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Report

223-1

Net energy balance and greenhouse gas emissions from renewable energy storage systems

June 2003

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ECW Report Number 223-1

Net energy balance and greenhouse gas emissions from renewable energy storage systems

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Authors:
Paul Denholm and Gerald Kulcinski
Fusion Technology Institute
University of Wisconsin-Madison

Project manager:
Craig Schepp

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595 Science Drive
Madison, WI 53711
608.238.4601
editor@ecw.org
www.ecw.org

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Abstract

Using life-cycle assessment, metrics for the calculation of input energy requirements and greenhouse gas emissions from utility energy storage systems have been developed and applied to three storage technologies: pumped hydro storage (PHS), compressed air energy storage (CAES), and advanced battery energy storage systems (BESS). Methodology for evaluating dispatchable renewable systems that combine renewable energy generation and energy storage is also introduced. In general, the use of energy storage with renewable generation substantially increases the input energy required to produce electricity, as well as the total greenhouse gas emissions. The change in input energy is reflected in an overall reduction in the system energy payback ratio (EPR). The change in EPR and emissions rate is relatively small when PHS is used, but is significant when CAES or BESS is utilized. CAES produces substantial emissions from the combustion of natural gas during operation, while BESS systems are highly energy-intensive in the construction phase. Coupling storage and renewable energy systems can increase the per unit GHG emission rate by a factor of 2-5 times over the base rate. Even so, this emission rate is still substantially lower than fossil fuel derived electricity sources.

1.0 Introduction

It is widely accepted that an economically viable, low impact source of utility scale energy storage is becoming increasingly important to the U.S. electric industry. Many renewable sources of electricity, such as solar photovoltaic (PV) and wind, are incapable of providing the variety of services now demanded by an increasingly deregulated industry. These services, which require a dispatchable source, include load following, peaking power, spinning reserve, standby reserve, voltage support and reactive power support. Wind power is especially limited by its relative lack of predictability, non-peak demand coincidence, and rapid swings in output. Photovoltaic energy has higher predictability and some coincidence with demand, but there is still a substantial difference between time of peak PV output and time of demand in both daily and seasonal cycles. It is generally accepted that no more than 20% of a total regional demand can be provided by intermittent renewables.[1] Energy storage allows non-fossil sources to provide dispatchable grid service, and will be an essential feature of a de-carbonized electricity industry.

Direct economic and environmental comparisons between intermittent renewables and traditional firm sources ignore the substantial limitations of intermittent sources and have been criticized as providing an incomplete picture of the true energy requirements and emissions related to non-fossil sources. Coupling intermittent renewables with storage creates a dispatchable source, and a life-cycle assessment of energy storage provides the opportunity to compare intermittent renewables with firm sources of power.

With the exception of pumped hydro storage (PHS), there is very little utility-scale energy storage installed in the U.S. Future development of pumped-hydro storage is limited due to environmental concerns and the lack of available sites. Two promising technologies for utility scale energy storage systems are compressed air energy storage (CAES) and battery energy storage systems (BESS). CAES is a mature, economically viable technology, whose adoption has been somewhat limited by market forces, but continues to be considered a prime candidate for large-scale storage applications.[2]

Advanced battery systems which utilize flowing electrolytes and completely reversible charge/discharge cycles, are now economically competitive for certain applications.

Since PHS is the dominant source of energy storage used worldwide (over 90 GW installed), it is the base technology to which other storage technologies should be compared.[3] In addition, there is continuing interest in developing new PHS facilities, potentially using less land-disrupting schemes such as underground or sea-based reservoirs.

In the near term, these three technologies will represent the most likely candidates for utility-scale storage applied to renewable energy systems. This life-cycle assessment will aid in understanding the energy requirements and greenhouse gas (GHG) emissions of these technologies.

1.1 Scope

While a variety of technologies have been utilized for storing energy, PHS, CAES, and BESS are currently the only energy storage technologies suitable for bulk energy storage systems. Energy stored in flywheels, capacitors, and magnetic fields is not included in the scope of this study because these technologies are not yet suitable for utility-scale electrical storage. Currently available hydrogen and thermal storage systems are also omitted, due to their low (less than 50%) round-trip conversion efficiencies.[4] These technologies are generally not cost competitive with PHS, CAES and BESS for most large applications. Figure 1 displays currently available energy storage technologies and their power and energy ratings, which demonstrate relative suitability for utility scale energy storage. Pumped hydro and CAES are the most suitable, with several battery technologies also considerable applicable to bulk energy storage. The VRB (Vanadium Redox Battery) and Lead-Acid Batteries are the BESS systems evaluated in this study.

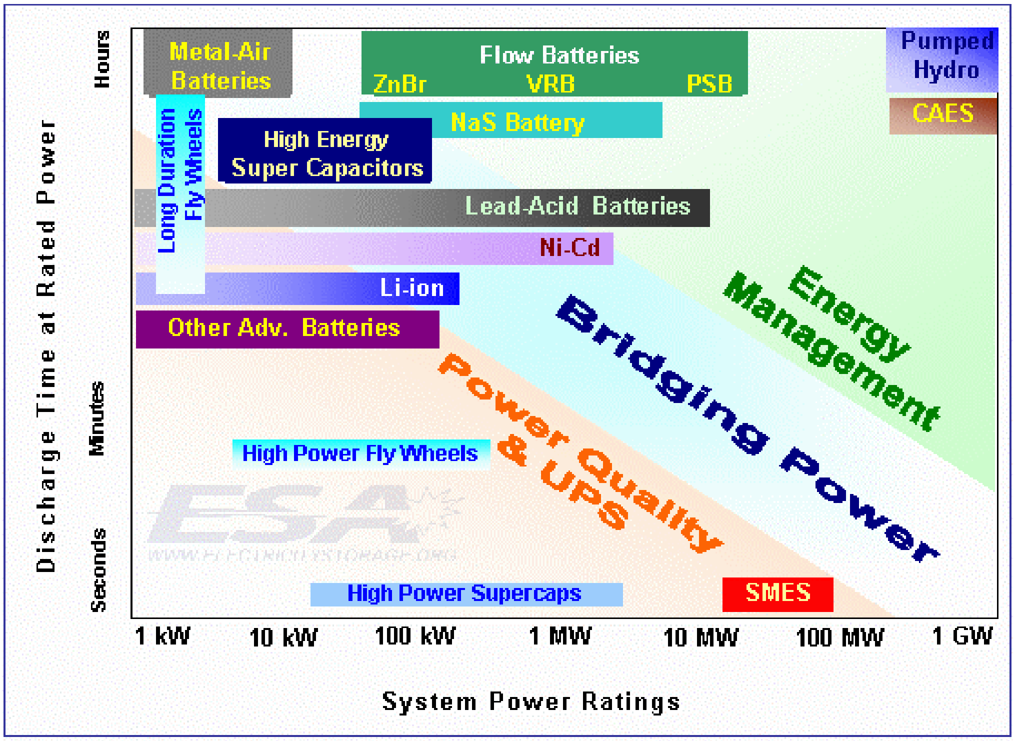

Figure 1: Power and Energy Ratings for Currently Available Energy Storage Technologies
(Courtesy Electricity Storage Association)[5]

2.0 Methods

Assessment Methods

A complete life-cycle assessment (LCA) requires an accurate accounting of all energy and emissions related to the construction, operation, and decommissioning of the storage plant. There are two basic tools used in life cycle assessment, Process Chain Analysis (PCA) and Economic Input/Output (EIO).[6] PCA uses material inventories and process flows to evaluate energy usage at each stage of product manufacture and use. PCA applied to a dam, for example, would obtain the total volume of a material, such as concrete, and estimate the total energy required to manufacture, transport, and pour the concrete. PCA requires a complete inventory of material and energy balances for each component of the system, as well as final manufacturing and installation. Complete material inventories are often not available, and manufacturing data for complete systems is often difficult to estimate. In evaluating a dam, for example, while it may be relatively easy to estimate the amount of steel in a water-turbine, it is more difficult to estimate the amount of energy required to make the turbine from the steel. In many products, such as batteries and electrical equipment the manufacturing energy exceeds the energy required to obtain raw materials. Manufacturing may require hundreds of integration steps, some of which may be proprietary and difficult to estimate. EIO methods avoid such difficulties by using estimates of the relationship between energy and the monetary value of materials and processes. A number of databases have been established that estimate the amount of energy required to manufacture classes of products or to provide categories of services.[7] In general, PCA assessments are more difficult, but often more accurate than EIO assessments. A hybrid-LCA approach is often used, where the majority of the assessment uses PCA, with EIO used where PCA would be too difficult, or complete information is not available. This study uses PCA for most material assessment, with EIO used to derive factors for certain system O&M, certain manufacturing steps, and other less material-intense activities.

System Boundary

The system boundary for this assessment includes the emissions related to resource extraction and construction of the energy storage facility and associated electrical transmission equipment, as well as operation and maintenance (O&M) and decommissioning. The elements of the "fuel cycle" for a storage system are shown in the dotted box in Figure 2. An assessment of a dispatchable renewable energy system would also include the entire fuel cycle of the generation source.

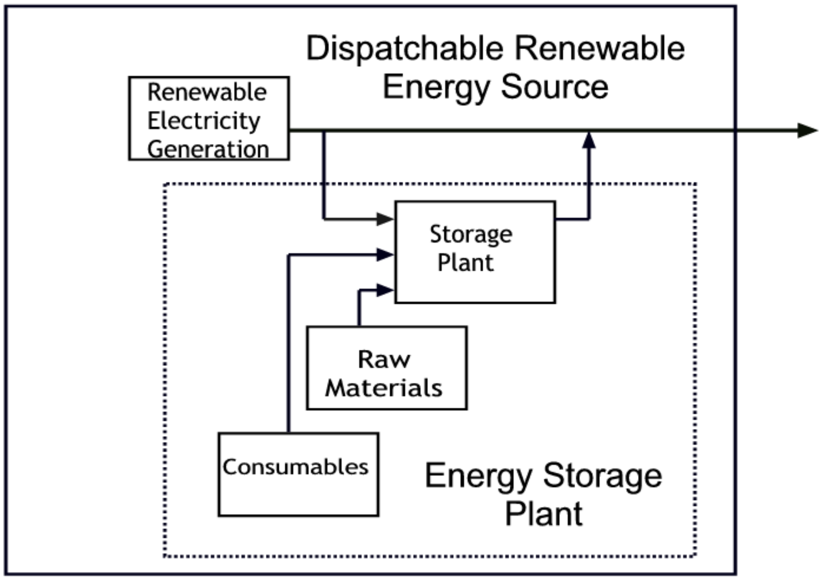

Figure 2: System Boundaries for an Energy Storage System and a Dispatchable Renewable Energy Source

System Analysis

A direct measure of energy balance and net emissions from energy storage systems in isolation is of limited use. However, an energy storage system can be evaluated in such a way as to assess the effect of adding storage to an electrical generation system. An LCA of energy storage can produce a set of quantifiable parameters, or “adders” which can be integrated into an energy production facility.

Storage System Efficiency

Potentially the single most important parameter of an energy storage system is the “roundtrip efficiency,” which represents the conversion efficiency during the storage and re-generation cycle. Since all storage facilities incur losses, the round trip efficiency is less than 100%. The most common industry term for efficiency is the energy ratio (ER), which is the inverse of system efficiency, defined as:

$$ER = \frac{kWh_{in}}{kWh_{out}} \tag{1}$$

ER is greater than 1 for all energy storage systems except CAES, which is a hybrid storage-generation system described in section 4.

In addition to storage inefficiencies, transmission losses must be considered. Figure 3 shows a highly simplified transmission infrastructure from generation to load. Generation occurs at a voltage typically between 10 and 21 kVAC, which is stepped-up to transmission voltage, typically between 100 and 600 kVAC. Voltage is stepped-down (generally several times) through transmission and distribution substations before final load. The addition of energy storage requires incremental transmission components, including an additional step-down and step-up stage, and the incremental transmission line "path" that electricity must travel from generator to load.

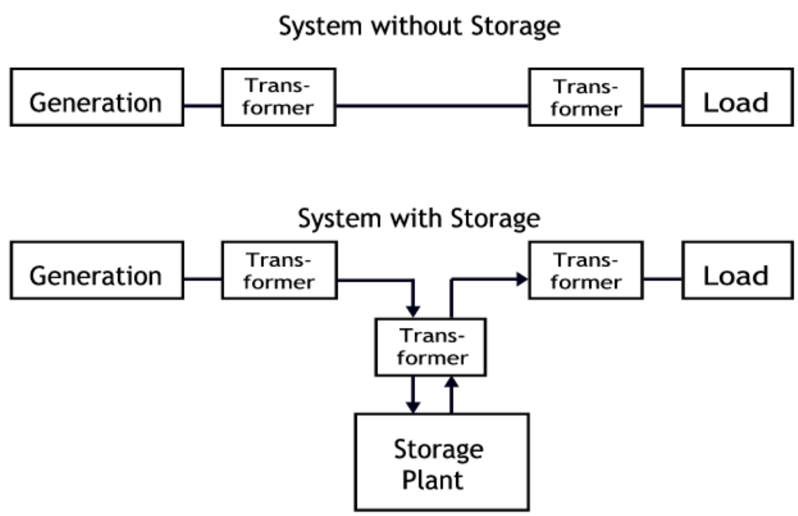

Figure 3: Additional Transmission Components Required by Energy Storage

The total net energy ratio, ER_{net}, considers storage inefficiencies and losses as well as the transmission losses resulting from the use of storage. Figure 4 shows a generalized energy flow diagram showing the sources of losses associated with energy storage.

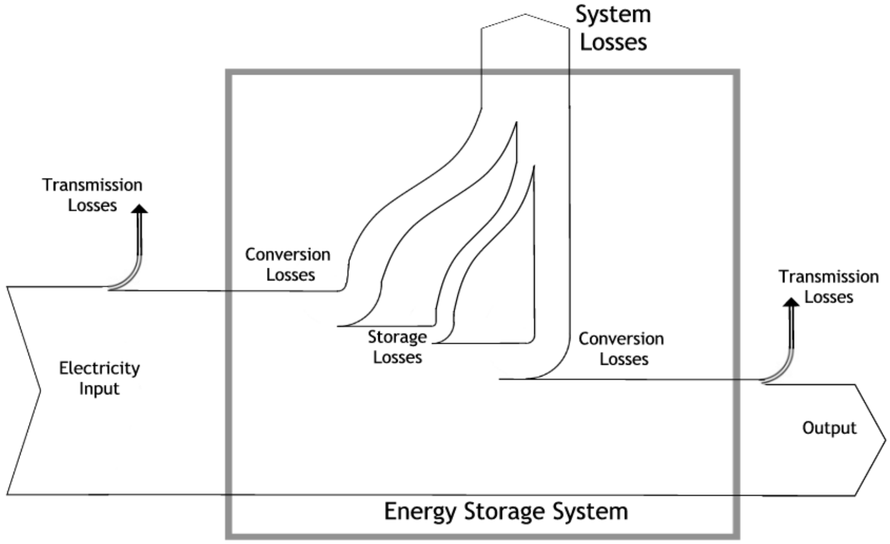

Figure 4: Energy Flow in an Energy Storage System

Total System Generation

The net delivered electricity from a dispatchable renewable system will be the sum of electricity delivered directly and electricity stored, then delivered. The quantity of electricity delivered by the storage facility, E_{stor}, is represented by:

$$E_{stor} = \frac{E_{tot} \bullet f_{stor}}{ER_{net}} \tag{2}$$

and the total electrical energy delivered by the complete system is:

$$E_{del} = E_{tot}(1 - f_{stor}) + E_{stor} \tag{3}$$

where
E_{del} is the total electrical energy delivered by the system
E_{tot} is the total primary electricity generation
f_{stor} is the fraction of primary electricity generation stored

An alternate view is to consider the storage system as an additional load on the complete system, where storage inefficiencies are considered losses. The total energy lost can be expressed as:

$$E_{loss} = E_{tot} \bullet f_{stor}\left(\frac{ER_{net} - 1}{ER_{net}}\right) \tag{4}$$

and the delivered electricity is

$$E_{del} = E_{tot} - E_{loss} \tag{5}$$

Net Energy Balance and Energy Payback Ratio

The net energy balance of a system compares the amount of useful energy derived (output) to the system energy inputs. This balance can also be expressed as the energy payback ratio (EPR) given by:

$$\text{Energy Payback Ratio} = \frac{\text{Electrical Energy Out}}{\sum \text{Energy Inputs}} \tag{6}$$

The energy inputs considered in the EPR must be measured consistently for this definition to be valuable. The energy input component of the EPR can be calculated in terms of electrical or thermal energy. Using thermal energy input is a more meaningful measure, as it requires less estimation of thermal-electrical conversion. Since less than 4% of primary energy generation in the U.S. is in the form of electrical energy (hydro, solar and wind), using thermal energy more realistically assesses the true nature of energy inputs.[8]

The addition of energy storage changes the EPR of a system by decreasing the net energy produced due to conversion and storage losses, and increasing the energy input requirements due to the construction of the energy storage system.

The effective decrease in EPR for energy systems that use storage is determined by four factors: the energy storage conversion efficiency (including transmission losses), the percentage of energy generated that requires storage, additional external energy requirements per unit energy stored, and the energy embodied in the energy storage system.

The EPR of the dispatchable renewable system can be expressed as

$$EPR = \frac{E_{del}^{L}}{E_{gen}^{L} + (EE_{stor} \bullet E_{cap}) + (EE_{op} \bullet E_{stor}^{L})} \qquad (7)$$

where

E_{del}^{L} is the total electrical energy delivered over the lifetime of the system
E_{gen}^{L} is the total lifetime thermal energy required by the primary electricity generation
EE_{stor} is the "embodied thermal energy" in the energy storage system per unit electrical energy stored
E_{cap} is the size of the energy storage facility
EE_{op} is the operations-related thermal energy required per unit of electrical energy stored
E_{stor}^{L} is the total electrical energy stored over the life of the system

While efficiency and energy parameters can be defined independently for any energy storage technology, the size of the storage system, and the amount of electricity stored, is based on the requirements of the generation system. As a result, the net energy increase resulting from the use of storage cannot be presented as a single number, but a set of data that must be integrated into the evaluation of a complete system.

GHG Emission Evaluation

An energy storage system increases net GHG emissions over a non-storage system due to system inefficiencies, "embodied" emissions associated with plant construction, and operation and maintenance. As with changes in EPR, the increase in carbon emissions resulting from the use of energy storage is represented by a set of data that must be combined with the system storage requirements to derive a net emissions factor for the complete system.

The net emissions factor for a generation source using energy storage system, EF_{net} is given by:

$$EF_{net} = EF_{gen} + EF_{stor} \cdot f_{stor} \qquad (8)$$

where EF_{gen} is the emissions factor from primary electricity generation and EF_{stor} is an emissions adder due to storage, given by:

$$EF_{stor} = EF_{gen}\left(\frac{ER_{net} - 1}{ER_{net}}\right) + EF_{op} + \left(\frac{EM_{stor}}{E_{stor}^{L}}\right) \tag{9}$$

where
EF_{op} is the emissions factor for plant operations, including plant non-electricity consumables
EM_{stor} is the emissions associated with plant construction
E_{stor}^{L} is the total electricity delivered by the storage facility over its lifetime.

Metrics of Energy Storage

From equations 1-9 we can summarize the values that must be determined to calculate the net energy requirements and emissions for any energy storage system as:

ER_{net}: a multiplier that increases the primary electrical energy requirements and emissions per unit of energy stored (GWh_e/GWh_e)

EE_{stor}: the "embodied" energy associated with storage plant construction per unit of storage required (GJ_t/MWh_e)

$EE_{op:}$ the operational energy requirement per unit of energy stored and delivered by the storage system (GJ_t/GWh_e)

EM_{stor}: the "embodied" emissions associated with storage plant construction per unit storage required (tonnes CO_2-equiv./MWh_e)

EF_{op}: the operational emissions factor per unit of energy stored and delivered by the storage system (tonnes CO_2-equiv./GWh_e)

Power vs. Energy Storage

Energy and emissions associated with plant materials are used to derive EE_{stor} and EM_{stor}, which represent the total energy or total emissions required for the construction of an energy storage facility divided by the total energy storage capacity. It is important to distinguish the difference between power storage and energy storage to accurately derive storage metrics. Energy storage generally consists of a storage medium, which may be water, air, or an electrolyte, and a power converter, which consists of a water or gas turbine, or a battery stack. Increasing the size of the storage vessel increases the total energy stored, while increasing converter size increases power delivery. As a result, it is possible to change the value of EE_{stor} and EM_{stor} by changing the size of the converter, without changing the total amount of energy that can be stored. As an example, a BESS system may be able to deliver 50kW for 8 hours, or 400 kW for 1 hour, both of which have identical storage capacity (400 kWh) but with different EE_{stor} factors. Storage facilities are designed for local conditions and requirements, which results in substantial differences in the energy/power ratio (MWh/MW) for different applications and different technologies. This ratio can vary from about 1 for power quality BESS systems, to 30 or more for some PHS facilities. However, most bulk energy storage facilities planned or in place are sized by economic constraints to deliver during the entire "typical" 8-hour peaking load, and the energy/power ratio is limited to between 8 and 16. While variations in the energy/power ratio produces some degree of inconsistency, since the energy storage component is a large fraction of the embodied energy in PHS and BESS systems, this effect is reduced. For CAES, the energy requirement for plant construction is relatively small, so the effect of power vs. energy storage has a minimal impact on total energy and emissions of the system.

3.0 Net Energy and Emissions Pumped Hydro Storage

Pumped hydro storage is widely used in the U.S. and worldwide, with U.S. installed capacity exceeding 18 GW at 36 installations.[9] PHS stores energy in the form of mechanical potential energy by pumping water from a lower reservoir to an upper reservoir. The amount of stored energy is the product of the height difference (head) between the upper and lower reservoir and the volume of water stored. During periods of high demand, water is extracted through a turbine in a manner similar to traditional hydroelectric facilities. With relatively fast start-up and ramp rates, PHS is used for ancillary services as well as bulk energy storage. A schematic representative of PHS is shown in Figure 5. In addition to an upper and lower reservoir, a powerhouse must also be constructed, which is often underground.

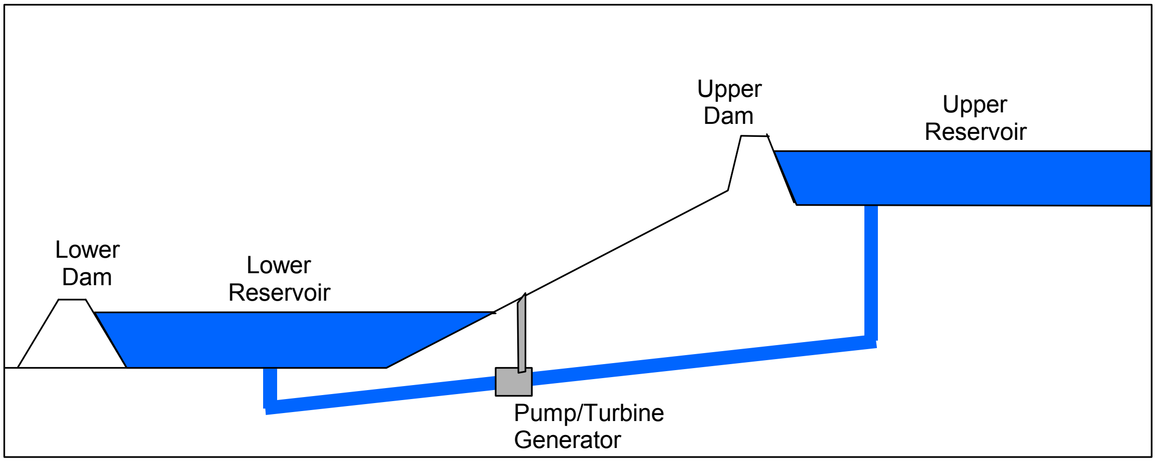

Figure 5. Pumped Hydro Storage

PHS has become the dominant storage technology due to its use of well-understood hydroelectric technology, and inexpensive storage medium (water.) The round-trip conversion efficiency of PHS has a wide range from 70-85%, but most modern plants operate in the 75%-80% range.[4] Conversion efficiency losses occur primarily during the pumping phase and energy extraction phase, but also during mechanical-electric conversion. Evaporative and seepage losses in the upper storage vessel also represent lost pumped energy.

System Model

Several facilities, described in table 1, were assessed to derive "average" values for PHS construction-related parameters, efficiency, and operational parameters such as O&M cost. The facilities chosen are representative of modern PHS facilities, all with completion dates after 1977. Facility sizes range from 200 to 2100 MW, with storage capacities from 209 to 23,000 MWh.[9] While quite a few PHS facilities have been recently constructed internationally, only U.S. facilities were selected due to greater availability of construction and operation data. Only dedicated pumped-storage facilities were considered. Some hydroelectric facilities combine conventional generators with additional storage pump-turbines. An appropriate assessment of these projects would require allocating energy and emissions between the generation and storage components, as well as other tradition multipurpose hydro uses such as irrigation and flood control.

Table 1: Modern U.S. Dedicated PHS Facilities Evaluated in this Study				
Facility	Location	Completion Date	Capacity (MW)	Storage (MWh)
Bad Creek	Salem, SC	1991	1000	24,000
Balsam Meadow	Shaver Lake, CA	1987	200	1,600
Bath County	Warm Springs, VA	1985	2,100	23,100
Clarence Cannon	Center, MO	1984	31	279
Fairfield	Jenkinsville, SC	1978	512	4,096
Helms	Shaver Lake, CA	1984	1,206	184,000
Mt. Elbert	Leadville, CO	1981	200	2,400
Raccoon Mtn.	Chattanooga, TN	1978	1,530	32,130
Rocky Mtn.	Armuchee, GA	1995	760	6,080

3.1 Plant Construction and Decommissioning

3.1.1 Site Preparation and Reservoir Development

Most pumped hydro projects are large in scale, with sizes often approaching or exceeding 2000 MW and requiring construction or modification of two or more reservoirs and multiple dams. In a few cases the lower reservoir is a river or an existing lake, which reduces the required energy input. Future projects may utilize underground caverns for the lower reservoir.

The major components of energy utilization and emissions associated with construction are:

- earth moving
- drilling and blasting operations
- concrete manufacturing and transport
- installation of rock fill, earth, and concrete dams
- construction, transport, and installation of pump-turbines, motor-generator sets and other electrical equipment.

Standard PCA and EIO data was utilized to calculate energy and emissions for each project based on:

- Amount of material moved to create reservoirs
- Total volume and composition of reservoir dams

- Total volume of rock displaced for shafts, tunnels and powerhouses
- Volume of installed tunnel and reservoir liners

There is considerable variation in PHS projects based on diverse local topography and geological variations. Large variations in construction energy can result from using earth fill versus concrete dams, and the use of existing lower reservoirs also reduces project energy intensity.

3.1.2 Capital Equipment

Most of the capital equipment associated with PHS is the electrical system, including electrical pumps and generators, as well as transformers, switchgear, and transmission systems. The life-cycle energy and emissions related to the additional transmission system components between generation and storage must also be considered.

3.1.3 Reservoir Carbon Emissions

A source of GHG emissions unique to hydro projects is related to the creation of the reservoir, which results in the decay of biomass under the flooded area. Most land flooded by hydro projects is carbon neutral (farming or seasonal plant growth) or a carbon sink (growing forest.) Most plant material flooded by the reservoir dies and decays aerobically, producing carbon dioxide, or anaerobically, producing both CO_2 and methane. The amount of carbon generated is dependant on reservoir size, previous vegetation, and climate. Assessments of most conventional power sources ignore carbon emissions resulting from biomass clearing due to the very small area used by these sources per unit energy produced. The area occupied by hydropower reservoirs is significant enough to have GHG consequences. There are also dynamic effects due to river flow, which largely do not apply to pumped hydro facilities.[10] The science of reservoir GHG emissions is relatively recent and includes many uncertainties.[11] PHS development generally involves clearing and tree removal in a large percentage of the reservoir area, so this assessment assumes carbon emissions will result from the aerobic decay of biomass based on reservoir size. Some of the energy and emissions associated with tree clearing is allocated to other uses, such as tree removal for raw materials and energy production. The GHG emissions associated with reservoir creation are a significant, but "reversible" source, since the reservoirs can be drained and replanted.

3.1.4 Decommissioning

Decommissioning a pumped hydro storage facility is primarily a function of concrete and earth removal. It is difficult to determine any additional requirements exclusive to PHS, as there has never been a PHS facility decommissioned in the U.S. However, it is likely that a true decommissioning would require extensive land remediation, involving the reshaping of the land contours and replanting. PHS decommissioning and the associated restoration may partially negate the net carbon emissions that resulted from the original flooding.

Table 2 shows the results of the energy and emissions assessment for the construction and decommissioning of a typical PHS project. The table shows the energy requirement and associated emissions per unit of installed storage capacity.

Table 2: Life Cycle Energy Inputs and GHG Emissions Related to PHS Plant Construction

	Life-Cycle Energy GJ_t/MWh_e storage capacity	GHC Emissions tonnes CO_2 equiv./MWh_e storage capacity
Dam Construction	37.0 (25%)	3.35 (21%)
Tunneling/Underground	38.1 (25%)	4.52 (29%)
Electrical Equipment	56.5 (38%)	4.31 (27%)
Reservoir Creation	0.1 (0%)	2.2 (14%)
Decommissioning	17.9 (12%)	1.3 (8%)
Total	**149.6**	**15.7**

Effect of project lifetime

Hydropower projects generally have much longer lives than traditional sources. Lifetimes for thermal, nuclear, and renewable sources are typically 20-40 years. The expected lifetime of most dams is well in excess of 40 years, and some dam analyses use a lifetime of 100 years. As a result, the embodied energy and emissions related to PHS construction should be divided over a longer life, resulting in lower impacts. In addition, energy and emissions related to decommissioning can potentially be discounted due to their impacts at a future date.

3.2 Operation

3.2.1 Delivered Electricity and Energy Ratio

Incremental transmission losses due to energy storage will result from one extra step-up and step-down transformer cycle, as well as line losses. Line losses are a function of incremental distance increases resulting from PHS operation, and may vary substantially. The ideal locations for PHS are typically in mountainous regions, which are often well away from population centers. A generally accepted loss factor for life-cycle assessments in the U.S. is approximately 7%.[12] This number, however, includes low voltage (10kV and below) distribution-related losses. PHS does not have distribution losses; electricity is typically transformed from the high transmission voltage to the pump and generator operating voltage, typically 19-21 kV. A 5% transmission loss factor is applied to electricity stored by PHS for this assessment, which is used as an estimate for the transmission losses for long distant transport of hydroelectricity.[13]

The large variability in round trip efficiencies between projects is the largest uncertainty in energy requirements and emissions resulting from PHS operations. The minimum efficiency for PHS plants installed after 1975 is 70%, and the maximum efficiency of any U.S. facility is 83%. The average ER for modern U.S. PHS facilities is derived by weighing the overall plant efficiency by total generation. The weighted average for plants in this assessment is 78%.

The net energy ratio is given by

$$ER_{net} = ER \cdot L_T \cdot L_S \tag{10}$$

where

L_T is the Transmission Loss Factor
L_S is the Storage Loss Factor, due to evaporation and seepage

The average roundtrip efficiency data includes losses from evaporation or seepage, as well as gains due to rainfall, since it is based on actual measurements provided by the operating utility. The net efficiency of an average PHS system is calculated at 74%, or a net energy ratio of 1.35.

3.2.2 Operation and Maintenance Requirements

There are no major consumables associated with PHS operation, so additional energy requirements are derived primarily from system maintenance and repair. Energy and emissions data is derived using EIO data, and publicly available O&M data from 24 U.S. PHS facilities and other reviews of hydro facility operational costs.[14,15] Reported data for O&M at U.S. pumped hydroelectric facilities is typically between 0.4 and 0.7 cents/kWh.[16] While O&M costs are not directly proportional to net facility output, it is assumed that these factors roughly correspond and can be attributed to facility generation.[17] Average O&M costs of 0.54 cents/kWh, result in an EE_{op} of 25.8 GJ_t/GWh_e and an EF_{op} of 1.8 tonnes CO_2 equiv./GWh.

3.3 Results

Table 3 shows the results of the of the PHS life-cycle analysis.

Table 3: Energy and Emissions Parameters for Pumped Hydro Storage		
	Life-Cycle Energy	GHC Emissions
Fixed Components		
Construction E_{stor}, EM_{stor}	149.6 GJ_t/MWh_e stored	15.7 tonnes CO_2 equiv./ MWh_e stored
Variable Components		
O&M EE_{op}, EF_{op}	25.8 GJ_t/GWh_e	1.8 tonnes CO_2 equiv./GWh_e
ER_{net}	1.35 times primary energy	1.35 times source emissions

By applying typical PHS capacity factors and lifetimes, the average energy requirements and emissions factors per unit of electricity delivered by PHS can be calculated. Using a capacity factor (CF) of 20%, and a lifetime of 60 years, construction and operation-related energy requirements are 37.2 GJ_t/GWh_e and emissions are 3.0 tonnes CO_2 equiv./GWh_e. A substantially decreased capacity factor and lifetime would likely increase these rates to no more than 80 GJ_t/GWh_e energy requirements and emissions of 6.0 tonnes CO_2 equiv./GWh_e. The greenhouse gas emission rate is small compared to most generation sources, and the energy requirement is also small compared to the energy requirement due to storage inefficiencies. Each GWh_e delivered by a PHS facility will require an electrical input of approximately 1.35 GWh_e (determined by ER_{net}), or 4860 GJ_e, which represents an additional energy requirement (losses) of 1260 GJ_e. If stored electricity is derived from thermal sources such as coal or gas, resulting storage losses are between 2520 and 3938 GJ_t/GWh_e.

4.0 Net Energy and Emissions from CAES Systems

Despite being a technological success with good economic potential, there has been little development of compressed air storage, with only two facilities worldwide. The only U.S. facility, completed in 1991, is the 110 MW, 26 hour Alabama Electric Cooperative (AEC) facility in McIntosh, Alabama. The AEC facility was funded in part by the Electric Power Research Institute (EPRI) to demonstrate commercial viability.[18]

In 1999, CAES Development Company (CDC) announced plans to build a 2700 MW facility in Norton, Ohio using an abandoned limestone mine as the storage vessel. Another company, Ridge Energy Storage, has announced plans to develop CAES using salt domes in the southern U.S. These plants may demonstrate the first large-scale profitable alternative to pumped hydro storage and may increase the use of CAES technology worldwide.

These facilities are not necessarily unique. Potential CAES sites have been identified in many areas of the U.S. (including the West and Midwest) and internationally.[1,4] If privately developed and operated CAES is successful, it may hasten the development of these sites. Given the limitations of other technologies, CAES is a likely source for storage in utility-scale renewable projects.[1] A pumped hydro facility utilizing the Norton, Ohio limestone mine was proposed, but later cancelled, perhaps demonstrating favorable economics for CAES facilities when an underground air-tight cavern is available.[19]

Description of System

CAES systems are based on conventional gas turbine technology. A single-cycle gas turbine generator combines compressed air with natural gas in a combustion chamber. Combustion produces high-pressure gas, which is then expanded through a turbine, which drives both a generator and the input air compressor. A schematic diagram of a gas turbine and CAES system is provided in figure 6. The principle of CAES is the utilization of the elastic potential energy of compressed air. During periods of low demand, or renewable "over-production," compressors pump air into an airtight underground storage cavern. During times of increased demand, the air is drawn from the storage vessel, heated, and then extracted through a high-pressure (HP) expander, which captures some of the energy in the compressed air. The air is then mixed with fuel and combusted in a low-pressure (LP) gas turbine expander. Both the high- and low-pressure expanders are connected to an electrical generator. Turbine exhaust heat is then captured in the recuperator to pre-heat cavern air (supplemented by gas burners.)

Unlike pumped hydro or storage batteries, CAES is not a pure storage system, because it requires combustion in the gas turbine. In this sense CAES can be considered a hybrid generation/storage system. The storage benefit of pre-compressed air is the elimination of the turbine compressor stage. The compression stage of a conventional gas turbine uses approximately 60% of the mechanical energy produced by the combustion turbine. Utilizing pre-compressed air, the CAES system effectively bypasses the input compressor, resulting in nearly all of the turbine mechanical energy being utilized in the electrical generator. CAES effectively "stores" the mechanical energy that would be required to turn the turbine compressor. Turbines using compressed air can deliver nearly three times the amount of power from a given turbine frame, reducing turbine capital costs. The effect of CAES is the creation of a gas turbine with a heat rate of approximately 4500kJ/kWh (4265 BTU/kWh), versus 10,000kJ/kWh (9500 BTU/kWh) for a simple combustion turbine (CT) or 7000kJ/kWh (6600 BTU/kWh) for a combined cycle unit. Of course, these gains are largely offset by the inefficiencies of the energy storage process; primarily the waste heat generated in the pumping stage.

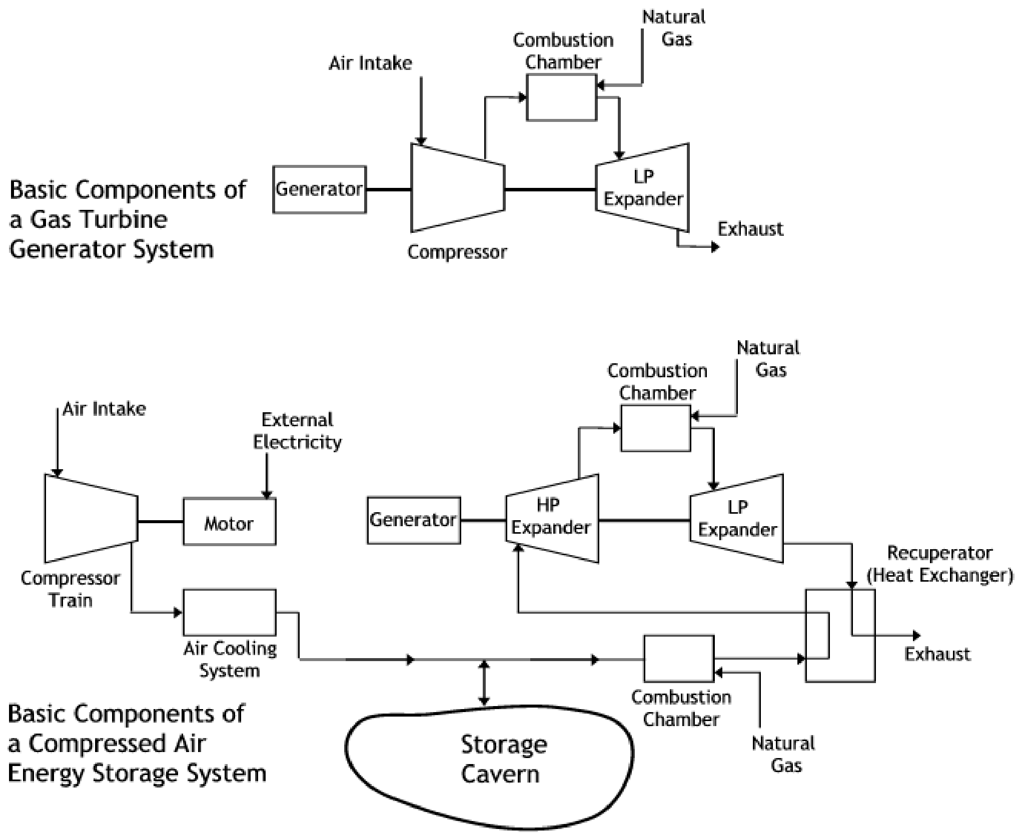

Figure 6: Schematic Diagrams of Gas Turbine Generation and Compressed Air Energy Storage

The AEC's demonstration system uses a common shaft turbo machinery train, with both compressors and turbine expanders connected to a common motor-generator set via clutches.[20] The next generation of CAES designs use dedicated motor-compressor and generator which allows for optimally sized and more efficient equipment, as well as faster transition from compression to generation (or even simultaneous operation) which is important for wind-energy systems that experience rapid changes in energy output.

While based on gas-turbine technology, and requiring natural gas fuel, CAES technology provides several advantages over gas turbines as a load-following source, enabling intermittent renewables to be competitive in the peaking power market. These include:

- Very fast ramp rates, greater than traditional peaking gas turbines due to the lack of compressor inertia.[2] Fast ramp rates allow for load following, as well as potentially fast response to intermittent renewables.
- Nearly constant heat rate at variable load and ambient conditions due to the constant fuel/air ratio made possible by a regulated input airflow. CAES also avoids the decreased efficiencies experiences by gas turbines when compressing hot ambient air during daytime peaking conditions.
- Capital costs and system complexities approaching those of single stage CT's, due to lack of steam cycle.

CAES System Model

The model for the evaluated system is the proposed Norton, Ohio facility, which was approved by the Ohio Power Siting Board in early 2002. This facility would be the largest CAES system in the world, with peak output of 2700 MW, and a total energy storage capacity of 43.2 GWh. The storage cavern is an abandoned limestone mine with a volume of 9.6 million cubic meters.

4.1 Plant Construction and Decommissioning

4.1.1 Site Preparation and Mine Development

Site preparation generally includes land clearing and leveling, as well as pad installation, pipe trenching, and mine development. The Norton facility requires additional work for the mine to be available as a storage vessel, including drilling storage compression shafts and sealing two mine entrances. Since the Norton facility is unique in that an existing storage reservoir exists, this assessment considers a salt-solution mined cavern, which is the likely vessel for many future CAES projects.

4.1.2 Capital Equipment

Compressors

The compression system uses a total of 18 compressor trains, each train comprising of low- and high-pressure compressors, and associated controls. Cooling of both the compressor units and the compressed air is required, and can be met utilizing water-cooling, air-cooling or a combination of both. The Norton system will utilize mechanical draft wet cooling towers for its cooling needs, which will reduce electrical demands and decrease the primary energy ratio.

Turbine Expander/Generator

The Norton facility will use Alstom ET11-NW combustion turbine expanders, which are essentially gas turbines without the compressor stage, but with an additional high-pressure (HP) expander stage.[21] Air entering the HP expander must be preheated, using exhaust heat recuperators, as well as a gas combustor, which slightly increases the net heat rate. Each turbine stage is connected to a 300MW AC generator

Controls and Electrical Transmission

Other system components are comparable to a standard gas plant of similar size. With the exception of some controls for the compressor motor starters and air-pressure monitoring equipment, the facility has no other unusual or energy-intensive capital equipment.[22] Additional transmission capacity required by the CAES systems includes high-voltage lines and transformers.

Natural Gas Pipeline

The use of natural gas requires an increase in gas delivery production and delivery infrastructure, primarily pipeline and pumping stations. The derivation of energy and emissions associated with natural gas infrastructure is included in section 4.2.3.

4.1.3 Decommissioning and Reclamation

A relatively small amount of energy is required for plant decommissioning and land reclamation. Unlike a traditional industrial facility, the nature of the storage cavern makes this plant unique. It can be assumed that as long as CAES is an economically viable technology, the plant would be maintained with new equipment and upgrades as required. For the purpose of a complete LCA, a 20-year plant life should be expected. After this time, all capital equipment will be scrapped or recycled.

Table 4 shows the results of the energy and emissions assessment for the construction and decommissioning of a typical CAES project using a salt dome for air storage. The table shows the energy requirement and associated emissions per unit of installed storage capacity.

Table 4: Life Cycle Energy Inputs and GHG Emissions Related to Plant Construction of CAES Systems		
	Life-Cycle Energy GJ/MWh_e storage capacity	Equivalent GHG Emissions tonnes CO_2 equiv./MWh_e storage capacity
Cavern Development	16.2	1.2
Site & Buildings	36.7	3.0
Plant Electrical	65.9	4.7
Total Plant	102.6	7.8
Electrical T&D	14.2	1.0
Gas Infrastructure	130.5	9.2
Decommissioning	2.3	0.2
Total	**235.5**	**17.2**

4.2 Operation

4.2.1 Delivered Electricity and Energy Ratio

CAES uses electricity primarily to operate the air compressors, with some additional electricity required to operate cooling systems and other system components. The total electricity use is represented in the plant energy ratio.

CAES systems have an energy ratio of less than 1, which indicates that they produce more electricity than they consume, due to the additional electricity produced using natural gas. Previously installed CAES systems have energy ratios between 0.75 and 0.85.[23] Projected energy ratios for new CAES installations are between 0.62 and 0.75.[24,25] This increased efficiency is due to the use of dedicated compressor motors and generators, and improved cooling and heat recovery systems.

The net energy ratio is given by

$$ER_{net} = ER * L_T * L_S \tag{11}$$

where

ER is the CAES energy ratio
L_T is the Transmission Loss Factor
L_S is the Storage Loss Factor

Transmission losses associated with CAES are expected to be similar to PHS, driven by site requirements. Transmission-related losses occur on both the input side and the generation side, and require an increase in both electricity and primary fuel. The effects of a 2.5% transmission loss rate on the input and output sides of the CAES system are shown in figure 7.

Cavern air leakage will result in some losses of stored energy. The hard rock mine at the Norton facility is highly impermeable, and geologic evaluations indicate negligible daily leakage rates.[26] Long-term effects, such as decreased cavern capacity due to water inflows, are expected to be negligible. No substantially energy-intensive maintenance on the cavern is expected over the life of the project.[27] Salt caverns are similarly impermeable, with daily leak rates of less than 10^{-5}.[4]

Using a system ER of 0.7, an L_T of 1.05, and an L_S of 1, the net energy ratio for CAES is 0.735.

4.2.2 Natural Gas Delivery

Energy requirements and emissions related to the use of natural gas require a full life-cycle assessment of natural gas production and transportation. Increased use of natural gas in single-cycle and combined cycle plants, as well as concern about electricity-related GHG emissions, has resulted in a number of studies of gas fuel cycles.[28 29]

Energy and emissions associated with natural gas delivery are a function of two quantities: a capacity (power) factor and a delivery (energy) factor. The capacity factor establishes the amount of delivery infrastructure required by the facility, while the delivery factor accounts for exploration, production, and transmission (including leakage.) For typical natural gas use, the delivery factor dominates, accounting for over 90% of energy requirements and GHG emissions. Energy requirements for gas infrastructure development are 1657 GJ_t/MW_{gas} gas capacity, and corresponding emissions of 117 tonnes CO_2 equiv./MW_{gas} capacity.[30] Reported energy requirements for natural gas delivery are 0.11 GJ_t per GJ of gas delivered, with a corresponding emissions rate of 11.1 kg CO_2- equiv./GJ gas delivered. Operation of the CAES facility requires 4542 kJ/kWh delivered, and has a system capacity of 3402 MW_{gas}. Energy and emissions associated with gas infrastructure and delivery are provided in tables 4 and 5.

4.2.3 Expansion/Generation

The expansion stage involves the injection of compressed air and natural gas fuel through the gas turbine. After heated air is extracted through a high-pressure expander, it enters the low-pressure expander, where it is mixed with fuel and combusted in the same manner as a traditional gas turbine. The heat rate of the combustion stage is 4536 kJ/kWh. The largest component of direct plant emissions will result from the combustion process. Using a standard emission factor of 0.503 g CO_2/kJ gas consumed, the CAES facility produces 228.3 tonnes CO_2 equiv./GWh_e from the combustion of natural gas.[31]

4.2.4 Emissions Controls

Nitrogen oxides (NO_x) are the primary regulated emission from the combustion of natural gas. Selective Catalytic Reduction (SCR) is commonly used in gas turbine power plants to reduce NO_x emissions. SCR utilizes a catalyzed reaction between NO_x and ammonia (NH_3), which is injected into the exhaust gas stream. In the presence of a catalyst, generally vanadium, platinum, or titanium, NO_x, NH_3, and O_2 react to form nitrogen gas and water vapor. Spent catalyst material represents the only solid waste from the natural gas fuel cycle. Energy inputs related to emissions controls are the production, transportation, and storage of ammonia, as well as the operations of the SCR equipment.

Life-cycle energy requirements and emissions from SCR have been evaluated by Spath and Mann to be 8.5 GJ/GWh_e and 0.44 tonnes CO_2 equiv./GWh_e based on a 7378 kJ/kWh heat rate, and a NO_x emission rate of 9.4 ppm.[29] Adjusting to the CAES system fuel use and emission rates, the energy requirements for SCR are 4.6 GJ/GWh_e, with equivalent GHG emissions of 0.24 tonnes CO_2 equiv./GWh_e.

4.2.5 Operation and Maintenance

Operation and maintenance includes all daily operations of the plant that have not been accounted for in construction or fuel usage. This includes repair and replacement of major mechanical and electrical components, as well as energy associated with cooling water acquisition and treatment. Energy and emissions data was calculated using EIO data for factory plant maintenance and administration. The expected annual O&M costs for the Norton facility are \$20 - \$30 million.[30] Using expected utilization factors and EIO data, this corresponds to an energy use of 11.98 to 30.8 GJ/GWh$_e$, and an emission rate of 0.8477 to 2.18 tonnes CO_2 equiv./GWh$_e$.

4.2.6 Net "Efficiency" of the CAES system

Calculating the overall efficiency of the CAES system is complicated by the use of supplemental fuel. The simplest method is to calculate the net thermal efficiency of the system:

$$\eta_{\text{thermal}} = \frac{E_{\text{out}}}{E_{\text{gas}} + E_{\text{in}}} \tag{12}$$

where
E_{out} = Electrical energy out
E_{gas} = Thermal energy content of input natural gas
E_{in} = Electrical energy in

While the $\eta_{thermal}$ of the CAES system is only slightly greater than 50%, this evaluation ignores the substantial difference in quality between electrical energy and thermal energy. A more realistic evaluation is to calculate the net electrical efficiency of CAES storage by assigning an electrical energy value to natural gas based on the application. The typical alternative to storage for peaking or renewable backup is the single-cycle gas turbine. The heat rate for a modern peaking turbine is 9743 kJ/kWh (at full load and ISO ambient conditions).[32] Each kWh produced by CAES requires 4649 kJ of natural gas, which if used in a peaking turbine produces 0.48 kWh. Using this value it is possible to calculate the net electrical efficiency of the system:

$$\eta_{\text{electric}} = \frac{E_{\text{out}}}{(E_{\text{gas}} \bullet \eta_{\text{gas}}) + ER_{\text{net}}} = 0.83 \tag{13}$$

If the goal is to calculate the efficiency of the electrical storage process, or to compare CAES directly to other storage-only technologies, the amount of energy "generated" by the natural gas can be subtracted to isolate the storage efficiency of CAES:

$$\eta_{\text{storage}} = \frac{E_{\text{out}} - (E_{\text{gas}} \bullet \eta_{\text{gas}})}{ER_{\text{net}}} = 0.74 \tag{14}$$

Calculated in this manner, the electrical storage efficiency of peaking CAES is 74%, which is roughly equal to the other storage technologies considered. There are a number of limitations to this approach, but it provides some idea of the approximate efficiency associated with compressing and expanding air as a means of energy storage. (The electrical value of natural gas varies widely depending on application. While modern combined cycle gas turbines may have heat rates below 7000 kJ/kWh, such plants are uneconomical for peaking or intermittent backup. In addition, partial load and higher ambient temperatures common in mid-day peaking conditions considerably reduce the efficiency of all gas turbines, compared to CAES turbines which have nearly constant efficiencies under most conditions.)

Figure 7 provides a detailed flow of the requirements for 1 kWh of electrical energy delivered by CAES storage. As can be seen, a majority of the energy requirements are from natural gas. There are considerable thermal losses in the CAES storage process. A breakdown of these losses are provided by Zaugg and Stys.[33]

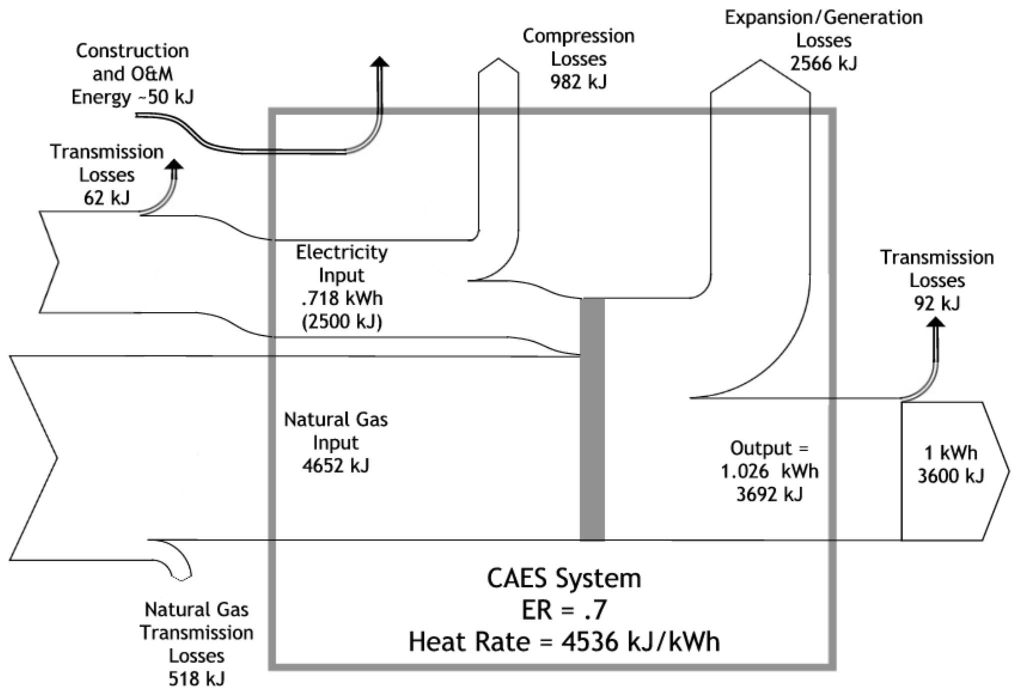

Figure 7: Energy Flow in Compressed Air Energy Storage

4.3 Results

Table 5 shows the results of the of the CAES life-cycle analysis.

Table 5: Energy and Emissions Parameters for Compressed Air Energy Storage		
	Life-Cycle Energy	GHC Emissions (CO_2 equiv.)
Fixed Components		
Construction E_{stor}, EM_{stor}	266 GJ_t/MWh_e stored	19 tonnes/MWh_e stored
Variable Components		
Fuel	4536 GJ_t/GWh_e	228 tonnes/GWh_e
Fuel Delivery	518 GJ_t/GWh_e	51 tonnes/GWh_e
O&M	29 GJ_t/GWh_e	2 tonnes/GWh_e
ER_{net}	0.735 times primary energy	0.735 times source emissions

Average emissions and energy requirements can be estimated using a capacity factor of 25% and equipment life of 40 years. The generation of a GWh of electricity from CAES requires 0.735 GWh of electricity, and 5246 GJ of thermal energy, of which only 49 GJ are related to construction and O&M, with the remainder natural gas fuel and fuel delivery. While the energy input requirements of natural gas exceeds the electricity requirements, it is possible to examine the energy distribution recognizing the greater "value" (exergy) of electrical energy compared to thermal energy. Figure 8 shows the distribution of energy requirements considering the value of $1GJ_e = 2.5GJ_t$.

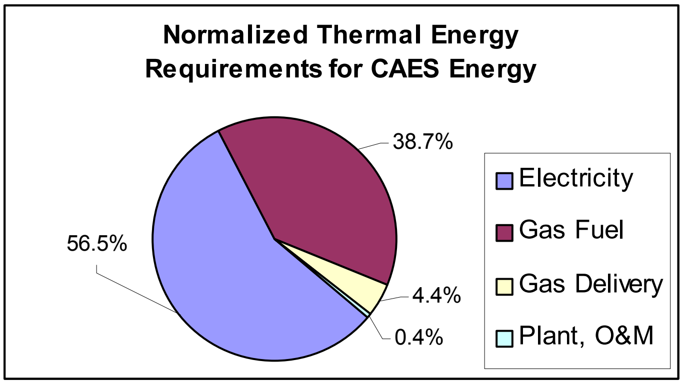

Figure 8. Distribution of CAES Energy Requirements by Source

Total GHG emissions are 291 tonnes CO_2 equiv./GWh_e plus emissions associated with primary generation. These emissions mostly result from the combustion of natural gas, with the remainder largely due to natural gas transportation and infrastructure.

5.0 Net Energy and Emissions Battery Energy Storage Systems (BESS)

Utility battery storage is rare due to a variety of factors. Until recently, the only battery technology that was economically feasible was lead-acid batteries. These batteries are only marginally economic compared to non-storage alternatives such as diesel generators, and have substantial space and maintenance requirements. Lead-acid batteries also suffer from a limited life, which decreases rapidly if the battery is discharged below 30%.[34] This effectively reduces the energy density, and increases capital costs. Lead-acid batteries are commonly installed in uninterruptible power supply (UPS) systems as well as off-grid applications such as renewable and fossil-based distributed power systems. There are a few utility-scale lead-acid BESS systems in place. Two examples are the 20MW, 14MWh system in Puerto-Rico and the 10MW, 40 MWh system in Chino, California.[35] These systems are designed primarily to solve local power quality issues and as opposed to bulk energy storage as demonstrated by their low energy/power ratio. Lead-acid battery technology will likely be limited to small scale and niche applications. It is a relatively static technology with limited possibility of substantially increased energy density, or decreased costs. The use of toxic lead is also a limiting factor. Resources for stationary batteries must also compete with automotive and other traction battery applications, where lead-acid batteries are expected to dominate for many years to come. While development of traditional electrolyte materials such lead-acid and Nickel-Cadmium continues, these technologies have fundamental limitations including toxicity of materials, limited life, relatively inflexible designs, high maintenance, and depth-of discharge (DOD) limitations.

While lead-acid will likely be the choice for small renewable-storage systems for the near future, it appears that several new battery technologies are on the verge of surpassing the basic economic and technical performance of lead-acid batteries for large stationary applications. As a result, it is likely that future utility scale battery storage will be less likely to utilize lead-acid technology, but an analysis of lead-acid batteries is important for reference as the "base" technology.

Perhaps the most promising battery storage technology for large stationary applications to emerge recently is the flow battery. Flow batteries use liquid electrolytes that are pumped through a "stack" which contains an ion-exchange membrane, or an electrode array. Three electrolyte materials have been developed and commercialized in recent years. These include Vanadium-Acid and Sodium-Bromide/Sodium-Polysulphide (trademarked as Regenesys) and Zinc-Bromine.[36-38] The Vanadium and Regenesys batteries use an ion-exchange membrane similar to fuel cells, and are sometimes referred to as regenerative fuel cells (RFCs). These two technologies are also more modular in scope and more suited for very large storage applications. Figure 9 shows a schematic of the basic RFC-type flow-battery components.

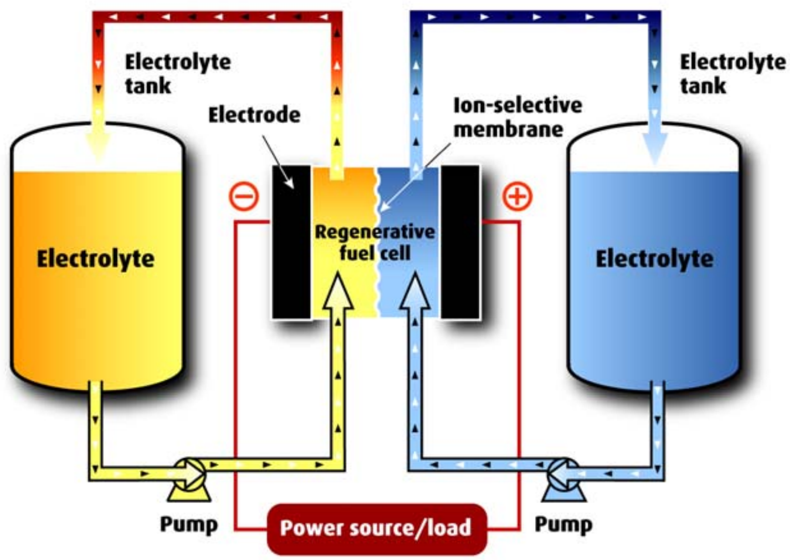

Figure 9: Flow Battery
(Courtesy Regenesys Technologies Ltd.)[39]

Features common to RFC-type flow batteries include:

1) High depth of discharge (~100%)
2) High cycle life (2000+ cycles)
3) Flexibility in both power and energy, by the ability to vary both stack size and electrolyte tank size
4) Reduced maintenance requirements
5) Easier measured state of discharge
6) Non- or low-toxicity components
7) Size and shape flexibility of electrolyte storage
8) Requirement of active components (pumps)
9) Negligible hydrogen production with no venting or ventilation requirements

Table 6 provides a comparison of the basic characteristics of lead-acid and Vanadium batteries

Table 6: Battery Technology Characteristics		
Battery Type	Lead-Acid	Vanadium
Electrolytes	Lead Sulfuric Acid	Vanadium- Pentoxide Sulfuric Acid
Efficiency (AC-AC)	70%	75%
Energy Density (Wh/kg)	37	20
Cost per kWh (system cost)	\$300-\$500	~\$1000
Cycle-Life	2000	>10,000
Operating Temperature (˚C)	-10 to 40	10 to 45

A number of large flow battery systems for utility scale systems are scheduled to enter service in 2003, including a 120MWh Regenesys system near Columbus Mississippi, and a 2 MWh Vanadium battery near Moab, Utah.

This assessment uses the Vanadium battery as the base technology to represent flow batteries due to availability of data on electrolyte and battery production methods. The primary differences between Vanadium and Regenesys batteries from an energy utilization standpoint are:

1) Electrolyte and system energy intensity. The Regenesys system cost is significantly lower than the Vanadium battery. This should correspond to substantially lower energy requirements and emissions associated with battery production. The energy requirements for producing the stack and electrolyte component of a Regenesys system may be as much as 50% less than the Vanadium Battery.
2) Electrical efficiency. The round-trip efficiency for the Regenesys system is substantially lower than the Vanadium system. Estimates of AC-AC conversion efficiency for the Regenesys system is 55%-75%, while the Vanadium efficiency is 70%-85%

Functional Unit Definition

Battery size is determined by both power and energy capacity. Most battery applications require an energy/power ratio of between 4 and 8, which provides near full power coverage for a peaking period from 4-8 hours. This assessment uses a ratio of 8, which is more suitable for the large energy loads required by a renewable source, and more closely approximates the energy/power ratio of PHS and CAES systems.

5.1 Plant Construction and Decommissioning

5.1.1 Site Preparation

A BESS facility is typically much smaller than a PHS or CAES facility, largely because there are fewer geological requirements, economy of scale factors, and because BESS facilities can be placed close to the load. Site buildings are dependent on the type of battery: lead-acid batteries are be housed in an enclosed structure, while flow batteries may use separate external storage tanks, depending on the application. The Power Conditioning System (PCS), which consists of rectifiers and DC-AC inverters, requires cooling under high load conditions. The presence of potentially hazardous liquid electrolytes may restrict siting, and require additional monitoring and containment equipment.[40] Figure 10 shows the basic features of a large 15 MW, 120 MWh flow battery system, including external electrolyte tanks, and an enclosed structure that contains the stack and PCS system.

Figure 10: Artist's Rendering of a Complete Utility Scale BESS system
(Courtesy Regenesys Technologies Ltd.)[39]

5.1.2 Capital Equipment

A complete BESS system consists of PCS, battery stacks, electrolyte tanks and pumps, as well as electrolyte materials. The battery components vary widely depending on type, but the PCS and balance of plant are similar, and will be assessed equally for both types. In order to assess the facilities equally, a unit lifetime of 15 years is assumed. During this time, the lead-acid batteries will require replacement. Virgin materials are assumed for the manufacture of all components, except the second set of lead-acid batteries, where a 99% secondary lead source is assumed, representing a closed-loop recycling process. Primary vanadium pentoxide is assumed, but the effect of using secondary vanadium, recovered from boiler soot is demonstrated in table 8.[41] The lead-acid battery is oversized by 30% for equal comparison, due to its limited (70%) DOD.

5.1.3 Decommissioning

Decommissioning would consist primarily of material scrapping and recycling, as well as site reclamation. The recycling process receives an energy and emissions “credit” by producing raw materials that would otherwise be derived from primary sources. The lead-acid battery recycling process is well developed, but energy intensive relative to recycling of the vanadium electrolyte.

Tables 7 and 8 show the results of the energy and emissions assessment for the construction and decommissioning of a complete BESS system.

Table 7: Primary Energy Requirements for Installation of BESS (GJ_t/MWh_e storage capacity)		
Battery Type	Lead-Acid	Vanadium Redox
Electrolyte Materials	689	869 (53 using secondary Vanadium source)
Other Battery Materials	296	319
Manufacturing	1032	660
Transportation	56	24
PCS	270	270
Balance of Plant	42	42
Decommissioning and Recycling	52	2
Total	**2437**	**2186 (1370 secondary V)**

Table 8: GHG Emissions Associated with Installation of BESS (tones CO_2 equiv./MWh_e storage capacity)		
Battery Type	Lead-Acid	Vanadium Redox
Electrolyte Materials	37.9	65.6 (4.0 secondary)
Battery Materials	16.7	24.1
Manufacturing	172	110
Transportation	9.3	4.0
PCS	45.0	45.0
Balance of Plant	7.0	7.0
Total	**287.9**	**255.7 (194.1 secondary V)**

5.2 Operation

5.2.1 Energy Ratio

A substantial advantage of BESS is the ability to place the unit at or near the point of use. There are no geologic requirements, and since there are no operation-related emissions, batteries can be placed near or in occupied buildings. BESS units may be placed at substations for local voltage support, and may also provide additional economic benefits such as transmission and delivery (T&D) deferral and increased system reliability. This geographical benefit translates to substantially reduced transmissions losses associated with BESS use as compared with CAES or PHS. Placement at substations reduces the incremental BESS transmission distance to near zero.

While the round trip electrical conversion efficiency for a battery cell can be substantially higher than PHS system (in excess of 90% for vanadium) additional loads substantially decrease the net efficiency of BESS systems. Flow batteries require fluid pumps, which decrease overall efficiency by approximately 3%, and active cooling requirements result in additional losses. Unlike PHS or CAES, batteries store and produce direct current, which require AC-DC converters. These solid state devices have improved in both efficiency and cost, but are still more expensive and less efficient than transformers of equivalent power.[42,43] Typical losses associated with roundtrip AC-AC conversion are at least 4%, and can be significantly higher depending on loading conditions. Individual component efficiencies were not calculated to derive ER_{net}, as different batteries use different types of PCS systems, pumps, and temperature controls. Manufacturer's data and operation experience was used to derive an ER_{net} for each type.[44]

5.2.2 Operation and Maintenance Requirements

There are no major consumables associated with BESS operation, so additional energy requirements are derived primarily from system maintenance and repair. Energy and emissions requirements are calculated using EIO methods based on estimated annual maintenance costs. Costs for lead-acid batteries are generally available, while O&M costs for flow-batteries is more difficult to assess due to a lack of an installed base. Flow batteries are expected to require substantially less maintenance then lead-acid batteries, primarily electrolyte evaluation, and periodic replacement of pumps and stack components. Large scale advanced BESS systems do not require full-time manual supervision.

5.3 Results

Tables 9 and 10 show the results of the of the BESS life-cycle analysis.

Table 9: Energy Parameters for Battery Energy Storage Systems		
	Lead-Acid	**Vanadium Redox**
Fixed Components		
Construction E_{stor}	2437 GJ_t/MWh_e stored	2186 GJ_t/MWh_e stored
Variable Components		
O&M EE_{op}	207.4 GJ_t/GWh_e	92.3 GJ_t/GWh_e
ER_{net}	1.43 times primary	1.33 times primary

Table 10: GHG Emissions Parameters for Battery Energy Storage Systems (CO_2 equiv.)		
	Lead-Acid	**Vanadium Redox**
Fixed Components		
Construction EM_{stor}	288 tonnes/MWh_e stored	256 tonnes/MWh_e stored
Variable Components		
O&M EF_{op}	14.7 tonnes /GWh_e	6.5 tonnes /GWh_e
ER_{net}	1.43 times primary	1.33 times primary

Assuming a 20-year life and a 20% capacity factor, the delivery of 1 GWh from a lead-acid battery system requires 763 GJ_t, while the Vanadium Battery requires 591 GJ_t in addition to primary generation. GHG emissions are 80.5 tonnes CO_2 equiv./GWh from lead-acid BESS, and 64.9 tonnes CO_2 equiv./GWh from Vanadium BESS.

6.0 Comparison of Storage Technologies

6.1 Construction Energy

BESS systems have substantially greater (roughly 10-15 times) the energy requirements associated with plant construction compared to PHS and CAES systems. PHS requires large earth moving operations, but this results in large amounts of storage capacity. PHS and CAES use energy-free (as well as largely cost free) storage media (water and air) as opposed to BESS electrolytes, which require energy intensive mining and ore processing. While BESS systems do not require extensive earth moving operations, salt solution mining and earth dam preparation are relatively low in energy intensity compared to building structures to house battery components and electrolytes. The geologic components of CAES and PHS are also very long-lived compared to batteries. Battery systems have much higher initial energy outlays due to complicated manufacturing techniques and materials required for battery electrodes, stacks and AC-DC converters, while components for PHS and CAES, such as turbines, compressors, and generators, are simpler per unit power. Batteries also require a greater amount of transportation energy, considering the large mass of electrolytes. While PHS systems requires the movement between 50 and 200 times more mass of materials per unit energy stored, these materials are generally moved over a short distance, whereas a 10 MWh BESS system may require the movement of 200 tonnes of materials several thousand kilometers.

O&M energy requirements for BESS systems are also substantially (5 to 10 times) higher than PHS or CAES systems, again due to the comparatively complicated storage medium and power conversion equipment.

6.2 Efficiency

The large variability in efficiencies makes a direct comparison between storage technologies complicated. The "average" net efficiency for a U.S. PHS facility is 74%, while the Vanadium flow battery net efficiency is 1-2% higher. The additional inefficiencies in PHS resulting from additional transmission is more than offset by the DC-AC conversion process, as well as heating, cooling and electrolyte pumping requirements from BESS systems. The Vanadium Redox battery appears to have a slight advantage over the average PHS system. As previously discussed, deriving a true efficiency for CAES requires a number of assumptions about the electrical "value" of natural gas, but the efficiency of the electricity storage component can be considered about the same as PHS.

6.3 Greenhouse Gas Emissions

Since greenhouse gas emissions are generally proportional to energy usage, the BESS systems have substantially higher greenhouse gas emissions related to construction than PHS or CAES systems. BESS systems also have higher emissions resulting from non-fuel related O&M. CAES has considerably higher emissions during operation than the other storage-only technologies due to its combustion of natural gas, although its hybrid nature should be considered when evaluating its GHG emissions.

6.4 Future Developments

Since CAES and PHS are mature technologies, there is little forecast improvement for either energy input or efficiency, with the possible exception of minor improvements in the CAES turbine. BESS systems are still under extensive development and significant cost reductions are expected, which should correspond to decreases in energy input. Increased use of recycled materials would also dramatically reduce energy and emissions from BESS systems. To demonstrate the relative immaturity of this technology, it should be pointed out that there are perhaps no more than 40 large battery systems in place worldwide, while there are thousands of dam-based hydroelectric facilities and tens of thousands of gas turbines (the basis of CAES technology) installed. Increases in battery efficiencies will require the development of new electrolyte materials, although there are several electrolyte materials that hold promise for greater overall efficiency.[45,46]

7.0 Evaluation of Dispatchable Renewable Energy Systems

Using the energy and emissions factors from energy storage, it is possible to develop the net emissions and energy requirements for a dispatchable renewable energy system. The site-dependent nature of renewable energy limits the possibility of a deriving general EPRs and emissions factors for renewable technologies; a detailed analysis must be performed for each system. Much depends on the size of the storage system, which can have a substantial impact on the net energy requirements, as well as the total emissions from a dispatchable renewable source.

System Sizing

The sizing of a storage system is determined by the desired qualities of a renewable-energy system, and is beyond the scope of this report. In general, however, system requirements include overall capacity factor, as well as the system availability factor, also described as the loss of load probability. It should be noted that some traditional thermal sources may also require storage to achieve certain performance requirements.

Integrating storage into a renewable system may increase its value as a peaking source so that lower capacity factors may actually be desired.

The scenarios described in sections 7.1-7.3 outline three possible dispatchable renewable sources and their total energy requirements and GHG emissions.

7.1 Wind-PHS

A number of studies have been performed to evaluate the energy requirements and GHG emissions from wind-generated electricity. Using data from White and Kulcinski[47] it is possible to consider the net energy and emissions associated with a wind-PHS facility, such as the proposed Alta Mesa facility in Southern California. This project consists of a 28.17 MW of wind generation and a PHS facility rated at 70 MW with 420 MWh of storage and a claimed ER of 1.35.[48,49] The wind farms' average capacity factor is 31%.[50] The PHS facility is significantly larger than required by the wind farm, and it will also be used with conventional sources, so only 50% of the construction energy and emissions are allocated to the wind farm in this analysis. Due to non-coincidence with load, an economically viable wind-energy system must operate under baseload conditions, similar to a nuclear or large coal facility, with a capacity factor of 80%-90%. Based on calculations by Cavallo[51], it is estimated that approximately 40% of the energy from a wind turbine must be stored by the PHS system. A 20-year project lifetime is assumed. The results from the Wind-PHS case are provided in table 11.

Table 11: Energy and GHG Emissions associated with Wind Generated Electricity with and without Pumped Hydro Storage

	System w/o Storage	System with Storage
Total energy produced by wind farm (GWh_e)	1530	1530
Energy lost to storage (GWh_e)	0	111
Total energy produced by system (GWh_e)	1530	1371
Total energy input into system GJ_t	239720	306153
System EPR (GWh_e/ GWh_t)	**23**	**16**
Total Emissions (tonnes CO_2 equiv.)	21688	28033
Emissions rate (tonnes CO_2 equiv./ GWh_e)	**14**	**20**

The resulting dispatchable wind-energy system has a GHG gas emissions rate which is about 6 tonnes CO_2 equiv./GWhe greater than the non-dispatchable source. The EPR falls considerably, but is still favorable to most other sources of electrical energy (see Fig. 10.)

7.2 Wind-CAES

The high-wind areas of the U.S. are mostly located in the midwestern regions of the U.S., far from population centers, and the high cost of transmission between these areas and high demand regions requires storage to increase the economic competitiveness of wind. Geologic conditions in these areas are also favorable for CAES, and it has been suggested that a Wind-CAES system might be technically and economically feasible.[51]

Typical wind turbines in the western U.S operate at a capacity factor of 35% with large ramp rates of nearly 100%/hour.[52,53] A CAES system would operate to levelize the output from a wind farm to best utilize transmission capacity, and provide a roughly baseload operation with a capacity factor of 80-90%. The system output level would approximate the wind farm capacity factor times the maximum power output from the wind plant, so a 1000 MW wind plant with a CF of 35% coupled to an ideal storage system would produce a near constant output of 350 MW. The CAES system would likely be rated at about 50% of the wind farm size output to fully absorb peak output, and provide increased output at peak demands.

From this data, and using storage rate data from Cavallo,[51] it is possible to calculate the energy and emissions associated with a hypothetical Wind-CAES system consisting of 1000 MW of wind capacity and 500 MW of CAES. The results from this case are provided in table 12.

Table 12: Energy and GHG Emissions associated with Wind Generated Electricity with and without Compressed Air Energy Storage		
	System w/o Storage	System with Storage
Total energy produced by wind farm (GWh_e)	61320	61320
Energy delivered to CAES (GWh_e)	0	17170
Energy Produced by CAES	0	23361
Total energy produced by system (GWh_e)	61320	67511
Total energy input into wind farm TJ_t	8510	8510
Total energy input into CAES TJ_t	0	14906
System EPR (GWh_e/ GWh_t)	**26**	**10**
Total Emissions (tonnes CO_2 equiv.)	769800	733411
Emissions rate (tonnes CO_2 equiv./ GWh_e)	**12.5**	**109**

The addition of CAES storage increases the emissions rate substantially due to the combustion of natural gas, although this rate of 109 tonnes CO_2 equiv./GWh_e is substantially lower than any fossil technology. The EPR is reduced substantially, due to the high energy intensity of transporting natural gas, as discussed by Meier and Kulcinski.[28]

7.3 Solar PV-BESS

While more predictable and having considerably more coincidence with demand than wind, solar PV-derived electricity benefits substantially from energy storage. A common proposal for solar PV is to provide peak-load generation to offset peaking power and T&D requirements. Since solar peak and thermal peak (which corresponds to demand peak due primarily to air-conditioning) are non-coincident by several hours, PV cannot directly offset generation or T&D.

A system to provide peaking power based on solar PV and BESS would require approximately 50% of the daily energy generated from the PV system to be stored. The energy and emissions data from a 8 kW solar PV system[54] is scaled to a 50 kW system, with 400 kWh of storage. Since the PV system already includes a DC-AC inverter, the energy and emissions associated with the battery PCS is omitted. The results from this case are provided in table 12.

Table 12: Energy and GHG Emissions associated with Solar PV Generated Electricity with and without Battery Storage			
	System without Storage	System with Lead-Acid Storage	System with Vanadium Storage
Total energy produced by solar plant (MWh_e)	1348	1348	1348
Energy lost to storage (GWh_e)	0	203	167
Total energy produced by system (MWh_e)	1348	1150	1187
Total energy input into solar plant (GJ_t)	1181	1181	1181
Total energy input into BESS (GJ_t)	0	863	766
Total energy input into system (GJ_t)	1181	2044	1947
System EPR (GWh_e/ GWh_t)	**4**	**2**	**2**
Total Emissions (tonnes CO_2 equiv.)	78	175	162
Emissions rate (tonnes CO_2 equiv./GWh_e)	**60**	**152**	**136**

The addition of BESS substantially reduces the EPR, and substantially increases the emissions rate for the resulting dispatchable solar-energy system. The relatively poor performance of this system compared to wind-storage systems results from the combination of highly energy intensive generation and storage technologies. The greenhouse gas emission rate is still substantially lower than any fossil technology, although roughly 50% higher than the semi-fossil based wind-CAES system. The energy intensity of a PV-storage system is reflected in the high price of electricity from this system. For these technologies to be economically viable, the cost, and corresponding energy intensity, must decrease substantially.

7.4 Comparison to Other Technologies

Figures 11 and 12 compare the energy payback ratios and emission rates from previous studies to the examples provided in 7.1-7.3. It is important to recognize that the renewable-storage models provided do not represent absolute measurements for wind and solar PV with storage, as both the size of the storage medium and the amount of energy stored will vary depending on the application.

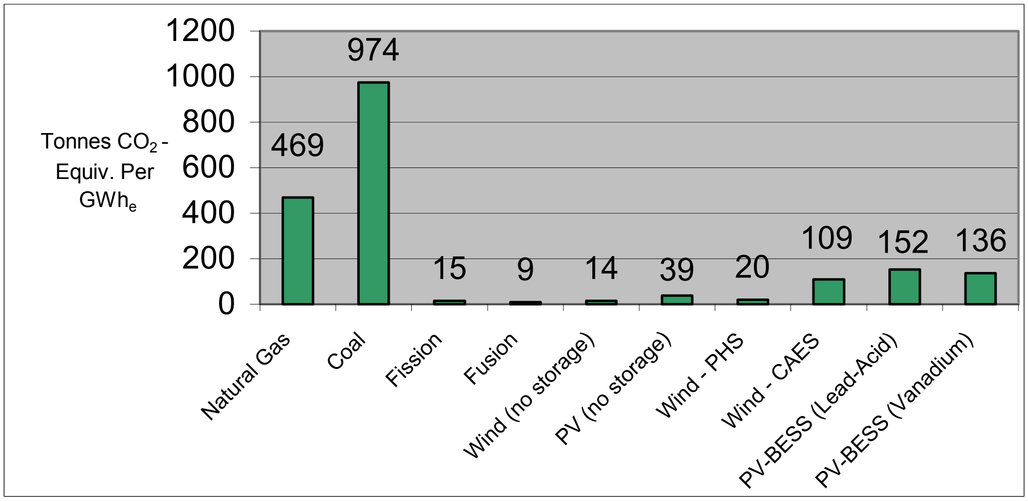

Figure 11: CO_2 Emissions Rates for Various Generation Technologies

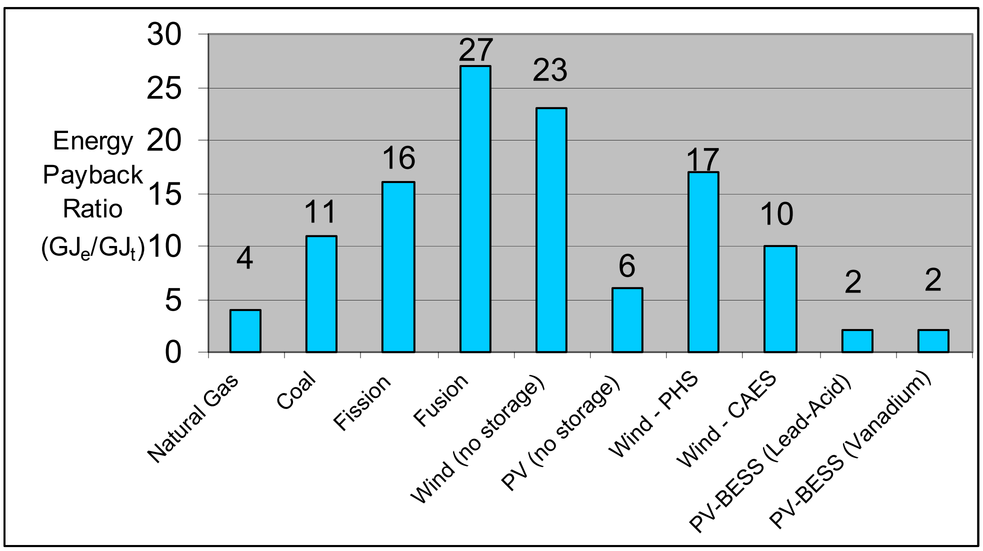

Figure 12: Energy Payback Ratios for Various Generation Technologies

8.0 Conclusions

Current economically viable technologies for large-scale energy storage include pumped hydro, compressed air energy storage and battery energy storage systems. Pumped hydro systems stores energy hydraulically and require the construction of large dam facilities, which have relatively small energy requirements and emissions relative to the volume of energy stored. The CAES storage system is unique in its use of both energy storage and fossil fuel combustion to provide a hybrid storage-generation system. The result is that this storage system is a significant point source of GHG emissions during operation, unlike PHS or BESS. BESS has similar efficiencies to PHS, but require substantially greater construction, and O&M energy inputs than CAES or PHS.

The use of energy storage increases the net emissions from the generating source and lowers the energy payback ratio due to conversion and transmission inefficiencies, but the addition of energy storage to low-carbon generation from renewable sources can produce a completely dispatchable and relatively low-carbon electricity infrastructure. While the effects of storage on intermittent renewables are highly site and condition specific, results from an analysis of three representative renewable-storage systems are:

- For a Wind-PHS system the EPR decreases from 23 to 17, while the GHG emission rate increases from 14 to 20 tonnes CO_2 equiv./GWh_e.
- For a Wind-CAES system the EPR decreases from 23 to 10, while the GHG emission rate increases from 14 to 109 tonnes CO_2 equiv./GWh_e. The majority of the difference is due to natural gas consumption.
- For a Solar PV-BESS storage system the EPR decreases from 4 to 2, while the GHG emission rate increases from 30-50 to 130-160 tonnes CO_2 equiv./GWh_e. The use of lower energy electrolytes reduces the emissions to 100-145 tonnes CO_2 equiv./GWh_e.

While the increase in GHG emissions due to storage can be substantial, any likely combination of renewable generation and storage will produce substantially less greenhouse gas emissions than fossil generation sources. The highest levels of emissions, from a wind-CAES, or a PV-BESS system, are 4-10 times that of nuclear-derived electricity, but still less than 1/3rd that of a modern combined cycle gas turbine, and less than 1/5th that of coal. In addition, the suitability of western and midwestern geography for CAES may enable this technology to be integrated in regions with both high wind potential and high rates of emissions due the dominance of coal-fired utilities.

In the long-term, energy storage technologies may increase the economic and technical viability of non-fossil sources, and in combination will provide significantly reduced emissions of greenhouse gasses compared to the current generation mix. In this sense, storage is an enabling technology for increased penetration of low-carbon sources.

Acknowledgements

The authors would like to thank those who helped make this work possible. The study was supported in part by the Energy Center of Wisconsin, the University of Wisconsin-Madison, and the U.S. Department of Energy. Discussions with Professor Paul P.H. Wilson and Dr. Paul J. Meier also provided considerable assistance.

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