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Hydrogen Energy Storage Comparison

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EXECUTIVE SUMMARY

Hydrogen energy storage systems have been compared to other types of energy storage systems for electric utility applications. Three such applications are 1) end-use power quality, i.e. ride-through of a system disturbance, 2) distributed generation with scheduled dispatch, 3) load management, e.g. load leveling or spinning reserve. The technologies compared include batteries, compressed air energy storage (CAES), pumped hydro, superconducting magnetic energy storage (SMES), flywheels, and supercapacitors (although not all technologies are suitable for all applications).

The results show that:

- Hydrogen fuel cells can be used in power quality applications where 15 seconds or more of ride-through are required.
- Hydrogen fuel cells or combustion engines are suitable for distributed generation with dispatch. The cost benefit comparison is positive for the median utility benefit value.
- Large hydrogen systems can provide cost-effective load management, especially where CAES and pumped hydro are not suitable.
- Hydrogen-fueled engine systems may be a logical step towards placing hydrogen technologies in stationary situations because of today's low cost and availability.
- High-efficiency reversible fuel cells make sense for long duration discharge (> 4 hrs).

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1.

INTRODUCTION

For hydrogen storage to play a role in utility applications, it must compete with other types of energy storage, just as hydrogen energy generation (via fuel cells or combustion) must compete with other generation types. Hydrogen systems can be compared to the other technologies on the basis of performance and cost. Thus the objective of this study was to make side-by-side comparisons of Hydrogen Energy Storage systems with other kinds of utility energy storage, such as CAES, batteries and pumped storage.

A number of application areas were selected, since energy storage can be used in many different ways within the electric system. These range from power quality to load leveling. Over the range of applications, a spectrum of system sizes (defined by both storage capacity and power rating) are required. Not all technologies are suitable for all sizes, and thus hydrogen-based systems are compared only with appropriate technologies in each case.

Section 2 describes the applications and technologies selected for comparison. Section 3 discusses the systems capital costs and cost algorithms. Section 4 describes the results and findings for capital cost analysis. Section 5 presents the life cycle cost analysis. Section 6 presents conclusions and recommendations.

2.

APPLICATIONS AND SUITABLE TECHNOLOGIES

Energy storage has been proposed and is in use for many applications within the electric system. One of the earliest and largest applications has been the use of pumped hydro electric facilities for large-scale load leveling. Another common application has been the use of batteries in uninterruptible power supplies. The broad range of applications has been described in many reports [1-3].

A summary of some applications, along with typical power levels and duration of use is shown in Table 1. The deliverable storage capacity required is determined by multiplying power by duration.

Table 1. Representative Energy Storage Applications and Sizes

Application	Power Quality	Remote/UPS/ Distributed Utility	Transmission & Distribution	Spinning Reserve/ Load Management	Load Leveling
Power level, MW	~1	1-2	20 to 50	50 to 100	50 to 1000
Duration	1-20 sec.	1-60 min.	~1 min.	0.5-8 hrs.	0.5 to 8 hrs.
Deliverable Storage range	1-2 MJ	60 MJ to 3600 MJ (0.17 to 1 MWh)	1200 to 3000 MJ (0.33 to 0.83 MWh)	25 to 400 MWh	25 to 4000 MWh

In most utility applications, the energy storage system will be connected directly into the electric grid via a suitable power conversion or power conditioning system (PCS). The energy storage unit is charged when energy is available and discharged when energy is required, both conversion processes making use of the PCS. This is shown schematically in Figure 1.

Figure 1. An energy storage system connected directly to the electric grid via a power conditioning system

In end-use applications, primarily where power quality disturbances are being addressed for a single customer, the energy storage system may be connected to the bus feeding the load, as shown in Figure 2.

Figure 2. An energy storage system connected to the bus which feeds the load

Hydrogen energy storage systems differ from most of the other energy storage technologies, in that the charging and discharging conversion devices may be (are likely to be) separate units. Figure 3 shows the additional electrolyzer which is used to produce the stored hydrogen. Power is produced by utilizing the hydrogen in an electric generator which could be either a fuel cell or combustion engine.

Figure 3. Hydrogen energy storage system showing the electrolyzer used to produce the stored hydrogen

In an end-use application, the hydrogen may simply be delivered to the site. Power quality applications typically require rapid time response, so the most appropriate hydrogen-fueled electric generator will be a fuel cell. A hydrogen end-use system is shown in Figure 4.

Figure 4. For end-use applications, hydrogen is directly delivered to the site.

The technologies compared in this study include:

- Batteries,
- Compressed air energy storage (CAES),
- Pumped Hydro,
- Flywheels,
- Superconducting magnetic energy storage (SMES),
- Capacitors (double-layer electrochemical, super-, or ultra-capacitors), and
- Hydrogen, stored either as pressurized gas or in a hydride matrix.

These technologies and their principles of operation are described in detail in Ref. 4 and 5.

Over the range of applications, not all possible technologies are suitable. Pumped hydro is effective for large, long-duration load-leveling. Advanced flywheels and supercapacitors are designed for short-duration carryover; they are ideal for end-use power quality. Batteries are particularly suitable for longer outages. SMES in various configurations is in use and has been proposed across the spectrum of applications.

Hydrogen-based systems can be designed for use over the range of applications, if components are appropriately selected. For example, large combustion units or banks of fuel cells could be used for load-leveling. Modest size fuel cell systems have been proposed for distributed utility applications. Power quality can even be addressed using small-to-medium fuel cells with hydrogen storage cartridges [6-8].

For the purpose of this study, only suitable technologies have been compared in each application area. These are listed in Table 2.

Table 2. Technologies Compared for Utility Energy Storage Applications

	Power Quality	Remote/UPS/ Distributed Utility	Transmission & Distribution	Spinning Reserve/ Load Management	Load Leveling
<i>Technologies</i>					
Hydrogen-fueled Electric Generator with storage	✓	✓	✓	✓	✓
Batteries	✓	✓	✓	✓	
Compressed Air Energy Storage (CAES)		✓	✓	✓	✓
Pumped Hydro			✓	✓	✓
Flywheels	✓	✓			
Superconducting Magnetic Energy Storage (SMES)	✓	✓	✓	✓	✓
Supercapacitors	✓				

3

SYSTEM COST ANALYSIS

3.1 Energy Storage System Costs

One major objective of this study has been to compare system capital costs for the various technologies in several representative applications. For those systems which consist of the energy storage unit and a single power conditioning system that operates in both the discharge and charging modes, the system cost is the sum of the component costs:

$$\text{Cost}_{\text{total}} (\$) = \text{Cost}_{\text{pcs}} (\$) + \text{Cost}_{\text{storage}} (\$) \quad (1)$$

Hydrogen system costs are developed somewhat differently, as described later in this section. For most systems, the cost of the PCS is proportional to the power level:

$$\text{Cost}_{\text{pcs}} (\$) = \text{UnitCost}_{\text{pcs}} (\$/\text{kW}) \cdot P (\text{kW}), \quad (2)$$

where P is the power rating.

For many systems, the cost of the storage unit is proportional to the amount of energy stored:

$$\text{Cost}_{\text{storage}} (\$) = \text{UnitCost}_{\text{storage}} (\$/\text{kWh}) \cdot E (\text{kWh}), \quad (3)$$

where E is the stored energy capacity.

In the simplest case, E is equal to $P \times t$, where t is the discharge time.

There are some exceptions and constraints to these simple equations. To begin with, all systems have some inefficiency. To account for this, Eq. 3 is modified as follows:

$$\text{Cost}_{\text{storage}} (\$) = \text{UnitCost}_{\text{storage}} (\$/\text{kWh}) \cdot (E (\text{kWh}) / \eta_{\text{dis}}) \quad (4)$$

where η_{dis} is the discharge efficiency.

In addition, many storage units are not discharged completely in operation because of voltage or mechanical considerations. In these cases, the storage must be oversized; the unit cost must then reflect $\$/\text{kWh}$ -delivered.

Also, for some technologies, the unit cost is not a constant over the range of sizes (i.e., economies of scale prevail). This is especially true for SMES, where the unit energy cost scales approximately with $E^{2/3}$. Thus, for this study, the unit costs for SMES are a function of E , as indicated in Figure 5 [9].

Figure 5. Estimated SMES Costs [9]

Finally, for batteries, the unit energy costs do not hold for short discharge times [10], because it is not possible, except in special cases (which do not include the inexpensive batteries considered here), to get all the energy out in a short pulse. Thus, the smallest batteries considered in this study were one-hour batteries.

3.2 Hydrogen System Costs

As indicated previously in Figure 3, a hydrogen-based energy storage system must include a separate "charging" component - the electrolyzer. A compressor is also required if the stored hydrogen is pressurized. To cost these additional items, their rating must be determined by the time available for charging. An important point to note is that the electrolyzer and compressor will operate during the time that the fuel cell or combustion generator is NOT operating, and thus the rating of these devices can be very small compared to the power rating at discharge. This is shown schematically in Figure 6.

Figure 6. Schematic diagram of discharging and charging time for a hydrogen energy storage system

A typical case might have a distributed utility unit discharging for a time, t_d , of 1 hour each day at power level $P_{\text{discharge}}$. The electrolyzer can recharge over the remaining $t_{\text{ch}} = 24 \text{ hr} - t_d(\text{hr}) = 23 \text{ hours}$ and be rated at:

$$P_{\text{charge}} = \frac{P_{\text{discharge}} \cdot t_d}{t_{\text{ch}}}, \quad (5)$$

or 1/23 the power level of the fuel cell.

In general, the charging time:

$$t_{\text{ch}} (\text{hr}) = 24 \text{ hr} - t_d (\text{hr})$$

$$t_{\text{ch}} (\text{min}) = (24 \text{ hr} \cdot 60 \text{ min/hr}) - t_d (\text{min})$$

$$t_{\text{ch}} (\text{sec}) = (24 \text{ hr} \cdot 3600 \text{ sec/hr}) - t_d (\text{sec})$$

This approach was used in calculating hydrogen system costs throughout this study. (This algorithm is modified if a duty cycle greater than once per day is anticipated.)

For pressurized storage, the compressor is sized to refill the storage over the same extended period. The compressor is sized based on hydrogen flow rate in standard cubic feet per minute. Cost data from [11] were used. Thus the total system cost for a hydrogen energy storage system is given as:

$$\begin{aligned}
Cost_{H_2 total}(\$) = & UnitCost_{gen}(\$ / kW) \times P_{discharge}(kW) + UnitCost_{storage}(\$ / kWh) \times \frac{E(kWh)}{\eta_{H_2 dis}} + \\
& UnitCost_{electrolyzer}(\$ / kW) \times \frac{P_{discharge}(kW) \times t_d}{(t_{ch}) \times \eta_{H_2 dis}} + UnitCost_{comp}(\$ / scfm) \times \frac{E(scFH_2)}{t_{ch}(\min) \times \eta_{H_2 dis}}
\end{aligned}
\tag{6}$$

where:

$UnitCost_{gen}$ = cost of hydrogen fuel cell or engine, (\$/kW)

$UnitCost_{storage}$ = cost of hydrogen storage (cylinder or hydride), (\$/kWh)

$UnitCost_{electrolyzer}$ = cost of advanced electrolyzer (\$/kW)

$UnitCost_{comp}$ = cost of compressor for pressure required (\$/scfm)

$E(scFH_2) = E(kWh) \cdot 3600 \text{ kJ/kWh} \cdot 0.002722 \text{ scFH}_2/\text{kJ}$

$\eta_{H_2 dis}$ = discharge efficiency

For the hydride system, low pressure storage was assumed and so compressor costs are discounted compared with cylinder storage.

$\eta_{H_2 dis}$ is the discharging or generating efficiency of the hydrogen system. This determines the sizing of the hydrogen reservoir to provide sufficient delivered energy. $\eta_{H_2 dis}$ for a fuel cell system was assumed to be 0.59 [12] and for a combustion engine 0.44 [13]. Reversible fuel cells for which a separate electrolyzer is not needed were also considered—with two values of efficiency: 0.7 and 0.85.

The costs and efficiencies used in this study are listed in Table 3. Most of these were developed through discussions with vendors while others are found in recent literature [4, 5, 9-19].

Table 3. Energy Storage Technologies Cost and Efficiencies

	Energy related cost (\$/kWh)	Power related cost (\$/kW)	Electrolyzer (\$/kW)	Compressor (\$/scfm)	η , Discharge Efficiency
Batteries (low)	175	200			0.85
Average	225	250			0.85
Batteries (high)	250	300			0.85
μ -SMES	70000	350			0.95
mid-SMES	3000	300			0.95
Flywheels	50000	300			0.93
Supercapacitors	100000	300			0.95
SMES	800	300			0.95
CAES	10	425			0.79
Pumped Hydro	15	600			0.87
Hydrogen Fuel Cell/Cylinder storage (low)	10	500	300	112.5	0.59
Hydrogen Fuel Cell/Cylinder Storage (high)	20	1500	600	112.5	0.59
Hydrogen Fuel Cell/Underground storage	1	500	300	112.5	0.59
Hydrogen engine/hydride storage	15	350	300	57	0.44
Reversible fuel cell	10	600	0	0	.70, .85

4.

COMPARISON RESULTS AND DISCUSSION- CAPITAL COSTS

In this section, results are shown graphically for three selected cases:

- 1) power quality: short discharge at 1 MW power level,
- 2) distributed generation: scheduled dispatch of up to 1 hr/day at 1 MW power level,
- 3) load management: hours of discharge at 50 MW.

Results for the power quality case, shown in Figure 7, indicate a variety of technologies may be suitable over the 1 to 20 second range. Fuel cells with delivered, stored hydrogen are competitive for carry-over greater than about 15 seconds. Nearly instantaneous start-up (less than 1 cycle) is assumed.

Figure 7. Capital Costs of Power Quality Systems (1 MW)

For distributed utility applications (Figure 8), only batteries, hydrogen and SMES were considered. Hydrogen energy storage using either a fuel cell or a combustion engine is competitive. A hydrogen-fueled engine was considered for this case (but not the power quality case) because it is assumed the dispatch can be scheduled with at least a minute or so for engine start-up.

Figure 8. Capital Costs of Technologies for Distributed Utility Applications (1 MW) up to 1 hr

For long duration discharge at high power levels, i.e. for load management or spinning reserve, a number of technologies may be suitable (Figure 9). CAES looks especially attractive because of low storage costs, but this is only true where suitable aquifers are available. Hydrogen technologies are appropriate over most of the range.

Figure 9 Capital Costs of Load Management Technologies (50 MW)

A comparison of just the hydrogen technologies is shown in Figure 10.

Figure 10 Costs of Hydrogen Energy Storage Systems (50 MW)

Other studies have compared hydrogen energy storage specifically with battery energy storage, on a \$/kW basis. Figure 11 shows the results from this study for high and low cost assumptions. The cross-over points are indicated at less than 2 hours for low-end estimates and about 5-1/2 hours for high-end estimates. The differences from Ref. [10] are due primarily to sizing the electrolyzer for the longer available charging period.

Figure 11 Comparison of Battery and Hydrogen Energy Storage Systems

Figure 12 is the same as Figure 11 with the addition of a hydrogen combustion system. Today's prices are based on diesel technology quoted by Cummins for an engine modified for hydrogen combustion [13].

Figure 12 Comparison of Battery and Hydrogen Energy Storage Systems, including a hydrogen combustion system

Reversible fuel cell systems at high efficiency (70% and 85%) were also compared with other hydrogen technologies. These costs are shown in Figure 13.

Figure 13 Hydrogen Technology Comparison including Reversible Fuel Cells

5.

LIFE CYCLE COST ANALYSIS

In addition to capital cost comparison, a life-cycle cost comparison was performed on all the technologies in both load leveling and distributed utility applications. On this basis, differences in efficiency and operational factors are also taken into account. For this analysis the parameter being compared is the revenue requirement in ¢/kWh. This is the cost of delivered electricity required to cover all levelized expenses for operation of the system. (Power quality systems are dominated by capital costs and operate only minutes per year. Thus, an analysis of revenue requirements on a delivered energy basis not appropriate.)

Revenue requirement can be calculated as \$/kW-yr and converted to ¢/kWh using the assumed number of hours operated per year. The annual revenue requirement is made up of the following terms:

$$\begin{aligned} \text{RR (\$/kW-yr)} = & \text{carrying charge for capital equipment} \\ & + \text{levelized fixed O\&M costs} \\ & + \text{levelized variable costs for energy and O\&M} \end{aligned}$$

The calculation was performed as follows [20, 21]:

$$\begin{aligned} \text{RR (\$/kW-yr)} = & \text{FCR} * \text{TCC} + \text{OMf} * \text{Lom} + \\ & [\text{OMv} * \text{Lom} + \text{UCg} * \text{HR} * 10^{-6} * \text{Lg} + \text{UCe} * (1/\eta) * .01\text{Le}] * \text{D} * \text{Ho} \end{aligned}$$

where:

FCR	=	Fixed Charge Rate or Carrying Charge Rate (1/yr)
TCC	=	Total Capital Cost (\$/kW)
OMf	=	Fixed O&M Costs (\$/kW/yr)
OMv	=	Variable O&M Costs (¢/kWh)
Lom	=	Levelization Factor for O&M Costs (a function of I and Y)
UCg	=	Unit Cost of Natural Gas (\$/MBtu)
HR	=	Heat Rate (Btu/kWh)
Lg	=	Levelization Factor for Gas
UCe	=	Unit Cost of Input Electricity (¢/kWh)
η	=	Storage Efficiency ($\text{kWh}_{\text{out}}/\text{kWh}_{\text{in}}$)
Le	=	Levelization Factor for Electricity
Ho	=	Operating Time per Day (hr/d)
D	=	Operating Days per year (d/yr)
I	=	Discount Rate (1/yr)
Y	=	Levelization Period or System life (yr)

The analysis requires economic assumptions as well as input cost parameters for each technology. The economic assumptions are listed in Table 4. These are based on current IEA values [22]. Hydrogen fuel cost is based on delivered fuel from a central reformer [14].

Table 4 Economic Parameters for Life Cycle Cost Analysis

Parameter	Value
General inflation rate	2.5%
Discount rate	12.0%
Levelization period	20 years*
Carrying charge rate	15%
Fuel cost, natural gas	\$2.64/MBTU
Fuel cost, hydrogen	\$9.00/MBTU
Fuel cost, escalation rate	0%
Electricity cost (off-peak)	2.5 ¢/kWh
Electricity cost (mid-day)	4 ¢/kWh
Electricity cost, escalation rate	0%
O&M cost escalation rate	0%
Days operation/year	250

* 30 years for CAES and pumped hydro

Technology parameters include capital cost of power and energy related equipment, efficiency, product lifetime, and fixed and variable O&M. Capital costs were given in Table 3. The other values are listed in Table 5. Most technologies were assumed to have 20 year lifetime. CAES and pumped hydro were assumed to have 30 year lifetime. Battery replacement was included as a fixed O&M charge.

Operating parameters include hours per day of discharge operation and number of days of operation per year. For this analysis, it was assumed that the storage unit discharges fully once per day and that the system operated 250 days per year (i.e., 5 days/week, 50 weeks/year). For all technologies, except hydrogen systems with a separate electrolyzer, the recharge time was assumed equal to the discharge time. Electrolyzers were sized to recharge over the hours when the fuel cell or engine system is not actively discharging (i.e., 24- t_d).

5.1 Load Leveling Results

The results for all load leveling technologies are shown in Figure 14, with the hours from 2-7 expanded in Figure 15. CAES looks very attractive, but if a suitable storage site is not available, hydrogen technologies will be competitive at the costs assumed here.

Table 5 Technology Parameters for Life Cycle Cost Analysis

	$\text{kWh}_{\text{in}}/\text{kWh}_{\text{out}}$	Fixed O&M, \$/kW-yr	Variable O&M, ¢/kWh	Other
Batteries (low)	1.18	1.55	1.0	Replacement: 8 yrs $\Rightarrow$ 15.20 \$/kW-yr
Batteries (high)	1.18	1.55	1.0	Replacement: 5 yrs $\Rightarrow$ 33.50 \$/kW-yr
mid-SMES	1.05	8.0	.5	Refrigeration reqt. = 0.5%
SMES	1.05	1.0	.1	Refrigeration reqt. = 0.1%
CAES	0.76	3.0	.2	Heat rate = 4040 Btu/kWh _{out}
Pumped Hydro	1.15	3.8	.38	
Hydrogen fuel cell / cylinder storage	1.88	10.0	1.0	Heat rate = 5783 Btu/kWh _{out} (when buying fuel)
Hydrogen fuel cell / underground storage	1.86	10.0	1.0	
Reversible fuel cell (70% eff.)	1.43	10	1.0	
Reversible fuel cell (80% eff.)	1.18	10	1.0	
Hydrogen engine/hydride storage	2.53	.7	.77	Heat rate = 7755 Btu/kWh _{out} (when buying fuel)

Figure 14 Comparison of Load Leveling Energy Storage Technologies

Figure 15 Expanded View of Load Leveling Technologies

A specific comparison of battery energy storage and a hydrogen fuel cell with cylinder storage is shown in Figure 16. This chart is a companion to Figure 11, where only capital costs are compared. Table 6 shows the comparison of input parameters. The crossover points shift to smaller number of hours of storage primarily because battery replacement has been included in the fixed O&M costs; it was not included in the original capital cost.

Figure 16 Comparison of Battery and Fuel Cell Technologies in Load Leveling

Table 6 Battery and Fuel Cell Comparison Parameters

Parameter	High	Low
Battery		
Power component cost	300 \$/kW	200 \$/kW
Energy component cost	250 \$/kWh	175 \$/kWh
Efficiency	.85	.85
Replacement period	5 years	8 years
Fuel Cell		
Power component cost	1500 \$/kW	500 \$/kW
Electrolyzer cost	600 \$/kW	300 \$/kW
Storage cost	20 \$/kWh	10 \$/kWh
Efficiency	.53	.53

All the hydrogen technologies are compared in Figure 17. The curves cross-over in an interesting fashion. For discharge period up to 3 hours, the combustion engine is least expensive, but by 5 hours it becomes most expensive. The reversible fuel cell become the least expensive option for operation greater than 4 hours.

Figure 17 Load Leveling - Hydrogen Technologies

5.2 Distributed Utility Results

For the distributed utility application, with an ideal discharge period of about one hour to meet local and systematic peaks, the only truly competitive technologies examined in this report are batteries, the hydrogen-fueled combustion engine, and a low-cost fuel cell. This is shown in Figure 18. The lowest revenue requirement at 1 hr is about 28¢/kWh or 71 \$/kW-yr. This can be met by the estimated combined generation, transmission, and distribution peaking benefit of 82 \$/kW-yr typical for a utility with median benefits, not even including energy value [19].

An expanded view of the distributed utility technologies is found in Figure 19, where the hydrogen technologies are shown with and without electrolyzers included. A system without electrolyzer would require hydrogen delivery to the site. When the volume of hydrogen used (and stored) is small, this is a cost-competitive approach.

Figure 18 Comparison of Technologies in Distributed Utility Application

Figure 19 Comparison of Technologies in Distributed Utility Application—Expanded View

6.

CONCLUSIONS

Hydrogen compares well with other energy storage technologies in some niche applications:

- Hydrogen fuel cells can be used in power quality applications where 15 seconds or more of ride-through are required.
- Hydrogen fuel cells or combustion engines are suitable for distributed generation with dispatch. The cost benefit comparison is positive for the median utility benefit value.
- Large hydrogen systems compete with CAES for cost-effective load management.
- Hydrogen-fueled engine systems may be a logical step towards placing hydrogen technologies in stationary situations because of today's low cost and availability.
- High-efficiency reversible fuel cells make sense for long duration discharge (> 4 hrs).
- On a life-cycle cost basis for long duration applications, fuel cell technology competes with battery systems at discharge times greater than about 2 hours, depending on cost assumptions, and with hydrogen-fueled engines at discharge times greater than about 4 hours.

7.

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