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# PROJECTIONS OF LEVELIZED COST BENEFIT OF GRID-SCALE ENERGY STORAGE OPTIONS

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## ABSTRACT.

The levelized costs of delivered energy from the leading technologies for grid-scale energy storage are calculated using a model that considers likely number of cycles per year, application-specific expected lifetime, discount rate, duty cycle, and likely trends in the markets. The expected capital costs of the various options evaluated – pumped hydrostorage, underground pumped hydrostorage (UPHS), hydrogen fuel cells, carbon-lead-acid batteries, advanced adiabatic compressed air energy storage (AA-CAES), lead-acid batteries, lithium-ion batteries, flywheels, sodium sulfur batteries, ultra capacitors, and superconducting magnetic energy storage (SMES) – are based on recent installation cost data to the extent possible. The marginal value of the delivered stored energy is analyzed using recent grid-energy prices from regions of high wind-energy penetration. Grid-scale energy storage is expected to lead to significant reductions in greenhouse gas (GHG) emissions only in regions where the off-peak energy is very clean. These areas will be characterized by a high level of wind energy with cheap off-peak and peak prices. At the expected price differentials, the only conventional options expected to be commercially viable in most cases are hydro storage, especially via dam up-rating, and UPHS. The market value of energy storage for short periods of time (under a few hours) is expected to be minimal for grid-scale purposes. Only low-cost daily storage is easily justified both from an economic and environmental perspective.

## 1. INTRODUCTION.

There is the general perception that increased grid-scale energy storage will facilitate expansion of renewables. This has led to many discussions about costs and competitiveness of various storage options, and most of these discussions address cycle efficiency and capital costs of energy storage in terms of both \$/kW and \$/kWh [*1-4*]. However, likely number of cycles per year, marginal value of delivered energy, impact on GHG emissions, application-specific expected lifetime, discount rate, likely trends in the markets, and other factors are seldom addressed for grid-scale applications. We attempt here a first-pass inclusion of the major cost factors in an approximate manner to improve the comparison between several of the oft-discussed candidates for energy storage. We begin with brief discussions of these factors and then present the results of simple model calculations. We conclude that of the conventional storage options, only pumped hydro storage and underground pumped hydro storage (UPHS) are likely to be both competitive and beneficial from a GHG perspective. A lesser-known option of using off-peak energy to recycle $CO_2$ into liquid fuels shows more promise. This option, called “WindFuels” or “RFTS”, is briefly introduced and reviewed as well.

Generally, the total capital cost $C_T$ is expressed simply as

$$C_T = PC_P + EC_E \tag{1}$$

where $P$ is the peak plant power output (kW), $C_P$ is the cost per kW, $E$ is the maximum storage capacity (kWh), and $C_E$ is the cost per kWh. A balance-of-plant cost is sometimes added, but it is sufficient to include it in the other terms for the purposes here of comparing various options of similar size. The cost per delivered kWh of energy, $C_D$, is sometimes simply estimated from

$$C_D = C_T / (E * \eta * n * t) \tag{2}$$

where η is the cycle efficiency, $n$ is the maximum number of cycles per year, and $t$ is the expected lifetime in years. The units for the above make sense (\$/kWh), but the numeric result is generally an underestimate of real delivered cost by a factor of 3 to 30. It is difficult to find analyses with up-to-date cost data that address the following: (1) the value of storage duration; (2) likely number and mean depth of storage cycles per year; (3) a non-zero discount rate; (4) O&M costs, and (5) likely changes in the market.

Any of the above items can individually have a factor-of-two impact on the actual cost of energy storage, and the combined impact could be as high as a factor of 30. Moreover, the actual effect of storage on GHGs is seldom quantified, and it depends heavily on the generation profile of the energy that is stored. The GHG benefit of storing coal-generated energy and using it an hour later at 50% cycle efficiency is extremely negative, so the percentage of fossil energy that is on the regional grid at the time will largely determine whether the storage has a positive or negative climate impact.

## 2. THE RAPIDLY CHANGING GRID MARKET.

As illustrated in **Figures 1 and 2**, real-time (RT) prices plummeted between early 2008 and mid 2009 for the Minnesota Hub on MISO, as wind energy grew to over 7% of the regional grid energy, saturating the local off-peak market [*5*].

Some observers have postulated that eventually there will be sufficient expansion of the grid to reduce the amount of grid energy that is available at very low prices in areas of high wind penetration, but the counter arguments seem stronger.

The price of wind turbines in the U.S. dropped 20% from early 2008 to mid 2009 [*6, 7*]. The mean levelized cost of energy (LCOE) at current U.S. turbine prices (\$1600/kW, as of 12/2009) is about \$45/MWh (assuming a 7% discount rate); but installed turbines are already being quoted by major Chinese manufacturers at \$800/kW in some parts of the world [*7, 8*].

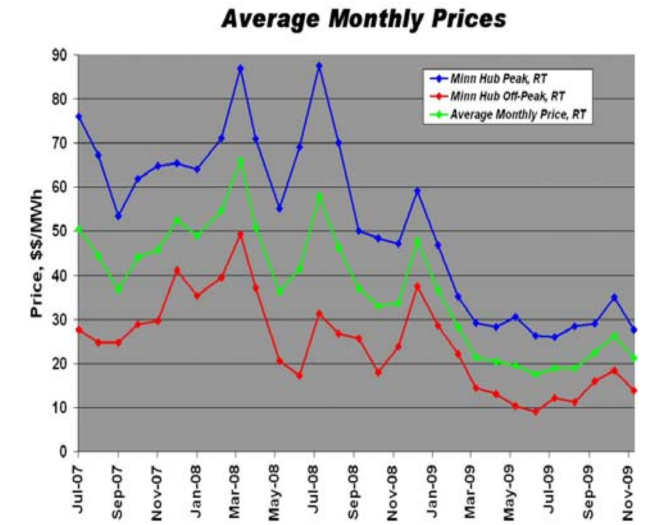


**FIGURE 1. PEAK, MEAN, AND OFF-PEAK REAL-TIME (RT) GRID ENERGY PRICES ARE SHOWN FOR THE MINNESOTA HUB.**

A reasonable projection is for the LCOE from wind energy throughout the wind corridor and in some coastal areas to be about \$29/MWh by 2025. That would suggest the regional data shown for recent quarters in Figures 1 and 2 are likely to be representative of broad areas across the U.S. before long. Therefore, the RT rates in this region should provide a useful basis for assessing what the future renewable grid could justify with respect to energy storage. Note that increased wind penetration has cut peak rates much more than off-peak rates in an absolute sense.

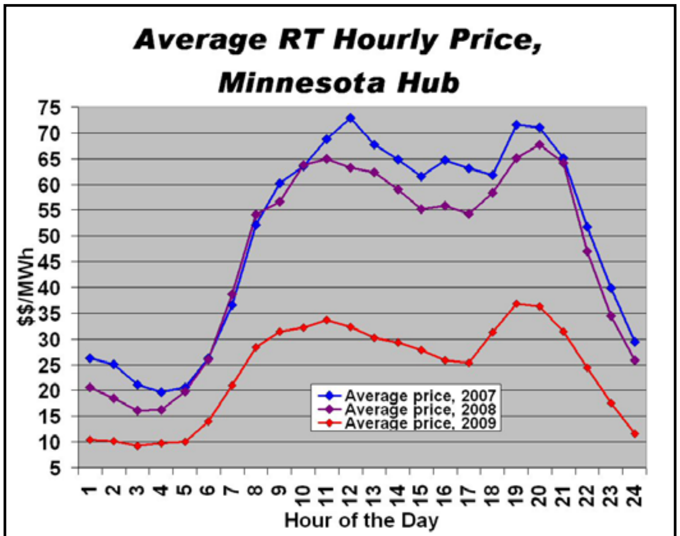


**FIGURE 2. COMPARISON OF THE AVERAGE RT PRICES OF ENERGY FOR 2007, 2008 AND 2009 ON AN HOUR-BY-HOUR BASIS.**

## 3. THE NUMBER AND DURATION OF DAILY CYCLES.

**Figure 3** compares the mean hourly price of grid energy for four recent quarters. An enormous amount of wind energy came online during the second half of 2008 and beginning of 2009, and then grid expansion in the last quarter of 2009 brought prices back up. As shown, during the first and fourth quarters (winter) there are two price peaks: one occurring from 7:00 to 9:00 am and one from 7:00 to 9:00 pm, with a minor trough in between. The two peaks seen are ~\$15/MWh greater than the minor trough, and ~\$25/MWh greater than the 8 hour nadir through the middle of the night. Otherwise, all average cycles show a long broad peak during the middle of the day which has an average price of energy ~\$25/MWh greater than that seen during the 8 hours of the night. (Note that MISO price information is listed in EST, though the Minnesota Hub trades energy in the central time zone, so the hours are recorded one hour off from local time). Of course, the average price for any given hour does not well reflect any individual hour-by-hour variation.

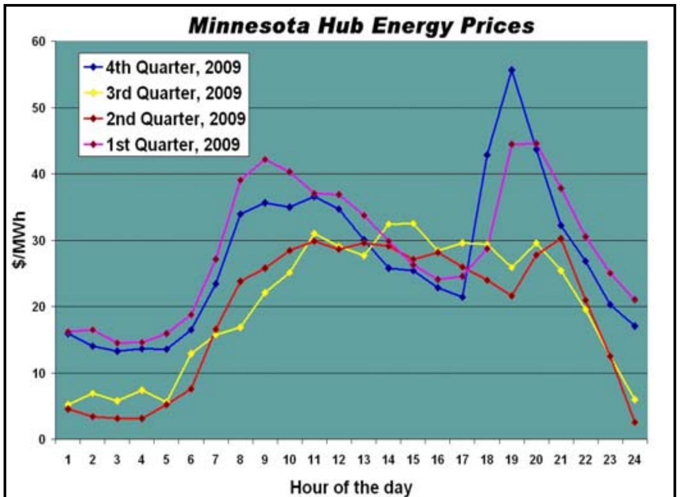


**FIGURE 3. COMPARISON OF THE AVERAGE PRICE OF ENERGY OVER THE LAST FOUR QUARTERS THROUGHOUT THE DAY.**

The scatter-plot in **Figure 4** shows the price of energy at every hour during the month of July 2009 for the Minnesota Hub, with different colors for different days of the week. Several points are plotted at negative prices. This occurs when enough excess energy (beyond the local demand) is introduced onto the local grid that municipals must pay to offload the energy before damage is done to equipment owned by the grid or customers.

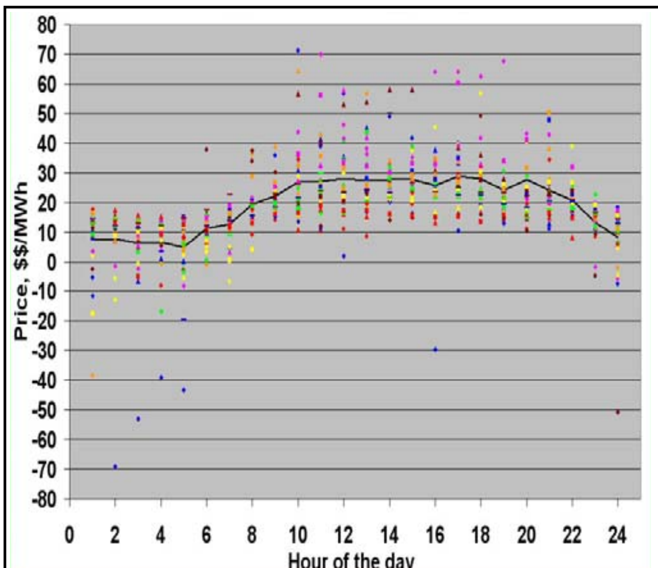


**FIGURE 4. HOUR-BY-HOUR PRICE OF ENERGY TRADED THROUGHOUT THE MINNESOTA HUB, EVERY DAY DURING JULY 2009.**

As can be seen, deviations from the mean varied greatly depending on the day; but the overall arc – a long peak throughout the course of the 16 hour "peak" period from 6:00 am to 10:00 pm, gradually drawing down to an 8-hour trough during the middle of the night – is maintained.

Current efforts are being made to implement "smart grids" and "time of day pricing", which would reward families with lower energy prices if they shift their power usage to lower demand timeframes, but there are significant limits to how much can be done. While the dishwasher might be programmed to run a 3:00 am, the lights, TV's, computers, and other gadgets of our modern lifestyles will not be used in the middle of the night, regardless of price incentives.

## 4. THE VALUE OF STORED ENERGY.

A study in 2004 on growth potential for storage options in California suggested the peak-power needs for ancillary services for maintaining power quality and regulation over periods under 1 hour would be about 5% of generation capacity [*9*]. However, over 98% of energy storage in the U.S. is currently pumped hydro, and its peak rating is about 22 GW [*10, 11*], or ~2.0% of total domestic generating peak capacity. The sum of all other current storage systems (for use beyond several minutes) is roughly 300 MW, though the majority is used to address regulation at a time scale under fifteen minutes. The only major exception appears to be the lone CAES 100 MW plant in Alabama (McIntosh facility).

Mean wind power over state-wide areas seldom changes faster than 40%/hour or 2%/min, and forecast errors 36 hours ahead for even a single wind farm are off by 20% or more only about 15% of the time [*12*]. Forecast errors drop by a factor of two for a 3-hour time horizon (gate-closure time) [*12*]. Real-time prices are usually bid on an hourly basis [*5*], and forecast errors under 5% can soon be expected 90% of the time for a 1-hour gate-closure time. Current gas turbines typically ramp at the rate of 3%/min (though their efficient operating range is quite limited), and pulverized coal plants can ramp up to 50%/hour [*13*]. As a result, the amount of additional short-term storage capacity needed (under 20 minutes) as wind energy grows will remain relatively small. This implies limited justification for large energy storage solutions that cycle more than once or twice per day.

The generating capacities in most dams were initially sized to roughly accommodate the mean river flow into the reservoirs. Clearly, a much better use of that hydropower is for peaking, especially since recent variable-speed hydro-generators can respond to major demand changes (from near-zero to full power) in under 15 seconds. Consequently, there has been 1.6 GW of dam up-rating (adding additional hydro-generators) in the past three decades in the U.S. at an average cost of reportedly only $70/kW [*14*]. The total name-plate hydro power capacity in the U.S. is 78 GW [*11*], which immediately suggests it should be quite easy to increase grid-energy-storage capacity by more than a factor of three – possibly much more – via up-rating. Dam up-rating will continue to strongly dominate storage expansion and will provide formidable competition to all other grid-energy-storage options (other than chemical) for decades.

One of the primary factors in the economics of energy storage will be the difference in sale price of the lowest-priced energy and the highest-priced energy in any given day. **Figure 5** illustrates the margin, based on mean MISO data for the first 9 months of 2009, for buying energy during the cheapest hours of the day and selling it during the most expensive hours for several different cycle efficiencies. For example, buying energy during the cheapest hour and selling it during the most expensive hour with 65% cycle efficiency could be worth $48/MWh, assuming one could always time the transactions perfectly. The chart suggests buying and selling the cheapest 2 hours optimally could be worth $32/MWh, but the method used here assumes sufficient storage capacity to buy the energy when it's cheap and sell it when expensive. Normally, the two cheapest hours would be consecutive. Figure 3 and other data suggest that for about half of the year there will be two one-hour cycles per day with about $25/MWh marginal gain. The mean period of increasing price during the other half of the year lasts about seven hours per day; so in principle, a one-hour storage system could cycle three times during this period, but the mean marginal value of this energy, assuming 100% efficiency, would be under $8/MWh.

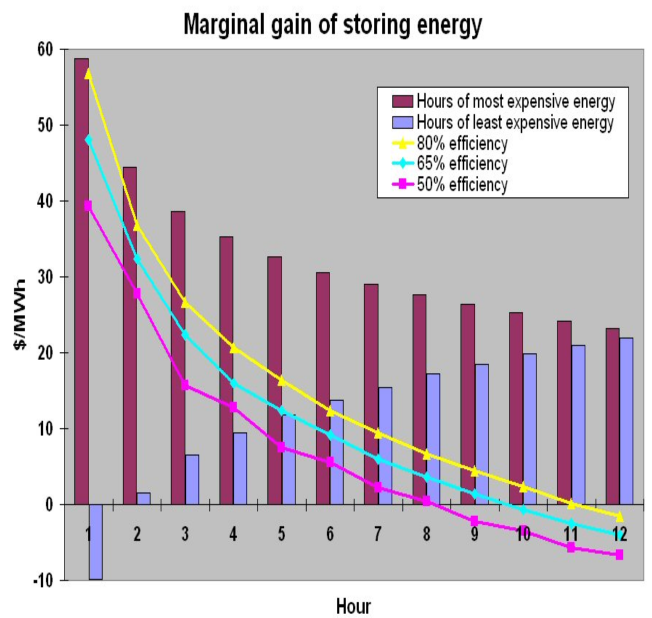


**FIGURE 5. A LOOK AT THE LOWEST AND MOST EXPENSIVE PRICES OF ENERGY, AND THE MARGINAL YIELD IN STORING INCREASING AMOUNTS OF ENERGY AND SELLING IT LATER IN THE SAME DAY.**

Most of the points below the average trace in Figure 4 correspond to Saturday and Sunday. All hours on these two days are considered "off peak", so it is of interest to compare the weekend average price of energy to that during the weekdays. **Figure 6** shows that the marginal value of storage on the weekend (about $7/MWh for 70% efficiency) would often discourage cycling then. Moreover, only with very cheap bulk energy storage would it be practical to store energy from the weekend for use throughout the week.

From this data, several little appreciated characteristics emerge that help illuminate the value of energy-storage duration.

1) There is little value in multiple-cycle-per-day grid-scale storage options, as the market shows little profit in more than one cycle per day.
2) Week-long energy storage would not be justified unless the cost/kWh is extremely low.
3) With storage options that are 80% efficient, the marginal gain for the seventh hour of storage is under $10/MWh – one-sixth the gain in the first hour of storage.
4) At 50% efficiency, the marginal gain of the fifth hour of storage is under $8/MWh.

Of course, the marginal values of energy storage mentioned above have limited relationship to profit. They are simply a starting point in estimating income. The primary expense will be the cost of capital, which is addressed shortly. The results from our model, as will be seen, suggest that of the conventional storage options, only hydrostorage has a chance of being profitable for most grid-scale applications, and even that will be limited.

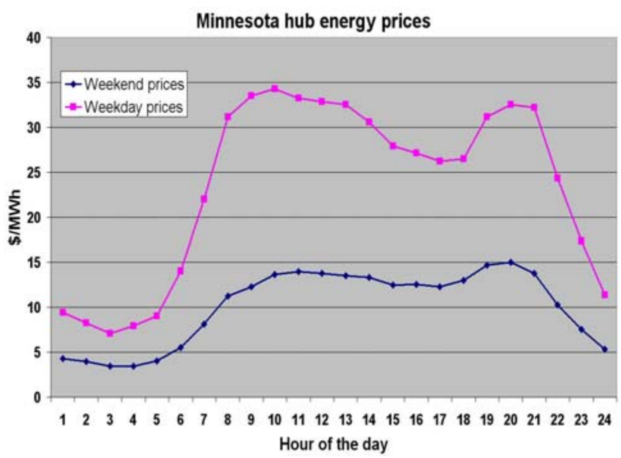

**FIGURE 6. COMPARISON OF WEEKEND PRICES VS. WEEKDAY PRICES, SUMMER 2009.**

### 4.1 Reduction in GreenHouse Gasses.

Grid-scale energy storage can lead to reductions in GHGs only if its input energy is extremely clean (mostly wind, hydro, and nuclear) and if the economics drive increased utilization of clean energy. (For discussion purposes, clean energy is used interchangeably with renewable energy, and reduced- or zero-emission sources.) The only place cheap, clean, grid energy is available is in good wind areas or near nuclear power plants during off peak hours. Note that we see little potential for solar to participate in electrical energy storage, as it is available during off-peak hours only on weekends, and the price variation during the day on weekends is small.

While the energy on the grid can be over 90% clean during off-peak hours, during peak hours it is only ~25% clean. Increased use of high-cycle storage during peak hours (except if directly associated with a solar plant in an area that often has scattered clouds) is more likely to increase rather than decrease GHGs. Therefore, storage times of 12 hours or more are needed for significant load shifting and GHG reductions.

### 4.2 Number and Depth of Discharge Cycles per Year.

The above observations imply detrimental impacts on cost effectiveness and environmental benefit of high-cycle options such as flywheels, lithium ion batteries, and ultra-capacitors. There will always be need for some fast storage beyond the capabilities of spinning reserves or available hydro for short-term regulation and cost avoidance, but the above data suggest there may be only 500 to 800 profitable cycles per year (c/yr) for options geared toward an hour of charge or discharge. In most cases there would be a maximum of about 310 cycles a year that could have a potential environmental benefit. The need for high-cycle storage during peak hours could be a little greater near some solar power plants, but these are likely to be infrequent events.

It seems reasonable to expect that the storage cycles essentially co-incident with the expectations from Figure 3 could be to full depth, but the other half (those responding to random fluctuations) may be only to half depth. Hence, the mean cycle depth for one-hour storage may be about 70%.

### 4.3 Discount Rate.

Not long ago, most VCs were expecting risky ventures to use a discount rate of 15-20%. The events of the past three years have dramatically reduced expectations. Perhaps a zero-risk utility project now could be financed with projections based on a 5% discount rate, but energy storage is not risk free. Thirty-year fixed-rate home mortgages in December 2009 were 4.7% (15-year rates are even lower), compared to 6.7% in October 2008; but energy storage involves much more risk. In our analysis, we use 7%, which is probably the lowest discount rate that could possibly be considered for a storage project. At 7%, the present value of the energy delivered in the 30th year, for example, is only 11% of that in the first year, and its mean value over the lifetime is 39% of its initial value.

### 4.4 Operating and Maintenance Costs.

Transformers operate with nearly zero O&M costs, but nothing else does. Reliable data are simply not available on new storage concepts, so crude estimates have been used, based on some related data. For example, O&M for wind energy is currently about $1/MWh [*15*], while it's about $5/MWh for geothermal. Estimates for lead-acid batteries in 2002 averaged about $1/MWh [*16*]. We have estimated O&M to be $2-6/MWh for the storage options listed in **Table 1**.

## 5. ENERGY TRANSFER INTO WINDFUELS.

Using excess off-peak renewable energy to synthesize standard transportation fuels from $CO_2$ and water electrolysis has recently been proposed as a method of providing sustainable, competitive, carbon-neutral transport fuels, including gasoline, ethanol, and jet fuel [*17*]. Preliminary simulations indicate it should be practical to synthesize all hydrocarbons and alcohols from $CO_2$ and water at system efficiencies in the range of 51-62%, depending mostly on the product mix. The process would be based largely on the commercially proven technologies of wind energy, water electrolysis, and Fischer Tropsch (FT) chemistry, along with new developments in reduction of $CO_2$ to CO via the reverse water gas shift reaction [*18*].

This has the potential of being market competitive by transferring energy from the local grid – which must be saturated in order for energy storage to be environmentally justified – to the global liquid-fuels market, where energy can easily be transported. At $4.00/gallon (which seems likely before long), the value of the energy stored would be ~$110/MWh, and the marginal value of storing the six cheapest hours of energy each day as liquid fuels at 60% efficiency works out to an average gain of $57/MWh (compare to the much lower numbers mentioned for grid storage in the earlier discussion).

The tank-component cost of storing energy in liquid fuels is only $0.02/kWh [*17, 19*], so the energy could be stored for longer periods at extremely low cost, whether for national security or simply to optimally yield the highest price from the market. There is sufficient domestic wind-resource potential and sufficient point-source $CO_2$ to synthesize over twice the current domestic fuel usage, and these "windfuels" are projected to be competitive with fossil fuels within six years, assuming sufficient R&D support.

An electrolysis-based fuels-synthesis process would completely eliminate the need for short-term storage during off-peak hours, as the electrolyzer would be able to respond as quickly as needed (even within milliseconds) to changes in supply or demand. Hence, the presence of sufficient off-peak Windfuels plants on the grid would essentially eliminate the need for other storage systems during off-peak hours. Windfuels would also provide a nearly limitless demand for excess off peak energy. This would add value to the wind farm off-peak output, which will strongly drive the growth of wind power thereby: (1) increasing supply of wind energy during peak hours, (2) halting the growth of coal power plants, and (3) hastening the decommissioning of old inefficient coal plants [*20*]. The carbon-neutral Windfuels would dramatically reduce GHGs, first by ending reliance on tar sands, and eventually by displacing the use of conventional oil and limiting the use of coal to mostly peaking power.

## 6. THE INCREMENTAL LIFETIME COST OF DELIVERED, STORED ENERGY.

The results from our model calculations for several storage options are summarized in Table 1, where they are listed in order from least to most expensive. The last column, headed "Incremental Energy Cost", is the projected mean levelized $/MWh above the input energy cost for delivered energy over the project lifetime. In other words, if the cost of the input energy were zero, this column would be the break-even mean selling price. In all cases, the annual discount rate was assumed to be 7%.

We have chosen storage capacities and peak power ratings that appear to be consistent with plant designs that would cost about 90 million dollars. This size appears to be about the largest amount likely to be funded in a demonstration of pre-commercial technology by a private-public consortium in today's financial climate, especially when several technologies expect to be funded simultaneously.

The ratio of storage to power ratings selected will appear surprising in some cases. They are strongly influenced by the expected number of cycles per year and the expected cycle depth as well as the costs. As explained earlier, we anticipate high-cycle options will see far fewer cycles per year than some have expected. A low number of annual cycles was chosen for lead-acid batteries because this extends their lifetime, and it will be more cost effective to use the battery only when there is a large difference between off-peak and peak rates.

The efficiencies for storage and discharge were each assumed to be the square root of that listed for cycle efficiency. The lifetime delivered energy was calculated by two methods. (1) The product of the mean annual number of cycles, mean cycle depth, storage capacity, square root of cycle efficiency, and lifetime years. (2) The product of the peak power, mean duty cycle (i.e., ratio of average power to peak power), lifetime hours, and cycle efficiency. The average of the two (which were always nearly equal) was used for lifetime delivered energy.

We suspect the products of the number of annual cycles and mean cycle depth estimated for most of the technologies are actually high, as there are only 3400 hours normally considered "peak" annually. The combination of these high estimates, the low discount rate, and the long project lifetimes may mean most of the costs listed are somewhat optimistic – but this may serve to reflect our general optimism with respect to technical progress.

## 7. ESTIMATING CAPITAL COSTS.

The largest uncertainty lies in the numbers used for capital costs of storage capacity and power rating, partly because these numbers are often combined when reported. The values shown in the table come from a combination of recent peer-reviewed papers, discussions with industry insiders, company price quotes, and publicly available price data. Most of the numbers assume several more years of progress (more yet for Windfuels) in technology at rates similar to that of the past few years. In the following sections, we present some comments and references, mostly in the order listed in **Table 1.**

### 7.1 Pumped hydrostorage.

The energy cost, $C_E$, of pumped hydrostorage could be as little as one-quarter or as much as twice that shown ($120/kWh) [*1, 4*], depending on political and geographical factors. Much higher power costs, $C_P$, than shown here ($300/kW) are usually cited [*1, 10, 16*], but the 1.6 GW of up-rating on 58 existing dams over the past three decades has reportedly averaged only $70/kW [*14*], as previously noted. This suggests the current mean power cost could be only $105/kW for limited-variability generators and that most of the cost in new hydro projects is energy related rather than power related. The LEAPS project in California was recently projected (by a detailed study) to provide 7-9 GWh of storage and 500 MW power for $1.1B [*21*]. If we assume 20% of this is power-related and 80% is energy related, the costs would be $440/kW plus $110/kWh. The storage and power of a $90M project would be expected to be less than estimated by linear extrapolation from a large project; but recent reliable price data in the U.S. are scarce, and the data on up-rating costs suggest much lower prices should be possible.

### 7.2 Underground Pumped Hydrostorage.

UPHS is a concept with considerable promise and growing interest [*22, 23*]. Based on experience with large tunnels, the cost of boring very deep caverns in solid rock is likely to be $1500-2500/m$^3$ [*23, 24*]. This would put the energy cost in the range of $80-150/kWh, depending partially on the depth, as the energy cost decreases with increasing head [*25*]. Very efficient Francis-turbines are currently available for heads up to 650 m, and over 1000 m could be accommodated [*22*]. However, the power cost will be higher than for conventional pumped hydro storage because of the need for a flexible power conditioning system, which adds $140-200/kW at moderate power, but even more at high power [*26*].

### 7.3 Compressed Air Energy Storage (CAES).

Some have estimated that the cost of CAES in highly favorable situations may be very low [*27*], but those estimates are based on a number of highly optimistic assumptions. Some low-cost natural caverns are available, and low-cost solution-mined salt caverns will be possibilities in some areas. However, achieving acceptable efficiency with simple adiabatic cycles requires extremely large caverns that will tolerate very high temperatures (at least 500 K) with large swings in pressure and temperature; and efficiency will still probably be under 40% [*24*] – much lower if the cavern is not tight, as would often be the case if an aquifer were coupled into it. An advanced adiabatic cycle (AA-CAES) can achieve 52-64% efficiency, but it requires enormous reservoirs of a high-temperature heat-storage oil [*24, 28*]. A deficiency of all designs is the very limited power range over which they can be operated during either charge or discharge without seriously degrading efficiency. We analyzed an AA-CAES design that appears to permit 61% mean cycle efficiency and broader operating range, but it requires three large oil reservoirs, three stages of re-heat (using the thermal energy stored in the oil), and high-performance turbo machinery. The cost of just the oil for such a cycle was seen to be $140/kWh. Another study estimated the oil cost to be $80/kWh for 55% efficiency [*24*], but the turbo machinery requirements would have been much more severe and the power-response flexibility less. Our design required a cavern volume of 0.15 m$^3$/kWh, cycling from 5 to 10 MPa with temperature swings of only 310-370 K [*28*]. With tunnel boring costs at about $2000/m$^3$, that sets the upper limit for a gas-tight cavern at about $300/kWh. The cost of above-ground steel tanks would be a little higher.

A 300 MW project using a porous saline reservoir (Kern County, CA) has recently been estimated to cost $365M [*29*]. The $25M DOE grant appears to be largely for initial survey work and studies, and no substantive information could be found. Another project toward CAES in a porous geological structure (the Iowa Stored Energy Park) does not appear to have progressed significantly in the past eight years of study. Power costs for simple cycles are being informally quoted at $750/kW [*30*]. In Table 1, we assume very little mining will be required to develop the needed cavern, though there may be few such sites that prove satisfactory. Our estimate of $1200/kW for an AA cycle (with its enormous heat exchangers and oil reservoirs) does not appear excessive [*22, 24, 28*].

### 7.4 Batteries.

There are currently only a few battery storage projects above 8 MW. The world's largest may be the 40 MW, 5 MWh, NiCd system in Fairbanks. There are now good reasons to expect growth in the electric-vehicle market to drive primarily three types of batteries: carbon-lead-acid, lithium ion, and lead acid. That technology driver is likely to mean that other types of batteries (NiCd, NaS, V Redox, ZnBr, NaBr, etc. [*10*]) which cannot participate in the automotive market will be left behind, notwithstanding the strong DOE support they have recently received [*31*]. Thus, the only non-automotive battery we list in Table 1 for reference purposes is that which is currently most advanced, NaS, as demonstrated by its relatively common usage in Japan. Recent actual price data from several sources indicates these batteries at the 6-MWh size currently cost $3000/kWh [*1*, *2*], which is an order of magnitude higher than many estimates that have been published over the past few years [*27*, *32*]. In contrast, performance data often published on lead-acid batteries tend to reflect older technology. Recent carbon-lead-acid, and even "conventional" lead-acid batteries, show enormous potential for greatly increased lifetime, especially at higher discharge rates and low cycle depth [*33-37*]. The numbers listed in Table 1 appear to be realistic for near-term technology with optimum usage, regulation, and control [*33-37*].

**Table 1. Projected Incremental Energy Delivery Cost at 7% Discount Rate in $90M facilities (ignoring input energy cost) for 2015 Technology**

| Device | Storage Capacity | Peak Power | Storage Cost | Power Cost | Cycle Effic. | Mean Cycle Depth | Cycle Rate | Power Duty Cycle | Life Time | Incremental Cost of Energy |
|---|---|---|---|---|---|---|---|---|---|---|
| **units** | MWh | **MW** | $/kWh | **$/kW** | % | | cycle/yr | | years | **$/MWh** |
| **Windfuels** | 2000 | **100** | 0.05 | **900** | 0.52 | **0.5** | 320 | **0.5** | 30 | **38** |
| **H2 fuel cell** | 2800 | **120** | 10 | **540** | 0.7 | **0.4** | 320 | **0.4** | 10 | **51** |
| **pumped hydro storage** | 600 | **50** | 120 | **300** | 0.8 | **0.7** | 330 | **0.4** | 50 | **56** |
| **UPHS** | 550 | **40** | 120 | **500** | 0.75 | **0.7** | 320 | **0.4** | 50 | **68** |
| **carbon-lead-acid battery** | 750 | **70** | 100 | **250** | 0.75 | **0.4** | 500 | **0.3** | 10 | **102** |
| **AA-CAES** | 350 | **30** | 150 | **1200** | 0.61 | **0.55** | 320 | **0.3** | 30 | **162** |
| **lithium-ion battery** | 160 | **40** | 500 | **250** | 0.8 | **0.6** | 600 | **0.2** | 20 | **167** |
| **lead-acid battery** | 1100 | **100** | 60 | **250** | 0.75 | **0.5** | 250 | **0.2** | 5 | **181** |
| **flywheel** | 30 | **20** | 2800 | **500** | 0.85 | **0.7** | 800 | **0.1** | 30 | **532** |
| **NaS battery** | 75 | **9** | 1200 | **300** | 0.74 | **0.7** | 280 | **0.25** | 15 | **774** |
| **ultra-capacitors** | 5 | **5** | 20K | **400** | 0.7 | **0.7** | 1000 | **0.1** | 30 | **2910** |
| **SMES** | 0.6 | **0.2** | 150K | **700** | 0.5 | **0.6** | 300 | **0.1** | 30 | **94,000** |

### 7.5 High-cycle options.

The costs and performance for Li-ion batteries are still unclear even though they are beginning to appear in electric vehicles [*38*, *39*]. Expectations for the GM-Volt battery price are currently about $700/kWh, though recent financial data from A123 indicates their batteries are not yet profitable at $1800/kWh suggesting the actual manufacturing cost will be much higher for quite some time. Li-ion (and PbC-acid) batteries may not be developed specifically for grid applications for quite some time, as automotive applications will be much larger. Here, we have used the expected price of $500/kWh from a recent study [*27*]. A long lifetime (20 years) is expected when advanced automotive Li-ion batteries are used in grid-scale applications cycling only 600 times per year.

Some previous studies [*16*, *27*] have projected much lower energy prices for flywheels than experience has shown can be expected [*22*, *40*]. The costs listed here are consistent with what is actually currently available for moderate-speed flywheels [*40*], where the technology has been mature for several decades [*1*, *22*]. High-speed 6-MWh flywheels are over twice this expensive [*22*].

The numbers listed for ultra-capacitors are not much beyond the characteristics of current products [*41*] and could well be exceeded within 5 years (especially lifetime, for the low cycle rate shown). Flywheels and ultra-capacitors are more competitive where there would be over 30K c/yr, but most "grid-scale" storage applications are likely to see fewer than 1000 c/yr. There could be tens of thousands of applications for Li-ion batteries, flywheels, and ultra-capacitors at substations near factories, trams, and subways where large loads are frequently switched – to improve power quality during these transients. These needs will certainly grow, but there the storage requirements per installation are two to four orders of magnitude less than needed to impact growth in renewables. Clearly, the incremental delivered energy cost for the high-cycle options listed in Table 1 (Li-ion batteries, flywheels, ultra-capacitors) could be well over an order of magnitude less than shown here in those applications.

### 7.6 Superconducting Magnetic Energy Storage

The storage cost listed for SMES differs by nearly three orders of magnitude from optimistic projections some have voiced [*42*], but it agrees both with current industrial experience (a 3 T MRI magnet stores about 1 kWh and costs about $2M) and with theoretical calculations, which put the wire cost alone (NbTi) at $30,000/kWh [*43*]. Other wires (NbSn and high-temperature superconductors) are an order of magnitude more expensive. SMES demonstrations a decade ago cost about $1M/kWh in current dollars [*22*].

### 7.7 Chemical energy storage.

The Windfuels and the $H_2$-fuel-cell rows are different from the other rows in Table 1 in that they each represent only half of a storage/discharge cycle. In the Windfuels case, most of the off-peak energy is stored as chemical energy in liquid hydrocarbon and alcohol fuels for the transport market, though some hydrogen would be available for other purposes. The costs are based on the only known estimates that are yet available, and they do not include development costs [*44*]. They also assume continued, strong progress in price reduction of electrolyzers, where stack efficiencies above 93% have been demonstrated and price reductions of a factor of six over the next decade are expected [*45*]. Note that the primary motivation for the Windfuels plant is to produce sustainable, carbon-neutral transportation fuels, not grid-peaking power, so its energy sales price is independent of grid peak prices.

Some explanation is needed for our projections of fuel-cell (FC) prices, as current small-scale (5 kW) PEM H2-to-AC power systems cost $3000/kW, but several recent DOE studies project near-term costs of automotive PEM FCs (with 2010 technology) would be ~$104/kW for 80-kW units at the production rate of only 30,000/yr [*46*]. These DOE projections seem unrealistic, as an automobile manufacturer believes it will cost $1000/kW for 30-kW units at the rate of 50,000/yr [*47*]. Recent projections for methane-to-AC solid-oxide fuel cells (SOFCs) using near-term technology at the 5 MW size are $870/kW [*48*] for a build rate of dozens per year. For SOFC H2-to-AC, the cost would likely be $650/kW, even though the stack cost may be under $140/kW. For either PEM or SOFC, 2012 technology should permit 10-yr lifetimes [*22, 49*]. Our estimate for a 5 MW PEM FC H2-to-AC station in 2012 is $550/kW, assuming dozens of stations are being built annually and a manufacturer is producing the stacks at the rate of 5 GW/yr. For either the PEM or SOFC, the unit cost of a single 120 MW station is expected to be 10% less than for moderate-scale production of 5 MW stations. Using the mean of the above PEM and SOFC estimates, we arrive at $540/kW.

Of course, chemical energy storage – mostly in the form of coal – has been the norm thus far for the grid, and a strong argument can be made that coal should continue to be used to meet most of peak requirements beyond that which can readily be supplied by wind, hydro, solar, and nuclear. Pulverized-coal power plants often have 8 parallel turbine trains that can rather quickly be shut down or brought up to respond efficiently over more than an order of magnitude range in power demand. Undoubtedly, engineering changes would be possible to improve responsiveness and efficiency over an even broader range of output power levels. If coal were supplying only the essential peaking needs of the grid, coal usage could be only about one-third of present usage. The $CO_2$ produced from that level of coal burning would be about what is needed to allow the Windfuels plants to synthesize all the fuels needed for transportation.

## 8. CONCLUSIONS.

A simple model was used to calculate the incremental cost of the energy delivered, based mostly on industry data for the primary parameters. The value of storage duration in the preliminary model was not explicitly included, as all examples were assumed for use primarily in daily cycles. However, we showed that the market value of energy storage for short periods of time (under a few hours) is likely to be minimal for grid-scale purposes in areas of high wind penetration. Only low-cost daily storage is easily justified, both from an economic and environmental perspective.

Grid-scale energy storage could lead to significant reductions in GHG emissions in regions where the off-peak energy is very clean. These areas will be characterized by a high level of wind energy with cheap off-peak prices (probably under $12 MWh) and cheap peak prices (probably under $50 MWh for the mean annual rates). At this price differential, the only full-cycle options with a chance of being commercially viable are hydro storage and UPHS. The next closest options to being competitive may be $H_2$ fuel cells, carbon-lead-acid batteries, and AA-CAES in some favorable locations.

Windfuels is in a class by itself because its primary products are transportation fuels, which could be priced at $150/MWh (~$5/gallon of gasoline) by 2015. The transportation fuels market will justify Windfuels, and the Windfuels plants will have the side benefit of solving the primary grid-storage problems at little additional cost. They will also improve power quality during the off-peak hours, and they will make hydrogen fuel cells much more attractive for improving power quality during the peak hours.

The need for high-cycle-rate storage (using lithium-ion batteries, PbC-acid batteries, flywheels, or ultra-capacitors) to deal with rapid transients at substations near factories, subways, and trams will grow as these demands grow, but their need would decrease with the growth of dam up-rating, Windfuels, UPHS, and $H_2$ fuel cells, as all of these would also help improve power quality.

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