure 5 Structure of Huntorf CAES plant salt dome storage with caverns and plant on same scale [35]

1.3.1. Salt

The two CAES plants currently operating use solution-mined cavities in salt domes as their storage reservoirs (see Figure 5 and section 1.4 "Existing and Proposed CAES Plants"). In many ways, such formations are the most straightforward to develop and operate. Solution mining techniques can provide a reliable, low cost route for developing a storage volume of the needed size (typically at a storage capital cost of ~ $2.00 per kWh of output from storage) if an adequate supply of fresh water is available and if the resulting brine can be disposed of easily [11, 12]. Furthermore, due to the elasto-plastic properties of salt, storage reservoirs solution-mined from salt pose minimal risk of air leakage [33, 36].

Large bedded salt deposits are available in areas of the Central, North Central and North East United States while domal formations can be found in the Gulf Coast Basin [37].

Although both bedded and domal formations can be used for CAES, salt beds are often more challenging to develop if large storage volumes are required. Salt beds tend to be much thinner and often contain a comparatively higher concentration of impurities which present significant challenges with respect to structural stability [37]. Caverns mined from salt domes can be tall and narrow with minimal roof spans as is the case at both the Huntorf (see Figure 5) and McIntosh CAES facilities. The thinner salt beds cannot support long aspect ratio designs because the air pressure must support much larger roof spans. In addition, the presence of impurities might further compromise the structural integrity of the cavern and further complicate the development a large capacity storage system.

Although the locations of domal formations in the United States are not well correlated with high quality wind resources (see Figure 17), there are some indications the prospects may be more favorable in Europe (see Figure 6).

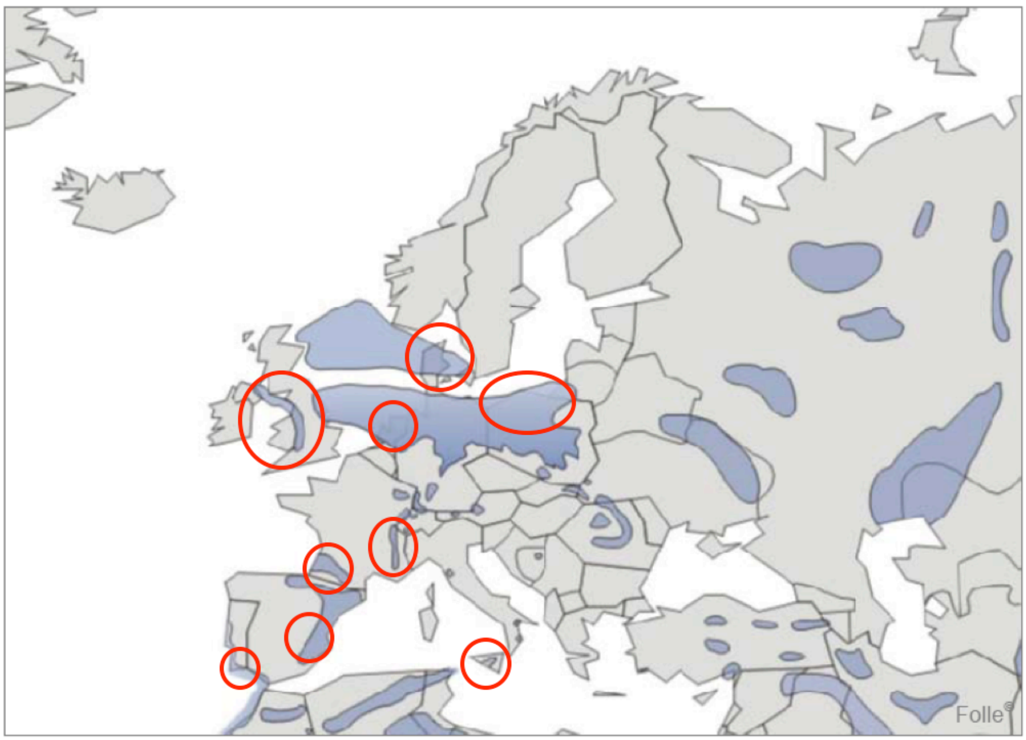


Figure 6 Coincidence of high wind potential and salt domes in Europe. Red circles indicate areas investigated for CAES development [38]

1.3.2. Hard Rock

Although hard rock is an option for CAES, the cost of mining a new reservoir is often relatively high (typically $30/kWh produced). However in some cases existing mines might be used in which case the cost will typically be about $10/kWh produced [11, 39, 40] as is the case for the proposed Norton CAES plant, which makes use of an idle limestone mine (see section 1.4).

Detailed methodologies have been developed for assessing rock stability, leakage and energy loss in rock-based CAES systems including concrete-lined tunnels [44-46]. Several such systems have been proposed [47] and known field tests include two recent programs in Japan: a 2 MW test system using a concrete-lined tunnel in the former Sunagaawa Coal Mine and a hydraulic confinement test performed in a tunnel in the former Kamioka mine [11].

In addition, a test facility was developed and tested by EPRI and the Luxembourg utility Societe Electrique de l'Our SA using an excavated hard-rock cavern with water compensation [48]. The site was used to determine the feasibility of such a system for CAES operation and to characterize and model water flow instabilities resulting from the release of dissolved air in the upper portion of the water shaft (i.e. the "champagne effect").

Hard rock geologies suitable for CAES are widely available in the continental US and overlap well with high-quality wind resources (see Figure 7). However, because the development costs are currently high relative to other geologies (especially given the limited availability of preexisting caverns and abandoned mines [36]), it is unlikely that this option will be the first option pursued for a large-scale deployment of CAES. Although future developments in mining technology may reduce the costs of utilizing such geologies, it appears that other geologies may currently offer the best near-term opportunities for CAES development.

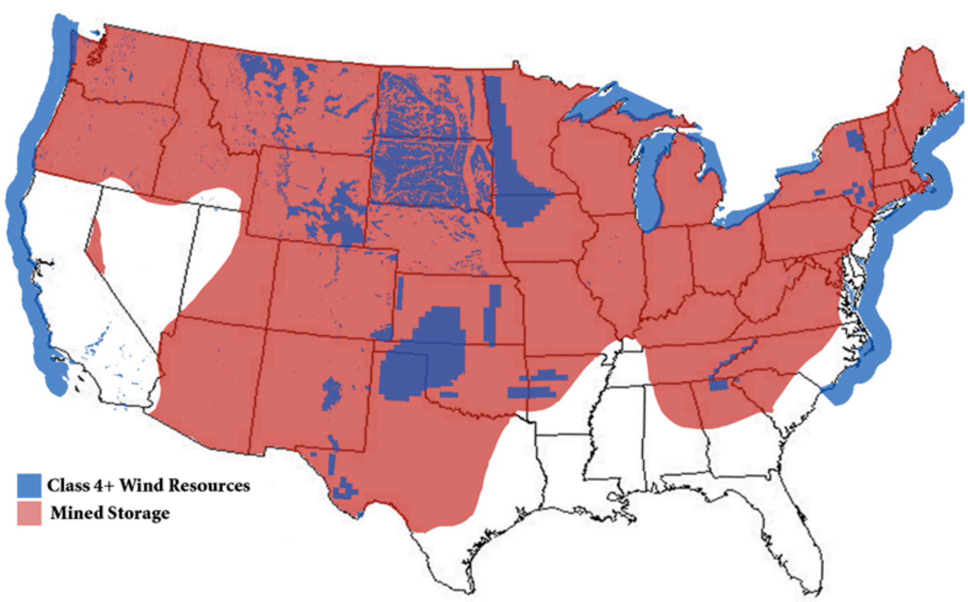


Figure 7 Areas with geologies suitable for mined storage (red) and high-quality wind resources (blue) [33, 41-43]

1.3.3. Porous Rock

Also suitable for CAES are porous rock formations such as saline aquifers. Porous reservoirs have the potential to be the least costly storage option for large-scale CAES with an estimated development cost of ~$0.11/kWh for incremental storage volume expansion [11]. In addition, large, homogeneous aquifers potentially suitable for CAES operation can be found throughout many areas of the central US. Because this area coincides with areas of high quality wind (see Figure 17) and because of the limited availability and/or cost-effectiveness of other options, aquifer CAES will be especially relevant to the discussion of energy storage for balancing wind. Despite its potential for low cost development, utilization of an aquifer for CAES requires extensive characterization of a candidate site to determine its suitability (see section 3, “Aquifer CAES”).

A 25 MW porous rock-based CAES test facility operated for several years in Sesta, Italy. Although the tests were successful, a geologic event disturbed the site which led to closure of the facility [11]. In addition, EPRI and the U.S. Department of Energy have conducted tests on porous sandstone formations in Pittsfield, Illinois to determine their feasibility for CAES (see section 3, “Aquifer CAES”). Construction of the first commercial CAES plant with a porous rock reservoir is scheduled to begin in Dallas Center, Iowa in 2009 (see section 1.4)

1.4. Existing and Proposed CAES Plants

1.4.1. Huntorf

The Huntorf CAES plant, the world's first CAES facility, was completed in 1978 near Bremen, Germany (see Figure 9 and Figure 8). The 290 MW plant was designed and built by ABB (formerly BBC) to provide black-start services[7] to nuclear units near the North Sea and to provide inexpensive peak power. It has operated successfully for almost three decades primarily as a peak shaving unit and to supplement other (hydroelectric) storage facilities on the system to fill the generation gap left by slow-responding medium-load coal plants. Availability and starting reliability for this unit are reported as 90% and 99% respectively.

Because the Huntorf plant was designed for peaking and black start applications, it was initially designed with a storage volume capable of two hours of rated output. The plant has since been operationally modified to provide up to three hours of storage and has been used increasingly to help balance the rapidly growing wind output from North Germany [35, 49].

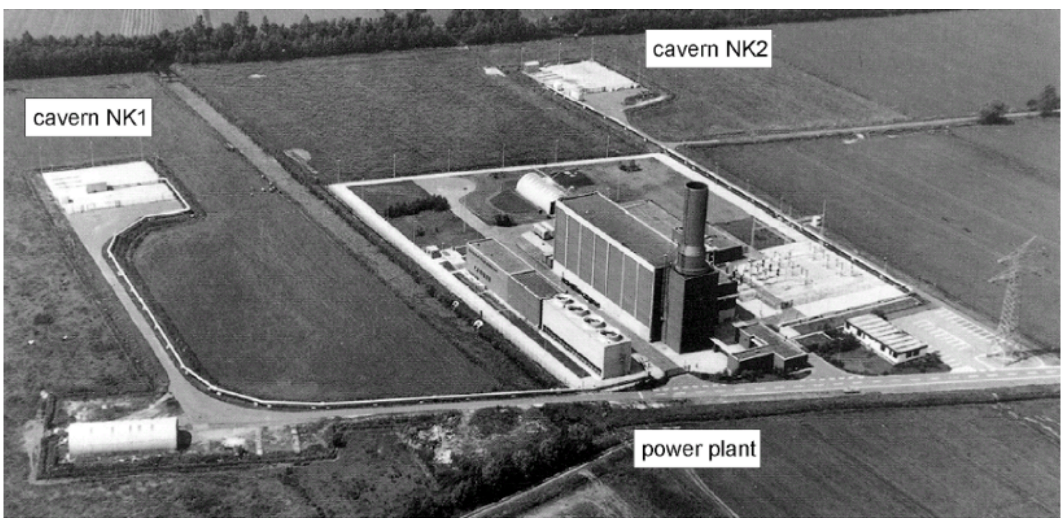


Figure 8 Aerial view of the Huntorf CAES plant [35]

The underground portion of the plant consists of two salt caverns (310,000 m^3 total) designed to operate between 48 and 66 bar. The air from the salt caverns was found to cause oxidation upstream of the gas turbine during the first year of operation, leading to the installation of fiberglass reinforced plastic (FRP) tubing. Because the turbine expanders are sensitive to salt in the combustion air, special measures were taken to ensure acceptable conditions were met at the turbine inlet as well [35].

[7] Black start refers to the ability of a plant to start up during a complete grid outage. Because nuclear power stations require some power to resume operation, the Huntorf CAES plant was built in part to provide this start up power.

The compression and expansion sections draw 108 and 417 kg/s of air respectively and are each comprised of two stages. The first turbine stage expands air from 46 to 11 bar.

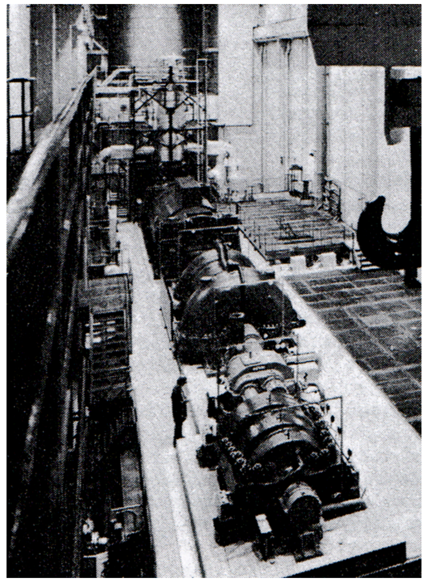


Figure 9 Huntorf Machine Hall [50]

Because gas turbine technology was not compatible with this pressure range, steam turbine technology was chosen for the high-pressure (hp) expansion stage. Due to the increase in heat transfer coefficient at elevated pressure and temperature and to ensure proper cooling (and to control NO_x emissions as well), the hp turbine inlet temperature was held to only 550° C compared to 825° C for the lp turbine (typical for a gas turbine without blade cooling). Moderate combustion inlet temperatures also facilitate the daily turbine starts needed for CAES operation [50].

Although the plant would be able to operate at a lower heat rate if equipped with heat recuperators (so as to recover exhaust heat from the lp turbine for preheating the gas entering the hp turbine), this addition was omitted in order to minimize system startup time [51, 52].

1.4.2. McIntosh

Although high oil and gas prices through the early 1980s continued to draw the attention of utilities to CAES as a source for inexpensive peak power [47] it was not until a decade later that a CAES facility began operating in the United States. The 110 MW McIntosh plant was built by the Alabama Electric Cooperative on the McIntosh salt dome in southwestern Alabama and has been in operation since 1991 (see Figure 10). It was designed for 26 hours of generation at full power and uses a single salt cavern (560,000 m^3) designed to operate between 45 and 74 bar.

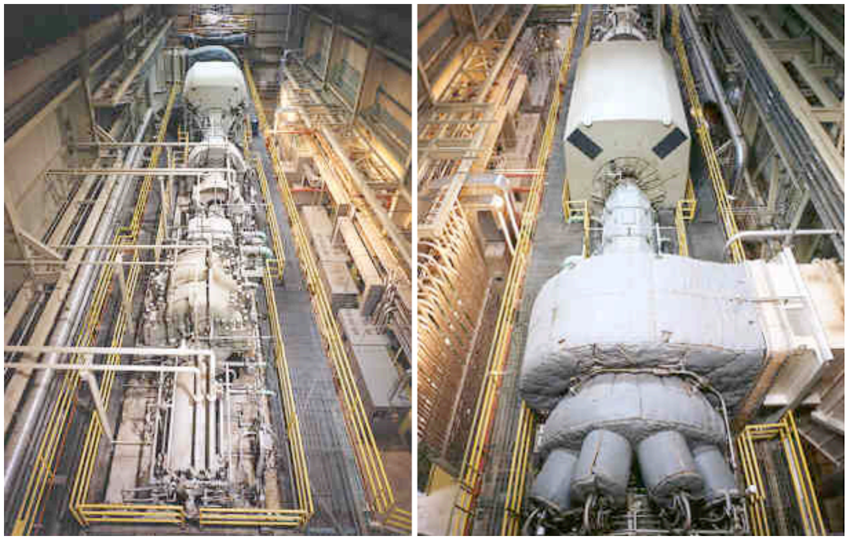


Figure 10 McIntosh CAES system compressor train (left) and combustion turbine (right)

The project was developed by Dresser-Rand, but many of the operational aspects of the plant (inlet temperatures, pressures, etc) are similar to those of the BBC design for the Huntorf plant. The facility does, however, include a heat recuperator that reduces fuel consumption by approximately 22% at full load output and features a dual-fuel combustor capable of burning No. 2 fuel oil in addition to natural gas [11].

Although the plant experienced significant outages in its early operation, the causes of these outages were addressed through modifications of the high pressure combustor mounting and a redesign of the low pressure combustor [53]. These changes enabled the McIntosh plant, over 10 years of operation, to achieve 91.2% and 92.1% average starting reliabilities as well as 96.8% and 99.5% average running reliability for the generation cycle and compression cycle respectively [54].

1.4.3. Norton

A proposal has been under development to convert an idle limestone mine in Norton, Ohio into the storage reservoir for an 800MW CAES facility (with provisional plans to expand to 2,700 MW [9 x 300 MW] see Figure 11). The mine, purchased in 1999, would provide 9.6 million cubic meters of storage and operate at pressures of between 55 and 110 bar. The project, initially approved by the Ohio Public Siting Board in 2001, was granted a five-year extension in 2006. Project negotiations are currently underway and it appears that the project will move forward [52, 55-57].

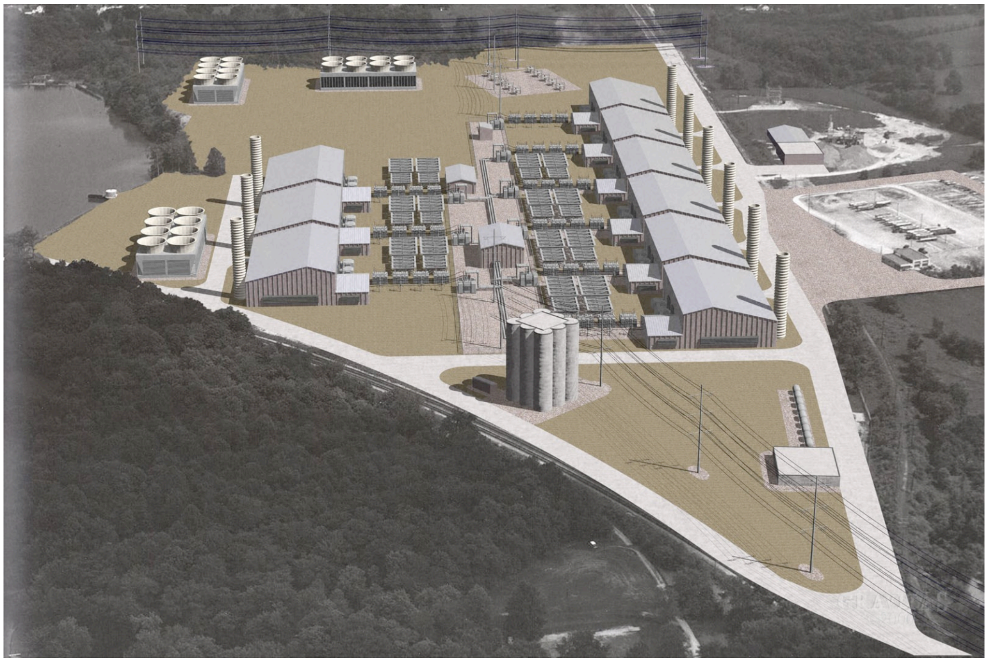


Figure 11 A rendering of the proposed 2700 MW CAES plant based on an abandoned limestone mine in Norton, OH [55]

1.4.4. Iowa Stored Energy Park

The Iowa Association of Municipal Utilities (IAMU) is developing an aquifer CAES project in Dallas Center, Iowa that will be directly coupled to a wind farm (see Figure 12). The Iowa Stored Energy Park (ISEP, a 268 MW CAES plant coupled to 75 to 100 MW of wind capacity, was formally announced in December 2006. This is the only publicly announced project to date directly linking CAES with wind energy and the only one using a porous rock storage reservoir. The CAES facility will occupy 40 acres located within 30 miles of Des Moines, Iowa and use a 3000 ft deep anticline in a porous sandstone formation to store wind energy generated as far away as 100 to 200 miles from the site. This was the third location studied for ISEP after an initial screening of more than

Figure 12 Diagram of the Iowa Stored Energy Park [58]

20 geologic structures in the state. Studies of the chosen formation have verified it has adequate size, depth and caprock structure to support CAES operation. Construction is due to begin in 2009, with completion and operation scheduled for 2011 [58].

1.4.5. Proposed Systems in Texas

Several factors make Texas and the surrounding region attractive for CAES development: First, the rapid growth of wind power in Texas (currently the largest and fastest growing wind market of any US state) is putting increasing burdens on existing load-following capacity in the region. Second, there are considerable transmission bottlenecks and few interconnection points with neighboring grids presenting a significant curtailment risk for wind developers as wind penetrations continue to increase. Lastly, domal salt formations such as those used at the existing Huntorf and McIntosh CAES sites exist in the state. This geology has been proven to work well under CAES operating conditions and thus poses limited risk.

Consequently, Ridge Energy Storage & Grid Services L.P. have announced plans to develop several CAES projects throughout Texas, including a 540 MW (4x135MW) system in Matagorda County, TX based on the McIntosh Dresser-Rand design and utilizing a previously developed brine cavern.[8]

Ridge also prepared two CAES studies focused on the Texas panhandle and surrounding region. The first, commissioned by the Texas State Energy Conservation Office (SECO) and led by the Colorado River Authority, analyzed the alleviation of transmission curtailment through the use of CAES [7]. The second addressed the broader economic impacts of CAES in Texas, Oklahoma and New Mexico (the study area comprised the control area of SPS, an operating company of Excel Energy) [8]. The studies found compelling reasons for pursuing CAES in this region—including improved delivery profile for renewable energy on the system, reduced ramping of other system capacity due to wind energy, and transmission cost offsets. Furthermore, the study estimated a net value of $10 million per year to SPS for developing a 270 MW CAES unit with 50 hours of storage. The report also claims that such a system could enable the development of an additional 500 MW of wind without any additional ramping burdens on the system.

More recently, Shell and TXU have announced they intend to explore the possibility of adding CAES to a proposed 3,000 MW wind farm in the Texas Panhandle [59].

[8] At the time of the release of this report, it appears that this project is not moving forward.

2. CAES Operation and Performance

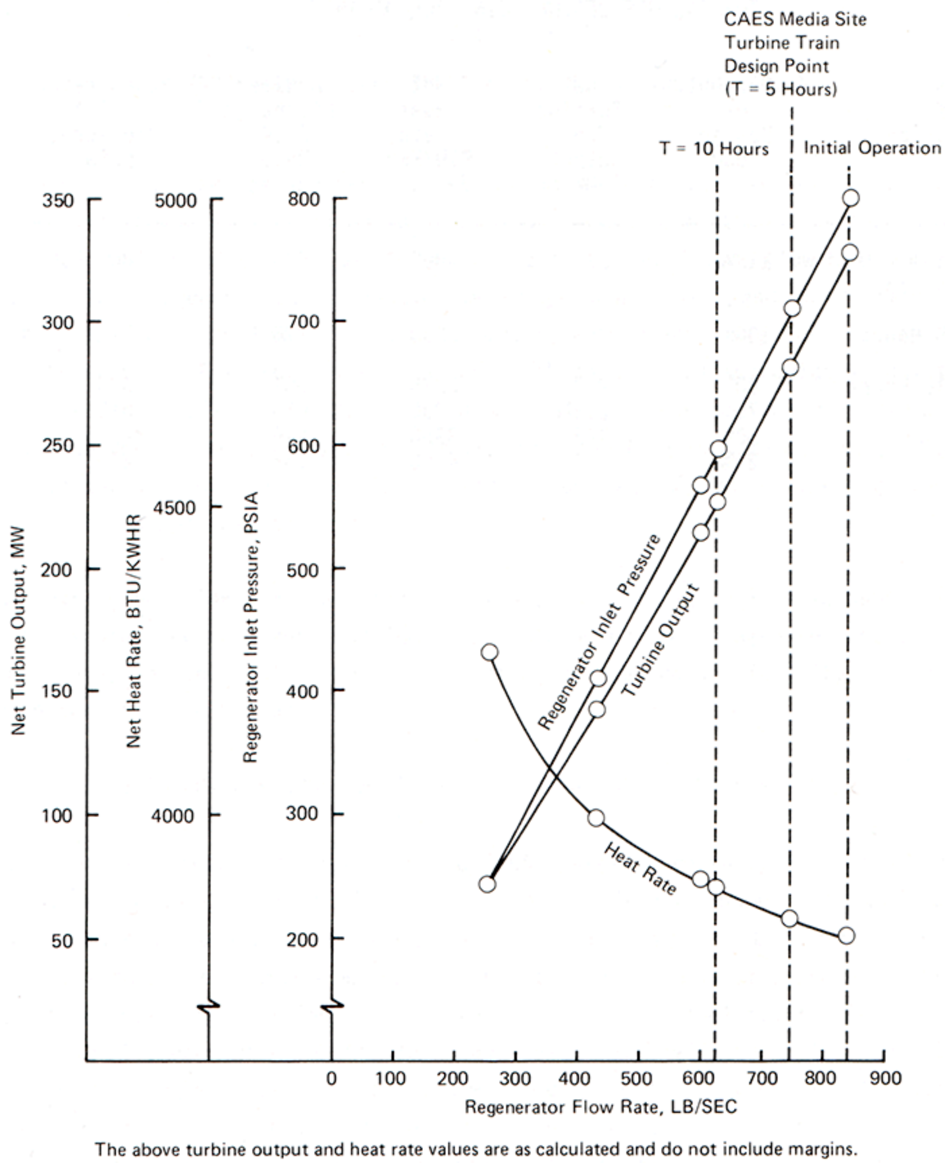


Figure 13 Turbine performance characteristics for Aquifer CAES based on EPRI design for Media, Illinois site [60]

2.1. Ramping, Switching and Part-Load Operation

The high part-load efficiency of CAES (see Figure 13) makes it well suited for balancing variable power sources such as wind. The heat rate increase at part-load is small relative to a conventional gas turbine because of the way the turboexpander output is controlled. Rather than changing the turbine inlet temperature as in a conventional turbine, the CAES output is controlled by adjusting the air flow rate with inlet temperatures kept constant at both expansion stages. This leads to better heat utilization and higher efficiency during part-load operation [51].

The McIntosh CAES plant delivers power at heat rates of 4330 kJ/kWh (LHV) at full load and 4750 kJ/kWh (LHV) at 20% load [53]. This excellent part-load behavior could be further enhanced in modular systems such as the proposed Norton plant where the full plant output would be delivered by multiple modules. In this case, the system could ramp down to 2.2% of the full load output and still be within 10% of the full load output heat rate.

The ramp rates for a CAES system is also better than for an equivalent gas turbine plant. The McIntosh plant can ramp at approximately 18 MW per minute, which is about 60% greater than for typical gas turbines. The Matagorda Plant proposed by Ridge Energy Storage is designed to be able to bring its four 135 MW power train modules to full power in 14 minutes (or 7 minutes for an emergency start)—which translates to 9.6 to 19 MW per minute per module. These fast ramp rates together with efficient part load operation make CAES an ideal technology for balancing the stochastic variations in wind power.

To initiate compression operation, the turbine typically brings the machinery train to speed. After synchronization, the turbine is decoupled and shut off and the compressors are left operating. This means that the turbines are called upon to initiate both compression and generation. In the case of the Huntorf CAES system the switch from one operating mode to another is completely automated and requires a minimum of 20 minutes during which time the system is neither generating power nor compressing air [50]. The switchover time could have a significant impact for balancing rapid fluctuations in wind output. It is possible alternative startup designs, such as use of an auxiliary startup motor could reduce this interval further [60].

Operation switchover time limitations could even be eliminated altogether with new system designs that decouple the compression and turboexpander trains. By separating these components rather than linking them through a common shaft via a clutch as in the McIntosh and Huntorf system, direct switching between compression and expansion operation is possible. This change also means compressor size can be optimized independently of the turboexpander design and permits standard production compressors to be used in the system configuration [52].

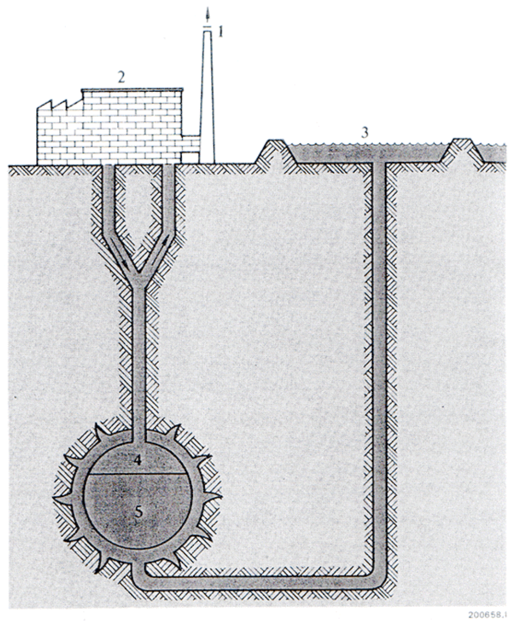


Figure 14 Constant pressure CAES reservoir with compensating water column. (1) Exhaust (2) CAES Plant (3) Surface Pond (4) Stored Air (5) Water Column [51]

2.2. Constant Volume and Constant Pressure

A CAES system can operate in a number of different ways depending on the type of geology being utilized for the storage reservoir. The most common mode is to operate the CAES system under constant volume conditions. This means that the storage volume is a fixed, rigid reservoir operating over an appropriate pressure range.[9] This mode of operation offers two design options: (1) it is possible to design such a system to allow the hp turbine inlet pressure to vary with the cavern pressure (reducing output) or (2) keep the inlet pressure of the hp turbine constant by throttling the upstream air to a fixed pressure. Although this latter option requires a larger storage volume (due to throttling losses), it has been pursued at both of the existing CAES facilities due to the increase in turbine efficiency attained for constant inlet pressure operation. The Huntorf CAES plant is designed to throttle the cavern air to 46 bar at the hp turbine inlet (with caverns operating between 48 to 66 bar) and the McIntosh system similarly throttles the incoming air to 45 bar (operating between 45 and 74 bar).

A third option is to keep the storage cavern at constant pressure throughout operation by using a head of water applied by an aboveground reservoir (see Figure 14). The use of

[9] Although aquifer bubbles are not rigid bodies, the time scale at which the air-water interfaces migrate is much longer than CAES storage cycles and therefore porous rock systems can be approximated as fixed-volume air reservoirs in this context (see section 3.6)

compensated storage volumes minimizes losses and improves system efficiency, but care must be taken to manage flow instabilities in the water shaft such as the so-called champagne effect [61].

This technique is incompatible with salt-based caverns since a continual flow of water would dissolve walls of the cavern. Brine cycling with a compensating column connected to a surface pond of saturated brine could be implemented, but biological concerns and ground water contamination issues would need to be addressed [51]. Since pressure compensated operation cannot be employed in aquifer systems (see Flow in Aquifers below), the use of constant-pressure CAES operation is primarily limited to systems with reservoirs mined from hard rock.

2.3. Storage Volume Requirement

Although several CAES systems have been successfully implemented and even though suitable geologies appear plentiful, the realistic potential for large scale worldwide deployment will not be known until there is much better understanding of the geologic resources available to support many plants deployed under a wide variety of conditions.

One of the keys to assessing the geologic requirements for CAES is to understand how much electrical energy can be generated per unit volume of storage cavern capacity (E_{GEN}/V_S). The electrical output of the turbine (E_{GEN}) is given by:

$$E_{GEN} = \eta_M \, \eta_G \int_0^t \dot{m}_T \, w_{CV,TOT} \, dt \tag{1}$$

where the integral is the mechanical work generated by the expansion of air and fuel in the turbine,

$w_{CV,TOT}$ = total mechanical work per unit mass generated in this process

$\dot{m}_T$ = air mass flow rate

t = time required to deplete a full storage reservoir at full output power

η_M = mechanical efficiency of the turbine (which reflects turbine bearing losses)

η_G = electric generator efficiency

Since all CAES systems to date are based on two expansion stages, the work output can be expressed as the sum of the output from the two stages. The first term reflects the work output from the hp turbine that expands the air from the hp turbine inlet pressure (p_1) to the lp turbine inlet pressure (p_2). Likewise, the second term reflects the expansion work derived from the expansion from p_2 to barometric pressure (p_b).

$$w_{CV,TOT} = w_{CV1} + w_{CV2} = -\int_{p_1}^{p_2} v \, dp - \int_{p_2}^{p_b} v \, dp \tag{2}$$

Consider first the work output from the first expansion stage. Assuming adiabatic compression and that the working fluid is an ideal gas with a constant specific heat (so that $P \cdot v^k = c$, a constant, where $k_1 \equiv C_{p1}/C_{v1}$) the work per unit mass is:

$$w_{CV1} = \int_{p_2}^{p_1} v \, dp = c^{1/k_1} \int_{p_2}^{p_1} \frac{dp}{p^{1/k_1}} \tag{3}$$

$$= \frac{k_1}{k_1 - 1}\left[p\left(\frac{c}{p}\right)^{1/k_1} \right]_{p_2}^{p_1} = \frac{k_1}{k_1 - 1}\left[p_1 v_1 - p_2 v_2 \right] \quad (4)$$

$$= \frac{c_v}{c_p - c_v}\frac{c_p}{c_v} p_1 v_1 \left(1 - \frac{p_2 v_2}{p_1 v_1}\right) \quad (5)$$

$$= c_p T_1 \left[1 - \left(\frac{p_2}{p_1}\right)^{\frac{k_1 - 1}{k_1}} \right] \quad (6)$$

Combining with a similar expression for the second stage gives the total work per unit mass for the process ($w_{CV,TOT}$):

$$w_{CV,TOT} = c_{p2} T_2 \left(\frac{c_{p1} T_1}{c_{p2} T_2} \left[1 - \left(\frac{p_2}{p_1}\right)^{\frac{k_1 - 1}{k_1}} \right] + \left[1 - \left(\frac{p_b}{p_2}\right)^{\frac{k_2 - 1}{k_2}} \right] \right) \quad (7)$$

Furthermore, the total mass flow through the turbine can be expressed as separate air and fuel input terms:

$$\dot{m}_T = \dot{m}_A + \dot{m}_F = \dot{m}_A \left(1 + \frac{\dot{m}_F}{\dot{m}_A}\right) \quad (8)$$

Since

$$\frac{\dot{m}_F}{\dot{m}_A} \approx \text{constant} \quad (9)$$

The result is:

$$\frac{E_{GEN}}{V_S} = \frac{\alpha}{V_S}\int_0^t \dot{m}_A \left(\beta + 1 - \left(\frac{p_b}{p_2}\right)^{\frac{k_2 - 1}{k_2}} \right) dt \quad (10)$$

where

$$\alpha = \eta_M \, \eta_G \, c_{p2} T_2 \left(1 + \frac{\dot{m}_F}{\dot{m}_A}\right) \quad (11)$$

and

$$\beta = \frac{c_{p1} T_1}{c_{p2} T_2} \left[1 - \left(\frac{p_2}{p_1}\right)^{\frac{k_1 - 1}{k_1}} \right] \quad (12)$$

2.3.1. Case 1: Constant Cavern Pressure

First consider the case of a CAES system with constant cavern pressure such as a hard rock cavern with hydraulic compensation (see Figure 14). In this case, the mass flow of air is constant throughout the process and can be expressed as a simple ratio:

$$\dot{m}_A = \frac{m_A}{t} = \frac{p_S V_S M_W}{R T_S t} \tag{13}$$

Likewise, since the inlet pressures and temperatures are constant in time, equation (10) reduces to the following:

$$\frac{E_{GEN}}{V_S} = \frac{\alpha}{V_S}\dot{m}_A\left(\beta + 1 - \left(\frac{p_b}{p_2}\right)^{\frac{k_2-1}{k_2}}\right)\int_0^t dt \tag{14}$$

Combining these expressions,

$$\frac{E_{GEN}}{V_S} = \frac{\alpha\, M_W}{R T_S}\, p_S\left(\beta + 1 - \left(\frac{p_b}{p_2}\right)^{\frac{k_2-1}{k_2}}\right) \tag{15}$$

2.3.2. Case 2: Variable Cavern Pressure, Variable Turbine Inlet Pressure

In the case of a variable pressure CAES system, the pressure at the turbine inlet is allowed to vary over the operating range of the storage volume (from p_{S2} to p_{S1}). However, since the pressure ratio across the hp turbine (p_2/p_1) remains constant, the pressure ratio across the lp turbine is proportional to the cavern pressure p_S [32]:

$$\frac{p_b}{p_2} = \frac{p_1}{p_2}\frac{p_b}{\varphi p_S} = \frac{\text{constant}}{p_S} \tag{16}$$

where φ is a correction factor that accounts for the pressure loss from the storage reservoir to the turbine inlet (~0.90).

$$\dot{m}_A = \frac{d}{dt}\left(\frac{V_S p_S\, M_W}{R T_S}\right) = \frac{d}{dt}\left(\frac{V_S M_W p_S}{R T_{S2}}\left(\frac{p_{S2}}{p_S}\right)^{\frac{k_S-1}{k_S}}\right) \tag{17}$$

$$\dot{m}_A = \frac{1}{k_S}\left[\frac{V_S\, M_W}{R T_{S2}}\left(\frac{p_{S2}}{p_S}\right)^{\frac{k_S-1}{k_S}}\right]\frac{dp_S}{dt} \tag{18}$$

Substituting equations (16) and (18) into (10), the energy storage density is:

$$\frac{E_{GEN}}{V_S} = \frac{\alpha\, M_W}{R T_{S2}}\frac{p_{S2}^{\frac{k_S-1}{k_S}}}{k_S}\int_{p_{S1}}^{p_{S2}}\left(\frac{1}{p_S}\right)^{\frac{k_S-1}{k_S}}\left(\beta + 1 - \left(\frac{p_1}{p_2}\frac{p_b}{\varphi\, p_S}\right)^{\frac{k_2-1}{k_2}}\right)dp_S \tag{19}$$

$$= \frac{\alpha\, M_W}{RT_{S2}} \frac{p_{S2}^{\frac{k_S-1}{k_S}}}{k_S} \left\{ (\beta+1) \int_{p_{S1}}^{p_{S2}} \left(\frac{1}{p_S} \right)^{\frac{k_s-1}{k_S}} dp_S - \left(\frac{p_1}{p_2} \frac{p_b}{\varphi} \right)^{\frac{k_2-1}{k_2}} \int_{p_{S1}}^{p_{S2}} \left(\frac{1}{p_S} \right)^{\frac{k_s-1}{k_S}+\frac{k_2-1}{k_2}} dp_S \right\} \quad (20)$$

$$= \frac{\alpha\, M_W\, p_{S2}}{RT_{S2}\, k_S} \left\{ (\beta+1) \frac{1}{p_{S2}^{1/k_S}} \int_{p_{S1}}^{p_{S2}} p_S^{\frac{1}{k_S}-1} dp_S - \left(\frac{p_1}{p_2} \frac{p_b}{\varphi} \right)^{\frac{k_2-1}{k_2}} \frac{p_{S2}^{-\frac{k_2-1}{k_2}}}{p_{S2}^{\frac{1}{k_S}+\frac{1}{k_2}-1}} \int_{p_{S1}}^{p_{S2}} p_S^{\frac{1}{k_S}+\frac{1}{k_2}-2} dp_S \right\} \quad (21)$$

$$= \frac{\alpha\, M_W\, p_{S2}}{RT_{S2}} \left\{ (\beta+1) \left(1 - \left(\frac{p_{S1}}{p_{S2}} \right)^{1/k_S} \right) - \left(\frac{p_1}{p_2} \frac{p_b}{\varphi\, p_{S2}} \right)^{\frac{k_2-1}{k_2}} \frac{1}{k_S \left(\frac{1}{k_S} + \frac{1}{k_2} - 1 \right)} \left(1 - \left(\frac{p_{S1}}{p_{S2}} \right)^{\frac{1}{k_S}+\frac{1}{k_2}-1} \right) \right\} \quad (22)$$

2.3.3. Case 3: Variable Cavern Pressure, Constant Turbine Inlet Pressure

The third case we consider is one in which the air recovered from storage is throttled from the reservoir pressure p_s to the hp turbine inlet pressure p_1 such that the mass flow and expansion work output are constant in time. As in case 1, the integral representing the mechanical work in turbine expansion can be reduced to a simple time average, but in this case, the net air mass withdrawn from storage is a function of the storage pressure fluctuation over the range p_{S2} to p_{S1}:

$$\dot{m}_T = \frac{\Delta m_A}{t} \left(1 + \frac{\dot{m}_F}{\dot{m}_A} \right) \quad (23)$$

$$\Delta m_A = \frac{V_S p_{S2}}{RT_{S2}} - \frac{V_S p_{S1}}{RT_{S1}} = \frac{V_S p_{S2}}{RT_{S2}} \left(1 - \left[\frac{p_{S1}}{p_{S2}} \right]^{\frac{1}{k_S}} \right) \quad (24)$$

Substituting these into equation (10) yields

$$\frac{E_{GEN}}{V_S} = \frac{\alpha\, M_W\, p_{S2}}{RT_{S2}} \left(\beta + 1 - \left(\frac{p_b}{p_2} \right)^{\frac{k_2-1}{k_2}} \right) \left(1 - \left[\frac{p_{S1}}{p_{S2}} \right]^{\frac{1}{k_S}} \right) \quad (25)$$

2.3.4. Cavern Size

Figure 15 shows the energy storage density for the above three cases as a function of the maximum reservoir pressure, and, for cases 2 and 3, as a function of the storage pressure ratio as well.

For all three cases, the electric energy storage density E_{GEN}/V_S increases approximately linearly with increasing reservoir pressure p_{S2} (or equivalently with mass per unit volume $p_{S2}*M_W/RT_{S2}$). In some cases however, this might result in large heat loss in the aftercooler depending on the thermal constraints of the cavern [62].

The use of a constant-pressure compensated cavern requires the smallest cavern by far. Zaugg estimates for a configuration similar to the Huntorf design (with a storage pressure of 60 bar), a constant pressure cavern could deliver the same output with only 23% of the storage volume required for a constant volume configuration with variable inlet pressure (p_{S2}/p_{S1}=1.4) [32]. If hard rock reservoirs are unavailable or too costly, pressure compensated systems will most likely not be an option, so that a case 2 or a case 3 design would be required.

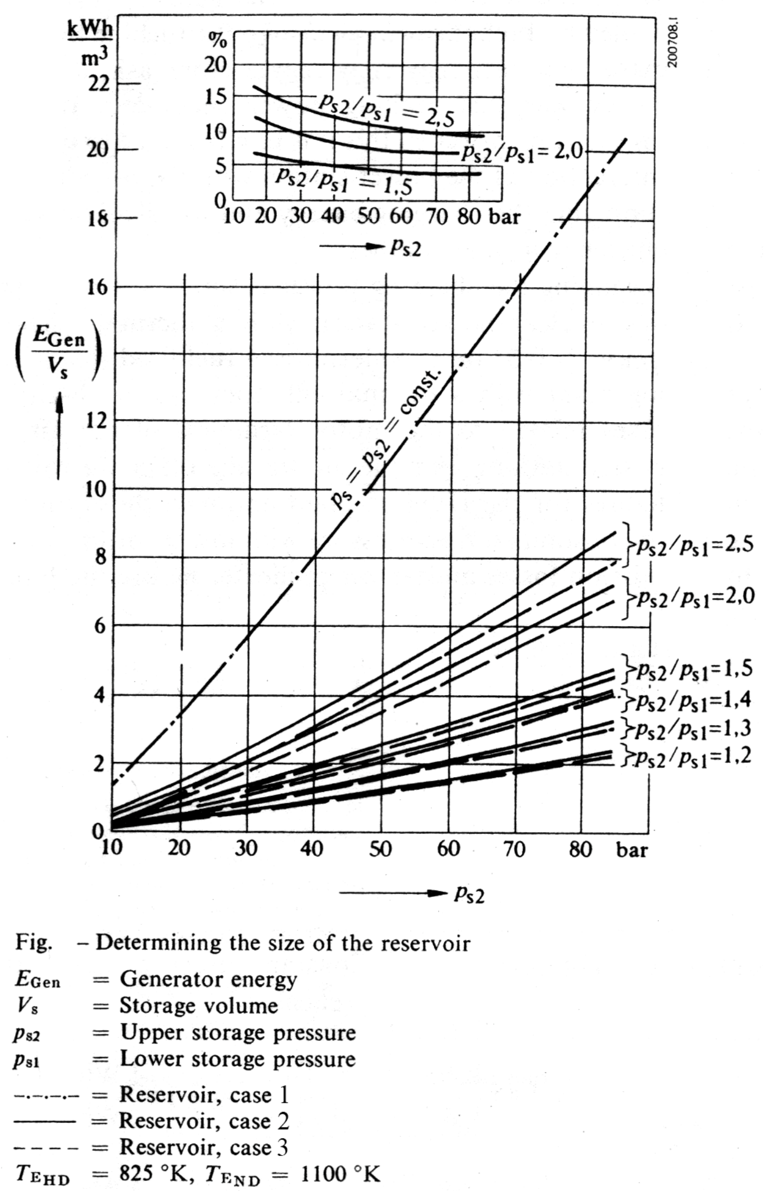


Figure 15 The energy produced per unit volume for CAES with constant pressure reservoir (case 1), variable pressure reservoir (case 2) and variable pressure reservoir with constant turbine inlet pressure (case 3). Inset shows throttling losses associated with case 3 relative to the variable inlet pressure scenario (case 2)- figure from [32].

Notably, although the throttling losses incurred in case 3 relative to the variable turbine inlet pressure system (case 2) implies a required larger storage volume, the penalty is not large (see Figure 15 inset). In particular the throttling losses are small with large initial pressures (p_{s2}>60 bar) that is consistent with all known existing and proposed CAES systems. Because this small penalty is offset by the benefits of higher turbine efficiency and simplified system operation, it is often optimal to operate a CAES system in this mode (as is the case at both the Huntorf and McIntosh plants).

However, in some cases it might be advantageous to allow the inlet pressure to vary depending on the geologic characteristics of the system. For aquifer systems for example, due to the large amount of cushion gas needed, the storage pressure ratio p_{s2}/p_{s1} is relatively small (<1.5) such that the hp turbine can operate over the full storage reservoir pressure range with relatively small penalties relative to the design point performance

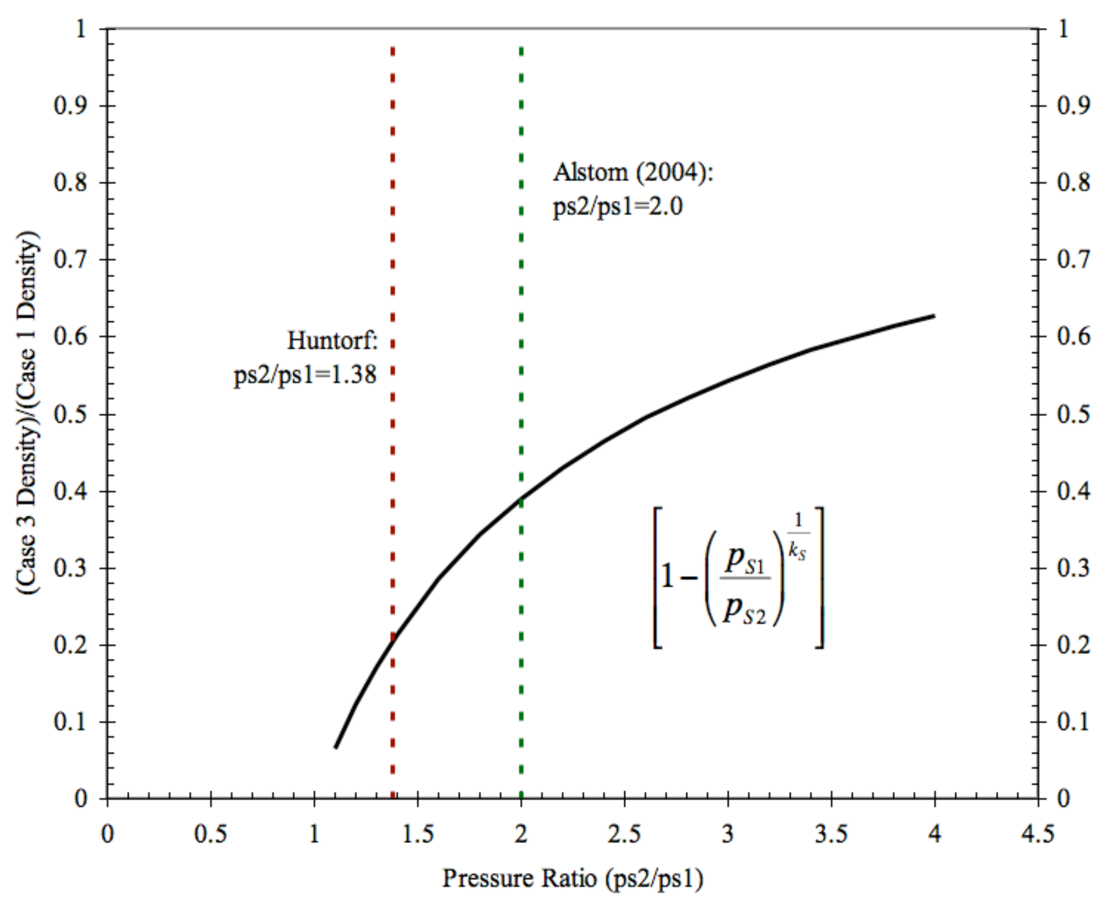


Figure 16 The ratio of storage energy density between a constant volume CAES system with constant turbine inlet pressure (case 3) and a pressure compensated CAES reservoir (case 1) as a function of the ratio between the operating pressures of the case 3 system (p_{S2}/p_{S1}). [10]

[10] Here we assume k_S=1.4 and $(p_{S2}/T_{S2}) / (p_{S1}/T_{S1}) = 1$

(see Figure 13) [50, 60].

Although a variable pressure reservoir CAES system requires a larger storage volume than a compensated reservoir, volume requirements might be reduced substantially by an appropriate design of the storage volume pressure range, to the extent that so doing is consistent with the pressure limits of the reservoir and the turbomachinery. The ratio of the energy storage density for case 3 relative to case 1 is given by (compare equations (25) and (15)):

$$\left(1-\left[\frac{p_{S1}}{p_{S2}}\right]^{\frac{1}{k_S}}\right) \tag{26}$$

This term increases with p_{S2}/p_{S1} as shown in Figure 16. Thus selecting formations that can accommodate large pressures swings and high maximum reservoir pressures will reduce land area requirements for CAES through increased storage energy density.

Typical numbers for E_{GEN}/V_S are 2-4 kWh/m^3 for lower pressure ratios such as those at Huntorf (p_{S2}/p_{S1}=1.38, p_{S2}=66 bar, E_{GEN}/V_S=3.74) and 6-9 kWh/m^3 for the newer designs such one proposed by Alstom, which is designed with higher operating pressures and larger pressure ratios (p_{S2}/p_{S1}=2.0, p_{S2}=110 bar, E_{GEN}/V_S=8.44) [11, 63].

In section 4, "Wind/CAES Systems in Baseload Power Markets", a CAES system design is described which converts wind power into baseload electricity. The system configuration includes a storage reservoir capable of supporting 2 GW of baseload power for 88 hours (176 GWh of storage). The land area requirement for the wind turbine array is 860 km^2. For a system with an electricity storage density consistent with a formation depth similar to the Dallas Center, Iowa CAES plant (depth 880m, discovery pressure ~ 80 bar, E_{GEN}/V_S ~ 5 kWh/m^3) the total pore volume needed for the cycled air would be 35 million cubic meters.[11] Assuming the ratio of total air mass (cushion air plus cycled air) in the reservoir to the mass of cycled air is 5 [64], and assuming an average reservoir height of 10 meters and an effective porosity of 15%, the "footprint" of the reservoir would occupy an area of land equal to approximately 14% of the land area of the wind turbine array.

2.4. Performance Indices for CAES Systems

The energy performance of a conventional fossil fuel power plant is easily described by a single efficiency: the ratio of electrical energy generated to thermal energy in the fuel. The situation is more complicated for CAES due to the presence of two very different energy inputs. On the one hand, electricity is used to drive the compressors and on the other natural gas or oil is burned to heat the air prior to expansion. This situation makes it difficult to describe CAES performance via a single index in a way that is universally useful—the most helpful single index depends on the application for CAES that one has in mind. Before turning to a discussion of alternative options for a single CAES

[11] This volume corresponds to a gas volume that is of the same order as the working gas capacity of the largest porous rock natural gas storage sites in the US and Canada, but is considerably larger (by about an order of magnitude) than the mean capacity among these facilities (AGA, 2004).

performance index, it is worthwhile considering the two performance indices that apply to each energy input separately: the heat rate and the charging electricity ratio.

2.4.1. Heat Rate

The heat rate (HR) or fuel consumed per kWh of output for a CAES system is a function of many system design parameters, but the design choice that most critically affects the heat rate is the presence of a heat recovery system. The addition of a heat recuperator allows the system to capture the exhaust heat from the lp turbine to preheat the air withdrawn from the storage reservoir. Heat rates for CAES systems without a heat recovery system are typically 5500-6000 kJ/kWh LHV (e.g., 5870 kJ/kWh LHV for Huntorf). Heat rates with a recuperator are typically 4200-4500 kJ/kWh LHV (e.g., 4330 kJ/kWh for McIntosh). By comparison, a conventional gas turbine has at least twice this level of fuel consumption (~9500 kJ/kWh LHV) because two thirds of the electrical output is used to run the compressor. Because the CAES compression energy is supplied separately, the system can achieve a much lower heat rate [11, 51].

The addition of the heat recuperator reduced the fuel consumption at McIntosh by 22% relative to operation without this component [53], but a high pressure combustor was still required in this case. Newer CAES designs feature higher inlet temperatures at the lp turbine. The added heat generated at this stage facilitates the removal of the hp combustor from the design altogether (as for the CAES unit shown in Figure 3). In addition to further reducing fuel consumption, these systems also offer significant NO_x emissions benefits relative to prior designs [63].

2.4.2. Charging Electricity Ratio

The second performance index for CAES is the ratio of generator output to compressor motor input—the charging electricity ratio (CER). Because of the fuel input, the CER is greater than unity and will typically lie in the range of 1.2 to 1.8 (kWh_{output}/kWh_{input}) [11, 32, 65]. The CER also takes into account piping and throttling losses as well as compressor and expander efficiencies. Throttling loss is a function the reservoir pressure range (see Figure 15). Turbine efficiency is especially important in the low-pressure expansion stage, in which most of the enthalpy drop occurs and where approximately three quarters of the power is generated [66]. Increased turbine inlet temperatures (e.g., by using expander blade cooling technologies) would enhance the turbine and CAES electrical efficiencies as well [67].

2.4.3. Toward a Single CAES Performance Index

Several single-parameter performance indices have been proposed for CAES. The simplest possible index is an efficiency η defined as the ratio of energy generated by the turbine (E_T) to the sum of electrical energy delivered to the compressor motor (E_M) and the thermal energy in the fuel (E_F)

$$\eta = \frac{E_T}{E_M + E_F} \tag{27}$$

Typical HR and CER values of, respectively, 4220 kJ/kWh and 1.5 imply $\eta = 54\%$. However, because of the substantial difference between the energy qualities of the thermal energy in the fuel and the electrical energy supplied to the compressor, their sum is not a meaningful number. In order to estimate the total energy input to CAES, it is necessary to express both the fuel and compressor electricity on an equivalent energy basis. One approach is to express the electrical input as an equivalent quantity of thermal energy.

2.4.3.1. Primary Energy Efficiency

When CAES is used to convert baseload thermal power into peaking power (in place of gas turbines or other peaking units) one can introduce a primary energy efficiency η_{PE} defined in terms of the thermal efficiency of the baseload plant (η_T). Here compressor motor energy input E_M is replaced by an expression for the effective thermal energy input required to produce E_M. Thus, the overall efficiency value reflects the system (grid + CAES) efficiency of converting primary (thermal) energy into electrical energy:

$$\eta_{PE} = \frac{E_T}{E_M/\eta_T + E_F} \tag{28}$$

This methodology has been applied to CAES units charged by nuclear and fossil fuel power plants [32], CHP plants [62], as well as grid-averaged baseload power [68]. Assuming $\eta_T = 40\%$ (as might characterize a modern supercritical steam-electric plant) and the same other parameters as considered in the earlier calculation of η, implies η_{PE} = 35%.

In principle, this formulation of system efficiency can be applied to a wind/CAES system by using the atmospheric efficiency of the wind turbines η_{WT} in place of the thermal plant efficiency η_T. This formulation, proposed by Arsie et al, gives rise to a system efficiency of 39% [69]. However, the use of atmospheric efficiency in this case does not serve the same function as the thermal efficiency. In the case of fossil fuel or nuclear power as the source of compressor energy, use of the thermal efficiency provides a measure of the amount of primary fuel needed to deliver a quantity of electrical energy E_M. In contrast, the extraction of "fuel" in the case of wind energy does not affect the environmental impact or overall cost of the plant. Consequently, this measure of the amount of atmospheric kinetic energy captured in providing E_M is not very helpful and in the case of wind/CAES systems and therefore this is not the optimal formulation for CAES efficiency.

2.4.3.2. Round Trip Efficiency

A CAES unit powered by wind energy will be compared to other electrical storage options that might be considered for wind back up such as electrochemical or pumped hydroelectric storage. Such alternative storage systems are typically characterized by a roundtrip electrical storage efficiency η_{RT} defined as

η_{RT} = (electricity output)/(electricity input).

To facilitate comparisons of CAES to other electrical storage devices, a round trip efficiency can be introduced that employs an "effective" electricity input ≡ $E_M + \eta_{NG}*E_F$. The second term is the amount of electricity that could be have been made from the natural gas input E_F, had that fuel been used to make electricity in a stand-alone power plant at efficiency η_{NG} instead of to fire a CAES unit. The round-trip efficiency $\eta_{RT,1}$ so defined is:

$$\eta_{RT,1} = \frac{E_T}{E_M + \eta_{NG} E_F} \tag{29}$$

This methodology has the advantage of providing an electricity-for-electricity roundtrip storage efficiency that isolates the energy losses in the conversion of electricity to compressed air and back to electricity. Several values for η_{NG} have been proposed including the hypothetic Carnot cycle efficiency [65] as well as the efficiencies of commercial simple cycle and combined cycle power plants [2, 70]. For typical natural gas power systems, (heat rates in the range 6700-9400 kJ/kWh) CAES roundtrip efficiencies are in the range of 77-89% assuming a 1.5 ratio of output to input electricity and a heat rate of 4220 kJ LHV per kWh. An exergy analysis of conventional CAES systems indicates that 47.6% of the fuel energy input is converted into electrical work [71]. For this measure of the thermal efficiency, the roundtrip efficiency is 81.7%.

An alternative formulation $\eta_{RT,2}$ of an electrical roundtrip storage efficiency introduces an output correction term $E_F*\eta_{NG}$. Instead of expressing the fuel input as an effective electrical input, the electrical output is adjusted by subtracting the assumed contribution to the output attributable to the fuel. Correspondingly the output attributable to the electrical input is $E_T - E_F*\eta_{NG}$ [72].

$$\eta_{RT,2} = \frac{E_T - E_F \eta_{NG}}{E_M} \tag{30}$$

Using the same assumptions as for $\eta_{RT,1}$ with the Zaugg efficiency for fuel conversion, η_{NG} = 47.6%, the round trip efficiency is 66%.

Thus, depending on the index chosen for its measure, the roundtrip efficiency for CAES is typically in the range 66-82%. This is in the same range as the roundtrip efficiencies cited for other bulk energy storage technologies such as pumped hydroelectric storage (74%) and Vanadium flow batteries (75%) [70].

2.4.3.3. Additional Approaches

Still another measure of the efficiency of CAES proposed by Schainker et al might be useful for an economic evaluation of CAES in load leveling or arbitrage applications. This approach is similar to $\eta_{RT,1}$ in that it adjusts the fuel input by a correction factor:

$$\eta_{AD} = \frac{E_T}{E_F/CR + E_M} \tag{31}$$

In this case however, the fuel input is converted to equivalent electricity not by using the primary energy conversion efficiency for natural gas but rather the cost ratio CR ≡ (off-peak electricity price)/(fuel price) [73] . Although this index might be helpful in deciding how to operate a given CAES unit over time, the measure varies significantly both over time and with geographical region and so is not a useful general plant characterization.

A final description of CAES efficiency compares the CAES output to the electrical output of a thermodynamically ideal CAES plant operating between ambient temperature T_o and T_{max} [65]:

$$\eta_{II} = \frac{E_T}{E_{T,REV}} \tag{32}$$

$$E_{T,REV} = E_M + E_F - T_o \bullet \Delta S = E_M + E_F - T_o \bullet E_F / T_{MAX} \tag{33}$$

Analysis of a conventional CAES system yields a second law efficiency of η_{II}=68% with a recuperator and 59-61% without[12].

Ultimately, the choice of efficiency measure remains an open question because thermal energy and electrical energy quantities cannot be combined by algebraic manipulation. The formulations provided in this section help only to provide a basis for comparison with other storage technologies, but as indicated above, the relevant expression is determined in large part by the application one has in mind.

[12] The range of efficiencies for the system without recuperator reflects change in system performance due to varying storage pressures (p_S = 20 to 70 bar). The change in efficiency was < 1% for the system with recuperator.

Table 2 Selected CAES Efficiency Expressions and Values in The Literature

Parameter	**Definition**	**Reported Value**	
		No Recuperator	*With Heat Recuperator*
Heat Rate	$\eta_F = \frac{E_T}{E_F}$	6000-5500 kJ/kWh (~60-65%)	4500-4200 kJ/kWh (~80-85%)
Charging Energy Ratio	$\eta_{PE} = \frac{E_T}{E_M}$	1.2-1.4	1.4-1.6
Primary Energy Efficiency	$\eta_{PE} = \frac{E_T}{E_M / \eta_T + E_F}$	CAES Charged From Nuclear Power (η_T=33%) [32]	
		24.5%	29.7%
		Charged From Fossil Fuel Power Plant (η_T=42%) [32]	
		28.2%	34.4%
		Charged from Combined Heat and Power Plant (η_T=35%) [62]	
			35.1-41.8%
		Charged from grid-averaged Baseload Power (η_T=35%, CER=1.4) [68]	
			42-47%
Roundtrip Efficiency (1)	$\eta_{RT,1} = \frac{E_T}{E_M + \eta_{NG} E_F}$	4220 kJ LHV/kWh, CER=1.5, η_{NG}=47.6%, [2]	
			81.7
Roundtrip Efficiency (2)	$\eta_{RT,2} = \frac{E_T - E_F \eta_{NG}}{E_M}$	4220 kJ LHV/kWh, Eo/Ei=1.5, η_{NG}=47.6% [72]	
			66.3%
Second Law Efficiency	$\eta_{II} = \frac{E_T}{E_{T,REV}}$	T_O=15 C, T_{MAX}=900 C, p_S=20 bar [65]	
		58.7%	68.3%

3. Aquifer CAES Geology and Operation

3.1. Motivations

Interest in aquifer CAES technology stems from the widespread availability of this formation type and the expected relatively low development costs. Furthermore, Figure 17 shows that onshore wind resources in the US of class 4 and above correlate well with aquifers.

While solution-mined salt domes offer advantages in terms of reliability and flexibility of design, the supply of salt domes is limited in the U.S. to the Gulf Coast region (see Figure 17). However, most of this region has very poor wind resources (typically wind classes 2 and below) that are not economically exploitable. If the aim of storage is to provide backup for large quantities of wind power, salt domes will not play a large role in the United States. While bedded salt formations might be used, their development will likely be more challenging and costly than the salt dome CAES systems that have been deployed (see section 1.3.1).

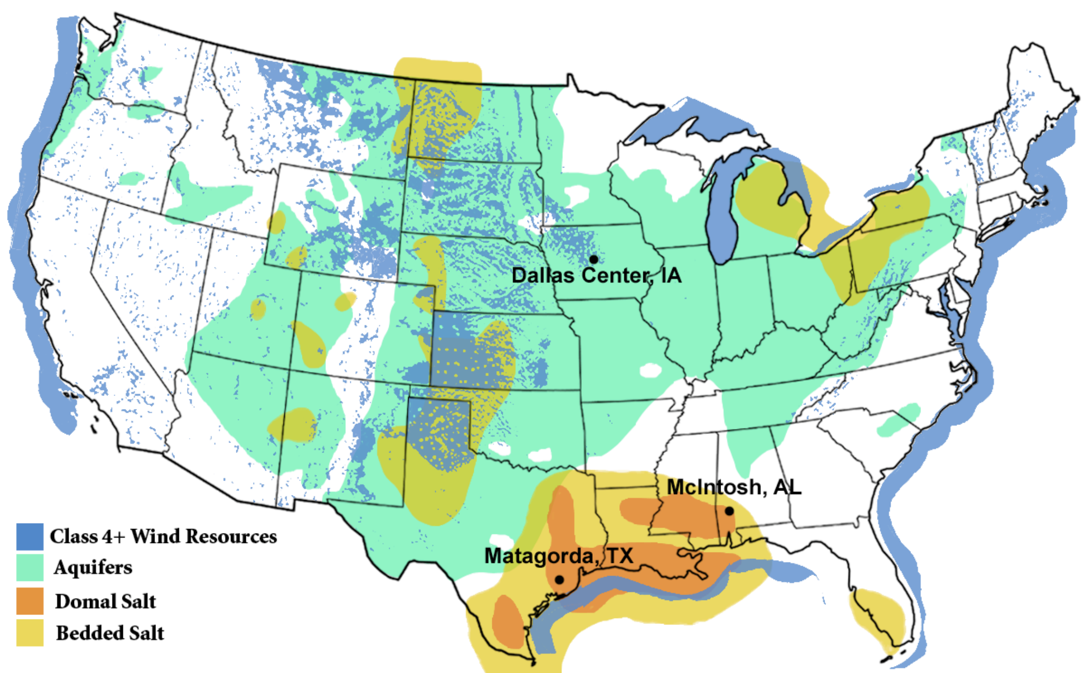


Figure 17 A comparison of areas of high quality wind resources and geology compatible with CAES (areas suitable for mined rock caverns omitted due to the high estimated cost of developing such formations for CAES) [33, 37, 41-43]. Locations of the existing McIntosh CAES plant, the recently announced Dallas Center wind/CAES system and the proposed Matagorda plant are indicated as well.

Figure 17 indicates areas favorable for air injection into porous rocks overlaid with areas with wind resources of class 4 and above (today, class 5 winds are economical, and class 4 resources are considered marginally viable). The overlap includes large areas in the southern tier states that extend from New Mexico to Arkansas, and includes large areas of Colorado, Wyoming, Montana, Kansas, Iowa, and Minnesota and Iowa, and most of the Dakotas. Although resource maps such as Figure 17 can be useful in helping to decide where to site a CAES storage unit, a detailed geologic site characterization is needed to ascertain whether a site is actually suitable for CAES development.

Although the total cost of developing a porous rock formation for CAES will depend on the characteristics of the storage stratum (e.g. thinner, less permeable structures will require more wells and therefore a higher development cost), it appears that this type of geology is often the least cost option. Prior CAES cost estimates (see Table 3) indicate that total development costs are in the range $2-$6 million per Bcf of total volume (working gas and base gas) which is similar to development cost estimates for natural gas storage in porous rock [74]. This implies a capital cost of $2.0-$7.0 per kWh of storage capacity depending on the site characteristics and assuming a five-to-one base gas to working gas volume ratio [64]. These costs are somewhat lower than those estimated for salt cavern storage ($6-$10 per kWh of storage capacity) which is the next cheapest option.

Table 3 Estimated Well and Reservoir Development Costs for Aquifer CAES[a]

	Site 1: Oneida	Site 2: Rockland County	Site 3: Buffalo
Depth	910	460	610
CAES Well, Each ($)	775,000	480,000	520,000
Well Lateral, Each ($)	100,000	100,000	100,000
Gathering System ($)	2,600,000	2,600,000	2,600,000
Number of Wells	18 - 38	80 – 107	40 - 71
Total Cost ($ per kWh of storage capacity)[b,c]	2.0 – 2.2	5.6 – 7.0	2.7 – 3.4

a. Costs based on a 1994 survey of CAES plant sites in New York State [64] inflation-adjusted to a $2006 basis

b. Wells, laterals and gathering system account for 90% of total cavern development costs. Remaining costs include reservoir characterization activities such as a seismic monitoring array for the candidate site.

c. Storage costs assume a five-to-one ratio of base gas volume to working gas volume. Actual base gas volume ratios will depend on the characteristics of individual sites.

Aquifer CAES has the further advantage that the cost of incremental additions to storage capacity is significantly lower than for alternative geologies. Assuming sufficient wells are in place to ensure adequate air flow to the surface turbomachinery, the cost of increasing the storage capacity of the aquifer is simply the compression energy required to increase the volume of the bubble [60]. This cost (~$0.11/kWh) is an order of magnitude lower than the equivalent marginal costs of solution mining salt and more than two orders smaller than excavating additional cavern volume from hard rock [11].

Because this combination of low cost and potential for widespread availability is unique among the options for storage reservoirs types, it will be essential to pursue development of aquifer-based systems if CAES is to serve more than a niche role in balancing U.S. wind capacity.

3.2. Applicability of Industrial Fluid Storage Experience

To gauge the potential for aquifer CAES, much can be gained from existing studies on other underground fluid storage applications. To date the storage of natural gas has been the principal commercial application for storage of fluids in porous rock strata, but storage of other materials such as liquid fuels, propane and butane have been pursued as well.

3.2.1. CO_2 Storage

More recently, storage of supercritical CO_2 in deep formations has garnered significant attention in the context of carbon capture and storage (CCS) technology development for climate mitigation.

Assessments of CO_2 storage are somewhat less relevant to CAES however. The minimum depth required for CO2 to become supercritical (~800m) is typically at the high end of acceptable limits for CAES (see Geologic Requirements below). In addition, because CO_2 is stored permanently rather than being cycled, the presence of an anticline is not necessary. Flatter caprock layers are in fact more desirable for storage of carbon dioxide, since they promote further migration and faster dissolution of the injected CO_2 in the brine. In addition, the higher viscosity of CO_2 under storage conditions and the lower average permeability of deep aquifers imply that flow behavior relevant to carbon storage will be different than for CAES.

3.2.2. Natural Gas Storage

In contrast, natural gas is stored under conditions much closer to those needed for CAES. Consequently, consideration of natural gas storage provides a valuable starting point for an analysis of air storage in porous rock formations.

The extensive industrial experience with natural gas storage provides a theoretical and practical framework for describing underground storage media and assessing candidate sites for seasonal storage of natural gas [75]. Field tests and prior studies discussed below indicate that this theory is applicable to CAES site analysis and operational planning.

Seasonal storage of natural gas began as an industry in 1915 when the Natural Fuel Gas Company used a partially depleted natural gas reservoir in Ontario, Canada to meet peak winter demand for gas. By 2004 the working gas capacity of the natural gas storage industry in the U.S. and Canada had grown to 4.1 trillion standard cubic feet in 428 facilities spread over 30 U.S. states and 5 Canadian provinces. This storage capacity corresponds to roughly 17% of the total annual demand for natural gas in the U.S. and Canada for 2002 [76, 77]. Over 95% of this capacity is held in porous rock formations (mostly in depleted gas fields) making this industrial experience base especially relevant to the understanding of aquifer CAES systems.

3.2.2.1. Site Characterization and Bubble Development

While there are important differences in the details of storing air versus natural gas in underground formations, the methodologies developed for evaluating natural gas storage sites are directly applicable to CAES.

High-resolution seismic surveys can help to define the shape of a geologic structure, the thickness of a zone of interest and presence of viable cap rock. Also, pump tests can be used to measure critical flow properties of the reservoir. Following successful site characterization, the reservoir is developed over the course of several months.

By injecting fluid above the discovery pressure (the hydrostatic pressure in the formation prior to well drilling), the brine can be displaced from the porous stratum with gas - initially fingering through the stratum and eventually resulting in formation of a coalesced bubble. The bubble is developed to the point that bubble volume and closure rating are deemed sufficient (for further discussion of closure rating see Geologic Requirements section and Figure 18 below). From this point forward, the reservoir can begin storage operations.

During operation the mean pressure in the reservoir is kept at the discovery pressure to ensure that the bubble volume remains constant and so that there is no long-term migration of the bubble walls (migration of water interface is more pertinent to seasonal natural gas storage than to high frequency reservoir cycling for CAES, see section 3.6, "Flow in Aquifers").

Formation flow (injectivity and deliverability) is critical for determining the suitability of a candidate storage site. The analytical description of reservoir flow begins with calculations of steady state flow, which is described by Darcy's Law:

$$\frac{q}{A} = -\frac{k}{\mu}\frac{dp}{dL} \tag{34}$$

where

q = flow rate (cm^3/s)
A = cross-sectional area (cm^2)
k = permeability (darcy)
μ = viscosity (centipoises)
dp/dL = pressure gradient in the direction of flow (atm/cm).

Assuming radial laminar flow near a well (injection well or recovery well) through an aquifer [described as a homogeneous formation of thickness h (with A = 2πrh) and permeability k], the flow rate for a single well can be expressed as.

$$q = -\frac{2\pi\, r\, h\, k}{\mu}\frac{dp}{dr} \tag{35}$$

From the real-gas equation-of-state, the number of gas moles n is given by:

$$n = \frac{pV}{ZRT} \tag{36}$$

where:

Z = gas deviation factor

The flow rate q at temperature T and pressure p can be expressed in terms of the flow rate q_{SC} at standard conditions (p_{SC}, T_{SC}) by:

$$\frac{pV}{zT} = \frac{p_{SC}V_{SC}}{T_{SC}} \tag{37}$$

and so

$$q_{SC} = \frac{q}{z}\frac{T_{SC}}{T}\frac{p}{p_{SC}} \tag{38}$$

In English units, T_{sc} = 519.67 ^oR (60 ^oF) and P_{sc} = 14.7 psia, so that the flow Q_{sc} (in MMscfd) is:

$$Q_{SC} = -\frac{0.447x10^{-6}\pi\ k\ h\ p\ dp}{\mu\, T\, Z\, dr/r} \tag{39}$$

Because the total radial flow rate is independent of the radial distance from the well, Q_{sc} can be evaluated by integration from the wellbore radius to the formation radius. Assuming the temperature in the reservoir is constant, the deliverability equation is:

$$Q_{SC} = \frac{0.703\times10^{-6}\ k\ h\left[p_F^2 - p_S^2\right]}{\mu\, T\, Z \ln\left[r_F/r_W\right]} \tag{40}$$

where:

r_W = wellbore radius (ft)
r_F = formation radius (ft)
p_S = pressure at the wellbore (psia)
p_F = pressure at the formation edge (psia)
h = formation height (ft)
k = permeability (millidarcy)
T = temperature in the reservoir (ºR)
μ = viscosity (centipoises)
Q_{sc} = gas flow rate (MMcfd)—which is positive for flow out of the reservoir

This equation is widely used to describe the flow capacity of natural gas fields [78]. Additional terms are needed to reflect effects of turbulence, but field studies indicate that the assumption of laminar flow is adequate to describe CAES operation [79].[13]

3.2.2.2. Applicability to CAES

The applicability of this methodology for describing airflow in aquifer-based CAES systems was verified during the Pittsfield Aquifer Field Test, which took place at the Pittsfield-Hadley Anticline in Pike County, Illinois from 1982-1983. Prior to conducting deliverability measurements of the site, data sources such as core sample analysis, pump tests, injection tests, and earlier geophysical tests were sampled. These provided estimates of formation thickness and permeability data that were used to calculate

[13] Steady state flow equations are useful for evaluating reservoir deliverability, but time-dependent unsteady-state and pseudosteady-state flow expressions are required to adequately describe the evolution of flow during bubble development (see section 3.6, "Flow in Aquifers")

predicted deliverability rates. Ultimately, the deliverability measurements acquired during site operation corresponded closely with the predicted values based on the geophysical data:

> During the process of reviewing and analyzing the multitude of operating data for the Pittsfield experiment, most of the questions and apprehensions regarding the Pittsfield reservoir were answered satisfactorily. The flow behaviors of the Green and White St. Peter are now understood to the extent necessary to conduct an underground storage operation. Natural gas equations have been shown to be applicable to air flow. There is no question that the experiment proved that CAES in porous media is feasible in terms of storage and flow of air [79].

The applicability of natural gas storage formation analysis techniques extends beyond porous rock formations (aquifers). In the case of salt dome storage, the fact that both the Huntorf and McIntosh CAES facilities are located adjacent to natural gas storage facilities mined from the same formation[14] suggests that the conditions favorable for CAES development and natural gas development might often overlap. Since a large volume of test data is available from state geological surveys on potential natural gas storage facilities, it is likely that this body of knowledge will be useful in identifying potential sites for CAES.

3.2.2.3. Differences

While natural gas storage provides an important departure point for a discussion of CAES, several important differences must be considered. First, the differences in the physical properties of air relative to natural gas have important implications for the geologic requirements for aquifer CAES. Second, a CAES system used for arbitrage or backing wind power will likely switch between compression and generation at least once a day and perhaps several times a day. In contrast, most natural gas storage facilities are often only cycled once over the course of the year to meet the seasonal demand fluctuations for natural gas. Third, several oxidation processes might take place in the presence of oxygen from the air depending on the mineralogy of the formation. Also, introduction of air into the formation might promote propagation of aerobic bacteria that might pose a significant corrosion risk. Finally, additional corrosion mechanisms might be promoted due to the introduction of oxygen into the formation. These considerations and their impact on system design and operation are discussed in the following sections.

3.3. Geologic Requirements

The requirements for air storage in a porous rock reservoir encompass a broad range of geologic features. In general terms, CAES operation requires an anticline consisting of permeable, porous media such as sandstone capped by an impermeable caprock (see Figure 20). Other important considerations during site selection are the volume requirement of the storage application, the pressure requirements of the surface turbomachinery, the homogeneity of the formation and the detailed mineralogy.

[14] The Huntorf CAES facility was built adjacent to a preexisting natural gas storage facility consisting of four caverns solution-mined from a Permian salt dome. The McIntosh Salt dome natural gas storage facility was completed three years after the CAES facility began operating.

One of the most complete studies on the feasibility of aquifer-based CAES systems, prepared by the Public Service Company of Indiana and Sargent and Lundy Engineers for the Electric Power Research Institute (EPRI) in 1982, explores the potential benefits of these systems [60]. Although no field tests were conducted as part of this EPRI study, a detailed methodology was presented for identifying formations with the necessary geologic requirements. A score-based system was developed to evaluate candidate sites on the basis of geologic, economic and environmental considerations (see Table 4). The parameters used to evaluate the geologic aspects of the formation include permeability, depth, porosity, closure, geology type, and caprock properties.

3.3.1. Porosity, Permeability and Thickness

Each parameter will impact different aspects of CAES operation including reservoir capacity, compressed air deliverability and compatibility with operating pressures for standard turbomachinery. The permeability and reservoir thickness will determine the deliverability of the reservoir (see section 3.2.2.1) and together with the porosity will determine the pore volume per unit land area and the number of wells needed to achieve the desired total flow.

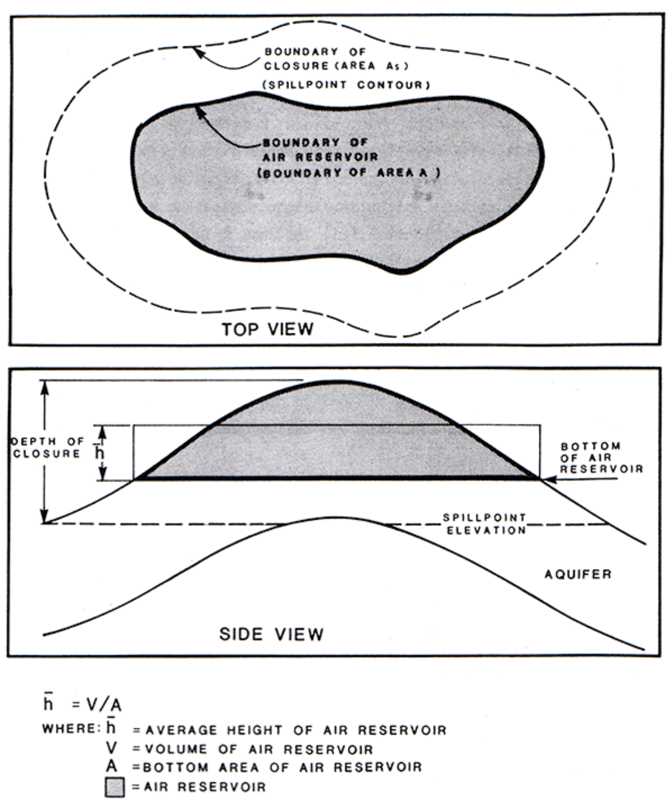


Figure 18 Aquifer dimensions relevant to total closure rating [60]

Air has a viscosity approximately twice that of natural gas over a wide range of pressures and temperatures as well as a higher gas deviation factor (see Figure 19). Therefore in order to achieve the same flow rate, a formation for storing air must have a higher flow capacity[15] than a natural gas storage facility operated under similar conditions (see equation 40).

This underscores the importance of careful site characterization, including seismic monitoring, core sample analysis, injection tests, pump tests, and careful well observation. A reliable permeability value for the formation is essential for predicting bubble development and deliverability characteristics of a reservoir for air storage.

Porosity indicates the percentage of the media that consists of voids and interstices. A lower porosity implies a larger areal expanse is needed to contain the necessary volume of air. In the context of the 1982 EPRI study, 13% was deemed the minimum porosity needed for CAES operation. All of the aquifers screened for this study met this criterion and 12 of 14 candidate sites exceeded 16% porosity.

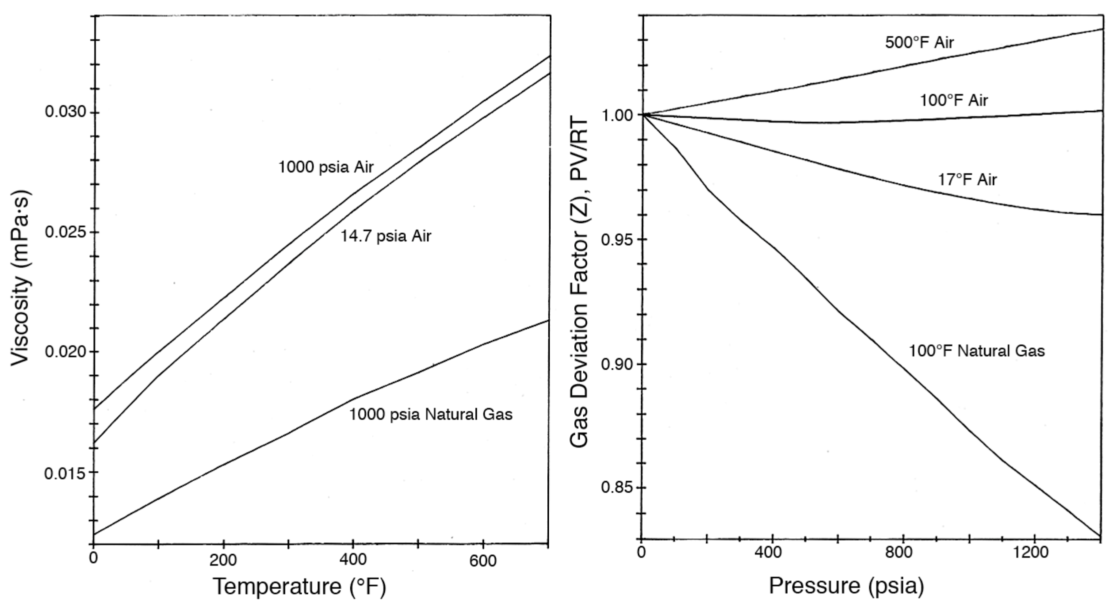


Figure 19 Viscosity and Gas Deviation Factor of Air versus Natural Gas [79]

3.3.2. Reservoir Dimensions

The total void volume of the aquifer above the spill point contour (V_R) must be at least as great as the volume needed for CAES operation (V_S). But if V_R is much bigger than is needed for CAES operation, excessive land rights acquisition costs might be incurred and hence values of V_R/V_S greater than 3 receive a reduced score.

[15] "Flow capacity, " the product of formation thickness and permeability (kh), is a parameter used to characterize the flow properties of geologic formations used for underground storage of fluids.

The total closure rating is defined as the ratio of the total thickness of the formation (H) to the thickness of the fully developed air bubble (h) (see Figure 18). This parameter is important with regards to water encroachment into the wellbore.

Water might be drawn up into the well during extended air withdrawal periods due to the radial pressure gradient created as air is withdrawn. To avoid this condition sufficient distance between the bottom of the well perforations and the air-water interface should be maintained at all times. Typically, the reservoir will be developed such that 10 to 15 feet of air is maintained below the well perforations, but the actual distance depends on the pressure relative to the discovery pressure of the formation as well as the permeability and porosity of the structure.

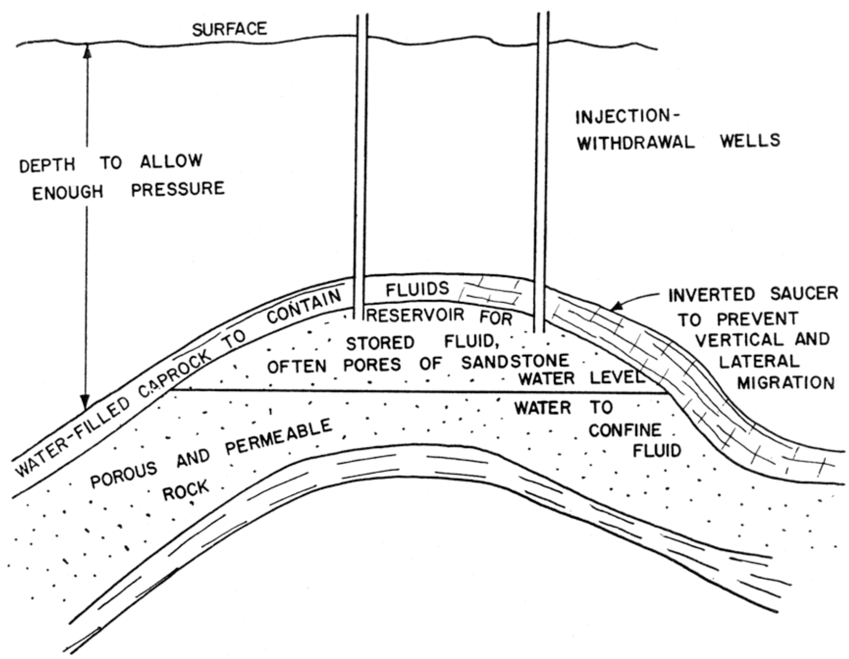


Figure 20 Porous Rock CAES Storage Volume [19]

It would be optimal to develop the air bubble to the extent that it spans the full formation thickness (h/H=1.0), in which case the possibility of water encroachment is eliminated. This is more easily accomplished in thinner anticlines with larger curvature so that a smaller volume of air is needed to displace the air/water interface sufficiently. In the case of flatter and thicker reservoirs, it might not be possible to develop the bubble to this extent.

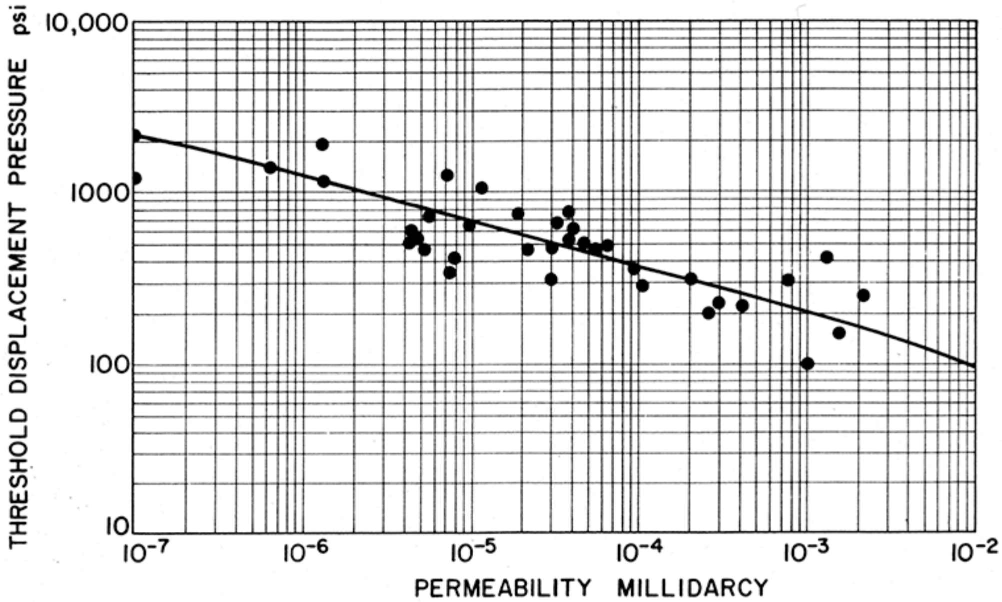


Figure 21 Measurements of threshold pressure as a function of permeability [19]

3.3.3. Pressure Limits and Caprock Characteristics

Pressure limits presented in the EPRI study were based on considerations related to caprock integrity and turbomachinery operational limits. For the 1982 EPRI study, the allowed pressure range was set at 14-69 bar.[16] However, to make best use of existing turbomachinery and to ensure optimal performance, the desired range was 39-50 bar. Both the McIntosh and Huntorf systems operate in this range (45 and 46 bar inlet pressures, respectively). The pressure limits or depth limits in a new CAES application might be substantially different from these values, depending on the caprock characteristics and the CAES turbomachinery design.

The caprock layer must be a relatively impermeable stratum immediately over the porous storage reservoir. The rock, usually shale, siltstone or dense carbonate, must be thick enough to prevent fracturing and have low permeability together with large capillary forces in order to prevent air from migrating through the media. As a rule of thumb, the pressure of injection is not allowed to exceed the discovery pressure of the formation by more than 0.16 bar per meter depth to avoid caprock fracture [19].

An important measure for determining the adequacy of the caprock layer is the threshold pressure, which is defined as the pressure at which air begins to displace water from a

[16] Based on the turbomachinery available at the time, the maximum allowable turbine inlet pressure and maximum compressor discharge pressure was 62 bar and 76 bar respectively. The minimum turbine inlet pressure was 10 bar and a 3.4 bar pressure drop from the storage reservoir to the surface turbomachinery was assumed.

porous rock. A sufficiently high threshold pressure is needed to ensure that air will not migrate through pore spaces in the caprock in response to pressure fluctuations during CAES operation. This threshold pressure reflects the wetability of the rock and is a function of the surface forces at the water-rock interface. These forces are ultimately responsible for the water-filled caprock layer's ability to act as an impermeable barrier to air migration [75]. Threshold pressure and its relationship to caprock permeability can be determined by measurements of water migration through core samples subject to differential pressures (see Figure 21).

3.3.4. Residual Hydrocarbons

In addition to using saline aquifers for CAES, it is also possible to use depleted oil and gas reservoirs, which are fundamentally aquifers. Since the bulk of natural gas storage experience is in depleted fields, many issues related to residual hydrocarbons have been extensively studied; however the injection of oxygen would present challenges not encountered when storing natural gas.

For example, residual hydrocarbons in the pore spaces of the formation might lead to the formation of permeability-reducing compounds and corrosive materials. Another possibility is that the presence of residual hydrocarbons may introduce the risk of flammability and insitu combustion upon the introduction of high-pressure air.

The flammability of the natural gas/air mixture may be a concern for CAES operation, but displacement of natural gas away from the active bubble area can mitigate this risk considerably. In some cases, nitrogen injection may be desirable to further minimize air/natural gas mixing. Previous studies indicate that these methods adequately address the challenge of using depleted natural gas fields for CAES and that these structures can provide a suitable air storage medium [79].

Table 4: Ranking Criteria for Candidate Sites for Aquifer CAES [60]

Score	1	2	3	4	5
Score Interpretation	Unusable	Marginal	OK	Good	Excellent
Permeability (md)	< 100	100- 200	200- 300	300-500	> 500
Porosity (%)	< 7	7-10	10-13	13-16	> 16
Total Reservoir Volume (V_R/V_S)	<0.5		0.5 – 0.8 or > 3.0	0.8 – 1.0 or 1.2 – 3.0	1.0 – 1.2
Total Closure Rating (h/H)	< 0.5		0.5-0.75	0.75-0.95	0.95-1.0
Depth to Top of Reservoir (m)[17]	< 137 or >760	140-170	170-260 or 670-760	260-430 or 550-670	430 -550
Reservoir Pressure (bar)	< 13 or > 69	13-15	15-23 or 61-69	23-39 or 50-61	39-50
Type of Reservoir	Highly Discontinuous	Moderately vulgar limestone & dolemite	Reefs, highly vulgar limestone & dolemite	Channel sandstones	Blanket sands
Residual Hydrocarbons (%)	> 5%		1-5%		< 1%
Caprock leakage	Leakage evident	No data available	Pumping test shows no leakage		
Caprock Permeability (md)			$> 10^{-5}$	$< 10^{-5}$	
Caprock Threshold Pressure (bar)			21-55	> 55	
Caprock Thickness (m)			< 6		> 6

3.4. Oxidation Considerations

The Pittsfield CAES experiment, conducted during the period 1981-85 in Pike County, IL under EPRI/DOE sponsorship, involved extensive field tests to determine the feasibility of using aquifers for air storage [79]. One of the important findings of the study was that introduction of air into the reservoir leads to the reaction of oxygen with native species that in turn leads to a reduction in the O_2 concentration in the stored air. These oxidation reactions proceed with a characteristic time scales of the order of months.[18] The observed oxygen depletion was largely attributed to the presence of sulfide minerals in the formation and subsequent reactions that were catalyzed by the injection of air into the formation. The presence of oxygen can lead to reactions among several mineral species with various outcomes.

The primary reactant in the Pittsfield case was pyrite, a sulfide of ferrous iron (FeS_2). The oxidation of pyrite ultimately leads to the formation of hematite (Fe_2O_3):

$$4\,FeS_2 + 11\,O_2 \rightarrow 2\,Fe_2O_3 + 8\,SO_2 \qquad (41)$$

The products of this reaction do not present significant problems for reservoir operability. However, if this process does not proceed to completion the presence of intermediate species might lead to serious formation damage. Partial oxidation might lead to the

[17] Depth limits are based on a hydrostatic pressure of approximately 0.09 bar per meter.

[18] This oxygen depletion was not observed in short duration (several day) storage tests

presence of ferrous sulfate or $Fe(OH)SO_4$, which can result in the production of colloidal ferric hydroxide and melanterite[19] respectively.

$$2FeS_2 + 7O_2 + 2H_2O \rightarrow 2FeSO_4 + 2H_2SO_4 \quad (42)$$

$$4FeSO_4 + O_2 + 2H_2O \rightarrow 4Fe(OH)SO_4 \quad (43)$$

These species swell to as much as 500% of the original pyrite volume and result in considerable permeability decline in the reservoir. This expansion, together with the collection of these products on pore interiors could impact the permeability of the reservoir substantially. In addition, the volume increase due to oxidation of pyrite and carbonates might lead to deteriorating expansive stresses on caprock layers.

Another problematic oxidation product is gypsum ($CaSO_4 \bullet 2\ H_2O$), which might precipitate through dissolution of carbonate minerals. Gypsum forms scale deposit that might occlude porosity and impair CAES system performance [79].

The degradation of reservoir permeability is not the only challenge which oxidation poses for aquifer CAES systems. Because the withdrawn air is combusted with fuel, the depletion of oxygen might result in impaired combustion efficiency downstream. However, because current CAES systems do not utilize all the oxygen in the air stream, some depletion can be tolerated without any loss in combustion efficiency [79].

Oxidation might have significant impacts on CAES operation and as such it is essential to fully characterize the mineralogy of a candidate site. It might be possible in some cases to control the rate of reactions by dehumidification of incoming air. Such dehumidification might have additional benefits, as discussed below.

In addition, if the formation cement between sand grains consists predominantly of carbonates and/or sulfides, the dissolution of these materials through oxidation might release particulates. If this happens in the vicinity of the well bore, it is likely that these particles can find their way to the turbomachinery (the effect of particulates on surface turbomachinery will be covered below). For this reason and for reasons related to the effects mineralogical reactions described above, reservoirs having high sulfide content should be avoided [79].

3.5. Corrosion

The deterioration of wellbore tubulars and casing cement through corrosion is an important problem to consider for CAES applications. Prominent corrosion types include biological (esp. bacterial), uniform, galvanic, crevice, pitting, erosion, intergranular, stress corrosion cracking, fatigue, and fretting corrosion. The promotion of corrosion by air injection might be further exacerbated by high-pressure and high-temperature conditions, especially if significant moisture is present.

[19] Melanterite ($FeSO_4 \bullet 7\ H_2O$) is a hydrated form of ferrous sulfate often formed from oxidation in pyritic ore zones

While many corrosion types (e.g. erosion corrosion, corrosion fatigue, fretting corrosion) might be prevented by suitable choice of materials or might simply not be relevant to the conditions in a CAES reservoir (e.g. intergranular corrosion), some might present particular problems for air storage applications. Controlling electrochemical corrosion processes such as uniform corrosion and pitting corrosion might require internal coatings of piping and wellbore tubulars. Although such coatings and linings might mitigate some of the effects of corrosion, even the most corrosion-resistant materials might ultimately succumb to deterioration, and care must be taken to carefully monitor the condition of all piping and well materials (see Figure 22). Because water might form an electrolyte and enhance the corrosion rate, it might be desirable to dehydrate the injected air. In the oil and gas industry, use of dehydrated natural gas streams has been shown to control corrosion and stress corrosion cracking.

General aerobic bacteria (GAB) such as Thiobacillus thioxidans (sulfur oxidating) can flourish in a CAES environment. Such species might oxidize native sulfur to sulfuric acid, which might have detrimental effects on wellbore tubulars and casing cement. Presence of these bacteria can result in localized corrosion and pitting of steel surfaces. Free-floating planktonic species might be present as well, which could be detrimental to

Figure 22 This photograph, from the Huntorf CAES facility in Germany, shows where the protective fiberglass-reinforced plastic tubing fractured. [35]

formation permeability. Care must be taken to avoid contamination of the reservoir during drilling operations including careful choice of drilling fluids. To control populations of preexisting bacterial species, biocides might be injected into the air stream once relevant species have been identified. Comprehensive reviews of reservoir analysis techniques for the detection of corrosion causing bacteria are available in the literature [80].

3.6. Flow in Aquifers

The dynamics of air flow are important for determination of storage energy density and prediction of air –water interface evolution during initial bubble development and subsequent storage operation. The deliverability calculation outlined above (see section 3.2.2.1) is simply a static calculation of airflows, but in reality the flow conditions will evolve as the bubble size fluctuates. This in turn will impact the storage energy density and reservoir volume requirement for CAES. While detailed analysis of aquifer flow behavior is outside the scope of this report, it is useful to highlight some basic concepts and discuss the impact on aquifer dynamics on CAES design and operation.

Use of aquifers for air storage differs greatly from other storage options due to the limited mobility of fluids through porous media. Hard rock caverns and solution mined salt formations can be described as rigid, open-space containers where pressure changes quickly equilibrate throughout the volume. However, flow through porous reservoirs results in dynamic pressure gradients throughout the formation that evolve over hours, days or weeks. Steady-state deliverability estimates are useful, but operational planning must take into account the effects of unsteady-state and pseudosteady-state air flows within the reservoir. The dynamics of these flow modes and the deviations of airflow behavior from steady state conditions are determined by the propagation rates of pressure gradients through the reservoir.

The injection or withdrawal of air at the wellbore introduces pressure pulses within the formation that propagate according to the viscosity of the fluid, the size of the pressure gradient, as well as the permeability and porosity of the reservoir. As a pressure gradient propagates through the formation, the pressure within the formation varies as a function of both time and location. This condition, called unsteady-state flow, persists until a flow boundary is reached.

When airflow is impeded (e.g. by the air-water interface, a permeability pinch-off, the presence of an adjacent well or some other flow constraint) the pressure throughout the reservoir will vary uniformly with time. This flow condition is called pseudosteady-state flow and the edge of this advancing pressure gradient is called the radius of drainage (r_d). Under pseudosteady-state flow the rate of change of pressure is uniform within the formation (i.e. independent of radial distance from the wellbore).

Van Everdingen and Hurst developed expressions for the evolution of aquifer pressures under unsteady-state conditions subject to constant terminal pressure and pseudosteady-state in a finite reservoir [81]. The radius of drainage is described in terms of the stabilization time (hours) for the reservoir to transition to a pseudosteady-state flow condition [75] and the time for the radius of drainage to reach a radial distance r is expressed as:

$$t_{stabilization} \propto \frac{\mu \, \phi \, r^2}{k \; p} \tag{44}$$

where

r = radial distance from the well bore
μ = viscosity (cp)

ϕ = porosity
k = permeability (md)
p = mean pressure between the wellbore and the radius of drainage (psia)

Typical values for t_{stab} over small distances are of the order of hours. Over significant fractions of a kilometer, t_{stab} will typically be of the order of days. The speed at which the pressure gradient evolves impacts the relevant flow regime at a given time. More importantly, it is clear that whether the reservoir is managed under "unsteady-state" or "pseudo-steady-state" flow conditions, true "steady-state" flow cannot occur in aquifers and hence aquifers cannot operate efficiently as compensated, constant-pressure systems (see section 2.2 above) [79].

The flow of water through the formation follows the same behavior described above, but due to the much larger viscosity of water and forces acting at the water interfaces, the stabilization time will be 20 to 100 times longer. Thus, the bubble movement will occur over time scales of days/weeks and the initial bubble development will typically take several months. Consequently, the impact of air-water interface migration will typically be most relevant during initial bubble development and for seasonal storage applications.

Such considerations imply that over the time scales necessary to balance wind, the bubble will not change appreciably in shape or extent [19]. Aquifer CAES systems can therefore be approximated as rigid, constant-volume systems when determining the storage volume necessary to provide a given storage capacity (see section 2.3, "Storage Volume Requirement").

3.7. Particulates

When particulates are generated around the wellbore, they can be carried in the air flow to the CAES turbomachinery where they might damage the turbine blades and other sensitive equipment. The ability of the air to transport particles depends on the air flow rate, the particle size distribution, and the distance of particle formation from the wellbore. Previous studies have shown that because of the high flow rates that would be typical for CAES, the air stream will be able to pick up particles of nearly any size that are generated within a few feet of the wellbore [60].

The generation of particulates in the reservoir can come about via a number of different mechanisms. As mentioned above, the dissolution of minerals that act as cement between sand grains can generate free particles that can be entrained into the air stream. In addition, injection of air, especially at elevated temperatures, can lead to dehydration and destabilization of clays that might lead to particulate formation.

Several approaches can be taken to mitigate particulate damage on turbomachinery. Particle filtration units are available for any size particle, but the capital cost and energy penalty increases steeply for small particle sizes. Alternatively, injecting a silica solution into the formation can cement the grains in the structure. This is commonly done in the natural gas storage industry to preclude the formation of particles in loosely held sandstones. The procedure gives rise to only a slight change in permeability and costs only about $25,000 ($1982) per well [60].

4. Wind/CAES Systems in Baseload Power Markets

This section addresses the emissions, and economics of baseload wind/CAES systems to illustrate the prospective importance of developing CAES, and especially aquifer CAES, for baseload power applications based on wind. These systems are compared to baseload power systems, giving emphasis to economics under a climate change mitigation policy.

Baseload power is typically provided by technologies such as conventional coal and nuclear generation. Although wind has a low, stable short run marginal cost, the variability of wind implies that it is unable to deliver firm power at similar capacity factors (~70-90%) without some form of backup generation. However a baseload power system made up of wind power plus dispatchable backup generation can be compared to other baseload generation options.

Two options for backing wind are utilizing dedicated stand-alone natural gas capacity and CAES. Natural gas capacity is chosen as the stand-alone backup generation technology due to its low capital costs and its fast ramping rates that are well suited to balancing rapid fluctuations in wind power output.

To illustrate the potential benefits of these baseload wind options, costs are compared with those of three other baseload power systems: coal integrated gasification combined cycle (IGCC) with CO_2 vented (IGCC-V), coal IGCC with CO_2 captured and stored (IGCC-C) and natural gas combined cycle (NGCC).

Although coal IGCC power is currently more costly than coal steam-electric power, the incremental cost of CO_2 capture and storage (CCS) is less for IGCC plants (via pre-combustion CO_2 capture) than for steam-electric plants (via post-combustion CO_2 capture). Furthermore, the total generation cost of coal IGCC power with CCS tends to be less than that of coal steam-electric power with CCS—at least for bituminous coals [82]. Thus coal IGCC-C is likely to be the major competitor that wind/CAES will face in a world with a climate policy in place.

Costs are presented for greenhouse gas (GHG) emissions prices of \$0 and \$31 per tonne of CO_2 equivalent —the first carbon price for the current situation where there is no climate change mitigation policy and the second carbon price representing a GHG emissions valuation that is likely to characterize a climate change mitigation policy. (A GHG emissions price ~ \$31/tCO_2 is the minimum price on GHG emissions needed to make a coal IGCC-C plant with storage of CO_2 in deep saline aquifers competitive with a coal IGCC-V plant (see Table 8) [83, 84].

4.1. Methodology

Levelized generation costs for alternative baseload power systems are estimated using the financing model in the EPRI Technical Assessment Guide [85]. The assumed financing parameters are 50% debt (9%/y nominal return) and 45% equity (12%/y nominal return), a 30-year (20-year) plant (tax) life, a 38.2% corporate income tax rate, a 2%/y property tax/insurance rate, and a 2.35%/yr inflation rate. Under these conditions the discount rate (real weighted after-tax cost of capital) is 6.72%/year, and the levelized annual capital charge rate is 13.3%/year. It is assumed that plant construction requires four years (except wind capital which is built over one year), with the capital investment committed in equal annual payments, so that interest during construction factor (IDCF) is 1.0687 with Base Case financing.[20] All costs are expressed in 2006 inflation-adjusted U.S. dollars.

Table 5: **Coal IGCC System Parameters**[a]

	IGCC-V	**IGCC-C**
Fate of CO_2	Vented	Captured
Capacity Factor	80%	
Levelized Annual Capital Charge Rate (%)	13.3	
Coal Price ($/GJ HHV)	1.65	
Installed Capacity (MW_e)	640.3	555.7
CO_2 Capture Fraction (%)	0.00	90
Fixed Operation and Maintenance ($/kW-yr)	34.81	43.16
Variable Operation and Maintenance ($/MWh)	6.40	7.98
Efficiency (LHV/HHV, %)	(39.6/38.2)	(33.7/32.5)
CO_2 Transport/Storage ($/t$CO_2$)	0	5.0
Overnight Construction Cost ($/k$W_e$)	1789	2358

[a] All IGCC performance/cost estimates are for a water-slurry-fed single-stage GEE gasifier, which is currently the least cost IGCC option with CO_2 capture and storage. Data adapted from NETL 2007 [84] and expressed in 2006$.

[20] The levelized annual capital charge = LACCR*IDCF*OCC, where LACCR = 13.3%/year, IDCF = 1.0687, and OCC = overnight construction cost.

Table 6: Wind System Parameters

	Wind/CAES	Wind/Gas
Installed Baseload Capacity (MW_e)	2000	
Levelized Annual Capital Charge Rate (%)	13.3	
System Capacity Factor (%)	85	
Natural Gas Price ($/GJ HHV)	6.00	
Wind Farm Rated Power (MW_e)	3130	2000
CAES Expander Capacity (MW_e)	1270	0
CAES Compressor Capacity (MW_e)	1130	0
SC Capacity (MW_e)	0	234
CC Capacity (MW_e)	0	1700
Storage Capacity at CAES Expander Capacity (Hours)	88	0
Wind Turbine Specific Rating [86]	1.21	1.36
Transmission Loss Over 500 km (%) [b]	3.39	3.06
Transmission Line Capacity Factor After Losses for 85% System Capacity Factor (%)	85	42.2
Wind Energy Transmitted Directly for 85% System Capacity Factor (TWh/y)	10.3	7.40
Wind Energy Input to CAES at 85% System Capacity Factor (TWh/y)	2.97	0
CAES Output Power (TWh/y)	4.46	0
SC Power Output (TWh/y)	0	0.239
CC Power Output (TWh/y)	0	7.26
CAES Charging Energy Ratio (CER)	1.5	0
CAES Heat Rate (kJ/kWh)	4220	0
SC Heat Rate (kJ/kWh)	0	9020
CC Heat Rate (kJ/kWh)	0	6680
Wind Capital Cost at Nominal Rating $/kW$_e$ [a]	$1241/kW	$1241/kW
CAES Capital Cost [a]		
Cost of CAES surface turbomachinery and balance of plant capital ($/kW$_e$) [a]	610	0
Capital cost of incremental storage capacity ($/kWh)	1.95	0
SC Overnight Construction Cost ($/kW$_e$) [a]	0	410
CC Overnight Construction Cost ($/kW$_e$) [a]	0	611

[a] Wind turbine costs based on [31], CAES costs based on [11, 12], SC and CC costs based on [87]
Installed Capacity for systems with dedicated transmission lines reflects the discharge capacity at the end of the transmission line after losses.
[b] Transmission losses are expressed as a fraction of transmitted energy at the source of generation. Since transmission here reflects a differential in transmission distance, converter losses are not included. Such losses would add an additional 0.75% of loss at each terminal.

Energy quantities are expressed on a lower heating value (LHV) basis, except energy prices are on a higher heating value (HHV) basis—the norm for US energy pricing. Energy prices are assumed to be $1.65/GJ for coal and $6.00/GJ for natural gas [87]. The GHG fuel emissions include the CO_2-equivalent upstream GHG emissions (3.66 kg CO_2 per GJ of coal and 10.4 kg CO_2 per GJ of natural gas [88]), resulting in total CO_2-equivalent GHG emissions rates of 93.0 kg CO_2 and 66.0 kg CO_2 per GJ of coal and natural gas, respectively.

Coal IGCC plant performances, capital costs, and O&M costs are based on 2007 NETL data [84]. CO_2 transport and storage costs are estimated using the model developed by Ogden et al [89] (see Table 5). Cost modeling of wind energy systems and transmission as well as optimization methodology for variable scaling of wind turbine components (i.e. derating) are as described in previous studies unless otherwise noted (see Table 6) [2, 86, 90].

Although assumptions in this report relating to capital costs reflect the most recent numbers published in the open literature, the escalation of construction costs continues [91], so that estimated absolute costs may differ from actual realized cost levels for plants that might be built. However, construction cost escalation is a phenomenon affecting essentially all energy technologies, and it is reasonable to assume that continuing construction cost escalation will not appreciably affect the relative economics among the alternative baseload options considered or the conclusions of this analysis.

The cost of electricity (COE) or generation costs is estimated two ways. For the first set of COE estimates presented in Table 8, it is assumed that the power systems are operated at specified capacity factors. Subsequently, economic dispatch is discussed, which, in real markets, has the effect of reducing the capacity factors of systems with high dispatch costs.

4.2. Generation Costs for Alternative Baseload Power Systems Operated at Specified Capacity Factors

The COEs for alternate baseload power systems are presented in Table 8 disaggregated into components. The COEs are compared under three sets of conditions: The first set of costs are evaluated without a valuation on GHG emissions , the next set applies a CO_2-equivalent GHG emissions price of \$31/tCO_2 and the third includes the cost of transmitting remote wind supplies 500 km to demand centers.

Table 7 CO_2-equivalent GHG Emission Rates for Alternative Baseload Power Systems (kgCO_2/MWh)

IGCC-V	IGCC-C	Wind/CAES	Wind/Gas	NGCC
829	132	86.5	224	440

In the absence of a GHG emissions price, IGCC-V is the least costly baseload power option, while the cost for wind/CAES is a few percent higher than that of IGCC-C. When GHG emissions are valued at \$31/tCO_2, the wind and natural gas options become more competitive with the coal options. In this case, wind/gas and NGCC are the least costly baseload power options. At this GHG emissions price (the breakeven price for IGCC-C with respect to IGCC-V), wind/CAES is now has a nearly equivalent cost as both coal options. The addition of transmission line costs adds approximately 10% to the levelized cost of energy to both baseload wind options.

The generation cost estimates presented in Table 8 underscore the sensitivity of the results to the stringency of the climate change mitigation policy and the wind resource remoteness.

Table 8: Disaggregated Generation Costs for Coal IGCC, Baseload Wind and NGCC ($/MWh)

	IGCC-V	IGCC-C	Wind/CAES	Wind/Gas	NGCC
Fixed Costs					
Capital	36.37	47.94	65.15	39.66	13.49
Fixed Operations and Maintenance	4.95	6.15	3.90	3.95	1.75
Variable (Dispatch) Costs					
Variable Operations and Maintenance	6.38	7.99	8.98	5.42	1.94
Fuel	15.55	18.27	8.43	22.68	44.53
CO_2 Transport and Storage	0.00	4.21	0.00	0.00	0.00
Total Dispatch Cost	21.93	30.47	17.40	28.09	46.47
Total Generation Cost at Zero Carbon Price	**63.25**	**84.55**	**86.45**	**71.70**	**61.72**
GHG Emissions Costs @$31/t$CO_2$	25.35	4.04	2.64	6.86	13.48
Total Dispatch Cost	47.28	34.51	20.04	34.96	59.95
Total Generation Cost @ $31/t$CO_2$	**88.60**	**88.60**	**89.09**	**78.56**	**75.19**
Cost of 500km Dedicated TL for Remote Wind [a]	0.00	0.00	7.23	7.25	0.00
Transmission Losses [b]	0.00	0.00	3.29	1.29	0.00
Total Generation Cost Including TL Cost for Remote Wind @ $31/t$CO_2$	**88.60**	**88.60**	**99.61**	**87.11**	**75.19**

[a] This is the TL cost per total MWh of electricity production. Allocated only to the electricity transmitted, the TL cost for the Wind/Gas option is 95% *greater* than the TL cost for wind/CAES because of the lower TL capacity factor.

[b] Transmission costs based on 500kV bipole technology [92]. Since transmission distance is regarded as differential rather than absolute only the cost of the 500km increment are included (i.e. no convertor costs).

4.3. Dispatch Competition in Baseload Power Markets

The ordering of the total generation costs presented in Table 8 does not represent the ordering that would occur in real-world power markets, in which capacity factors cannot be assumed to be fixed at a specified rate. Rather, capacity factors are determined by market forces to reflect the relative dispatch costs of the competing options on the electric power grid.

For a given set of power generating systems connected to the electric power grid, the grid operator determines the capacity factors of these systems by calling first on the system with the least dispatch cost. Under this condition, deployment in sufficient quantity of the technology with the least dispatch cost can lead to a reduction of the capacity factors and thus an increase in the COEs of the competing options on the grid.

The impact of dispatch competition on capacity factors is well known. For example, as a result of the recent increases in natural gas prices in the U.S. this phenomenon has resulted in reducing capacity factors for natural gas combined cycle plants originally designed for baseload operation to average utilization rates in the range 30-50% where coal plants are available to compete in dispatch [82].

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

4.3.1. Dispatch Duration Curves

Table 8 presents average dispatch costs for the options considered. The table shows that in the presence of a GHG emissions price of \$31/tCO_2 the total average dispatch cost (i.e. the sum of all short-run marginal costs on average: fuel + variable operations and maintenance + GHG emissions cost) is the lowest by far for wind/CAES systems.

Since dispatch costs determine the relative suitability of alternative options for baseload operation, it is necessary to examine closely the *dynamics* of dispatch. Although to good approximation one can assume that the dispatch costs for coal IGCC plants are constant, the dispatch costs for wind-based power systems cannot be treated as simple averages.

Dispatch costs for wind-based systems vary from the minimum value (corresponding to times when all electricity is provided by wind—i.e., when fuel expenditures are zero) and increase significantly as backup generation comes on line to balance shortfalls in wind output. Thus, it is important to analyze the variations in dispatch costs for these options, not simply their average value as reported in Table 8.

Figure 23 shows the variation in dispatch costs in a manner similar to a "load-duration" curve or, more precisely, as an inverse cumulative probability curve counting from the top end of the distribution. The choice of horizontal axis (in reverse order from 1 to 0) can be useful since horizontal axis values at the intersection of the wind curves with each constant-cost IGCC line indicate the percent of time that it can deliver power at a lower dispatch cost. These dispatch cost curves are evaluated at both p_{GHG}=\$0/tCO_2 and \$31/tCO_2 (this is the break-even greenhouse gas emissions price for IGCC-C relative to IGCC-V as is evident from Table 8).

4.3.2. Results

Dispatch costs are the same lowest value for both the wind/gas and wind/CAES systems when all power comes directly from the wind array (right portion of each plot in Figure 23), but dispatch costs rise at very different rates as the fraction of power coming from the backup system increases (left portion of each plot). In addition, the wind/CAES system has an intermediate dispatch cost regime where CAES compressors are running to store wind energy that cannot be transmitted; this appears as a step in intermediate ranges on the wind/CAES dispatch cost curve.

Figure 23 shows that wind/gas has the highest dispatch cost of all the coal and wind options when natural gas generation is dispatched in significant quantities to balance wind output. For the portion of the dispatch duration curve corresponding to zero wind output, the dispatch cost matches the dispatch cost of NGCC as expected. These relationships hold true at both valuations of GHG emissions assumed in Figure 23. At

$0/t$CO_2$ wind/gas cannot compete in economic dispatch relative to the lowest cost coal technology for more than 35% of the time and even at $31/t$CO_2$ it will be competitive less than 40% of the time. Hence a baseload-level capacity factor cannot be sustained with wind/gas if either coal or wind/CAES capacity is available in significant quantity on the grid. Thus in light of current and prospective high natural gas prices, it is unlikely that

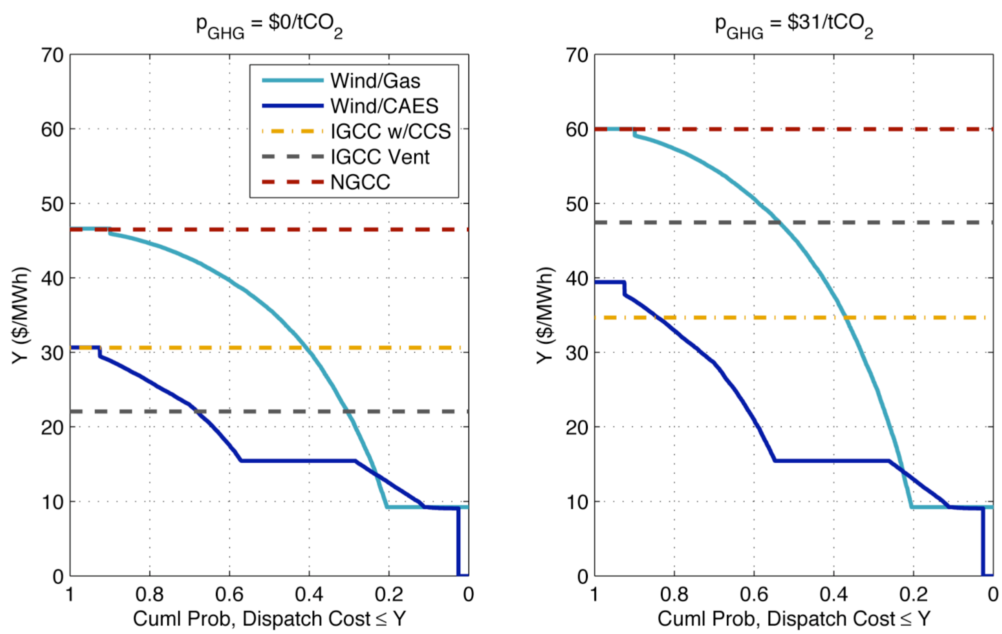


Figure 23 Dispatch costs for the four alternative power systems for two valuations of GHG emissions

wind/gas will be a viable baseload power option for the near future.[21]

In contrast, because wind/CAES systems have a lower heat rate (4220 kJ/kWh) and because direct energy from wind accounts for a larger fraction of the output (see Table 6), they are able to run at a lower dispatch cost than both coal options more than 70% of the time at $0/t$CO_2$ and more than 85% of the time at $31/t$CO_2$.

Thus, via dispatch competition, wind/CAES systems can be highly competitive with coal power systems—especially in the presence of a substantial valuation of GHG emissions. An economic model of the entire electric power system is needed to determine the capacity factors of coal power plants on the grid resulting from dispatch competition. Although such modeling is beyond the scope of this report, it is clear that the average capacity factor for coal systems would decline as more and more wind/CAES power is added to the grid. At a GHG emissions valuation of $31/t$CO_2$, the COE for a wind/CAES system at 85% capacity factor would be lower than for an IGCC-C system

[21] Wind power backed by existing reserve capacity might still be cost-effective in serving intermediate load applications, especially where diurnal variations in wind speed are positively correlated with electricity demand. However, analysis of intermediate load markets is outside the scope of this report.

when the latter has a capacity factor less than 79% when both systems are equally distant from major electricity markets or less than 71% when the wind supply is more distant by 500 km.

The coupling of wind farms to large scale storage technologies such as CAES opens the door to participation in baseload markets for both wind and natural gas—especially in the presence of a strong climate change mitigation policy. The variability of wind makes it impossible for a "pure" wind system to provide baseload power. Moreover, current and prospective high natural gas prices exclude natural gas combined cycle power technology from providing baseload power if there is a substantial amount of coal power on the grid. But coupling wind to CAES makes it possible for wind to deliver firm power. And the use of wind to provide compressor energy results in fuel consumption that is sufficiently low for wind/CAES to be competitive with coal in economic dispatch. This represents an important opportunity for both wind and natural gas to compete in baseload power markets, and opens the door to an important option for realizing cost-effectively deep reductions in GHG emissions from the power sector.

5. Advanced Technology Options

Although commercial CAES plants have been operating for several decades, the technology is still in an early state of development. This is reflected in the fact that the two existing plants are based largely on conventional gas turbine and steam turbine technologies. Consequently, various technological improvements might be pursued to enhance performance and reduce costs over relatively few product cycles.

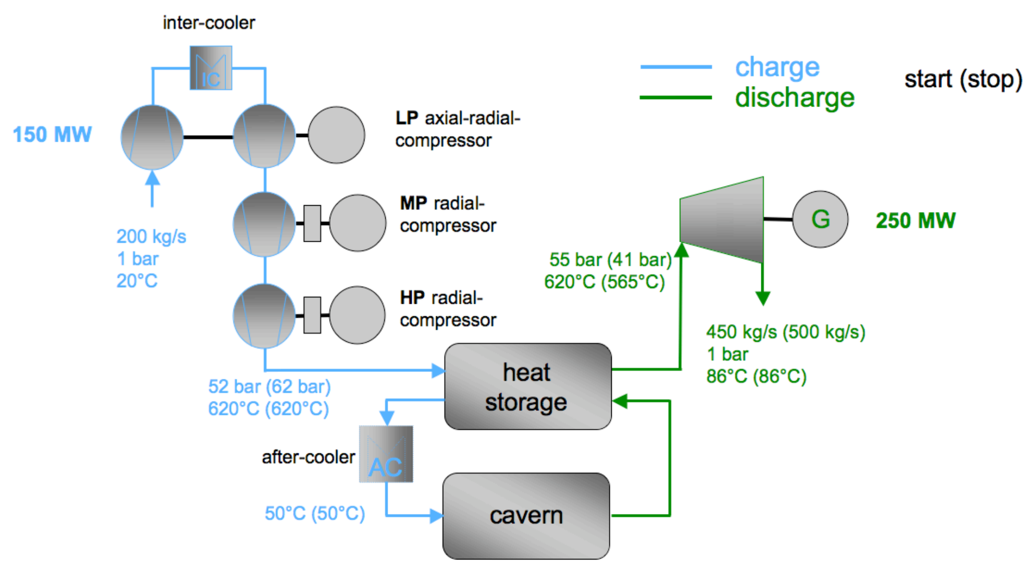


Figure 24 A possible technical concept for an AA-CAES system under development [38]

One option that has attracted interest is to reduce (and perhaps eliminate) the CAES fuel requirements and associated GHG emissions by recovery and storage of the high-quality heat of compression in thermal energy storage (TES) systems. Heat recovery could be implemented at some or all compression stages, which would then allow stored heat to be used in place of fuel to reheat air withdrawn from the CAES cavern thereby either partially or completely eliminating the need for natural gas [65]. In order to be economic, the fuel cost reductions must offset the additional capital cost associated with the TES system. Early studies found that very high fuel prices would be required to justify such systems making adiabatic CAES too costly for commercial use [93-97].

More recent studies however suggest that new TES technologies, together with improvements in the compressor and turbine systems might make so-called Advanced Adiabatic CAES (AA-CAES), economically viable [9, 98]. One such AA-CAES concept with a high efficiency turbine and a high-capacity TES, achieves a round trip efficiency of approximately 70% with no fuel consumption (see Figure 24) [38]. But it should be noted that the efficiency gain of adiabatic systems over multistage compression with intercooling is small (see Appendix A), and both the fuel use and GHG emissions for wind/CAES systems are already very modest (see Table 7).

Table 9 The main thermal energy storage (TES) concepts considered for AA-CAES [98] [a]

Concept	Solid TES					Liquid TES		
	Rock bed	Cowper-Derivative	Concrete Walls	Cast Iron Slabs	'Hybrid'-phase-change materials	Two Tank	1-Tank Thermo-cline	Air-Liquid
Contact	Direct	Direct	Direct	Direct	Direct	Indirect	Indirect	Indirect
Storage Materials	Natural Stone	Ceramics	Concrete	Cast Iron	Ceramics, Salt	Nitrate Salt, Mineral Oil	Nitrate Salt, Mineral Oil	Nitrate Salt, Mineral Oil

a. Storage technologies chosen on the basis of the capability to deliver 120-1200 MWh (thermal), maintain high consistency of outlet temperature, and cover the full temperature range (50 to 650°C)

Another proposal is to use biomass-derived fuels to reheat the air withdrawn from storage. This could reduce GHG emissions and decouple the plant economics from fuel price fluctuations [99]. This might also allow CAES to be run on fuel produced locally, thereby facilitating the utilization of energy crops in remote, wind-rich areas and eliminating the need to secure natural gas supplies. However, as in the adiabatic case, the emissions benefit would be small because the emissions level of wind/CAES is already quite low (~ 2/3 the rate for a coal IGCC plant with CCS, see Table 7). Moreover, a biofuels plant dedicated to a wind/CAES system would require fuel storage, because biofuels must be produced in large-scale plants that are run flat-out in order to be cost effective, while CAES expander capacity factors for backing wind will typically be modest (see Table 6)

A CAES variant proposed for wind applications is to replace the electrical generator in the wind turbine nacelle with a compact compressor. So doing would enable the wind turbine to generate compressed air directly, thereby eliminating two energy conversion processes.[22] However, the reduced losses and potential drop in turbine capital cost would have to offset the added capital cost of the compact compressors and the considerable cost of the high pressure piping network needed to transport the compressed air from each turbine to the storage reservoir.

In contrast to the option of coupling intermittent wind to CAES to enable the provision of baseload electricity, CAES might also be coupled to baseload power systems to facilitate the use of such systems to provide load-following and/or peaking power, the function originally envisioned for CAES—e.g., by coupling CAES to a coal IGCC plant [100, 101].

Improving CAES turbomachinery is a promising area for innovation. CAES turbine operating temperatures might be increased, thereby increasing their efficiency by introducing turbine blade cooling technologies routinely deployed in conventional gas turbines but not in commercial CAES units. Other advanced CAES concepts include various humidification and steam injection schemes which can be used to boost the power output of the system and reduce the storage requirement [102]. The CAES

[22] The company General Compression is currently developing this technology.

combined cycle is still another option that allows the system to generate electricity even when the compressed air storage reservoir is depleted [103, 104].

A recent hybrid CAES system design incorporates a standard combustion turbine in place of the turboexpander chain in a traditional CAES design. The air withdrawn from storage is heated by means of a recuperator at the turbine exhaust instead of by way of fuel combustors as in a conventional CAES plant. The heated air is then injected into the turbine to boost the output. The use of commercial technology and the elimination of fuel combustors could reduce the capital cost of the system substantially and provide a low risk option for early adoption of bulk storage. Such an Air-Injection CAES (AI-CAES) plant could also include a bottoming cycle and TES system to reduce fuel consumption further [52, 105].

Although it is possible that new CAES concepts will bring important changes to the way air storage operates or the way wind power is stored, performance/cost gains are most likely to arise in the near term as a result of marginal improvements in existing CAES designs as a result of learning by doing. Thus, after technology launch in the market, costs for new technologies such as CAES can be expected to decline at faster rates than for mature technologies and more quickly the faster the rate of deployment. This phenomenon bodes well for wind/CAES as a baseload power climate change mitigation option if there is a way forward that offers opportunity for substantial early market experience.

6. A Way Forward

Although the exploitable global wind potential is sufficient to meet total electricity demand several times over, the future role of wind will ultimately be determined by the extent to which the temporal variability and resource remoteness challenges can be addressed. Compressed air energy storage is a potential solution, but to evolve from the two commercial-scale CAES plants in the field today to wide-scale deployment of this technology requires clarification of several issues.

Widespread deployment of CAES will depend on the availability of suitable geologies that can be developed economically to provide the needed storage capacity. The two existing commercial CAES plants at Huntorf and McIntosh both use salt dome storage but, as Figure 17 shows, regions with domal salt formations do not have significant overlap with high quality wind resources. Bedded salt and hard rock geologies overlap well with windy areas (see Figure 7 and Figure 17), but there are challenges associated with each, namely structural issues in the case of salt beds and the high cost of mining new caverns in the case of hard rock (see section 1.3). Developments in mining technology may reduce the cost of using hard rock storage reservoirs making this geology a viable option for future CAES systems. However, porous rock formations can currently be developed at a much lower cost and appear to be available in many windy areas throughout the continental US and thus are the most likely candidate for coupling CAES with wind capacity in the near term.

Although the geographical distributions of good wind resources and potential aquifer storage opportunities seem to be well correlated (see Figure 17), this broad-brush judgment must be buttressed by detailed assessments of specific aquifers and local, facility-sized structures in the aquifers. In the necessary detailed resource assessments, clarification is needed of the extent of anticlines with suitable characteristics (permeability, caprock thickness, etc) among the porous rock formations of the regions where there are good wind resources and of the geochemical suitability of various formations for storing air. Data on local geology from US and state geological surveys including natural gas storage candidate site evaluations might aid in further characterizing these areas, but new data will also be needed especially in regions where natural gas storage is not commonplace.

The planned wind/CAES system in Iowa will help to establish the viability of aquifer CAES, but as indicated in section 3, the suitability of a porous rock formation for CAES depends on a host of geologic factors. As such, it will be important to demonstrate several commercial scale systems to ensure that CAES technology can be developed in a sufficiently broad set of geologic conditions as to have the potential for widespread deployment.

Finally, direct coupling of CAES with wind farms will present challenges not faced in today’s CAES systems. The system at Huntorf is primarily used for peaking services and the McIntosh system charges storage at night and provides output during the day. This is in contrast to the higher frequency fluctuations imposed by wind power and the more rapid switching between compression and generation modes needed to back up wind power.

The use of CAES in an intermediate load application such as that envisioned for the Iowa wind/CAES plant will provide a valuable demonstration of wind/CAES integration. However, demonstration of a much more closely coupled system capable of serving baseload markets is also needed to understand better the potential of wind/CAES for displacing new coal capacity in a carbon constrained future. Ultimately the role of wind as a tool for climate mitigation will depend on the extent to which it will be able to supplant new baseload coal-fired capacity.

7. Conclusions

Traditionally, CAES technology has been used for grid operational support applications such as regulation control and load shifting. But a new major possibility that is especially relevant for a carbon constrained world is to enable exploitation at large intermittent wind resources that are often remote from major electricity demand centers. CAES appears to have many of the characteristics necessary to transform wind into a mainstay of global electricity generation.

Backing wind to produce baseload output requires short response times to accommodate fluctuations in compressor power and turbine load. The ability of a CAES system to ramp output quickly and provide efficient part-load operation make it particularly well suited for balancing such fluctuations—key performance characteristics that are not often called upon at existing CAES plants that simply store low-cost off-peak electricity for use when electricity is more valuable.

Air storage volume requirements translate into a geologic footprint ~15% of the wind farm land area, so that CAES will have relatively limited impact on land use and ecology.

The wide availability of potentially suitable geology in wind-rich areas points to CAES as a technology well-suited for making baseload power from wind—thereby making it feasible to provide wind power at electric grid penetrations far greater than 20%+ penetration rates that are feasible without storage. And, to the extent that wind-rich regions are remote from major electricity markets, such baseload power can often be delivered to distant markets via high voltage transmission lines at attractive costs.

Aquifer CAES seems to be the most suitable storage geology for wind/CAES in the US due to the potential for low development costs and because regions with porous rock geologies are strongly correlated with the onshore wind-rich regions of the US.

Aquifer CAES technology has been studied for nearly three decades, but the first commercial plant was only recently formally announced. Nevertheless, a great deal of commercial experience can be gleaned from the natural gas storage industry, which uses geologies similar to those needed for CAES to meet seasonal heating demand fluctuations. The methodologies for evaluating natural gas storage reservoirs have been shown to be directly applicable to aquifer CAES development, but several differences between use of methane and air as a storage fluid must be taken into account. Care must be taken to carefully characterize local mineralogy, existing bacterial populations and relevant corrosion mechanisms in order to anticipate any problems resulting from the introduction of air into porous underground media. Methods for mitigating the impact of these factors such as air dehydration, particulate filtration or biocide application could help to expand the number of suitable sites. Despite the various issues that must be taken into account, none obviously diminish CAES as a strong candidate option for wind balancing.

The planned wind/CAES plant in Iowa will provide valuable experience both with an aquifer as a storage medium and with operating a CAES system under conditions somewhat different from those at Huntorf and McIntosh due to the coupling of CAES with variable wind power.

However, understanding the large-scale deployment potential of CAES will require both a more detailed characterization of existing porous rock formations as well as operational experience from multiple plants over a wide variety of geologic conditions.

An economic analysis of wind/CAES systems shows that its costs would be very similar to costs for other baseload power options offering low GHG emissions. The dispatch cost of wind/CAES systems is low enough to defend a baseload (~85%) capacity factor against other low carbon generation technologies such as coal IGCC with CCS. Furthermore, the fact that few commercial CAES systems exist suggests that significant cost reductions are likely to be realizable over relatively few product cycles of experience via "learning by doing"

The storage of energy through air compression offers the potential to enable wind to meet a large fraction of the world's electricity needs competitively in a carbon constrained world. If the needed resource assessments and system studies are completed soon, it should quickly become evident just how large this fraction might be.

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Appendix A Theoretical Efficiency of Compressed Air Energy Storage for Alternative Configurations

The storage efficiency of adiabatic compressors and storage in an insulated cavern is compared to that of intercooled compressors and storage at ambient temperature.

The theoretical maximum efficiency of compressed air energy storage η_S is ratio of the maximum work b (the exergy, in kJ) that can be extracted from 1 kmol of air stored at temperature T_S and pressure P_S to the work wc required to compress 1 kmol of air from ambient temperature T_o (= 300 K) and pressure P_o (= 1 atmosphere):

$$\eta_S = b/w_C \quad (45)$$

$$b\ (P_S,T_S) = h\ (P_S,T_S) - h\ (P_o,T_o) - T_o*[s\ (P_S,T_S) - s\ (P_o, T_o)], \quad (46)$$

where

h = air enthalpy, and
s = air entropy.

Suppose that air is compressed from P_o, T_o to P_C, T_C. Assuming air is an ideal diatomic gas with constant specific heats:

$$k = c_p/c_v = 7/5 = 1.4 \quad (47)$$

where:

c_p = specific heat at constant pressure,
c_v = specific heat at constant volume,

the exergy per kmol of compressed air is:

$$b\ (P_S, T_S) = cp*(T_S - T_o) - c_p*T_o*\ln\ (T_S/T_o) + RT_o*\ln\ (P_S/P_o) \quad (48)$$

$$= RT_o*[k/(k - 1)]*[[(T_S/T_o - 1) - \ln\ (T_S/T_o)] + [(k - 1)/k]*\ln\ (P_S/P_o)], \quad (49)$$

where R is the universal gas constant (R = 8314 kJoules/kmole/K).

Moreover, assuming a compressor with an efficiency η_c, with N stages of adiabatic compression, with perfect intercooling between stages, and with the optimal compression ratio per stage = $(P_C/P_o)^{1/N}$, the work required to compress a kmol of air from pressure P_o to P_C is:

$$w_C = RT_o*[Nk/(k - 1)]*[(P_C/P_o)^{(k-1)/Nk} - 1]/\eta_c \quad (50)$$

and T_C is given by:

$$T_C = T_o*(P_C/P_O)^{(k-1)/Nk} \quad (51)$$

The theoretical maximum efficiency of storage is thus:

$$\eta_S = (\eta_C/N)*[(T_S/T_o-1)-\ln\ (T_S/T_o)+[(k - 1)/k]*\ln(P_S/P_o)]/[(P_C/P_o)^{(k-1)/Nk}-1] \quad (52)$$

<u>Case I:</u> Consider first a system with one stage of adiabatic compression (N = 1) and perfect insulation of the air storage reservoir, so that $T_S = T_C$ and $P_S = P_C$. In this case, η_S

= η_C, and the highest possible storage efficiency is realized. However, this is not a good representation of the actual situation where the air in storage is typically cooled to the ambient temperature.

Case II: Consider next a system with N stages of compression, perfect intercooling between stages, and poor insulation of the storage reservoir so that $T_S \rightarrow T_o$ before energy recovery is attempted. In this case,

$$P_S \rightarrow P_C*(T_o/T_C) = P_C*(P_C/P_o)^{-(k-1)/Nk} = P_o*(P_C/P_o)^{1-(k-1)/Nk} \quad (53)$$

$$b(P_S, T_S) \rightarrow RT_o*[1 - 1/N + 1/(Nk)]*\ln (P_C/P_o) \quad (54)$$

and

$$\eta_S = (\eta_C/N)*[(k - 1)/k]*[1 - 1/N + 1/(Nk)]*\ln (P_C/P_o)/[(P_C/P_o)^{(k-1)/Nk} - 1] \quad (55)$$

For example, suppose air is compressed to P_C = 100 atmospheres and N = 1, so that T_C = 1118 K, and at the time of energy recovery, P_S = (300/1118)*100 = 26.8 atmospheres. In this case $\eta_S = 0.345*\eta_C$.

But if P_C = 100 atmospheres and N = 5, T_C = 390 K and P_S = 77.0 atmospheres at the time of energy recovery, so that $\eta_S = 0.824*\eta_C$.

In the limit of an infinite number of stages of compression with perfect intercooling, the compressor work is isothermal, and the compressor work required is:[23]

$$w_C \rightarrow (RT_o*/\eta_C)*\ln(P_C/P_o),\ P_S \rightarrow P_C,\ \text{so that } \eta_S \rightarrow \eta_C \quad (56)$$

This is the same as for Case I. Thus, via the use of large number of intercoolers, the theoretical efficiency of a CAES unit with storage at ambient temperature can approach that of a CAES unit compressing air adiabatically and storing air in an insulated cavern.

[23] Note that $(X^a - 1)/a \rightarrow \ln X$ as $a \rightarrow 0$.