Handbook of Energy Storage for Transmission or Distribution Applications

1007189

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Technical Update, December 2002

EPRI Project Manager

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This document describes research sponsored by EPRI.

The publication is a corporate document that should be cited in the literature in the following manner:

Handbook of Energy Stoage for ransmission or Distribution Applicaitons, EPRI, Palo Alto, CA: 2002. 1007189.

EPRI FOREWORD

EPRI's Energy Storage for Transmission & Distribution Applications program (Program 94) offers a portfolio of innovative energy storage options to support T&D owners in their objective to lower capital and operating costs of their equipment. This is accomplished by providing funders with credible and timely cost, performance and technology readiness data for all the energy storage options suitable to T&D applications. Since peak shaving and other applications of energy storage devices have been proven in specialized non-T&D applications the key issue for T&D decision makers is how to specify and deploy the proper energy storage option for the re-regulated industry of today.

Consistent with the above goal, EPRI is presently engaged in a project to create and maintain a set of guidelines for the application of energy storage technology in the electric utility T&D system. The project is titled:

> *Handbook of Current Energy Storage Options For Improved Reliability and Load Management At The Transmission & Distribution Level: Technology Status, Lessons-Learned, Applications & Economics.*

As a result of a recent increase of interest in and deployment of energy storage options for T&D applications, a large body of information has accumulated, but it is often not readily available to utility engineers in a single, succinct document. Facts on technology description, status, cost and performance information, and lessons learned are often dispersed among multiple vendors and users of prototype and developmental hardware. "Apple to apple" comparative data is virtually non-existent. This project intends to develop "one-stop-shop" handbook of current energy storage options useful for T&D application.

This report is an interim report. It focuses on a subset of the technologies that will ultimately be covered. There are seven chapters, each on a separate energy storage technology, as follows:

- Vanadium Redox Battery
- Regenesys Battery
- Sodium Sulfur (NAS) Battery
- Superconducting Magnetic Energy Storage (SMES)
- Flywheel Energy Storage
- Electrochemical Capacitor Energy Storage
- Compressed Air Energy Storage (CAES)

These chapters have been authored by different people, as shown on the title page for each. As this is an interim report, there has been minimal attention paid to making the formatting consistent.

For each technology, the topics covered in the handbook include:

- Technology description;
- Technology status (including lab and field test results and lessons-learned from existing plants and demonstrations);
- Technology applications (including plant design components and parameters, operating modes, efficiency, maintenance and life expectation); and
- Cost-benefit economics (including establishing a business case for storage).

EPRI plans to issue the full version of the Handbook in 2003. Periodic updates will be undertaken in order to maintain an up-to-date database of information. The Handbook will be available in print and electronic (on CD-ROM) media. The CD-ROM version will have electronic links and full word and phrase search capability.

EPRI Energy Storage Handbook: Vanadium Redox Battery Chapter

December 2002

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1. Description

1.1. Introduction

The Vanadium Redox Battery (VRB) is a flowing-electrolyte battery (or "flow battery") that lends itself to high capacity, high cycle count requirements necessary for utility-scale T&D electricity storage applications. As its name implies, the VRB is based upon chemical reactions employing the mineral vanadium, a commercially produced metal.

Unlike conventional batteries, the VRB stores its chemical energy in external electrolyte tanks that are sized according to the needs of the user. As necessary, aqueous liquid electrolyte is pumped from storage tanks into a set of reaction stacks where chemical energy is converted to electrical energy (discharge) or electrical energy is converted to chemical energy (charge). The electrolyte reactants can be thought of as a "fuel", so the VRB is sometimes referred to as a fuel cell or a reversible fuel cell (as are other flow batteries).

Figure 1 shows the stacks and tanks of a 250 kW / 520 kWh installation in Cape Town, South Africa.

Figure 1
Typical VRB stacks and tanks (Courtesy Vantech)

The VRB promises the following advantages over other storage technologies:

- **Power/Energy Design Flexibility**. Since electrolyte is stored separately from the reaction stacks, the energy storage rating (kWh) is independent of the power rating (kW). This allows for design optimization for power and energy separately, specific to each application.
- **Long Service Life**. Many of the failure modes associated with other batteries are avoided in the simple, elegant VRB electrochemistry. There are no

electrodeposited solids of the active substance, and the reactions do not require elevated temperatures.

- **Layout Flexibility**. The tanks can be easily arranged to fit the available space and shape of the facility. In one VRB demonstration, the tanks were made of rubber that conformed to the shape of basement walls in an office complex.
- **Low Standby Losses**. Depending upon the application, it is possible to drain the stacks and store the charged electrolyte for long periods of time without self-discharge or pump auxiliary loads.
- **Simple Cell Management**. Conventional batteries must be periodically charged at high voltages to equalize all cells to the same state of charge. This can produce undesirable levels of explosive hydrogen gas (a safety issue) and reduces the available water in the battery (a life issue). In the VRB, however, all cells share the same electrolyte at the same state of charge, so equalization is unnecessary.

There are also some relative disadvantages of the VRB, including:

- **Mechanical Complexity**. The advantages of storing electrolyte in tanks external to the stacks are offset by the complexity of hydraulic design. The VRB (as do other flow batteries) requires anolyte and catholyte pumps and associated plumbing to transport and distribute electrolyte to and from the stacks and within stacks to individual cells. Designs must address potential leaking throughout the system, and provide sufficient secondary containment in the event of leaks and spills.
- **Parasitic Losses**. Electrolyte pumps draw power while the system is operating, reducing overall system efficiency.
- **Footprint**. Relative to other battery technologies under consideration for T&D applications, the VRB requires 2 to 3 times the area per unit energy stored. This may limit applicability in locations where space is important.

The VRB is an emerging energy storage technology that is entering the commercialization phase of development. The basic electrochemistry research is essentially complete, and the leading manufacturers have demonstrated full-scale grid-connected systems in Japan, South Africa, and North America. However, true commercial, standardized, volume-produced products are not yet available in the marketplace.

1.2. History of Development

Early work on various redox batteries was undertaken by NASA in the 1970s and later by the Electro-Technical Laboratory (ETL) in Japan. In 1984, this foundation was applied to the VRB at the University of New South Wales (UNSW) in Sydney, Australia. Their work focused on the vanadium / vanadium redox couple, electrolyte stability at high concentrations, and production of electrolyte from raw materials. Several proof-of-concept systems were built by UNSW and others including a battery to store electricity produced by solar photovoltaic panels (Thai Gypsum Products, Thailand), an emergency back-up system for submarines (Australian Department of Defense), a battery for an electric golf car, and a 200 kW / 800 kWh load-leveling battery (Mitsubishi Chemicals/Kashima-Kita Electric Power Corporation, Japan).

In 1998, intellectual property rights to the technology were sold to Pinnacle VRB, Ltd. (Sydney, Australia). Sumitomo Electric Industries (Osaka, Japan) acquired the ETL technology and, under license to Pinnacle VRB, further developed the technology by designing cell stacks and complete integrated systems.

In addition to the UNSW/Sumitomo development efforts, several VRB-related technologies have been under development since 1995 by Squirrel Holdings, Ltd (Thailand). These include a series-flow battery, electrolyte production, and a vanadium-based fuel cell that is fueled by locally-grown agricultural crops.

1.3. Technology Description

As illustrated in Figure 2, the VRB cell is based upon electron transfer between different ionic forms of vanadium. At the negative electrode, V^{3+} is converted to V^{2+} during battery charging by accepting an electron. During discharge, the V^{2+} ions are reconverted back to V^{3+} and the electron is released. At the positive electrode, a similar reaction takes place between ionic forms V^{5+} and V^{4+}.

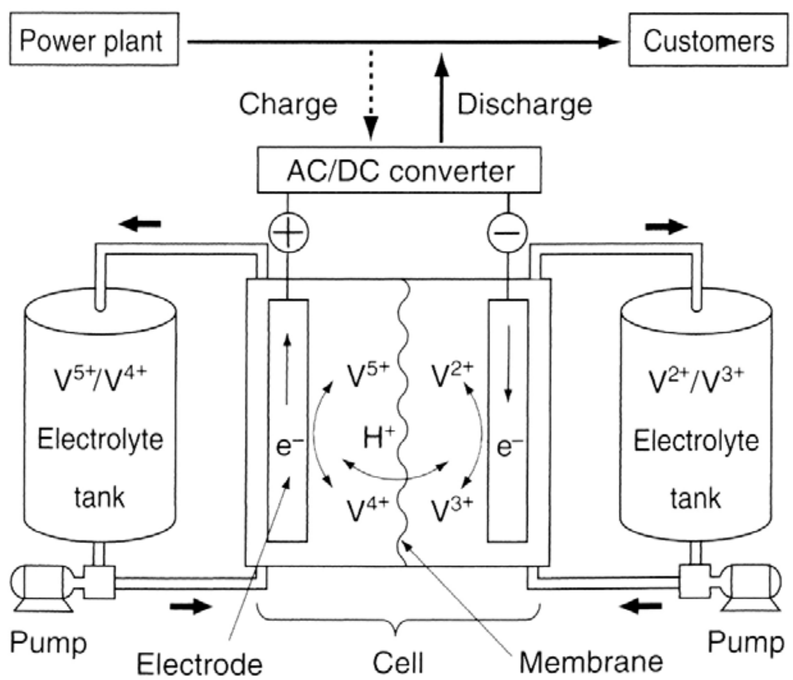

Figure 2
Principles of the VRB (Courtesy SEI)

Overall, the reactions that take place at the electrodes are given by the following equations:

$$\text{Positive Electrode:} \quad V^{4+} \underset{discharge}{\overset{charge}{\rightleftharpoons}} V^{5+} + e^{-}$$

$$\text{Negative Electrode:} \quad V^{3+} \underset{discharge}{\overset{charge}{\rightleftharpoons}} V^{2+} + e^{-}$$

Electrolyte is made up of a vanadium and sulfuric acid mixture at approximately the same acidity level as that found in a lead-acid battery. It is stored in external tanks and pumped as needed to the cells. Electrolyte concentration changes according to the state of charge.

The cell is divided into two "half-cells" by a proton exchange membrane (PEM). This membrane separates the two different vanadium-based electrolyte solutions – the anolyte and the catholyte – and allows for the flow of ionic charge (protons, or H+ ions) to complete the electrical circuit.

Cells have a nominal voltage of about 1.2 V (DC) as defined by the electrochemical properties. To achieve useful voltages (such as those used as inputs to a DC-to-AC power conversion system), cells are combined ("stacked") electrically in series. In most constructions, "cell stacks" are fed by distributing electrolyte through a manifold to each cell. Figure 3 illustrates a typical parallel-feed cell-stack design that combines electrodes, membranes, and frames.

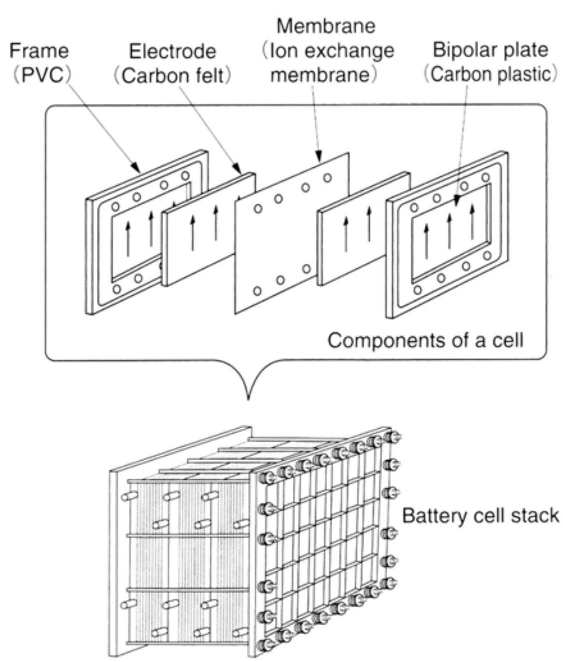

Figure 3
Construction of a VRB cell stack (Courtesy SEI)

1.4. Technology Attributes

Capacity

The capacity of a battery energy storage system (BESS) is measured in both maximum power level (kW) and energy storage capability (kWh). In the case of the VRB, these two system ratings are independent of each other. In principle, the battery stack and PCS capabilities determine the kW rating, while the electrolyte concentration and storage tank dimensions determine the amount of energy that can be stored.

For a given power level, the incremental cost of energy storage is based primarily upon the cost of additional electrolyte storage. The VRB technology favors applications having a high kWh/kW ratio, applications requiring several hours of storage. Most VRB systems fielded to date are capable of discharging at maximum design power for a period of 4-10 hours.

Space requirements

The main components of the VRB include the storage tanks, pumps and plumbing, cell stacks, and power conversion equipment. Footprint and volumetric space requirements scale with system ratings and can be very site-specific.

For example, in one project, the tanks and stacks were located on separate floor, increasing the height requirement, but decreasing the footprint. In another project, tanks were made from rubber bladders that could be folded and passed through confined passageways and then expanded and installed in an unused underground office basement area.

One study [Corey, 2002] estimated the size of a 2.5 MW/10 MWh VRB system to be 12,000 – 17,000 sq. ft. This was significantly larger than the 5,000 – 7,000 sq. ft. footprint estimated for the other technologies included in the study, sodium/sulfur and zinc/bromine. These results would suggest that the VRB is more suited to locations in which space is not a primary constraint.

Maintenance requirements

Without extended field experience, the system maintenance requirements are not well established. However, the primary maintenance items would be annual inspections, and the electrolyte pump bearings and impeller seals would need to be replaced at intervals of about every five years. As necessary, smaller parts, such as electronic boards, sensors, relays, and fuses would be replaced.

Life

The critical system component is the cell stack, which can degrade in performance over time and require replacement or refurbishment. At 100 charge/discharge cycles per year, it is expected that the cell stack would have a life of 10 – 15 years. However, the tanks, plumbing, structural elements, power electronics, and controls would have longer useful lifetimes. It is possible to replace only the stacks, and keep the remainder of the system in place.

Efficiency

Several losses must be accounted for in characterizing the VRB performance:

- **Transformer losses**. Most utility scale and industrial PCSs are designed with outputs around 480 VAC. To connect to utility distribution voltages, a transformer must be installed resulting in losses of a few percent. Even for non-utility systems, isolation transformers are installed to prevent DC injection into the AC grid.
- **PCS losses.** Whether charging or discharging, power flow through the PCS is subject to losses related to voltage drops across the switching devices. PCS throughput efficiency depends somewhat on load and PCS design, but is typically in the 92-96% range.
- **Battery DC losses**. The energy to charge the battery is typically 20% greater than the energy delivered during discharge. Internal battery losses include *voltaic* losses such as ionic flow resistance and *coulombic* losses such as cell-to-cell shunt currents (stray ionic flow through the stack manifold). Actual DC losses depend on rate of charge and discharge (the system is slightly more efficient at lower rates).
- **Pumping losses**. Pumping power is a relatively constant auxiliary load that is drawn whenever electrolyte must be supplied to the stacks, i.e., during charge and discharge. In some applications such as backup power, it is possible to charge the battery, then turn the pumps off for long periods of time. The actual efficiency penalty for pumping depends upon the operation of the pumping, the frequency of cycling, and the pump design. At the 250 kW Stellenbosch demonstration in South Africa (see below), four pumps each drew 2.2 kW (8.8 kW total).

The "round trip" ("turnaround") efficiency – including transformer losses during charge, PCS losses during charge, battery DC losses, PCS losses during discharge, transformer losses during discharge, and pumping losses – is on the order of 70%.

Response Time

The battery can is capable of transitioning from zero output to full output in microseconds – virtually instantaneously – provided the stacks are primed with reactants. However, the power electronics respond within milliseconds, and the response time of the controls and communications (sensing the load requirements and signaling the PCS to take action) can be even longer.

Where response time is important, the control system must be programmed to keep the pumps on and electrolyte flowing through the stacks. This requirement imposes a small performance penalty due to the constant auxiliary losses of the pumps. If response time is not critical, such as in peak shaving applications, then the stacks can be drained and the pumps turned off. This mode eliminates pumping losses and self discharge during downtime. When the battery is called into service, a minute or two would be required to start the pumps and transport electrolyte to the stacks.

Environmental impact

The VRB stacks, plumbing, and tanks, are primarily composed of recyclable plastic materials, and the electrolyte can be refurbished and reused. There are no toxic chemicals that must be disposed of at the end of life, such as found in other electrochemical storage technologies. For this reason, the VRB is promoted as a “green” storage technology.

The only chemical in the VRB system is the vanadium electrolyte, ionic vanadium in sulfuric acid at approximately the same concentration found in flooded lead-acid batteries. Its handling and safety requirements are the same as sulfuric acid. The electrolyte is internally contained within industrial-grade HDPE tanks and pressure-rated PVC pipe and fittings. The VRB is placed within a spill containment area compliant with local regulations.

As with all storage technologies, every charge/discharge cycle results in some loss of energy due to system inefficiencies. For typical grid-connected applications, this means that from a global perspective, there may be increased air emissions associated with the generation of this lost energy. Of course, for renewable energy applications, there are no air emissions considerations, and in some applications, the VRB serves to increase the utilization of renewable sources.

DC Electrical Characteristics

In most VRB systems, the DC bus is connected to the cell stack terminals. The DC voltage is determined by the cell count, and is typically 100 V or more. When power requirements exceed the current ratings of a single stack, multiple stacks are connected in parallel. However, other configurations are possible. Stacks can be placed in series to boost DC voltage, but this requires separate electrolyte hydraulic plumbing and storage to minimize ion flow losses (“shunt currents”) that increase with voltage. Cellenium is developing an unconventional power conversion technology in which individual cells are tapped and switched, providing near-sinusoidal outputs with incremental voltage steps equal to the cell voltage.

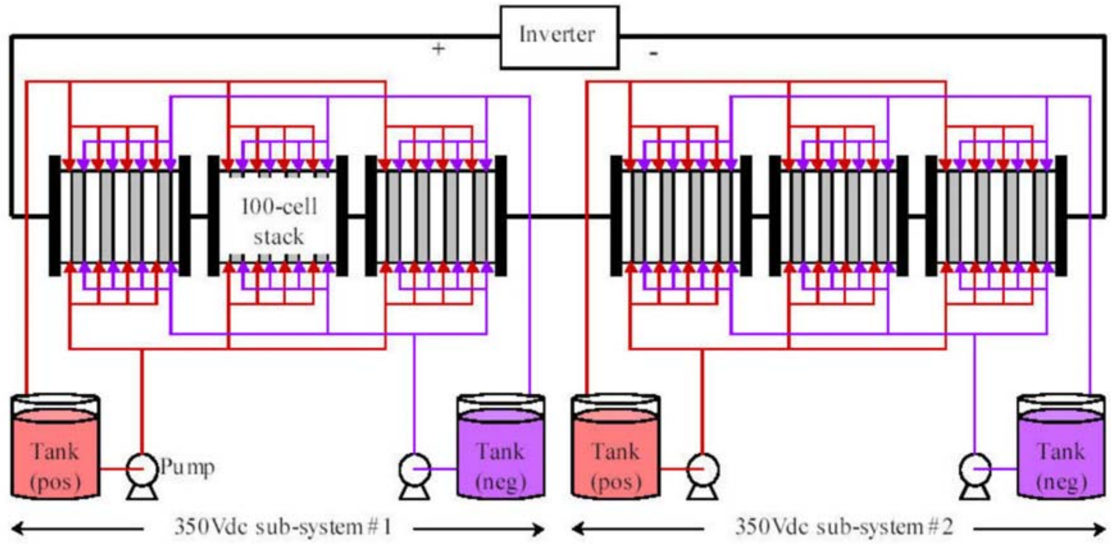

Figure 4
Typical flow configuration (Courtesy Telepower Australia)

It is likely that future VRB systems will be manufactured in several standard AC configurations to eliminate project-specific engineering costs. Today's systems, however, include custom-specified PCSs and project specific DC designs.

As the battery is charged and discharged, the DC bus varies in voltage. The open circuit voltage varies with the battery state-of-charge, and charging or discharging produces a corresponding increase or decrease in bus voltage. The PCS must be designed to handle the full voltage "window". At the Stellenbosch demonstration, for example, the DC bus voltage ranged from 650 to 850 VDC (1.08 to 1.42 volts per cell). Since the battery is occasionally fully discharged to 0 VDC (for maintenance and transport), a mechanism such as switched DC resistive loads must be provided to accommodate voltages below the operating range of the PCS.

As charged electrolyte is stored in separate anolyte and catholyte tanks, no self-discharge occurs during extended periods of downtime. This would be advantageous in applications such as spinning reserve that require availability of stored energy, but do not require instantaneous power on demand. Under these conditions, the pumps would be powered down, causing the stacks to drain back into the tanks, and the battery would retain its full charge without incurring ongoing parasitic pump losses. It could be restored to full power in a matter of minutes by restarting the pumps and flooding the stacks.

While it would be possible to design the hydraulic system to retain active electrolyte in the stacks when the pumps were off, the battery would self-discharge over a period of hours, depending upon the stack (and associated manifold) volume, the number of cells (stack voltage), and the concentration of electrolyte. Furthermore, the energy storage capacity would be negligible.

The battery is typically connected to the DC bus that feeds the PCS. In this configuration, the PCS would be designed to operate within the voltage window of the cell stack or series of cell stacks. An alternative configuration is to insert a DC/DC chopper circuit between the battery and the DC bus so that the PCS operates at a voltage independent of the battery state of charge. This configuration can be used to optimize the PCS according to the switching device characteristics and the AC voltage and to share multiple devices on the DC bus, such as fuel cells, flywheels, or photovoltaic systems as illustrated in Figure 5. The enhanced flexibility is offset by the cost of the chopper and the DC/DC conversion efficiency penalty.

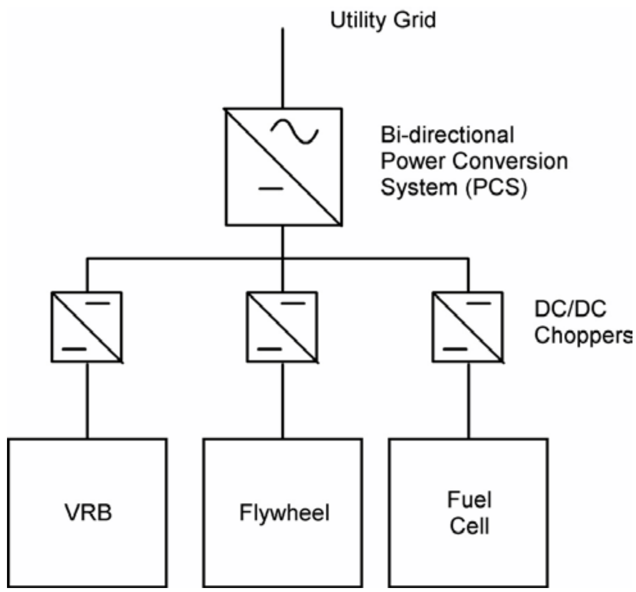

Figure 5
Possible Hybrid Configuration with DC Bus Isolation

AC Electrical Interconnection

Most VRB applications require a PCS to convert the DC energy of the battery into usable AC electric power. Modern power conversion technology provides for bi-directional power flow, so the same equipment can be used for both charging and discharging the battery.

A wide range of PCS configuration options are possible. These include off-grid systems, such as would be required for remote renewable energy applications that provide constant AC voltages to the load. Grid-connected systems, such as would be used for utility and industrial applications, are connected at a fixed voltage and vary current to and from the grid. PCSs are available for 50 or 60 Hz networks.

The systems are designed to meet all utility interconnection requirements, such as

- Over/under voltage protection
- Overcurrent protection

- Over/under frequency protection
- Manual disconnect switches

These requirements vary by utility, and they typically vary by power rating or interconnection voltage.

The PCS industry has evolved significantly over the past 20 years and supports a number of related technologies. These include variable speed wind turbines, fuel cells, photovoltaics, other battery energy storage technologies, and variable speed drives. These markets have reduced the cost and increased the reliability of systems, and the VRB manufacturers benefit by having multiple vendors to select from.

2. Status

2.1. Licensing

The largest VRB suppliers are Sumitomo Electric Industries (Japan) and Vanteck (VRB) Technology Corporation (Canada). These companies license certain intellectual property and marketing rights from Pinnacle (Australia). These companies each have non-exclusive rights to manufacture and market their products anywhere in the world[1]. In turn, they pay either royalties or site licenses to Pinnacle, depending upon the project location.

Key patents held by Pinnacle relate to the use of vanadium in each of the two half-cell reactions, the construction of cells such as the bipolar electrodes, and the electrolyte formulae that allows for high concentrations of vanadium sulfide in solution without precipitating into solid. Sumitomo and Vanteck each hold other VRB-related patents that are independent of the Pinnacle IP.

It is interesting to note that SEI and Vanteck are also component suppliers to each other. SEI has developed important stack manufacturing expertise, and is a supplier of stacks to Vanteck. Vanteck has a strategic alliance with Highveld Steel and Vanadium Corporation (South Africa), producer of 70% of the world's vanadium supply, and will supply electrolyte to SEI. Vanteck owns a 73% controlling interest in Pinnacle, so SEI royalty streams indirectly benefit Vanteck.

Cellenium (Thailand) is not a licensee of Pinnacle, and it is unclear whether they plan to (1) enter into a license agreement, (2) to delay commercialization until after the patents expire, or (3) to contest the legality of the patents. Cellenium has exclusive rights to a number of international patents as the sole licensee of Squirrel Holdings, Ltd.

[1] The licensing agreements call for certain restrictions in Japan and Africa, and they differentiate between applications as to whether royalties or license fees apply. However, in practice, these terms are not expected to materially impact the commercialization efforts of either supplier.

2.2. Sumitomo Electric Industries, Ltd.

SEI is a major supplier to the electric power industry with 8,500 employees and nearly $7B in annual sales. Since 1985, SEI has researched and developed the VRB, and has fielded a number of demonstration systems in Japan.

SEI markets its VRB products worldwide and has commercial sales of MW-scale systems in Japan. In North America, SEI's products are marketed exclusively by Reliable Power Inc. (Arlington, Virginia). SEI intends to establish a VRB manufacturing company in North America as the demand for VRB systems increases.

Various demonstration and commercial projects (Table 1) serve to establish the viability of the technology in a variety of applications and operating modes. While incremental improvements to the technology are anticipated, the basic research is complete, and efforts will be focused on product development and manufacturing.

Multiple cell stack designs have been and will be manufactured by SEI to meet a variety of application requirements. One such design, provided to Vantech for the Stellenbosch project, incorporated 100 cells in series, is rated at 42 kW continuous (130 kW peak), has dimensions of 1.2m (L) x 0.9m (W) x 1.1m (H), and a weight of 1,400 kg. Other projects in Japan incorporated stacks with ratings of 20 kW and 50 kW.

Table 1
SEI Project Experience

Location	Application	Ratings	Operation
Sumitomo Densetsu Co., Ltd.	Peak shaving	100 kW / 8h	Feb 2000
The Institute of Applied Energy	Stabilization of wind turbine output	170kW / 6h	Mar 2001
Tottori SANYO Electric Co., Ltd.	Power quality (voltage sag compensation) and peak shaving	1500kW / 1h (3000 kW instantaneous)	Apr 2001
Obayashi Corp.	Solar PV storage (DC only)	30kW / 8h	Apr 2001
Kwansei Gakuin University	Peak shaving	500kW / 10h	Jul 200l
(Italy) CESI	Peak shaving	42kW / 2h	Nov 2001

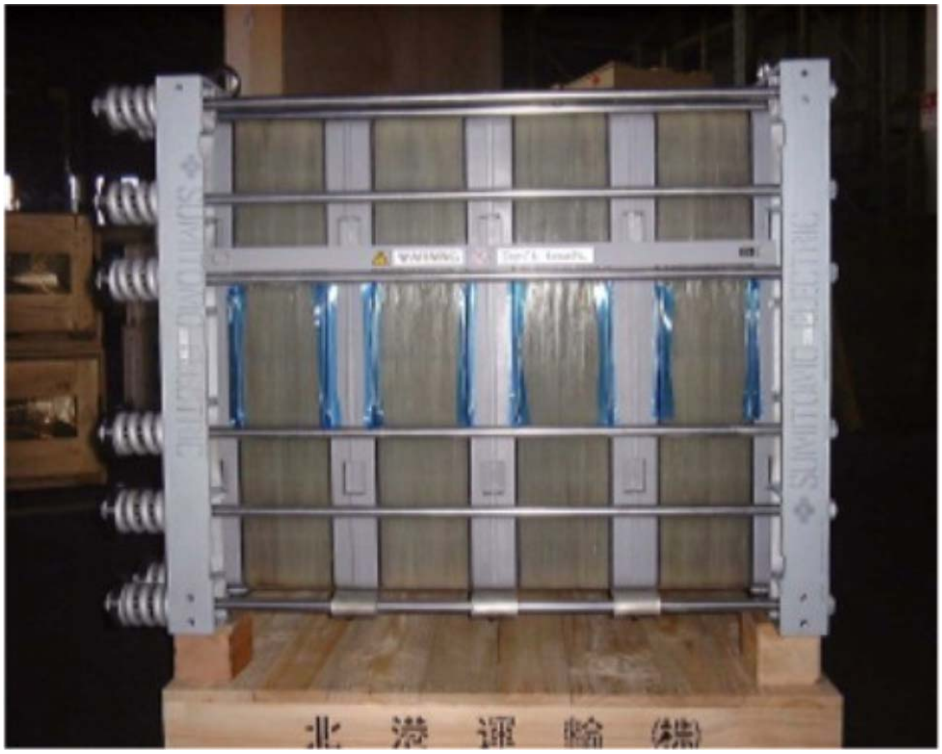

Figure 6
SEI Cell Stack (Courtesy Telepower Australia)

2.3. Vantech (VRB) Technology Corporation

Vantech is a small technology development company based in Vancouver, BC. Vanteck is listed on the TSX Venture Exchange ("VRB"), the OTC Pink Sheets ("VTTCF") and on the Frankfurt Exchange ("VNK"). Its largest shareholder is Federation Group with 34% ownership. The company has invested several million dollars on the advancement of VRB technology, with most of the effort in systems design rather than research.

The company has strategic relationships with Highveld Steel and Vanadium Corporation (South Africa) for vanadium material supply, SEI for cell stacks, Telepower Australia for systems integration and construction, and TSI-Eskom (South Africa) for power electronics. For small systems (1 to 5 kW), Vanteck has entered into a joint venture with Schmitt Industries, Inc., a precision manufacturing company in Portland, Oregon. A commercial product for this market is projected for July 2003.

To prove the system design and reliability of a large-scale system in the field, Vantech designed and installed a 250 kW / 2 hour VRB system at the University of Stellenbosch in Cape Town, South Africa in 2001. The system was made from six 42 kW, 100-cell stacks (650 – 850 VDC) arranged in series with two hydraulic systems. Figure 1 shows the stacks and tanks from this project, and Figure 4 shows the hydraulic configuration. Building upon the success of this project, the company is currently installing in 2002 the same stacks in a 250 kW / 8 hour system in Moab, Utah in a project sponsored by PacifiCorp.

Vantech also intends to develop VRB systems for the wind industry to provide load shifting and system stability. They were awarded a contract to install a 200 kW / 4 hour VRB for Hydro Tasmania at their King Island windplant. The system will be used to stabilize windfarm fluctuations and maximize energy production.

2.4. Cellenium Company, Ltd.

Cellennium was originally involved in the development of the VRB under the company name Thai Gypsum that, in 1995, demonstrated an early battery in a solar photovoltaic application. In its current corporate form, the company is not a licensee of the Pinnacle technology, and it is unique among the developers in its approach to the marketplace. The company is pursuing three separate vanadium technologies:

- a 1 kW battery with a unique "series" flow design and biomass application;
- a technique for dissolving vanadium pentoxide in acid to produce electrolyte; and
- a power conversion technology that uses the VRB stack design.

Cellenium is headquartered in Thailand with subsidiaries in US and Europe. Research is conducted by a variety of organizations in the US (Washington and Arizona), Sweden, Italy, Switzerland, and Thailand. Several million dollars of private investment has funded its development activities, and an additional $5-10M will be required for commercialization over the next two years.

Unlike the Pinnacle technology, Cellenium uses a unique series flow through its stacks as illustrated in Figure 6. This design virtually eliminates shunt currents and ensures that each cell has the same flow rate, however each cell operates at a different voltage, unlike parallel flow designs.

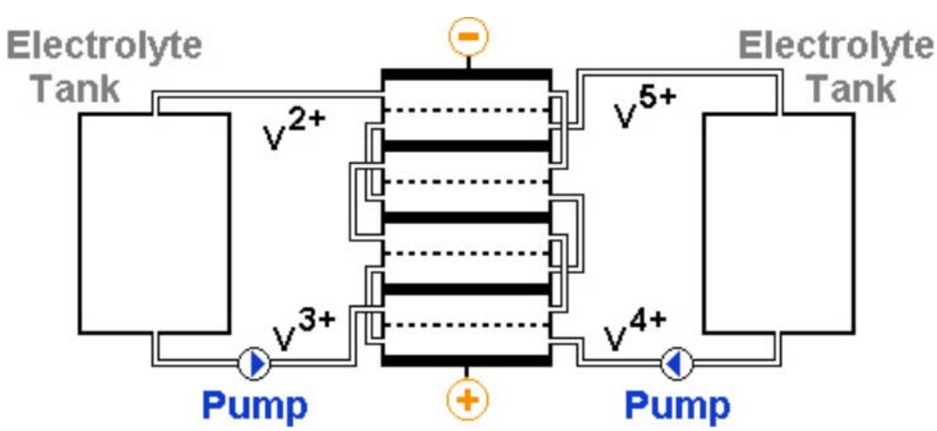

Figure 7
Cellenium Series Flow Design

Cellenium is developing other non-storage vanadium technologies, including a vanadium sulfate fuel cell technology that is capable of converting locally-produced sugar crops into electricity. Their market strategy focuses primarily on this application rather than the storage battery.

While the Cellenium VRB is capable of connecting to a conventional PCS, the company is developing a unique “inductionless” power conversion technology that would replace the conventional PCS. By tapping each individual cell within the stack, an AC waveform can be produced by switching individual cells. The “AC terminals” on the battery can produce a relatively smooth waveform with a peak of 170 V and a step resolution of 1.3 V (the cell voltage). The system can be used as a frequency converter or a standard AC/DC converter.

Precommercial 1 kW Cellenium VRB prototypes will be available by November 2002 including systems used for (1) solar grid connected applications, (2) solar stand alone applications, and (3) load leveling applications.

2.5. Technology Status Summary

Table 2 summarizes the status of the Vanadium Redox Battery in its current stage.

Table 2
VRB Technology Status

Technology/Company	Status	Funding Organization	Major Demonstrations	Lessons Learned	Development Trends/Plans	Issues
Sumitomo	Early commercial	Publicly traded company	Sumitomo Densetsu, 100 kW / 8h (Feb 2000) Institute of Applied Energy, 170kW / 6h (Mar 2001) Tottori SANYO Electric, 1500kW / 1h (Apr 2001) Obayashi Corp., 30kW / 8h (Apr 2001) Kwansei Gakuin Univ., 500kW / 10h (Jul 200l) CESI, 42kW / 2h (Nov 2001)	Construction and utility interconnection experience Experience with multiple applications (wind, PV, peak shaving, power quality) Developed capabilities to scale up to large power levels	Market expansion worldwide Larger, scaled up systems Standardized product lines	Systems not safety or performance certified (e.g., UL listing) Long term cycling experience lacking Large footprint Little ongoing maintenance experience
Vantech	Pre-commercial	Publicly traded company	Univ. of Stellenbosch, 250 kW / 2 h (Aug 2001) PacifiCorp, 250 kW / 8 h (Planned 2002) King Island, 200 kW / 4 h (Planned 2003)			
Cellenium	Developmental	Private funding in Thailand	Three units, each 1 kW (Planned 2002)	Proven series flow concept	Vanadium sulfate fuel cell "Inductionless" power conversion technology	IP rights uncertain Funding for commercial development

3. Applications

3.1. Applications Overview.

Due to its relative mechanical complexity and economies of scale, the VRB is most suited for utility-scale power systems in the 100 kW – 100 MW size range in applications having low power/energy ratios (long discharge durations). The principle T&D applications with these characteristics include:

- DR/Peak Shaving
- Spinning Reserve
- Windfarm Stabilization & Dispatch

It is generally accepted that the viability of electricity storage is dependent upon cases in which multiple operating modes – and multiple economic benefits – can be exploited. For example, peak shaving economics is driven primarily by the benefit of local T&D peaking capacity that the storage system provides. However, dispatch during peak times also reduces the import power requirements from the generation sources, thereby reducing generation costs. In this example, the economic benefits of the two applications are combined.

While the VRB (and other storage technologies) can be used in a wide variety of applications, it is not always possible to combine them. For example, energy storage allocated for spinning reserve could not be "spent" for energy arbitrage since, in a depleted state, energy would not available if called upon for reserve[2].

Table 3 presents an overall summary of the applications requirements. The remainder of this section covers the applications in additional detail.

[2] On the other hand, energy dispatched by the system operator for reserve power may result in incidental "arbitrage" benefits, depending upon the conditions of the performance contract and the market rules. This benefit would be small since the timing of the dispatch would not necessarily occur during optimal arbitrage conditions. It is worth noting that available energy capacity could be operationally "partitioned" to separately serve spinning reserve and arbitrage functions.

Table 3
Summary of Applications Requirements

Application	Size	Duration	Plant Capacity	Response Time	Duty Cycle	Roundtrip Efficiency	Plant Footprint	Environmental Impact
DR/Peak Shaving	0.5–25 MW	4-8 hours	1 MWh–100 MWh	1-10 min	20-50 events/yr	Low (<70%)	0.002 MW/m2	Low noise; aesthetics depends upon location; medium emissions
Spinning Reserve	1–1000 MW	2 hr	2–2000 MWh	10 min	5–60 events/yr	Low (<70%)	0.002 MW/m2	Low noise; medium emissions
Windfarm Stabilization & Dispatch	100 kW–100 MW	4–8 hours	0.5–800 MWh	1 sec (stability)	Continuous for stability (when operating); 10-50 events/yr for dispatch	Medium (70-90%)	Not a constraint – windplant space available	Low emissions; medium aesthetics

3.2. DR/Peak Shaving

Description

By strategically locating BESS technology such as the VRB in the T&D system, utility planners can efficiently manage load growth. Rather than constructing new substations (or upgrading capacity in existing substations) to meet future growth, the planner can use storage to add only the required "incremental" capacity, sized to serve peak loads for a year or two. To further enhance its value, the VRB can be constructed as a "transportable" BESS.

This use of storage defers T&D capacity additions, shifting substation capital costs into the future. In cases where forecasted load growth does not occur, temporary BESS installations would eliminate the substation capital expenditure entirely. Under this strategy, where load forecasts are uncertain, storage would be used as a risk management tool.

Whether temporarily deferring capacity upgrades or providing risk management, a transportable VRB could be scheduled and moved to other locations on the utility system as necessary. This strategy would allow the planner to target the most critical planning areas, capturing multiple benefits over the service life of the BESS. Unlike other generator technologies, the VRB can be easily sited with no emissions permits or fuel handling (although local regulations and standards related to occupational health and safety, materials handling, and transportation must be followed).

Alternatives

While other distributed resource (DR) technologies (such as diesel gensets and fuel cells) can also provide peak shaving service, the primary alternative to the VRB is the conventional method by which T&D planners provide for capacity: T&D upgrades. These generally include new substations and substation upgrades, and may also include line capacity increases.

Control/Dispatch Strategy

To maximize the peak power reduction for a given kWh energy rating, the VRB would be controlled to follow load above a user-defined threshold load. This caps the load at the threshold value and fully utilizes the energy storage capabilities of the battery.

The peak shaving technical requirements for interconnection and controls would be very similar for customer peak shaving. For large industrial or commercial customers, the VRB could be used to reduce the demand charges by capping load at a fixed threshold.

The system would be cycled for several weeks out of the year, depending upon the actual loads relative to the T&D capacity constraints.

Prospects for Success

The key issue for the VRB will be system reliability. The VRB can be packaged and controlled for this application, and could be a very effective load management tool. However, in order for the VRB to be successful, it must demonstrate a level of reliability that is comparable to substation transformers and other T&D equipment. Given that the VRB incorporates equipment (e.g., pumps, power electronics) for which there is little or no experience with failure modes and effects in the substation environment, this may be difficult to verify in the near term. Extended field experience will be required to validate this level of reliability.

3.3. Spinning Reserve

Description

Grid operators increasingly procure ancillary services in open competitive markets, either in long-term contracts or in daily auctions. These services provide stability to the grid in the event of loss of generation units. For example, the California Independent System Operator (CAISO) auctions four services as shown in Table 4:

Table 4
CAISO Reserve Power Definitions

Regulation Reserves	Generation that is on-line and synchronized with the ISO control grid so that the power can be increased or decreased instantly by the energy management system (EMS) through automatic generation control (AGC). Regulation is used to maintain continuous balance of resources and load to maintain frequency during normal operating conditions.
Spinning Reserves	Generation that is already on-line and "spinning" with additional capacity, capable of ramping over a specified range within 10 minutes and running for at least two hours.
Non-spinning Reserves	Generation that is available but not on-line. This generation must be capable of starting, synchronizing with the grid, and ramping to a specified level within 10 minutes, and it must be capable of running for at least two hours. Effectively, non-spinning reserves provide the same benefit to the ISO as spinning reserves, but differ only in that non-spinning reserves are not kept on-line continuously.
Replacement Reserves	Generation that is capable of starting up (if not already operating), synchronizing with the grid, ramping to a specified load within one hour, and running for at least two hours.

Source: “Ancillary Services Overview”, Settlements Guide (Draft), CAISO, May 8, 2002.

The VRB is capable of serving any of these four applications. However, due to the continuous system losses (battery losses, PCS losses, and pumping loads) that would be present during constant charging and discharging, regulation reserve may not be suitable. Of the others, spinning reserve would likely be the most viable since cycling would be relatively infrequent (a few times per year) and since this type of reserve power is the most costly to provide by competing thermal plants. For purposes of this analysis, spinning reserve is taken as the ancillary service provided by the VRB.

Alternatives

For this application, the VRB would compete with thermal plants in a competitive marketplace. For purposes of the benefits analysis, the VRB is evaluated against typical market prices for spinning reserve.

Control/Dispatch Strategy

The VRB would be charged to full capacity and kept in service to discharge its energy as required. Depending upon the technical requirements, the pumps may be turned off and the electrolyte tanks drained in order to minimize tare losses (full power could be delivered in 1-2 minutes). The system would be cycled only a few times per year, extending the useful service life of the equipment.

Prospects for Success

This application is a very good match for the VRB. The required cycling (i.e., the number of events per year) is relatively low, there is an emerging competitive marketplace, and it provides the opportunity for multiple applications (the energy storage rating could be increased beyond the spinning reserve requirements to serve other applications, such as peak shaving).

3.4. Windfarm Stabilization & Dispatch

Description

As the penetration of wind energy on a power grid grows to a significant portion of the overall generation mix, system impacts such as frequency stabilization and system reliability become increasingly important planning considerations. Wind energy has always been penalized as non-dispatchable resource (e.g., by not qualifying for capacity payments). Large-scale energy storage potentially overcomes these issues by absorbing undesirable power fluctuations and providing firm, dependable peaking capacity.

This is of considerable interest in Europe as wind energy is approaching significant penetration levels. Even today, the problems are present on smaller island grids where windplant power fluctuations cause system frequency excursions.

Alternatives

In this application, the primary purpose of storage – whether provided by the VRB or another storage technology – is to maximize the production and delivery of wind energy during periods of high wind turbulence and ramping. In the absence of storage, grid operators occasionally curtail production to ensure stability, forcing windplants to “spill” otherwise valuable energy by feathering turbine blades or disabling selected turbines.

The value of storage in mitigating the effects of wind turbulence is therefore defined by the value of spilled energy, set by the power purchase contract or wholesale market prices in effect at the time.

As for dispatchability, storage can absorb wind energy produced during off-peak periods (rather than deliver it to the grid) and later discharge this energy during on-peak periods. The value of this service is determined by the turnaround efficiency of the BESS and the contract or market prices for on-peak and off-peak periods.

Control/Dispatch Strategy

To mitigate the effects of power fluctuations from windplants, the VRB would charge and discharge in response to real-time load measurements at the point of utility interconnection. During power surges the VRB would charge, and during sags it would discharge, damping the power fluctuations and allowing the windplant to operate at full power. The VRB could be dispatched by the grid operator or energy supplier during peak periods.

The stability function would be invoked as necessary during the turbulent wind conditions. Dispatching would be invoked during the system peaks, on a daily basis over several weeks per year.

The energy to perform both of these functions would be allocated in the control system. Through simple energy accounting, the energy margins to charge and discharge during power fluctuations would never be compromised by the peaking function.

Prospects for Success

The VRB meets the cycle life and storage capacity requirements for this application. One study [Norris, 2002] estimated that the energy discharged by a 1.5 MW / 1.5 MWh flow battery to stabilize a 20 MW windplant would be only 28 MWh per year, equivalent to 19 complete charge-discharge cycles[3], well within the capability of the VRB. The energy storage specifications (MWh) of the VRB would be optimized to meet specific project objectives.

Again, it will be important to validate VRB reliability in the field. For the VRB to qualify as "firm capacity", for example, it may be necessary to prove a level of reliability equivalent to other generating sources.

[3] An additional 150 MWh were used to provide load shifting, totaling 119 equivalent cycles per year. However, the optimal load shifting operation for the VRB may be different based upon stack life and capital cost. In this application, windplant stability provides significantly more revenue than load shifting, so the cycling requirements are primarily determined from the stability application.

4. Costs and Benefits

4.1. Overview

Estimating costs for the VRB is complicated by the small number of field demonstrations, the lack of manufacturing in significant quantities, and the wide range of power ratings and energy ratings for the applications considered in this analysis. The basis of cost estimates come from discussions with the manufacturers, a previous EPRI study of advanced batteries [Symons, 1998], a survey of advanced storage technologies by Sandia National Laboratories [Corey, 2002] for a proposed 2.5 MW / 10 MWh project in Nevada, and experience with similar flow batteries and system integration efforts by the author.

The VRB can be thought of as having two distinct capital cost elements: (1) those associated with the power rating, including cell stacks and PCS, and (2) those associated with the energy storage rating, such as tanks, plumbing, pumps, and enclosure. This is not strictly true, since some items (such as the control system) are not related to either the power or energy ratings, and some items may be related to both elements. Nonetheless, it is useful to report capital costs in these terms, and one cost breakdown for the VRB is provided below.

4.2. Costs

Capital Costs

Stack costs include materials costs, such as electrodes and separators, labor costs, amortization of tooling and plant used in manufacturing, various overhead costs, shipping, installation, and taxes. While the VRB is not at present manufactured in automated or semi-automated processes, these have been estimated [Symons, 1998] at about $450/kW for quantities of 1 MW per year and $300/kW at 20 MW per year.

Balance of system (BOS) costs as defined here represent all installed system costs except for the stacks and PCS. These include the electrolyte, pumps, plumbing, electrolyte tanks, supporting structures and enclosures, control systems, shipping, installation, and taxes. The largest component of BOS cost, the electrolyte itself, is estimated [Symons, 1998] to be $30-50/kWh depending upon the quantities procured. However, this estimate was based upon the $6-7/kg price of vanadium chemicals in 1998. Vanadium commodity prices have since declined steadily each year[4] to about half that price in 2002. Furthermore, the strategic relationship between Vantech and Highveld may provide additional cost savings in VRB chemicals, and it is reasonable to expect that electrolyte costs will range from about $40/kWh for initial systems down to about $20/kWh for mature production quantities. Except for a handful of custom-built storage demonstration projects based on different battery chemistries, there is little quantitative information available about the remaining BOS cost components. Assuming these non-electrolyte

[4] U.S. Geological Survey, Mineral Commodity Summaries, January 2002.

costs drop from an initial \$100/kWh to a mature \$80/kWh, the total BOS costs would be approximately \$140/kWh and \$100/kWh, respectively, for a nominal 8-hour system.

The third cost component of the VRB system is the PCS, which is typically in the range of \$250/kW to \$300/kW at the 1 MW level, depending upon specifications such as power factor control and overload rating. These costs are expected to decline due to advances in technology and increased production quantities of power transistors. PCS costs corresponding to initial and mature VRB production are taken as \$250/kW and \$200/kW, respectively, representing both the PCS cost trend overall and the cost benefits of quantity orders from VRB suppliers. Furthermore, internal PCS costs for components such as enclosures and gate driver boards do not scale proportionately with power rating, and consequently systems rated at higher power levels may be procured at correspondingly lower costs. An EPRI investigation by Bechtel [Stolte, 1985] produced a relationship for scaling PCS costs in \$/kW:

$$\text{PCS Cost} = (\text{Base Cost}) \times (P)^n$$

where the Base Cost represents a 1 MW system and the power rating P is given in MW. For purposes of this analysis, the exponent is taken as -0.2 for “advanced” systems. For example, assuming a 1 MW Base Cost of \$200/kW, a 10 MW PCS would have a cost savings of 37% and cost \$130/kW.

The above relationship reflects the “incremental” (or “marginal”) cost of additional power capability for the PCS, but there is no corresponding relationship for the incremental stack cost. Stacks would be manufactured in standard sizes (such as the 42 kW SEI stacks), and a given system would be made up of multiples of the base stack component. Each of these would be produced on the same manufacturing line and would have identical per unit costs. The 1 to 5 kW stacks to be manufactured for Vantech by Schmitt Industries would be a departure from this concept, since these smaller stacks would involve processes having similar fixed costs with the larger stacks (e.g., parts assembly, molding, and tooling), and this would result in higher costs per stack and higher costs per kW. However, these small systems would be targeted for applications outside the scope of the present analysis, which is focused on much larger T&D applications.

Incremental costs associated with VRB energy ratings other than 8 hours relate to the differential electrolyte cost, but would also include the marginal cost of tanks and supporting foundations. Plumbing and pump costs would not change for systems rated for different discharge times since these would be sized according to the flow design for the stack. A reasonable approximation of incremental energy capital cost would be about \$50/kWh. For example, while a mature 1 MW / 8 MWh system would have BOS costs of \$140/kWh, a 1 MW / 10 MWh system would cost only about (140*8 + 50*2)/10 = \$122/kWh. Incremental costs apply conversely to systems rated at less than 8 hours due to savings in electrolyte quantities.

Prototype VRB system costs will be significantly higher than those discussed above since they include one-time engineering costs, they would be based upon relatively conservative design parameters, and they would use components without the cost-savings advantage of mass production or quantity purchases from sub-suppliers. The VRB cost estimate of $11 million for the 2.5 MW / 10 MWh Boulder City project is taken as a representative prototype project cost. Based upon the considerations above, the PCS cost (reduced from a 1 MW base cost of $300/kW) would represent about $250/kW, or $625,000. Using a baseline BOS cost for an 8-hour prototype system of $300/kWh, the BOS for the 4-hour prototype would be about $550/kWh, or $5.5M. The remaining $4.9M would be to procure prototype non-mass produced stacks at about $1,960/kW.

Sample system costs for representative sizes and applications are shown in Table 5, including Prototypes, "First of a Kind" (FOAK) commercial systems and "Nth of a Kind" (NOAK) mature systems. Prototype, FOAK and NOAK stack costs are assumed to be $1960/kW, $450/kW and $300/kW, respectively. Baseline PCS costs (representing a 1 MW PCS rating) are assumed to be $300/kW (Prototype), $250/kW (FOAK) and $250/kW (NOAK), and these are adjusted using the Bechtel relationship described above. Baseline 8-hour BOS costs are assumed to be $300/kW (Prototype), $140/kWh (FOAK) and $100/kW (NOAK), and these are adjusted to account for discharge times. Note that some scenarios have discharge times of less than 8 hours, and calculated costs reflect the lower BOS costs. However, the costs of these systems are higher on a $/kWh basis since the energy storage capacity is smaller.

O&M Costs

VRB maintenance costs are likewise subject to uncertainty due to limited field experience. Maintenance would be limited to periodic inspections and minor repairs as necessary. All systems are operated unattended. For purposes of this analysis, annual fixed maintenance cost is assumed to be the same on a per-system basis for the T&D size ranges considered here. Technician travel time and per-diem costs would be the major component of inspection cost, and the additional inspection time required for larger systems are assumed to be negligible. Inspection costs for one technician would be about $1000 per day, required 12 times per year for prototype systems, 4 times per year for initial commercial systems (FOAK) and 2 times per year for mature systems (NOAK).

Charging energy is assumed to be at off-peak wholesale pricing of $0.020/kWh and, with an AC/AC roundtrip efficiency of 70%, variable O&M costs are therefore $0.029/kWh.

Fixed and variable O&M costs using the above assumptions are shown in Table 5.

Table 5
VRB Capital and O&M Costs

Application	Size	Plant Capacity	Capital Cost – Power Related ($/kW)	Capital Cost – Energy Related ($/kWh)	Total Capital Cost ($)	O&M Cost – Fixed ($/kW-yr)	O&M Cost – Variable ($/kWh)
DR/Peak Shaving							
Prototype	1 MW	4 MWh	2260	550	4.5M	12.0	0.029
FOAK			700	230	1.6M	4.0	0.029
NOAK			500	150	1.1M	2.0	0.029
Spinning Reserve							
Prototype	10 MW	20 MWh	2150	1050	42.5M	1.2	0.029
FOAK			608	410	14.3M	0.4	0.029
NOAK			426	250	9.3M	0.2	0.029
Windfarm Stabilization & Dispatch							
Prototype	10 MW	80 MWh	2150	300	45.5M	1.2	0.029
FOAK			608	140	17.3M	0.4	0.029
NOAK			426	100	12.3M	0.2	0.029

4.3. Benefits

All benefits calculations were performed by a spreadsheet using discounted cash flows to determine the NPV. The analysis used EPRI-provided economics assumptions, including a real discount rate of 5% and annual inflation of 2%. In addition, all escalation is assumed to be 2%.

DR/Peak Shaving

Benefits include capital investment deferral and substation O&M deferral. The analysis assumes that each year, one substation capital project is deferred. During peak generation days, the system is used to provide peak generation support as well (charging with off-peak energy, accounting for system losses, and discharging during the on-peak period). The assumptions are given in Table 6.

Table 6
DR/Peak Shaving Assumptions

Utility		
Avg Substation Capital Cost	2,000,000	$
Substation O&M cost	25,000	$/sub/yr
Power - Peak	80	$/MWh
Power - Off Peak	20	$/MWh
Peak days	60	days/yr
Discount rate (real)	5	%
VRB		
System Size	1	MW
Energy Storage	4	h
Efficiency	0.70	
Cycle life	1500	cycles
Max life	20	years

Total NPV of the benefits over the 20-year study period is calculated as $1.5M.

Spinning Reserve

Spinning reserve benefits include (1) contract revenues from the open ancillary services market and (2) the generation benefits from discharging energy during the spinning reserve events. Table 7 shows the input assumptions.

Table 7
Spinning Reserve Assumptions

Contract Price	10	$/kW-mo
System Size	10	MW
Duration	2	hr
Events per year	60	
Power - Peak	80	$/MWh
Power - Off Peak	20	$/MWh
Efficiency	0.70	
Discount Rate (real)	5	%/yr
Study Period	20	yr

Total NPV of the benefits over the 20-year study period is calculated as $11.0M.

Windfarm Stabilization & Dispatch

The windfarm application derives its benefits from two sources: (1) increased power production and (2) peaking power sales. The VRB is sized based upon site-specific windfarm modeling such that the curtailment to meet grid power fluctuation limits is minimized. In addition, the bulk of the energy storage is allocated toward supporting peak system loads. Curtailment is assumed to take place during peak periods, and off-peak charging is assumed. The overall application assumptions are given in Table 8.

Table 8
Windfarm Assumptions

Windfarm size	100	MW
Curtailment ratio	50	%
Curtailment duty	1000	hr/yr
System Size	10	MW
Duration	8	hr
Dispatch events per year	60	
Power - Peak	80	$/MWh
Power - Off Peak	20	$/MWh
Efficiency	0.70	
Discount Rate (real)	5	%/yr
Study Period	20	yr

Total NPV of the benefits over the 20-year study period is calculated as $53M.

Benefit-Cost Ratios

The benefit-cost ratios for the three applications and the three capital cost scenarios are shown in Table 9.

Table 9
Benefit-Cost Ratios

T&D Peak Shaving	
Prototype	0.34
FOAK	0.93
NOAK	1.36
Spinning Reserve	
Prototype	0.26
FOAK	0.77
NOAK	1.19
Windfarm	
Prototype	1.17
FOAK	3.07
NOAK	4.32

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5.2. Keywords

Vanadium redox battery, electricity storage, T&D, peak shaving, spinning reserve, wind energy, flowing electrolyte.

5.3. Website Links

Oranization	*Type*	*Web Address*
Pinnacle VRB Ltd.	IP Holding Company	www.pinnaclevrb.com.au
Cellennium Company, Ltd.	Developer	www.vanadiumbattery.com
Vantech (VRB) Technology Corp.	Developer	www.vrbpower.com
Sumitomo Electric Industries, Ltd.	Developer	www.sei.co.jp/redox/e/index.html
University of New South Wales	Research	www.ceic.unsw.edu.au/centers/vrb
The Vanadium Page	General info on vanadium	www.vanadium.com.au

EPRI Energy Storage Handbook: Regenesys Battery Chapter

December 2002

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Introduction

The Regenesys electricity storage system of RWE's subsidiary Innogy (formerly National Power) of the United Kingdom is a flow battery, i.e., a battery in which one or more of the reactants or products is stored in a tank (or tanks) external to the battery cells and is passed with a pump from the tank(s) to the electrode(s) in the cells. Other flow batteries that are under development include those based on the zinc/bromine and vanadium redox chemistries.

Flow batteries have a number of inherent advantages including:

- Of being easily thermally managed, so that life and performance can be maximized;
- Of being amenable to use of bipolar cell-stack arrangements, so that the costs for high-voltage, multi-cell batteries can be minimized;
- Of being less affected by overcharge, overdischarge and partial state-of-charge cycling, as compared to most other batteries, so that they can be used in applications of interest to electric utilities without life degradation;
- Of having a means to chemically manage the electrolyte(s) for the entire battery, so that, for example, individual cell watering, as is required for flooded lead acid or nickel cadmium cells, is not required.

Counterbalancing these advantages are some disadvantages that result from using flowing electrolytes, and the pumps that are required to effect the flow, as follows:

- The pumps and plumbing add complexity and cost to the battery;
- Flow batteries are more prone to leakage than other systems, because of the plumbing that is obviously required;
- They have extra, non-electrochemical components that may occasionally need repair; this implies that there could be additional maintenance costs to affect any required repairs to the auxiliary equipment, as compared to batteries without such auxiliary equipment.
- They have lower than desirable efficiency, because of the energy consumed to provide the flowing electrolytes; thus operating costs may be higher for flow batteries than for batteries based on more conventional chemistries.

Flow batteries have long been considered the one of the best choices, from a life-cycle-cost perspective, for electric utility energy storage when the duration of discharge extends for more than five hours. This is because, in general, the costs of the materials that are electrochemically processed in flow batteries to provide the energy storage are relatively low. In addition, for those flow batteries in which all the active materials remain in solution throughout charge and discharge, such as the Regenesys system, energy capability and power capability can be independently designed into the energy storage system. In this way, flow batteries are more like a pumped-hydro or CAES plants than conventional batteries. This has the effect of allowing minimization of the capital cost for energy storage systems when storage times in the range of ten hours are required.

The chemistry of the Regenesys flow battery is quite different, and considerably more complex, than that of other flow batteries, as now summarized.

Regenesys Chemistry

Regenesys is a polysulfide-bromine flow battery, that is sometimes called by it's developers a regenerative fuel cell. Innogy has been involved in the development of this redox-like system since the early 1990s. However, Regenesys is not truly a redox system since both the positive and negative reactions involve neutral species, unlike a true redox system that involves only dissolved ionic species. The discharge reaction at the positive electrode is:

$$NaBr_3 + 2Na^+ + 2e \rightarrow 3NaBr$$

and that at the negative is:

$$2Na_2S_2 \rightarrow Na_2S_4 + 2Na^+ + 2e$$

At each electrode, the reverse of the above reactions occur in charge. Sodium ions pass through cation exchange membranes in each of the cells to provide electrolytic current flow and to maintain electroneutrality. The open circuit voltage of a Regenesys cell at a medium state of charge is approximately 1.5V, and this varies non-linearly by about $\pm$ 10% with state of charge.

Note that the electrolyte for the positive electrodes of the Regenesys battery and that for the negatives are quite different. The sulfur that would otherwise be produced from the sodium sulfide solution at the negatives in discharge dissolves in excess sodium sulfide that is present to form sodium polysulfide. The bromine produced at the positives in charge dissolves in excess sodium bromide to form sodium tribromide. Unlike the situation in zinc/bromide batteries, the bromine active material remains in solution in the tribromide ion form until it is consumed by the discharge reaction at the positives. Note also that the electrolyte for the positive electrodes is relatively inexpensive, and that used in the negative compartments of the cells is very inexpensive. A block diagram of a Regenesys energy storage plant is shown in Figure 1.[1]

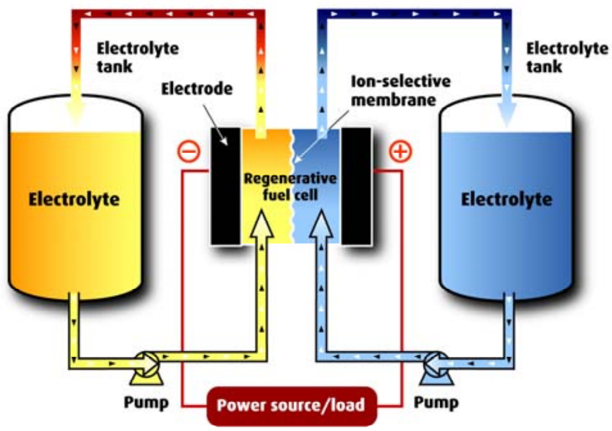

Figure 1
Flow Schematic of Regenesys Electricity Storage System

The cation-exchange membranes that are a vital part of the electrochemical operability of Regenesys batteries serve to separate the differing electrolytes in the positive and negative compartments of each cell, yet provide a path for the passage of sodium ions. A rupture of a membrane in one of the cells will allow the electrolyte in the positive compartments and that in the negative compartments to mix together. This mixing is undesirable, so the Innogy technology based on this chemistry includes measures to detect and isolate any membrane ruptures. Even when operating properly, no membrane is 100% effective, of course, so the coulombic efficiency of Regenesys cells is typically 99%, and some material can pass from one side of the membranes to the other, thereby causing a build up of a sodium sulfate in the

[1] Unless otherwise noted, all figures, diagrams and photos in this chapter are credited to Innogy/Regenesys Technologies, Ltd., which organization retains the copyright thereto. These graphics were downloaded from www.regenesys.com, and this acknowledgment is included in the current document as required as a condition of downloading and reproduction. There is no mention that specific authority to reproduce these graphics is required.

electrolyte for the negative compartments. This contaminating material must be removed as discussed in the following technology section.

Regenesys Technology

Here, we use the term "technology" to encompass the components and equipment that are necessary to allow operation of a rechargeable battery system with the chemistry described in the preceding section of the chapter. The design approach adopted by Innogy for their Regenesys technology is quite different than that of other flow battery developers, or indeed developers of any other battery technology. The Innogy design approach results from the needs dictated by the Regenesys chemistry and by the background of Innogy (i.e., National Power) personnel as employees of an electric utility generating company, as now indicated:

- Innogy have chosen to design on a basis that efficiency is a much less important factor than capital cost for electric utility applications, so they employ higher current densities, by a factor of two or so, than other flow battery developers, particularly as compared to the design approach used by Sumitomo Electric Industries for their vanadium redox battery (VRB).
- All the flow battery developers use carbonaceous materials in one form other another for both electrodes and for the bipolar element of their cell-stacks. (See Figure 2) In Innogy stacks, the electrochemical reactions occur at the specially prepared faces of the bipolar electrodes; unlike VRBs and other redox batteries, carbon felts are NOT used in either cell compartment.
- Significantly larger electrodes (up to 1 square meter instead of a few hundreds of square centimeters, i.e., a small fraction of square meter) are used by Innogy as compared to other battery developers. (See Figure 3)
- Innogy uses higher voltage, 300V versus ~100V or less, and much large capacity cell-stacks, 100kW versus 5-10kW, (larger electrodes, more cells in series/stack) as compared to other flow battery developers. (See Figure 4)
- Unlike other flow battery developers, Innogy utilizes single large tanks for the positive and the negative electrolytes, together with correspondingly large pumps and other auxiliaries, as opposed to the modularized tanks and auxiliaries used by US flow battery developers. (See Figure 5)

Regenesys Electricity Storage Technology

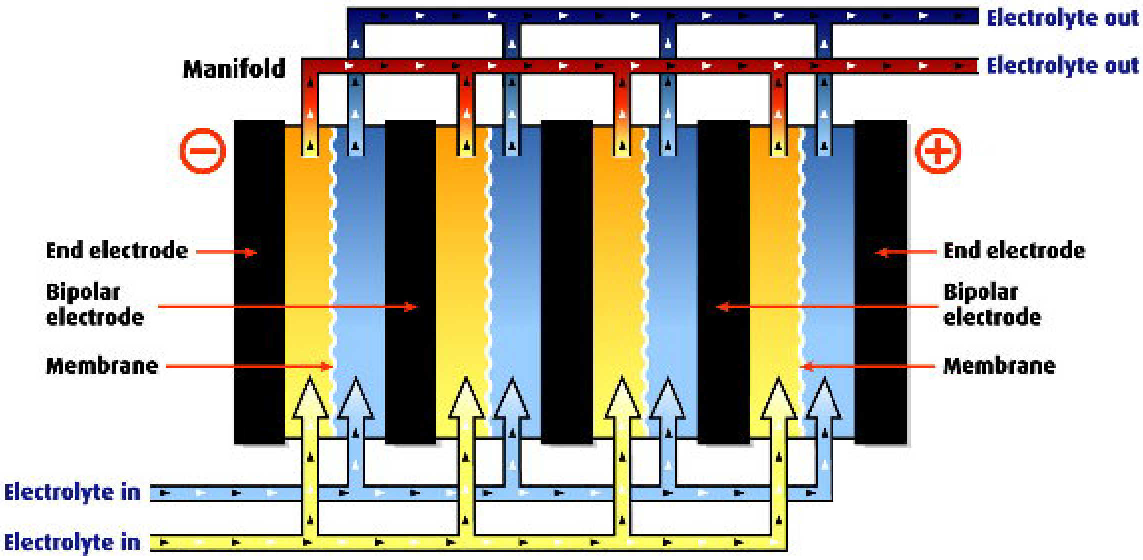

Figure 2
Bipolar Cell Stack

Regenesys Electricity Storage Technology
Figure 3
QC Testing of Regenesys Sub-Stack

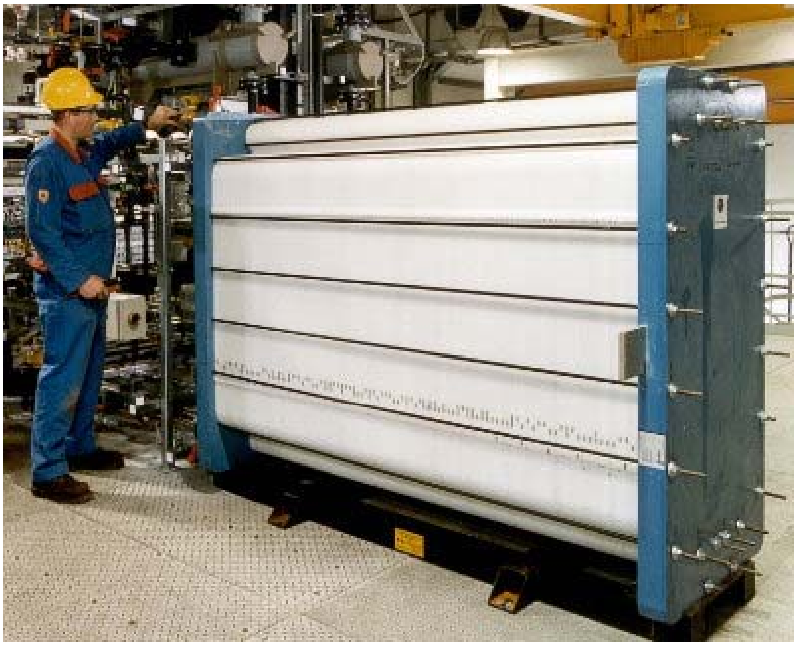

Figure 4
Regenesys 100kW XL Module

Regenesys Electricity Storage Technology
Figure 5
Artists Rendition of 10MW/100MWh Regenesys Energy Storage Plant

Regenesys cell stacks consist of bipolar electrode plates spaced and held by insulating polymer frames, see Figure 2, above. These frames also serve to manifold and distribute the electrolyte into the cell compartments, which are separated by pieces of membrane material. Innogy uses a proprietary sealing arrangement between the frames to prevent electrolyte leakage between cell compartments and out of the stack. As can be seen in Figure 4, the frames holding the electrodes and the membranes are held together with thick end plates and tie bars, items which are not used in the United States by Powercell or ZBB, developers of zinc/bromine battery technologies. In the Innogy approach to a 12MW Regenesys plant, 1200 cell-stacks (100kW each) are arranged in a parallel and series array for a plant DC voltage of ~3000V. Shunt currents can flow in the hydraulically-parallel flow channels of cells in electrical series, with these shunt currents being limited in all flow batteries by using flow channels that are long enough and narrow enough to provide an effective limiting resistance. However, extra pumping power losses are thereby introduced that must be balanced with the reduction in shunt current losses than can be effected. Shunt current and pumping power losses are thus limited to 5-10% in Regenesys ES plants by suitable arrangements in the plumbing from the two electrolyte tanks to the individual cells of the cell-stacks.

Plant-wide tanks, rather than modularized units, were used in the design for a variety of reasons, including the necessity to remove, via a processing unit based on conventional chemical engineering technology, the sodium sulfate that builds up at a rate of 250-300lbs per day (for a 12MW plant) in the negative electrolyte. Innogy indicates that such considerations also place a limit, for the next several years at least, on the minimum size plant that can be economically considered (nominally 100MWh/10MW).

As a result of all the above considerations, the characteristics expected for 100MWh/10MW Regenesys plant engineered according to the Innogy design approach are as follows:

- Space requirements: Innogy says that a 100MWh/10MW plant will occupy 1 hectare (2.5 acres) or less. This corresponds to a footprint of slightly less than $1kWh/ft^2$, or not too dissimilar to the total site area for single-story plant based on flooded lead-acid cells.

- Efficiency: Innogy estimates that the round-trip energy efficiency (AC energy out versus AC energy in) of early Regenesys plants will be 60-65%. Higher than the nominal rates of discharge (15MW versus 10MW nominal) are expected to be sustainable for up to a quarter of the normal 10-hour discharge time, but such higher rates of discharge will reduce the AC-AC efficiency to 50-55%.

- Life: According to Innogy publications (see Bibliography and www.regenesys.com) a plant lifetime of 15 years is being planned for. Since there is already considerable experience with the membranes (the expected life-limiting component) under much harsher conditions, a 15-year life expectation does not appear unwarranted.

- Maintenance Requirements: Within the fifteen year life expected for the plant, Innogy projects that 3-month inspections will be necessary, and that occasional repairs of some of the mechanical components (pumps, valves, etc.) might be needed. Moreover, the crystalline sodium sulfate that is the end product of inefficiency of the membranes (see above) will have to be collected every two weeks, trucked away, and sold or disposed of away from the site. Sodium sulfate is regarded as an environmentally benign material of low toxicity. It is produced in million-ton per year quantities in the US, with half the production being as by-product. Sales of the material lagged production by almost 50% in 1999. Sodium sulfate sells for, very approximately, $100/ton.

- Likely Environmental Impact, Safety Considerations: Regenesys plants have been designed and configured (see Figure 5) in such a way as to minimize any environmental impact and so as to ensure the safety of personnel visiting the plant and that of people living nearby. An Environmental Impact Assessment (see Bibliography) has been prepared which indicates that a Regenesys plant will be environmentally benign.

- Auxiliary Equipment Needs: Innogy is using a system approach to design of their Regenesys energy storage plants, and has even formed an alliance with ABB (see next section for further discussion) for provision of AC-DC-AC converters for their systems. Innogy indicates that no auxiliary equipment other than that provided by itself or its vendors will be needed for Regenesys plants.

- Power Converter Needs: No information is available on this since Innogy and ABB regard this as proprietary information. In any case, the developers regard the power converter as an integral part of the Regenesys energy storage plant. By comparison with other PCS units of similar capability, it is estimated that the efficiency of an ABB converter will be approximately 95% round trip

The performance characteristics, at a “black box” functional level, of a Regenesys plant are expected to be as follows:

- Maximum and minimum charge to discharge terminal voltage ratios: Innogy declines to disclose information at this level of detail. However, from overall round trip efficiency of 60-65% projected by Innogy, the PCS efficiency of 95% estimated above, and given 5-10% shunt current and pumping power losses, it can be inferred that the voltaic efficiency during 10-hour discharges followed by 10-hour charge will be 70-75%. Then, given a 10% variation of OCV for a 100% change in state-of-charge, the maximum charge to discharge terminal (DC) voltage ratio can be estimated as very approximately 1.5, while the minimum value of this ratio will be very approximately 1.3.

- Typical electrical power limits: The current reference design of a Regenesys plant is for a power output of 12MW. Larger power capabilities are of course possible According to an Innogy spokesman[2] the cell stacks can be discharged at 50% higher power than the nominal amount more-or-less continuously, although the efficiency will be lower than at the rated power output, see above. There will be no theoretical lower limit to power output, although the efficiency will be lower for very long (very low power) discharges because of the requirements to power auxiliaries.

- Typical storage capacities: Innogy states on their Web page that 5 hours of discharge capacity is the minimum being considered, while our estimation (see Costs and Benefits section, below) indicates ten hours as more economically attractive than 5. Innogy have indicated a minimum storage capacity of 100MWh, with higher capacities being more attractive from an economic perspective.

- Typical energy to power ratios: Although it is theoretically possible to design a Regenesys energy storage plant with a very short discharge time, it appears that longer discharge times, with say energy to power ratios of ten or thereabouts, are more economically attractive. This is because Innogy believes that multiple economic benefits can realized with the higher energy to power ratios. (See Applications section.)

- Typical response time for standby to full-power output: On their web site, Innogy quote a response time of 100ms for standby to full-power output. There are several factors that can influence this value, the most important of which is the period for which the full-power output is required. For shorter discharge times (as for transmission stabilization) there should be adequate capacity in the electrolytes contained within the cells for a much shorter response time, assuming of course that the converter is configured and programmed to provide the response. The response time quoted by Innogy is thought to reflect what is required for the Little Barford demonstration plant (see Demonstration Programs, below) rather than that needed to satisfy other applications.

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[2] Mark Kunzt, Innogy USA, Chicago. Except where otherwise noted, Mr. Kunzt supplied other information credited to "Innogy" in this chapter.

Business History, Status

Development Programs

The Regenesys chemistry was not originally developed by Innogy, but by Ralph Zito, an independent inventor working at the time in North Carolina, who assigned the rights to his inventions on the Regenesys chemistry and related topics in the early 1990s to Innogy. In parallel with Zito's work, Innogy performed a lot of research to elucidate the Regenesys chemistry, some of which work was contracted to universities in the UK. Innogy also collaborated with Du Pont (the manufacturer of Nafion membranes in the USA) to try to ensure availability of membrane with both acceptable performance and acceptable cost.

In parallel with the chemical and electrochemical research, Innogy initiated a cell stack development effort, engaging a plastics molder (Linpac of Birmingham in the UK) and Electrosynthesis, a technology development company in the Buffalo area of New York state, to assist in these efforts. Ultimately, Innogy acquired Electrosynthesis, which company continues to work on a variety of electrochemical engineering projects. Innogy built many multi-kW batteries in their development program, see for example Figure 6, with this part of the effort culminating in construction of 100kW cell stacks (modules) with electrodes of up to one square meter in area.

Figure 6
5kW Regenesys Cell-Stack

For their efforts on plant design, Innogy contracted with AGRA Birwelco Bristol (an architect-engineer, A&E) in the UK, and collaborated with this contractor to try to optimally design a Regenesys energy storage plant. An A&E also assisted with the design of the Regenesys 1MW test facility at the Aberthaw Power Station in South Wales, UK, at which several 100kW modules can be simultaneously tested. This facility has been in operation since the late 1990s.

More recently, Innogy has established an alliance (business arrangement unknown) with ABB so that AC-DC-AC converters and associated electrical equipment can be supplied together with the Regenesys energy storage component. Apparently, ABB have adapted the IGBT architecture the company has developed for other applications (Flexible AC Transmission Systems or FACTS; Golden Valley Electric Association's nickel cadmium battery energy storage facility) so that it is specifically optimized for Regenesys.

In addition to these development efforts, Innogy have expended significant resources in marketing the Regenesys technology. Included in this part of the work is a significant effort to try to establish the economic value for their energy storage technology.

As far as can be told from what Innogy has said since the beginning of 2001, at which point (see Bibliography) the company clamped down on most public pronouncements on the status of their programs, the development programs of the 1990s have continued until the present time, and are still continuing. We estimate that Innogy have expended somewhere in the range of $40 million to $120 million on development and initial commercialization of the Regenesys technology.

Demonstration Projects

Beginning in late 1990s, Innogy started a serious effort to find a demonstration site for the Regenesys technology. The first choice was a 100MWh/10MW plant for energy arbitrage to be sited at the Didcot power station in the United Kingdom (see Bibliography) but this was abandoned when Innogy sold this generating plant. Innogy have announced that by mid 2003 they should have completed construction and acceptance testing of a 15MW (18MVA) 120MWh Regenesys demonstration electricity storage plant at the Little Barford power station in the

United Kingdom. Progress with construction of the Little Barford Regenesys plant is shown in Figure 7.

Of the total storage capacity, 40MWh is reserved to provide black start for the Little Barford station. The economic benefit for black start is the subject of a proprietary arrangement between Innogy and National Grid. Innogy also plans to demonstrate the utility of the Little Barford plant for energy management (arbitrage), and for response (load following) and voltage control for the power network. Innogy regards the Little Barford plant as a demonstration project, however, and has not attempted to economically justify the plant on the basis of the benefits that can be garnered by it. From publications relating the to Didcot project (see above) and other sources, we think that the cost of the Little Barford Plant will be in the range of $25-40 million.

Figure 7
Progress with Regenesys Construction at Little Barford Generating Station

More recently, Innogy has also contracted to supply TVA with a 12MW, 120MWh Regenesys system that is to be used primarily to provide a higher level of reliability of electrical service to the Columbus Air Force Base (CAFB) in Mississippi.[3] By mid-2002, according to a TVA spokesman, concrete had been poured, some buildings constructed, tanks were already in place,

[3] See www.tva.org/

and the main building was being readied for cell-stacks and plumbing to be put in place at the Columbus Air Force Base site. See Figure 8.

The alternative to installing the Regenesys plant would have been a $5 million upgrade to the TVA sub-station and the sub-transmission system for the CAFB. The converter for the CAFB energy storage plant is rated at 16.8MW or 19MVA, so that the plant can be simultaneously used to demonstrate multiple applications, including improved reliability of service, transmission support, provision of ancillary services, and energy arbitrage. The cost of the CAFB plant to TVA is said to be $25 million. Similar to the Little Barford Regenesys plant, the CAFB plant is also a demonstration project for which TVA has not attempted to provide an economic justification.

Some of the cell-stacks for the Little Barford plant have been built, and these are being acceptance tested at the Aberthaw test facility. Manufacturing of the cell stacks for the TVA Regenesys plant will be initiated when those for the Little Barford project have been completed.

Figure 8
Exterior and Interior Views of Progress with Construction of Regenesys Energy Storage Plant at Columbus Air Force Base Site

Commercialization Issues

The initial target market for Regenesys plants is utility-side applications requiring 100MWh, 10MW capabilities or more. The applications for which such energy storage plants will be used are addressed in the next section of this chapter. The commercialization strategy being adopted by Innogy is, we understand, in the process of being changed, although the two demonstration plants imply an approach to commercialization that cannot be changed too dramatically. The biggest market and commercialization hurdles appear to be:

- Being able to sustain the financial commitment of Innogy, and now RWE, through what will probably be a long period of time in which the technology and the manufacturing will have to be refined.
- A relatively limited market, since there may not be a great number of potential customers with sites that are economically attractive.
- A changing "utility" market place, in which the major players are struggling to adapt to deregulation and re-regulation.
- An unknown role for distributed resources (DR), and an unaccepted place for energy storage in the DR marketplace, particularly in relation to renewable resources which are relatively expensive.

Applications

Introduction

Innogy, as one of the major generating companies in the United Kingdom, started into the process of developing an electricity storage technology with the understanding that storage had intrinsic value to a generating utility. Innogy analysts also concluded (as others before have done) that two or probably more applications will have to be addressed at any given site to give an attractive benefit to cost ratio. The nature of the Regenesys technology, which involves storage of inexpensive active material in external tanks, makes combination of both long discharge time and short discharge time applications possible. In fact, Innogy have often claimed that the reason for selecting Regenesys was that more storage capacity could be added to any given installation for small incremental cost. (See next section for a further discussion of cost factors.) Of course, using a Regenesys energy storage plant for multiple applications implies a capability to be able to dispatch the plant to an alternative or additional application when called upon to do so.

It must be clear from the information presented previously in this chapter that Regenesys energy storage systems are best suited to applications that utilize diurnal energy storage or the like, e.g., load leveling. With an appropriately sized converter, however, a Regenesys plant could also be available for much of the time for short discharge time applications. Thus, while being used for diurnal energy storage that typifies long discharge time applications such as load leveling, the Regenesys plant could also be used to help mitigate system instability or to improve power reliability for customers for whom this can be an economic benefit and thus a marketable commodity.

Innogy and others have proposed a long list of potential applications for systems that can accommodate both short and long discharge times, including:

- Load Leveling
- Energy Arbitrage
- Transmission Deferral/Support, supply-side Peak Shaving
- Provision of ancillary services such as area/frequency regulation, spinning reserve, and black start
- Maximization of generation assets profitability by providing ramping, load following, dispatch for emissions minimization
- System Stability and FACTS Storage
- Minimization of impacts of T&D disturbances on power reliability
- Power quality for industrial (transmission) customers provided from the supply side of the meter
- Peak shaving on the customer side of the meter
- Power quality for commercial customers provided on their side of the meter

Many of these potential applications for energy storage provide no benefit to the T&D system, for which this Handbook is intended. However, while not directly benefiting the T&D system, some of these applications can be readily served as additional functions by storage plants installed for T&D benefit (e.g., ancillary services such as area/frequency regulation). Some of the applications listed require power and energy capabilities that are much smaller (e.g., customer-side PQ) or much larger (e.g., FACTS storage) than are likely to be offered by Innogy for at least for the next several years. As a result of these consideration, not all the applications listed above are to be considered in detail in this section. Instead, only those applications shown in Table 1 will be subjected to detailed consideration. It again should be noted that Innogy believes that Regenesys electricity storage plants can only be built so as to provide a sufficiently high benefits to offset their costs if combinations of applications are included. Descriptions of the applications to be considered in detail for Regenesys are given in the following sub-sections.

Transmission Deferral/Support[4]

When growing demand for electricity approaches the capacity of a transmission system, transmission providers (wires company) currently add new lines and transformers. Since load grows gradually, new facilities are larger than necessary at the time of their installation, and there is an under-utilization of the new transmission assets during the first several years of operation. To defer the purchase of a new line and/or transformer, a wires company could instead install a Regenesys energy storage plant close to the load center and discharge the energy storage plant as necessary (e.g., shave peaks at the sub-station) to keep from overloading existing transmission assets. The deferral can be made until the load warrants purchase of conventional transmission upgrades.

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[4] Applications descriptions have been adapted from “Battery Energy Storage for Utility Applications: Phase I Opportunities Analysis”, P. Butler, Report for DOE by Sandia National Labs, SAND94-2605, 1994

Regenesys Electricity Storage Technology
Table 1
T&D Applications Chosen for Detailed Analysis for Regenesys Technology
(See notes after table)

Application	Size MW	Duration Hours	Plant MWh	Response Time	Duty Cycle	Roundtrip Efficiency	Plant Footprint
1. Transmission Deferral/Support	10	10	100	Seconds	20-200 per year	60-65%	2.5 acres
2. Area or Frequency Regulation	10	0.25	N/A	100 ms	Continuous in daytime	60-65%	N/A
3. Transmission Customer PQ	10	1-2	N/A	100 ms	6 per year	60-65%	N/A

Notes for Table 1:

a. T&D Deferral/Support, with Peak Shaving is regarded as the primary application of a Regenesys ES plant and as such sizes the reference plant 100MWh/10MW.

b. Provision of Area Regulation and Spinning Reserve is regarded as a secondary application for a Regenesys plant installed to meet the requirements of the primary application.

c. Power Quality, or improved reliability, for sub-transmission customers, is regarded as an alternative or additional secondary application for a Regenesys plant installed primarily for the T&D Deferral/Support, with Peak Shaving, application .

In the transmission deferral/support application, the Regenesys battery would be dispatched from 20 to 200 times per year, depending on how close to the limits of the line or transformer the system is being operated, and the local load requirements. When dispatched, the Regenesys plant could be discharged for up to ten hours, since there are times when the peaks on transmission facilities last for this long. Use of the Regenesys plant in this way could also potentially increase network efficiency.

The transmission deferral/support use could be particularly attractive for Regenesys application because of the low costs ($/kWh – see Cost section) for energy capacity and because of the long expected life for the system.

Area/Frequency Regulation

Interconnected utilities not only strive to regulate the frequency of their power output but also have ties with other utilities on the grid that add complexity to the task of regulating power. In addition to experiencing fluctuations in load demand from their own customers, interconnected utilities can experience unscheduled power transfers to and from utilities in the neighboring area. "Area regulation" refers to the activity undertaken by utility system dispatchers to reduce the <u>net</u> unscheduled exchange of power between neighbors to zero over a specified interval of time, typically 15 minutes.

To achieve such area regulation, Regenesys energy storage plants installed in the transmission system close to the load could respond to changing load conditions Instead of system operators dispatching "cycling" thermal power plants to adjust power flows (at significant operating expense), operators would dispatch the Regenesys energy storage plant to prevent the unplanned or unscheduled transfer of power between utilities on the grid.

In an isolated utility such as that on an island, large changes in electrical load (i.e., large relative to the total system capacity) affect the operating speed of generators at power plants. Additionally, loss of a generating plant or key transmission line would have a similar effect. Operating speeds that differ too much from 60Hz can damage the generators and lead to electricity that does not match the 60Hz requirements of electrical devices in the US. To regulate the frequency, a transmission company could install a Regenesys energy storage system that would discharge to meet rising load (or loss of supply), and charge when loads fall-off. In this way, the energy storage plant would protect the generator from fluctuations in load and prevents subsequent variations.

Both frequency regulation and area regulation would require Regenesys energy storage plants in the 10s of MWs. Both applications require about one hour of storage to ensure that the energy storage plant can deliver and accept power during the frequent, shallow charging and discharging that would occur during the 250 weekdays that the energy storage plant would operate. During low demand periods (e.g., weekends or nighttime hours), when other power sources can economically provide frequency and area control, and the energy storage plant would be inactive, the Regenesys system could be brought to a state of charge that would make up for an inefficiencies and imbalances in energy charged and discharged.

A Regenesys energy storage system would be particularly suited to the area/frequency regulation application because of the high cyclability (capability to be charged and discharged at all states of charge without degradation) and the long expected life under the conditions expected.

Transmission Customer Power Quality, Power Reliability

A variety of loads--ranging from modest industrial installations to substations of significant capacity--require energy to provide power quality and backup power. This energy is used for a variety of conditions such as when momentary disturbances require real power injection to avoid power interruptions. In the case of industrial customers, a local source of power may be required when there is an interruption of power from the utility. This power source may function until the power feed from the utility is restored, until a reserve generator is started, or until critical loads are shut down in a safe manner. In the case of a substation, a variety of momentary disturbances such as lightning strikes or transmission flashovers cause power trips or low voltages. The total energy storage requirement is greater and there may be a need power flow separation to insure continuous power to important customers.

Costs and Benefits

Projected Costs

In Table 2, we show projections for the costs for Regenesys energy storage plants at two levels or production: a first commercial plant (i.e., the plant after the one for TVA) and full implementation (say the 30th plant sold with sales of 10 plants per year). The costs shown, which are Symons/EECI projections based on values obtained from Innogy publications or from Innogy personnel, relate to a plant with a nominal power capability of 10MW and an energy storage capacity for a 10-hour discharge of 100MWh.

The columns headed $/kWh and $/kW in Table 2 relate to the portions of the total cost that can be attributed to energy capacity and power capability, respectively. Thus, to estimate the cost of a first commercial plant with a nominal capability of 120MWh and 12MW (the nominal capabilities of both the Little Barford and the CAFB plants), one would sum the products of \$120/kWh by 120MWh (\$14.4 million) and \$300/kW by 12MW (\$3.6 million) to obtain a total plant cost projection of \$18 million (\$1,500/kW). Similarly, for the 30th plant, the total plant cost would be calculated to be \$7.8M + \$1.8M = \$9.6M, or \$800/kW.

Table 2
Projected Costs for Turnkey 100MWh/10MW Regenesys Energy Storage Plant for Transmission Deferral plus Area Regulation Application (2002$)

Application: Transmission Deferral & Area Regulation	Plant Size MWh	Plant Capacity MW	Capital Cost: Power Related ($/kW)	Capital Cost: Energy Related ($/kWh)	Total Capital Cost (Millions of $)	O&M Cost: Fixed ($/kW-yr)	O&M Cost: Variable ($/kWh)
1st. Commercial Plant	**100**	**10**	**300**	**120**	**15**	**10**	**0.01**
30th. Plant with 10 plants/year	**100**	**10**	**150**	**65**	**8**	**1**	**0.005**

The capital cost parameters shown in Table 2 do not, however, represent appropriate arithmetic to use for plants that have a nominal discharge rate different than 10 hours, or for plants where the peak power capability is markedly different than one-tenth the energy capacity. In these circumstances, the parameters shown in Table 3 are thought to be more appropriate. The parameters listed in Table 3 should be used according to the following formula:

Total Plant Cost = Base \$/kWh x Baseline kWh
+ Incremental \$/kWh x (Plant kWh – Baseline kWh)
+ Incremental \$/kW x (Plant kW – Baseline kW)

Note that the parameters in Table 3 are Symons/EECI projections based on a limited amount of information from Innogy and our knowledge of cost breakdowns for other flow batteries. It must be noted that the parameters given in Table 3 are expected to have limited applicability, for excursions from the 100MWh/10MW baseline design of perhaps ±30% in the energy capacity and perhaps +50% in the power capability.

Regenesys Electricity Storage Technology
Table 3
Parameters for Incremental Changes in Energy and Power Capability of Regenesys Plants

	Base Projection $/kWh	Incremental $/kWh	Incremental $/kW
First Commercial Plant	**150**	**30**	**100**
30th Plant with 10 plants/year	**80**	**20**	**50**

According to the parameters given in Table 2, the cost of the 30th of a kind Regenesys plant based on a 100MWh/10MW design, but with an energy storage capacity 110MWh would be only $200,000 more than the baseline plant. Similarly, a first commercial plant with capacity of 90MWh would be only $300,000 less than the 100MWh baseline plant. The reader may make other calculations for plants having somewhat different energy specifications, according to the formula given above and the parameters in Table 3, as desired.

Changes in power capability would also be projected to have relatively small impacts on the total cost. For example, the cost of a first commercial Regenesys plant based on a 100MWh/10MW design, but with a power capability of 15MW would be only $500,000 more than the baseline plant. For the 30th plant with 10 plants/year case, the cost of the 15MW option would be only $250,000 more than the baseline. Clearly, these plants with higher power capability would have a discharge time at the higher power that would be significantly less than the nominal discharge time of 10 hours. Indeed, thermal and other effects might limit the time for which the higher power could be sustained to an hour or so.

Estimated Benefits

Table 3 shows the estimated benefits for the use of an electricity storage technology with a capability required for the specified application. These estimates are based on a review of estimates made by other analysts, as shown in the references below the table. In part, the review of benefits estimates was performed by Symons/EECI as part of a study on the "Second Use of EV Batteries".[5]

[5] "Technical and Economic Feasibility of Applying Used EV Batteries in Stationary Applications", Report in preparation (2002) for DOE Energy Storage Systems Program under Contract Number 20605 with Sandia National Laboratories

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Table 4
Estimated Benefits for Electricity Storage Applications (2002$)
(See notes for table)

	Low Estimate	Low Ref	High Estimate	Hi Ref
Peak Shaving/T&D Deferral, Note a	$50/kW/year	1	$150/kW/year	2
Area Regulation/Spinning Reserve, Note b	$700/kW	3	$1500/KW	4
Power Quality (reliability), Note c	$50/kW/yr	5	$250/KW/yr	6

Notes for Table 4:

a. Peak Shaving combined with Deferral of T&D is regarded as the primary benefit of a Regenesys ES plant. This application sizes the reference plant with a capacity of 10MW and a storage capability of 100MWh during a 10-hour discharge

b. Provision of Area Regulation and Spinning Reserve is regarded as a secondary and additional benefit for a Regenesys plant installed to meet the requirements of the primary application. In order to estimate the value of this secondary application, Area Regulation and Spinning Reserve is assumed to be provide a one-time benefit, at the time of installation, that can offset the cost of the Regenesys ES plant.

c. Power Quality, or improved reliability, for sub-transmission customers, is regarded as an alternative or additional secondary application. Thus, Power Quality (reliability) benefits will always assumed to be additive to the Peak Saving/T&D Deferral benefit, but may be additive to or an alternative to Area Regulation/Spinning Reserve benefits.

References for Table 4: Estimated Benefits

1. EPRI Energy Storage Workshop materials, Hurwitch et al, c.1991, adjusted for inflation and updated
2. Cost of Puerto Rico BESS, as a proxy for the value of this function, adjusted for inflation
3. Bert Louks, EPRI Journal 1988, based on Dynastor projections, adjusted for inflation and updated
4. H. Zaininger, SAND98-1904 (SMUD Wind and PV study)
5. S. Schoenung, “Superconducting Magnetic Energy Storage Benefits Assessment for Niagara Mohawk Power Corporation,” report prepared for Oak Ridge National Laboratory, DE-AC05-840R21400, 1994.
6. Projection by P. Symons of Symons/EECI for private-sector client

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Table 5 shows Benefit/Cost Ratios based on the benefits listed in Table 4 and specific system costs listed in Table 2. Note that T&D Deferral/Peak Shaving is the primary application. The Net Present Value for the T&D Deferral benefit shown in Table 5 was calculated using a discount rate of 7% and 20-yr life. As discussed above, Area Regulation and Spinning Reserve is an additional one time benefit, that offsets the cost of the Regenesys plant, and thereby increase the benefit/cost ratios. Only the lower value for the estimated cost offset shown in Table 4 is used for the Benefit/Cost ratio calculations, since the higher value is believed only pertinent to island systems such as Puerto Rico, rather than transmission systems in the 48 contiguous states. Power Quality (reliability) is an alternative or additional secondary benefit, the Net Present Value of which is factored in using a discount rate of 7% and 20-yr life. In Table 5, FOAK refers to the first of kind commercial plant, and NOAK refers to the n^{th} of kind plant, as defined for Table 3, above.

Table 5
Benefit Cost Ratios for 10 MW/100 MWh Regenesys units in T&D Applications

Application	FOAK Cost, $	NOAK Cost, $	Low NPV Benefits, $	High NPV Benefits, $	BC Ratio, FOAK	BC Ratio, NOAK
T&D Deferral/ Peak Shaving	15×10^6	8×10^6	5.30×10^6	15.9×10^6	.35 - 1.06	.66 - 1.99
T&D Deferral + Area Regulation Spinning Reserve	8×10^6	1×10^6	5.30×10^6	15.9×10^6	0.66 – 1.98	5.3 – 15.9
T&D Deferral + Transmission PQ	15×10^6	8×10^6	10.6×10^6	42.4×10^6	0.71 - 2.82	1.32 - 5.30
T&D Deferral + Area Regulation Spinning Reserve + Xmission PQ	8×10^6	1×10^6	10.6×10^6	42.4×10^6	1.32 - 5.3	10.6 - 42.4

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EPRI Energy Storage Handbook: Sodium Sulfur (NAS) Battery Chapter

December 2002

Dan Mears and Harold Gottshall
Technology Insights
San Diego, California

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1
DESCRIPTION OF SODIUM SULFUR BATTERIES

1.1 Introduction

Ford Motor Company is credited with initial recognition of the potential of the sodium-sulfur battery based on a beta-alumina solid electrolyte in the 1960's [Ref. 1-1 and 1-2]. By the early 1970's, Ford's work (Kummer and Weber) had catalyzed widespread research into sodium-sulfur battery technology, including programs in Europe (Brown Boveri (later ABB)) and in Japan (New Energy and Industrial Technology Development Organization (NEDO)), primarily for electric vehicle applications. By the late 1970's and early 1980's, a variety of developers had advanced sodium-sulfur technology for applications ranging from satellite communications to large stationary power. Notable contributors included Eagle Picher Industries in the U.S., Chloride Silent Power in the U.K., Asea in Sweden, Powerplex in Canada, and RWE in Germany. As recently as 1993, Ford equipped six electric Ecostar vehicles for use by the US Postal Service with sodium-sulfur batteries as part of a test program.

By the early 1980's, the Tokyo Electric Power Company (TEPCO) had selected sodium-sulfur technology as the preferred medium for dispersed utility energy storage to displace a growing reliance on central pumped hydro energy storage. TEPCO recognized that the key to development of sodium sulfur batteries suitable for utility-scale stationary power applications was in the production of ceramic components and sought the participation of NGK Insulators, Ltd., (NGK) for that role. By the late 1990's, NGK and TEPCO had deployed a series of large scale demonstration systems, including two, 6MW, 48MWh installations at TEPCO substations.

In April 2002, TEPCO and NGK announced commercialization of their sodium-sulfur battery product lines in Japan, plus their intent to introduce products globally. At present, NGK is the only known vendor of sodium sulfur batteries for utility applications, and the technology presented herein pertains to NGK's sodium-sulfur (NAS®, registered in Japan) battery module product lines.

1.2 General Characteristics

1.2.1 Electrochemistry

The normal operating temperature of sodium-sulfur cells is about 300C. During discharge, the sodium (negative electrode) is oxidized at the sodium/beta alumina interface, forming Na^+ ions. These ions migrate through the beta alumina solid electrolyte and combine with sulfur that is being reduced at the positive electrode to form sodium pentasulfide (Na_2S_5). The sodium pentasulfide is immiscible with the remaining sulfur, thus forming a two-phase liquid mixture.

After all of the free sulfur phase is consumed, the Na_2S_5 is progressively converted into single-phase sodium polysulfides with progressively higher sulfur content (Na_2S_{5-x}). Cells undergo exothermic and ohmic heating during discharge. During charge, these chemical reactions are reversed. Half-cell and overall-cell reactions are as follow:

Negative electrode: $2NA \xrightarrow{Discharge} \xleftarrow[Charge]{} 2NA^{+} + 2e^{-}$

Positive electrode: $xS + 2e^{-} \xrightarrow{Discharge} \xleftarrow[Charge]{} S_x^{-2}$

Overall cell: $2NA + xS \xrightarrow{Discharge} \xleftarrow[Charge]{} Na_2S_x$ (x = 5 to 3), E_{ocv} = 2.076 to 1.78 V

Although the actual electrical characteristics of sodium-sulfur cells are design dependent, voltage behavior follows that predicted by thermodynamics. A typical cell response is shown in Figure 1-1. This figure is a plot of equilibrium potential (or open circuit voltage (OCV)) during charge and discharge as a function of depth of discharge. The OCV is a constant 2.076V over 60 to 75% of discharge while a two-phase mixture of sulfur and Na_2S_5 is present. The voltage then linearly decreases while discharged within the single-phase Na_2S_x regime to the selected end-of-discharge, usually about 1.8 V. Greater depths of discharge cause the formation of Na_2S_x species with progressively higher internal resistance and greater corrosivity (Ref. 1-3 and 1-4).

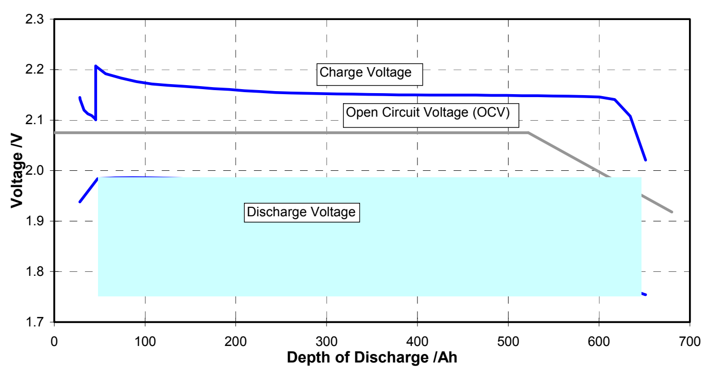

Figure 1-1. NAS Cell Voltage Characteristics

1.2.2 NAS Cell Design

The NAS cell design developed by NGK is illustrated in Figure 1-2. The negative sodium electrode in the center is surrounded by the beta alumina solid electrolyte tube, which in turn is surrounded by the positive sulfur electrode. In a charged state, liquid elemental sodium fills the central reservoir. As the cell is discharged, the liquid sodium is channeled through a narrow annulus between the inner surface of the beta alumina solid electrolyte and the safety tube. The safety tube is a design feature to control the amount of sodium and sulfur that can potentially combine in the unlikely event that the beta alumina tube fails. The volume of potential reactants is limited to that contained in the narrow annulus between the electrolyte tube and the safety tube, preventing the generation of sufficient heat to rupture the cell.

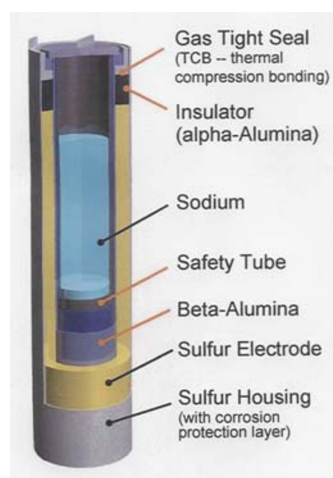

Figure 1-2. NAS Cell

1.2.3 NAS Battery Module Design

NGK has developed the NAS T5 cell for use in their commercial battery modules which are designated the NAS PS (for peak shaving) Module and the NAS PQ (for power quality) Module. The properties of the NAS T5 cell and the PS and PQ Modules are provided in Table 1-1.

Table 1-1.. NAS Cell and Module Properties

Parameter	NAS T5 Cell	NAS PS Module	NAS PQ Module
Nominal Voltage, V_{dc}	2	64 or 128	640
Operating Temperature	[290 to 360C]		
Cell Arrangement ("s" series; "p" parallel)	Single	(8sx6p)x8s or (8sx12p)x4s	320s
Electrical Protection	NA	Internal fuse within each 8s string	DC breaker and external fuse
Rated PS Capacity (Notes 1, 2)	628 Ah	430 kWh_{ac}	360 kWh_{ac}
Rated PS Power (Notes 1, 3)	NA	50 kW_{ac}	
Max Power for Interval Noted (Note 1, 4)	NA	60 kW_{ac} for 3hr	250 kW_{ac} for 30sec
Pulse Factor (Note 5)	NA	1.2	5
Projected Calendar & Cycle Life	15 years; 2500, 100% DOD cycles		
Avg DC Efficiency, %	90	85	
Standby Heat Loss, kW	NA	3.4	2.2 (PQ) 3.4 (PQ+PS)
Dimensions, mm (in)	515Lx91 (20.3Lx3.6)	2,270Wx1,740Dx720H (89.4Wx68.5Dx28.4H)	
Weight, kg (lb)	5.5 (12.1)	3500 (7920)	

Notes:
1. AC rating based on 95% inverter efficiency
2. Design basis Rated PS Capacity based on 1.82Vpc OCV at end of discharge and end-of-life
3. Design basis Rated PS Power for reference peak shaving profile yielding 100% DOD
4. Maximum power for short duration discharges (typically yield less than 100% DOD)
5. Pulse Factor: Ratio of maximum power to rated power for stated duration.
(Values above are the maximum achievable with operating temperature and electrical protection designs for the battery module.)

While both the PS and PQ Modules use the same T5 cell, the PS Module is designed for long duration discharge with modest voltage drop, and the PQ Module for pulse power delivery with voltage as low as 0.9 V_{pc}. The most notable design differences are in cell arrangements and electrical protection. PS Modules use 384 cells in arrays of 8 cells in series to yield module voltages of 64 or 128, while all 320 cells within a PQ Module are series connected for 640V.[1] The PS Module arrangement allows fuses to be incorporated within each 8-cell string. Electrical protection for the deeper voltage drops and higher currents encountered in PQ Module applications are addressed via an external DC breaker and a fuse at the terminals of each module.

A NAS Battery Module consists of the cell arrangements described above within a thermally insulated enclosure equipped with electric heaters to maintain a minimum operating temperature of about 290C, depending on the application. Cells are closely spaced and connected in series and parallel. A vacuum is drawn on the gap between the inner and outer walls of the enclosure to manage heat loss. This design feature enables the heat transfer characteristics of the PQ Modules to be adjusted to the needs of the application. As indicated in Table 1-1, units used in standby applications reject heat at about 2.2 kW under design basis conditions, while units for combined PQ and PS functions lose about 3.4 kW during standby. Figure 1.3 is a photograph of

[1] A 320-cell variant of the PS Module is also available. Rated PS Capacity is the same as for the PQ Module, while Rated PS Power and voltage options are the same as the PS Module (64 and 128 V) described above.

a NAS PS Module with the top cover removed to show cells. The interstices between cells are filled with sand which functions as both packing material and heat sink.

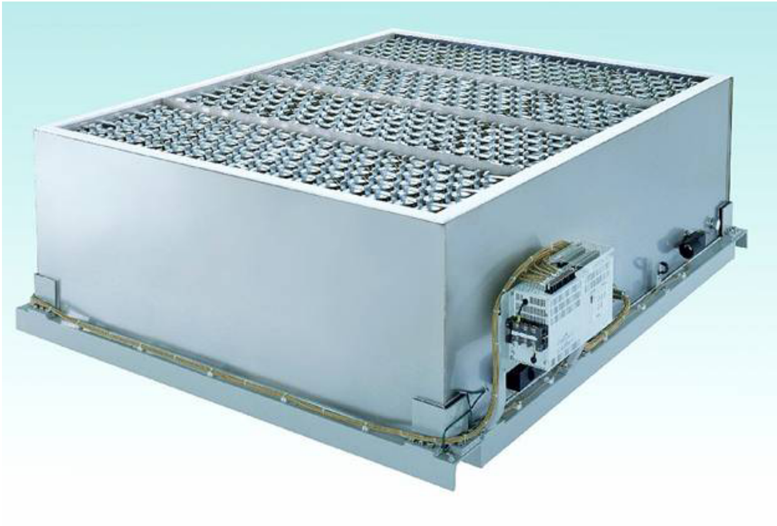

Figure 1-3. NAS PS Module

Voltage and temperature profiles during a 100% DOD charge-discharge cycle of a NAS PS Module are shown in Figure 1-4. (Temperature sensors are located on the inner side and bottom surfaces of the enclosure and are insulated from cells by the sand filler; hence, temperature data lag duty cycle events due to the rate of heat transfer from cells to the sensor location.) The internal temperature of the module is observed to increase steeply during discharge mode due to the combined effects of ohmic heating (I^2R) and the exothermic cell reaction. During the charge mode, ohmic heating combines with the cell endothermic reaction to effect a gradual cooling. Resistance heaters on the inner side and bottom of the enclosure maintain the module at a temperature above 290C during standby.

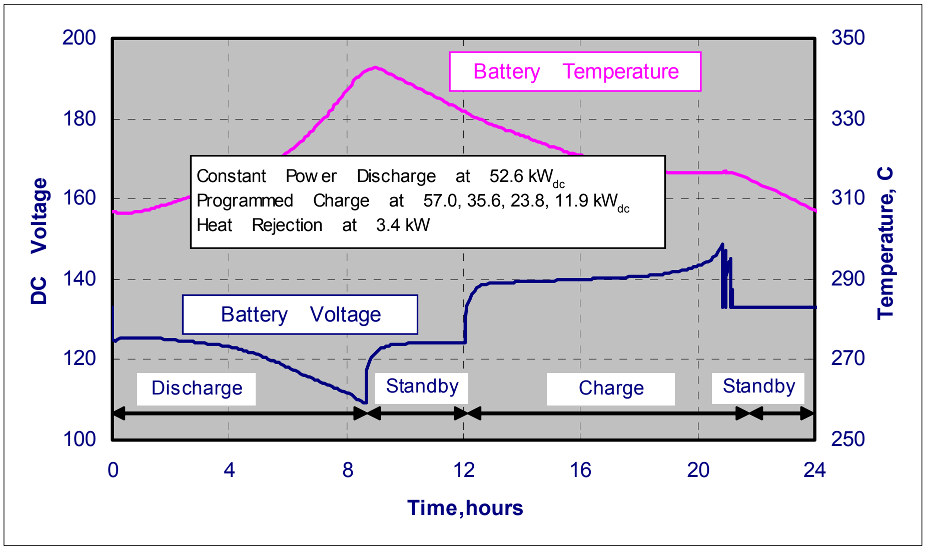

Figure 1-4. PS Module Voltage & Temperature During a Peak Shaving Cycle

Reference peak shaving profiles for both PS and PQ Modules are shown in Figure 1-5. These profiles show a gradual increase in power at the beginning of the discharge interval to minimize grid transients, a constant power plateau, and a gradual decrease in power at the end. These profiles illustrate a thermal management strategy that allows 100% depth of discharge within temperature limits over the minimum time interval. Since the majority of applications that only involve peak shaving do not require a rapid transition of power, these profiles are deemed to be an acceptable basis for defining basic performance parameters for NAS products. As shown on the figure, the Rated PS Capacities for the PQ and PS Modules are 360 and 430 kWh_{ac}, respectively; and the Rated PS Power for both modules is 50 kW_{ac}.

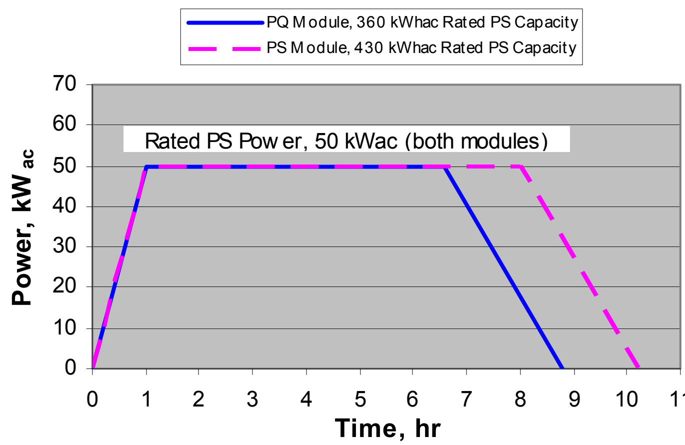

Figure 1-5. Reference Peak Shaving Profiles (both modules)

While gradual load changes yield the most energy efficient duty cycle, mitigation of power disturbances such as sags and momentary outages requires step load changes within a few milliseconds. Both NAS modules can reach full power within one millisecond, and the PQ Module has been specifically developed for PQ applications and combined PQ and PS applications. Figure 1-6 illustrates the capability of the PQ Module to deliver step load pulses of power for durations ranging from 30 seconds to 3 hours. (Thermal management of longer duration discharges requires discharge profiles similar to those shown in Figure 1-5.) As noted in Table 1-1, NGK defines the term “Pulse Factor” as the ratio of the maximum power for the stated duration to the Rated PS Power. For example, the PQ Module can deliver 400% Rated PS Power (i.e., 4 times 50 kW equals 200 kW) for 15 minutes as indicated Figure 1-6.

The PS Module can also deliver step load pulses of power. It is capable of supplying 60 kW (120% of rated power) for up to 3 hours.

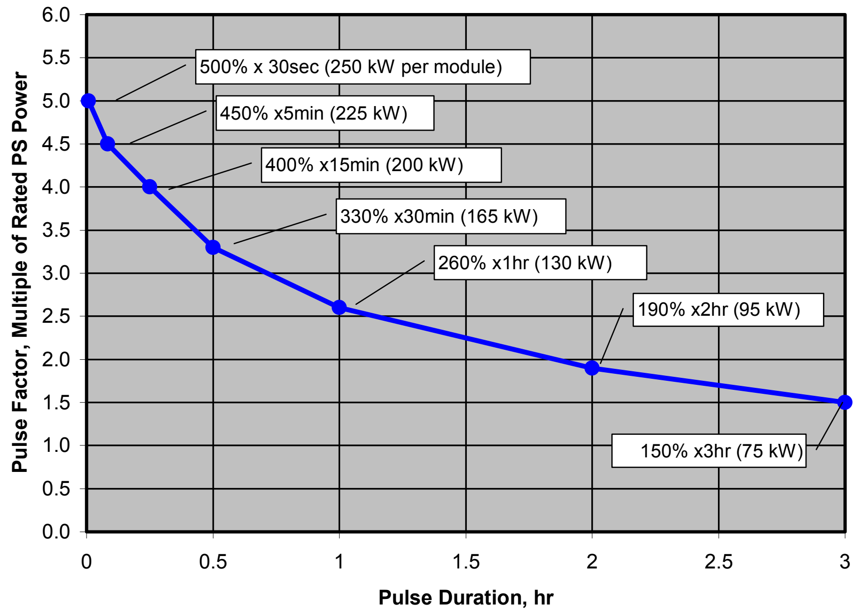

Figure 1-6. PQ Module Pulse Power Capability

The PQ Module was introduced in recognition that it is often necessary to combine energy storage functions to offer a cost competitive system. For example, in some circumstances, the mitigation of short duration power disturbances can be combined with peak shaving such that the same facility accomplishes both functions. Typically, the energy storage system is sized to protect the critical load using the Pulse Factor multiplier, and peak shaving is conducted at the Rated PS Power. Table 1-2 provides a list of operating regimes for the PQ Module including those that combine pulse power and peak shaving functions. The operating regimes are defined by NGK such that pulse power capability is maintained over the module life and battery temperatures remain within thermal limits during all modes of operation.

As described in Ref.1-5, extensive safety testing of NAS battery modules has been conducted under simulated accident conditions for fire, flood, vibrations, and mishandling events, as well as for electrical malfunctions.

Table 1-2. NAS PQ Module Combined Pulse and PS Operating Regimes

Operating Regime	Pulse Factor (1)	Pulse Interval (2)	PS Energy, kWh_{ac} (3)	Recharge Interval, hr (4)	# PS Cycles Over Life (5)	Coincident Pulse & PS (6)
30 second pulse duration						
1	5.0	5x/hr	0	NA	0	NA
2	4.3	5x/hr	155	5	2500	Yes
3	3.0	5x/hr	360	10	2500	Yes
4	3.0	5x/hr	155	5	5000	Yes
5 minute pulse duration (plus 30 sec cumulative within any prior 1 hour)						
5	4.5	12hr	0	NA	0	NA
6	3.5	12hr	155	5	500	Yes
7	3.5	12hr	360	10	500	No
15 minute pulse duration (plus 30 sec cumulative within any prior 1 hour)						
8	4.0	12hr	0	NA	0	NA
9	3.7	12hr	155	5	500	No
1 hour pulse duration (plus 30 sec cumulative within any prior 1 hour)						
10	2.6	12hr	0	5	0	NA

Notes

(1) Pulse Factor: Multiple of Rated PS Power for short duration power delivery

(2) Pulse Interval: Interval between successive pulses of the magnitude noted. For 5 minute, 15 minute, and 1 hour PQ regimes; cumulative short pulses up to 30 seconds per hour prior to a 5 minute, 15minute , or 1 hour pulse are also acceptable.

(3) PS Energy: Energy delivered from NAS battery during PS cycle (see profile)

(4) Recharge Interval: Minimum interval to recharge unit for next cycle

(5) # PS Cycles Over Life: The design basis number of 42% (155kWh) or 100% (360kWh) DOD cycles over the life of the system

(6) Coincident PQ & PS: Acceptability of simultaneous pulse and PS events with respect to thermal management

1.2.4 NAS Battery Installations

Figure 1-7 is a photograph of the 6MW, 48MWh NAS system at TEPCO's Ohito substation. A similar installation has been constructed at TEPCO's Tsunashima substation. These arrangements provide the bases for layout data used in Sections 3 and 4.

Figure 1-7. 6MW, 48MWh NAS System at TEPCO's Ohito Substation

Figure 1-8 shows a one-line diagram and dimensioned layout for NGK's recently introduced standard 5-module PS product line. As illustrated, modules are arranged in exterior enclosures in stacks of 5 corresponding to a rated power of 300 kW_{ac}, 2150 kWh_{ac} per unit.

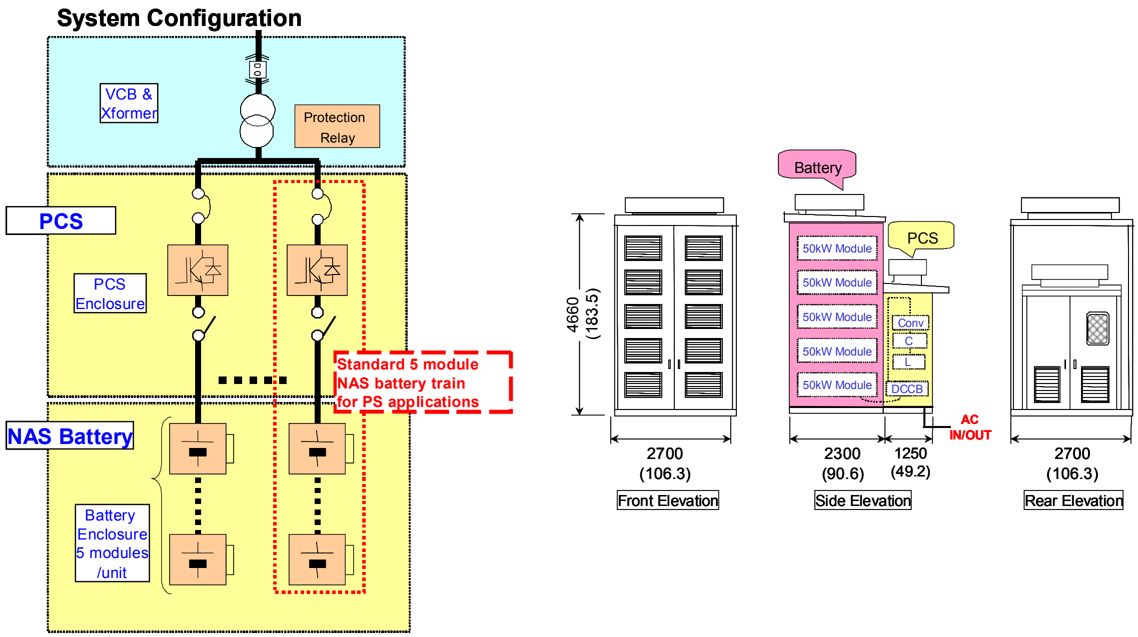

Figure 1-8. NGK's Standard 5 NAS PS Module Unit (Dimensions, mm (in))

A goal of NAS battery development is to require minimal onsite maintenance. NAS system operation in Japan is unattended and fully automatic. NGK's recommended maintenance program consists of continuous remote monitoring and detailed inspections conducted at 3-year intervals, which include:

- Inspecting for unusual vibrations, noise or odors
- Inspecting for abnormal conditions of connecting cables and the exterior enclosure
- Inspecting insulation resistance
- Retorquing terminal connections
- Collecting and analyzing battery resistance and OCV data
- Confirming the accuracy of DC voltage, DC current, and temperature sensors
- Adjusting module enclosure vacuum to control standby heat loss (every 1000 cycles)

Waste disposal and materials recycling is required in Japan and most other developed countries. NGK estimates that 98% of NAS materials can be recycled. Only sodium requires recycling as a hazardous material.

2
THE STATUS OF SODIUM SULFUR BATTERIES

2.1 Development & Demonstrations

Table 2-1 lists 19 NAS battery demonstration and early commercial projects through August 2002 rated at 500kW or more for cumulative capacity in excess of 28MW and 197MWh, including two, 6MW, 48MWH installations at TEPCO substations. Thirty projects smaller than 500kW are also in progress and add another 3.5MW and 25MWh of NAS-based capacity.

Table 2-1. In-Progress NAS Battery Systems Rated at 500kW or More

No.	Customer	Site	kW/kWh	Purpose	Start of Operation
1	TEPCO	Kawasaki Test Site	500/4000	Load Level	Jun-95
2	TEPCO Unit 1	Tsunashima Substation	6000/48000	Load Level	Mar-97
	Unit 2	(Unit 2 relocated, see "5")			Jul-97
	Unit 3				Jan-98
3	NGK	Head Office	500/4000	Load Level	Jun-98
4	TEPCO Unit 1	Ohito Substation	6000/48000	Load Level	Mar-99
	Unit 2	(Unit 2 relocated, see "18")			Jun-99
	Unit 3				Oct-99
5	TEPCO/TOKO	Saitama	2000/16000	Reloc "2", LL	Jun-99
6	Chubu EPCO	Odaka Substation	1000/8000	Load Level	Mar-00
7	TEPCO	Tsunashima Substation (New Unit 2)	2000/14400	Load Level	Nov-00
8	TEPCO	Shinagawa Substation	2000/14400	Load Level	Mar-01
9	TEPCO/Asahi Brewery	Kanagawa Plant	1000/7200	LL+UPS	Oct-01
10*	Metro City of Tokyo	Kasai Sewerage	1200/7200	LL+UPS	Oct-01
11	TEPCO/Takaoka	Oyama Plant	600/1440	LL+UPS	Oct-01
12	TEPCO/Takaoka	Oyama Plant	800/5760	Load Level	Feb-02
13	TEPCO/Fuji Xerox	Ebina Plant	1000/7200	Load Level	Feb-02
14	TEPCO/Pacifico	Media Center	2000/14400	LL+UPS	Apr-02
15	TEPCO	Chichibu Substation	1000/7200	Load Level	Jun-02
16*	TEPCO/Fujitsu	Akiruno Technology Ctr	3000/7200	LL+UPS (PQ=3)	Jun-02
17*	TEPCO/Tokyo Dome	Tokyo Dome Renovation	1000/7200	LL+EPS	Jul-02
18*	TEPCO/Ito Yokado	Maebashi Shopping Ctr	1000/7200	Reloc "4", LL	Jul-02
19	AEP	Gahanna, OH, USA	500/720	LL+UPS (PQ=5)	Aug-02
* Early commercial projects					

The pre-commercial development and demonstration program sponsored by TEPCO was conducted in recognition of the empirical nature of ceramics technology. The cost, performance and reliability of NAS cells require that beta alumina solid electrolyte with high strength, low ionic resistivity and excellent stability is economically mass-produced. Proof that these requirements had been met required prototypic manufacturing facilities, full-scale demonstrations and the accumulation of sufficient data to justify launching commercialization.

The first demonstration of NAS technology in the US is a multi-functional unit using two NAS PQ Modules for combined power quality and peak shaving. The demonstration is an EPRI

Tailored Collaboration (TC) research project with American Electric Power (AEP). The NAS unit can deliver 500 kW_{ac} for up to 30 seconds for power quality protection, or it can provide 30 seconds power quality protection at 300 kW_{ac} plus deliver 720 kWh_{ac} peak shaving at a maximum power of 100kW. Figure 2-2 is a photograph of the NAS unit installed at AEP's site.

This project evolved from an initial joint agreement between AEP, TEPCO and NGK. The power electronics and system integration was supplied by ABB. Extensive acceptance testing was conducted at ABB's factory in New Berlin, WI and the AEP site. The unit was formally commissioned in September 2002, at AEP's offices in Gahanna, Ohio (near Columbus). Performance monitoring for a period of two years and an evaluation of the economic potential of the project will be conducted under the EPRI/AEP TC project. Performance will also be monitored and assessed via a DOE sponsored program led by Sandia National Laboratories.

Figure 2-1 AEP's 500 kW (PQ) / 720 kWh (PS) NAS Unit

2.2 Commercialization

As of April 2002, TEPCO and NGK formally announced the sale of commercial NAS products in Japan, in concert with the expansion of manufacturing facilities. TEPCO will distribute NAS systems within its service area and other utilities are expected to follow this model. NGK has teamed with a major power electronics vendor to provide commercial systems in other Japanese markets. NGK also plans to expand manufacturing and team with one or more power electronics vendors to offer NAS systems in foreign markets commensurate with opportunities.

The NAS PS Module is best suited for energy management up to ~20MW, e.g., load leveling and broad peak demand reduction, plus mitigation of power disturbances and outages for up to several hours. The NAS PQ Module is best suited for pulse power applications up to ~100MW such as prompt spinning reserve, voltage and frequency support, short duration power quality protection and short peak demand reduction. The status of these product lines is characterized in Table 2-2.

Table 2-2. The Status of NAS Commercial Product Lines

Technology Variants/ Product Line	Status	Target Markets,	Funding Organizations	Power Electronics Vendors	Major Demonstrations	Lessons Learned	Major Development Trends	Unresolved Issues
Peak Shaving (NAS PS Module)	Commercial (in Japan)	Utility and large Comm'l/Ind'l >500kW to ~20MW	TEPCO, NGK	Teaming arrangements in progress	See Table 2-1 especially, TEPCO S/S at Ohito and Tsunashima 6MW, 48MWh	Confirmed comm'l scale manufacturing of large cells and modules Confirmed utility scale operations	Mass production scale-up	Competitive-ness, certification (outside Japan) Multiple functional value accrual
Power Quality (NAS PQ Module)	Early Commercial (in Japan, demo in US)	Utility and large Comm'l/Ind'l >2MW to ~100MW	TEPCO, NGK	Teaming arrangements in progress	See Table 2-1, namely: Fujitsu, 3MW (Pulse Factor: 3) AEP, 500kW (Pulse Factor: 5)	Value of prompt battery response PCS integration for combined PS and PQ	Mass production scale-up	Competitive-ness, certification (outside Japan) Multiple functional value accrual

3
T&D SYSTEM ENERGY STORAGE SYSTEM APPLICATIONS

This section addresses the following T&D applications for which NAS batteries are particularly well suited:

- Load leveling, typically 3 to 8 hours
- Power quality protection, 30 seconds and up to hours for power disturbance mitigation
- Automatic generation control (AGC), control power interchange and frequency management for events up to one hour
- Wind generation stabilization for hours of firm power delivery

Representative applications are described in more detail in Section 3.1, top-level energy storage system requirements for these applications are provided Section 3.2, and NAS battery performance with respect to requirements is characterized in Section 3.3. It should be noted that the functional attributes of the PCS, including the grid interface, are important elements of both cost and performance. It should also be noted that combining functional requirements where appropriate leads to improved economics. Examples of the economics of combined function applications are addressed in Section 4, and include load leveling combined with AGC and power quality mitigation combined with peak shaving.

3.1 Energy Storage System Descriptions

The following T&D system energy storage applications are representative of the primary functions listed above. Specific sizes have been selected for the convenience of NAS battery system arrangements and to facilitate comparisons.

1. **10MW distribution substation installation for ~8 hr load leveling (utilizing 200 NAS PS Modules):** Strategically located energy storage systems for load leveling are deployed to avoid or defer T&D system upgrades in locations constrained by access or by the admissibility of generation options. In most instances, this application does not require rapid response. That is, scheduled startup over a few minute interval is adequate, and such configurations avoid the expense of grid-interactive[2] power electronics and the

[2] For the purposes of this document, the term “grid interactive” describes a continuously connected, inverter-based power conversion system capable of providing immediate voltage and frequency support to the grid, as well as power disturbance mitigation, to the extent of stored energy.

standby power losses associated with maintaining the PCS in a "hot" condition. This application is functionally equivalent to the 6MW NAS installations at TEPCO's Ohito and Tsunashima substations in Japan. Where appropriate for the user's needs, grid interactive power electronics may be incorporated so that the same energy storage system can be utilized for both load leveling and AGC. The economics of such a case are discussed in Section 4.

2. **10MW distribution substation for up to 30 seconds power disturbance mitigation (utilizing 40 NAS PQ Modules)**: Growth in businesses relying on automated processes and digital transactions that are sensitive to power disturbances has created a demand for equipment to mitigate events such as voltage sags. In the future, the automation of T&D systems in concert with utility deregulation is expected to increase demand for equipment to maintain grid stability. DSTATCOM-type power conversion and grid interface systems utilizing energy storage provide a static alternative to rotary systems. Such applications also require both the PCS and energy storage media to be capable of full power within a few milliseconds. This application provides the grid support functions accomplished by D-SMES, plus sufficient energy to address 99+% of power disturbances and bridge to fast starting generation options. Where appropriate for the user's needs, this application and the previous application (load leveling) may be combined. The economics of such a case are also discussed in Section 4.

3. **26MW transmission substation installation for 1 hour AGC (utilizing 200 NAS PQ Modules):** AGC equipment contributes to controlling power interchange and interconnection frequency regulation between grid control areas by automatically adjusting the supply of power. Energy storage systems comprised of fast response energy storage media and grid interactive power electronic interfaces can contribute to enhanced grid stability. This application requires full power within a cycle for up to one hour equivalent discharge duration during periods of potential grid instability. It is functionally similar to the 40MW Golden Valley Electric Association Battery Energy Storage System at Fairbanks, Alaska, which is designed for 15 minutes grid support. Economic comparisons with the GVEA Battery Energy Storage System (BESS) are provided in Section 4.

4. **2MW energy storage stabilizing a 20MW wind farm (utilizing 40 NAS PS Modules):** The intermittent nature of wind resources inhibits economic utilization within a power marketing framework. That is, economic risks associated with uncertainties in wind patterns may limit the commitment to provide firm power during periods of peak demand to a small fraction of rated wind generation power. Energy storage systems can stabilize wind generation; however, identifying an economically viable configuration entails assessment of site specific factors including diurnal and seasonal variations in the wind resource, the wind farm interface with the utility grid, the prevailing electricity rate structure and viable business models. The application described herein is based on data from a wind turbine site. While detailed characterization of the wind resource is beyond of the scope of this Handbook, key elements of the assessment are insightful. These include:

- Analysis of hourly wind data to identify opportunities for energy storage to enhance the value of daily and seasonal variations of the wind resource, e.g., characterizing daily "time-shift" available wind energy from off-peak to on-peak usage intervals and seasonally switch the energy storage system from wind stabilization to grid support functions such as AGC.

- Development of a business model based on the prevailing electricity rate structure, e.g., establishing arrangements in which commitments to supply on-peak firm power are hedged via power purchased from the grid, and in which off-peak energy to recharge the energy storage media is purchased from the grid during periods of insufficient wind.

- Assessment of the incremental value of energy storage, i.e., conducting parametric assessments to identify the optimal amount of energy storage to maximize revenue.

The primary energy storage function is analogous to load leveling in that the energy storage medium is charged to capacity by off-peak wind generation or, as required, supplemental generation, and discharged to supplement direct wind generation during periods of peak load. This application also requires an interactive PCS to dynamically supplement on-peak direct wind generation and to store off-peak wind generation in response to temporal variations in the wind resource.[3] Accordingly, this system can provide reactive power and voltage/frequency support during those periods when it is not engaged in charging or discharging the energy storage media. The value of energy storage is derived from both shifting off-peak generation to serve peak load and from ensuring that transmission assets are efficiently utilized during energy delivery.

3.2 Energy Storage System Requirements

Top-level technical requirements for energy storage systems to serve the applications described above are listed in Table 3-1. System power, discharge duration, and energy capacity have been selected as representative of commercial "building blocks" based on market assessments, with specific values chosen to facilitate assessment. Likewise, system response time and duty cycle are representative values for each application.

Requirements for system efficiency are also representative of commercial options for these applications, but the basis noted for their calculation deserves further explanation. Three of the four applications identified use grid interactive PCSs and must respond within milliseconds to application demands. This functionality requires that the power electronics be maintained in "hot" standby for a high fraction of their duty cycles, which typically entails a loss of about 2% during standby. This loss must be combined with power conversion losses (e.g., rectifier, inverter and DC battery efficiencies), as well as other system inefficiencies such as standby heat

[3] Energy storage implemented via a PCS integrated with wind turbine output can also be used to stabilize short duration (seconds to minutes) wind variations which can cause excessive voltage and/or frequency excursions on the grid. The economic value of these functions is difficult to quantify because of the need to integrate wind generation and energy storage PCSs. A NAS battery demonstration of this application is briefly described in Ref. 3-1.

losses to maintain the operating state of NAS batteries. For convenience, the integrated system efficiencies noted in this table are expressed on the basis of annual losses.

Requirements for system footprint, which include space for maintenance access, and environmental impact provisions are consistent with industry practice.

Table 3-1. Energy Storage System Requirements for T&D Applications

Application	**ES System Rated Power, MW**	**ES Discharge Duration (Note 1)**	**ES System Response Time (Note 2)**	**ES System Duty Cycle**	**ES System Efficiency, % (Note 3)**	**ES System Footprint, MW/m^2 (MW/ft^2)**	**Environmental Impact**
Load Leveling	1 to 1000	6 to 12 hr	<1 cycle	>150 days/year	>90	At least 0.01 (0.001) (including space for access and maintenance)	<70db acoustic at 10m >95% materials recyclable
Power Quality Protection & Grid Support	2 to 1000	Up to 30 seconds (Note 4)	<1 cycle	<100 cycles/year	>95		
Automatic Generation Control	10 to 1000	Up to 1 hour	<1 cycle	<75 cycles/year	>95		
Wind Farm Stabilization	1 to 100	6 to 10 hours	<1 cycle	~250 cycles/year	>85		

Notes:

(1) Design basis ES system discharge duration at rated power for each event

(2) Time interval from receipt of signal to the start of ES system delivery of power in accordance with a programmed profile

(3) Net ES system efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated power times 8760 hours, expressed in percent

(4) Five, 30-second discharges within 1 hour is required to mitigate multiple events (e.g., lightning strikes) within a short time interval.

3.3 NAS Battery System Compliance with Application Requirements

As indicated in Table 3-2, integrated systems incorporating NAS batteries and the appropriate PCS interfaces meet the application requirements listed in the previous section. Key features include:

- **Load Leveling:** 200 PS Modules discharging 430 kWh_{ac} per module and equipped with a non-grid interactive[4] PCS to conduct scheduled load leveling in accordance with the profile shown in Figure 1-5 each day for the equivalent of 8 months per year (167 cycles) with battery replacement at 15 years. An alternative configuration equips the NAS batteries with a grid interactive PCS, which enables combined load leveling and AGC, also with battery replacement at 15 years.

- **Power Quality:** 40 PQ Modules discharging at a pulse factor of 5 (i.e., 250 kW per module) for up to 30 seconds to mitigate power disturbances on demand via a grid interactive PCS (e.g., DSTATCOM-type topology) with a battery replacement life of 15 years. An alternative configuration combines power quality and load leveling by increasing the number of modules to 47. Power is discharged at a pulse factor of 4.3 (i.e., 215 kW per module) for up to 30 seconds to mitigate disturbances on demand, while load leveling is conducted at 2 MW for 3 hours per day for the equivalent of 8 months per year (167 cycles) with battery replacement at 10 years.

- **Automatic Generation Control:** 200 PQ Modules discharging at a pulse factor of 2.6 (i.e., 130 kW per module) for up to 1 hour supports power interchange and voltage/frequency control on demand via a grid interactive PCS with a battery replacement life of 15 years. Alternatively, with an appropriately sized PCS, this NAS battery configuration will deliver 15 minutes of grid support at a pulse factor of 4 (i.e., 200 kW per module) corresponding to a 40 MW system power rating, thereby providing functional equivalence with the GVEA NiCad BESS,[5] also with battery replacement at 15 years.

- **Wind Stabilization:** 40 PS Modules discharging 375DCkWh per module and equipped with a grid interactive PCS to supplement wind generation for up to 14.4MWh per day for the equivalent of 250 cycles per year, corresponding to a battery replacement interval of 10 years. The bases for deriving the amount of energy storage for this application are described more fully in the following section.

Details of the integrated systems used to characterize the value of NAS batteries are summarized for the four application and variants in Table 3-3. These configurations are used as the bases for cost and benefit analyses in the following section.

[4] The term “non-grid interactive” is used to distinguish the functional requirements (hence, cost basis) of the PCS interface for peak shaving only applications from the PCS required for applications that deliver prompt power for voltage and frequency support and power disturbance mitigation.

[5] As described in Ref. 3-2, a 40 MW BESS using nickel cadmium (NiCad) batteries is being installed in Fairbanks, AK, by the Golden Valley Electric Association for the provision of VAR support, spinning reserve (backup for remote generation trip), automatic scheduling (instantaneous system support in the event of a breaker trip), frequency and voltage regulation, and AGC (similar to that of rotating machinery).

Table 3-2. NAS Battery Energy Storage System Compliance With Application Requirements

Application	NAS System Rated Power, MW	Number (Type) of NAS Modules (Note 1)	NAS Discharge Duration (Note 1)	NAS Capacity, MWh_{ac} (Note 2)	NAS System Response Time (Note 3)	NAS System Duty Cycle	NAS System Efficiency, % (Note 4)	NAS System Footprint, MW/m^2 (MW/ft^2) (Note 5)	Environmental Impact
Load leveling	10	200 (PS)	8.6 hr (equivalent duration at rated power)	86	~4msec	167 days/year	Net: 91.7% ES Cycle: 76.7% Standby: ….NAS: 95.5% ….PCS: NA	Net: 0.010 (0.001) ….NAS: 0.016 (0.0015) ….PCS: 0.03 (0.003)	<65dB acoustic at 10m >98% materials recyclable
Power Quality Protection & Grid Support	10	40 (PQ)	Up to 30 seconds	0.42 (Note 6)	~4msec	100 cycles/year	Net: 97.1% ES Cycle: ~70% Standby: ….NAS: 99.1% ….PCS: 98%	Net: 0.020 (0.002) ….NAS: 0.09 (0.007) …..PCS: 0.03 (0.003)	<65dB acoustic at 10m >98% materials recyclable
Automatic Generation Control	26	200 (PQ)	Up to 1 hour	26	~4msec	75 cycles/year	Net: 96.5% ES Cycle: ~70% Standby: ….NAS:98.5% ….PCS: 98.2%	Net: 0.016 (0.002) ….NAS: 0.04 (0.004) ….PCS: 0.03 (0.003)	<65dB acoustic at 10m >98% materials recyclable
20MW Wind Farm Stabilization	2	40 (PS)	Up to 9 hours	17.2 (Note 7)	~4msec	~250 days/year	Net: 91.4% ES Cycle: 76.7% Standby: ….NAS: 97.5% ….PCS: 99.3%	Net: 0.010 (0.001) ….NAS: 0.016 (0.0015) ….PCS: 0.03 (0.003)	<65dB acoustic at 10m >98% materials recyclable

Notes:

(1) Design basis NAS module selection and discharge duration at rated power for event duty cycle (refer to Figures 1-5 and 1-6 and discussion in Section 1.2.3)

(2) Design basis NAS battery energy discharge between recharging intervals expressed as energy delivered to the load after conversion and storage losses.

(3) Response time from signal to power delivery. (NAS batteries can reach full power from standby within about 1 msec; however, 4 msec is adequate for most applications.

(4) "Net" and "standby" efficiencies are expressed on an annual basis per Note 3 of Table 3-1, and include losses for energy conversion and system standby (e.g., NAS heating, PCS hot standby). "ES cycle" efficiency is expressed as the ratio of energy delivered to energy supplied and includes rectifier, inverter and NAS DC efficiencies for a single cycle.

(5) NAS space requirements are based on an exterior enclosure with stacks of 5 modules and includes space for fork lift access

(6) Five, 30-second discharges within 1 hour without recharging is required to mitigate multiple events (e.g., lightning strikes) within a short time interval.

(7) Optimal energy storage determined by electricity rate structure and variations in wind profile

Table 3-3. Summary of NAS Battery Application System Parameters

	Load Leveling		**Power Quality**		**AGC**		**Wind**
	Base	**Alternate**	**Base**	**Alternate**	**Base**	**Alternate**	**Base**
System							
NAS System Power, MW	10		10		26	40	2
PS Cycle Conversion Eff, %	76.7%		NA	81.2%	NA		76.7%
PQ Cycle Conversion Eff, %	NA		~70%		~70%		NA
Duty Cycle							
PS Duration, equivalent hr/cycle	8.6		NA	3	NA		8.6
PS Cycles, days/yr	167		NA	250	NA		~250
PQ Event Duration	NA		<30 sec		<1 hr	<15 min	NA
Expected PQ Events per Year	NA		<100		<100	<50	NA
PCS Parameters							
PCS Rectifier Eff, %	95%		95%		95%		95%
PCS Inverter Eff, %	95%		95%		95%		95%
PCS Standby Eff, %	NA	98%	98%		98%		98%
NAS Parameters							
Number – Type of Modules	200–PS		40–PQ	47–PQ	200–PQ		40–PS
Pulse Factor (kW per module)	1.0 (50)		5.0 (250)	4.3 (215)	2.6 (130)	4.0 (200)	1.0 (50)
Rated Energy/mod, kWh_{dc}	455		NA	160	NA		455
PS DC Eff, %	85%		NA	90%	NA		85%
PQ DC Eff, %	NA		~80%		~80%		NA
Standby Heat Loss/mod, kW	3.4		2.2	3.7	2.2		3.4
Replacement Interval, years	15		15	10	15		10

4
COST/BENEFIT ANALYSIS

4.1 NAS Battery Pricing and Integrated System Costs

In April 2002, NGK announced construction of expanded manufacturing facilities in Japan with an initial capacity commitment for 1000 modules per year in April 2003. Plans for future expansion include achieving 3600 modules per year in 2006 and 8000 by 2010. Nominal unit prices for utility scale applications of the NAS PQ and PS Modules addressed herein are:

NAS Module	2003 Price, K$	2006 Price, K$	2010 Price, K$
PS	$94.5	$75	$55
PQ	$92.5	$75	$55

The NAS scope of supply for the prices indicated includes NAS battery modules, the battery management system, DC circuit breakers (PQ modules only), exterior enclosures, import duties and fees, shipment from Japan to an inland US site, plus technical support for system integration, installation and startup. For the purposes of this document, NAS prices for year 2006 are used for initial costs, and replacement costs are based on the 2010 mature prices.

The cost of integrated systems is obtained by combining the cost of the NAS battery scope of supply with PCS and system interface equipment, plus balance of plant (BOP) scope. PCS and system interface equipment is assumed to include grid disconnect and breaker protection, transformers, controller(s) to synchronize one or more NAS system trains with the grid, and all equipment necessary for power conversion and isolation of the NAS battery system. Installed PCS and system interface equipment is valued at $230/kW for non-grid interactive systems and $280/kW for grid interactive systems. The BOP scope of supply consists of grid connection at the point of common coupling, land and improvements (e.g., access, services, etc.) and is valued at $20/kW. Cost components for the applications described in Section 3 are shown in Table 4-1.

4.2 Lifecycle Cost Analysis

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. The financial parameters in Table 4-2 are used to assess the applications described in the preceding sections and, except for wind stabilization, the assumed electricity rate structure is presented in Table 4-3. The electricity rate structure used to characterize wind stabilization is presented in Section 4.2.4.

cost/benefit analysis

Table 4-1. Capital and Operating Costs (2006 prices)

Application	NAS System Rated Power, MW	NAS Battery Capacity, MWh_{ac}	PCS & BOP Initial Cost, $/kW (Note 1)	NAS Battery Initial Cost $/kWh (Note 2)	Total Capital Cost, M$	O&M Cost – Fixed, $/kW (Note 3)	O&M Cost – Variable, $/kW (Note 4)
Load leveling	10 (200 NAS PS Modules)	86	250	176	17.7	9	13.7
Power Quality Protection & Grid Support	10 (40 NAS PQ Modules)	0.42	300	7310	6.0	6.6	8.8
Automatic Generation Control	26 (200 NAS PQ Modules)	26	300	585	23.0	7.2	10.1
20MW Wind Farm Stabilization	2 (40 NAS PS Modules)	17.2	300	176	3.7	9	2.8

Notes:
(1) Installed cost of power electronics and system interface valued at $230/kW for non-grid interactive and $280/kW for grid interactive systems. Balance of plant scope is valued at $20/kW.
(2) NAS scope of supply (see text) plus installation estimated at $500 and space at $600 per module, assuming use of the NGK exterior enclosure with modules arranged in stacks of 5, 10-ft wide access lanes, and land valued at $20 per sqft.
(3) Based on 3 hours technician labor per module per year at $50 per hour plus $6/kW for PCS maintenance
(4) Includes electricity consumption for NAS heating and for PCS "hot" standby as appropriate to the application

Table 4-2. Financial Parameters

Dollar Value	2002
System Startup Date	June 2006
Project Life, years	20.0
Discount Rate (before tax), %	5%
Inflation Rate, % (Note)	2%
Escalation Rate, % (Note)	2%
Property Taxes & Insurance, %	2%

Note: Inflation and escalation rates effectively cancel in NPV analyses

Table 4-3. Electricity Rate Structure

Load-Leveling Periods	5d/wk, 8mo/yr	5d/wk, 12mo/yr
Cycles per year	167	250
On-Peak Energy – 3-hr, $/MWh (Note 1)	160	120
On-Peak Energy – 8-hr, $/MWh (Note 1)	80	60
Off-Peak Energy , $/MWh (Note 2)	20	
Average Energy , $/MWh (Note 3)	35	
Transmission Demand Charge, $/kW-mo	7.5	
Automatic Generation Control (ISO price), $/MWh	20	

Notes:
(1) Differences in on-peak energy rates reflect locational opportunities and the spread in seasonal average pricing
(2) Cost of energy to recharge energy storage
(3) Cost of energy consumed during standby for NAS heating and PCS standby

4.2.1 Application 1: 10MW Load Leveling (200 NAS PS Modules)

The base-case load-leveling application assumes that value elements consist of:

- Avoided T&D system upgrade valued at $1000/kW, e.g., any combination of right-of-way, transformers, conductors, peak generation
- Energy price and demand charge reduction per Table 4-3.

For this application, a system designed for simple peak shaving the equivalent of 8 months per year (~167 cycles) with no other functions yields a NPV of $4.6M. However, if the same system is equipped with PCS suitable for grid interactions, it can also provide AGC 16 hours per day during the equivalent 4 months per year when it is not assigned to peak shaving duty. Assuming an incremental increase in PCS/BOP of cost from $250 to $300/kW for the grid-interactive capability, the NPV of this combined function application is assessed to be $8.4M. Costs and benefits for these options are summarized as follows:

Table 4-4. Cost/Benefit of Load-Leveling Applications

	Base Case Load Leveling (LL)	**Alternate LL & AGC**
Initial Installed Cost, M$	17.7	18.2
Total Costs, M$ (Note 1)	31.0	32.1
Total Benefits, M$ (Note 2)	35.6	40.6
NPV, M$ (Note 3)	4.6	8.4

Notes:
(1) Total Costs: Present value of initial capital, operating, replacement, taxes and insurance costs
(2) Total Benefits: Present value of avoided costs and revenues
(3) NPV: Total Benefits minus Total Costs

4.2.2 Application 2: 10MW Power Quality (40 NAS PQ Modules)

The base-case power quality application assumes that the system is valued at the avoided cost of a commercial system of functional parity. Specifically, it is assumed that a static DSTATCOM PCS with four-quadrant control and NAS energy storage is functionally equivalent to a bank of Piller Triblock rotary systems which can provide grid interactive sag protection plus frequency and VAR support. The value of the Triblock is estimated at $1000/kW based on initial (commercially quoted) price plus capitalized values for operating, maintenance, taxes and insurance costs. For the base-case application, the NAS system is configured to deliver 5 times rated power (250 kW per module) for up to 30 seconds.

On this basis, NPV of the NAS system for the base case application is slightly positive ($100K), indicating the lifecycle costs for the two systems are essentially equal. However, if power quality functions are combined with load leveling, as indicated in the Alternate case in Table 3-3, the NPV increases to $1.4M. The duty cycle provided by the NAS system consists of the 30-second pulses to mitigate power disturbances at any time, plus 3 hours load leveling, 5 days per week. Adding load leveling requires that the number of modules be increased from 40 to 47 and that the modules be replaced at 10-year intervals. Costs and benefits for these options are summarized as follows:

Table 4-5. Cost/Benefit of Power Quality Applications

	Base Case Power Quality	Alternate PQ & LL
Initial Installed Cost, M$	6.0	6.5
Total Cost, M$ (Note 1)	9.9	12.2
Total Benefits, M$ (Note 2)	10.0	15.2
NPV, M$ (Note 3)	0.1	3.0

Notes:
(1) Total Costs: Present value of initial capital, operating, replacement, taxes and insurance costs
(2) Total Benefits: Present value of avoided costs and revenues
(3) NPV: Total Benefits minus Total Costs

4.2.3 Application 3: 26 MW Automatic Generation Control (200 NAS PQ Modules)

The base-case AGC application assumes that this service is valued at $20/MWh, based on typical rates of the New York Independent System Operator (NYISO). The NAS system is equipped with grid interactive PCS architecture equivalent to DSTATCOM systems and with NAS energy storage that can deliver 2.6 times rated power (130 kW per module) for up to one hour. Based on providing AGC for 16 hours per day, 350 days per year, the NPV of this system is negative ($0.8M).

However, if a NAS system also comprised of 200 NAS PQ modules is configured for functional equivalence with the NiCad-based GVEA BESS (see footnote, page 3-6), the NAS system appears to be a cost effective alternative, especially when energy density (space cost) is considered.[6] For this configuration, a NAS system can deliver 40MW at 4 times rated power (200 kW per module) for up to 15 minutes. The cost of the GVEA BESS is estimated to be $1220/kW based on initial cost in a temperature controlled space plus capitalized values for operating, maintenance, taxes and insurance costs. This comparison yields a NPV for the NAS system of $4.9M. Costs and benefits for these options are summarized as follows:

[6] This comparison assumes that NiCad systems are housed in a temperature controlled building, while NAS is in an exterior enclosure, which would be the case in most of the U.S. In Alaska, NAS would also require interior space and the NPV would decrease to about $4.1M.

Table 4-6. Cost/Benefit of AGC Applications

	Base Case AGC (NYISO)	**Alternate GVEA Equivalent**
Initial Installed Cost, M$	23.0	27.2
Total Cost, M$ (Note 1)	37.1	43.9
Total Benefits, M$ (Note 2)	36.3	48.8
NPV, M$ (Note 3)	(0.8)	4.9

Notes:
(1) Total Costs: Present value of initial capital, operating, replacement, taxes and insurance costs
(2) Total Benefits: Present value of avoided costs and revenues
(3) NPV: Total Benefits minus Total Costs

4.2.4 Application 4: 20MW Wind Farm Stabilization (40 NAS PS Modules)

A wind generator business model based on forward contracts to supply on-peak energy at firm rates is assumed, wherein shortfalls in wind generation are supplemented with purchased power from the grid or auxiliary generation. It is also assumed that the wind generator commits to the transmission capacity necessary to distribute the amount of power contracted. Wind generation during other periods is sold at non-firm rates and no transmission tariff is charged because of excess capacity during off-peak hours. When the wind farm incorporates energy storage, the storage media is assumed to be charged during off-peak hours. If the off-peak wind resource is inadequate, the amount necessary on a daily basis is also purchased. The electric rates shown in Table 4-4 are assumed to apply.

Table 4-7. Electricity Rates & Business Model for Wind Stabilization

Rate Descriptor	Time Period	Explanation	$/MWh
On-Peak Firm Energy (sell),	10am to 7pm	Firm on-peak power sold via contract	120
On-Peak Energy (buy),	10am to 7pm	On-peak power purchased to hedge wind deficiency	144
On-Peak Non-Firm Energy (sell)	10am to 7pm	On-peak wind in excess of contract	60
Off-Peak Energy (sell),	9pm to 7am	Off peak wind in excess of battery charge	20
Off-Peak Energy (buy),	9pm to 7am	Off-peak power purchased to hedge wind deficiency required to charge	21
Semi-Peak Energy (sell),	7 to 10am; 7 to 9pm	Wind during other hours	40
Transmission Tariff, $/kW-mo	10am to 7pm	Tariff charged wind generator for on-peak generation	3

The wind data summarized in Figure 4-1 illustrates the nature of the wind resource. This data represents the power generated at a 20MW wind farm. It indicates that the maximum capacity of the wind farm is reached at some point during each month, but that there was no wind resource about 20% of the time. It also shows that the average annual capacity is about 5MW or 25% rated capacity. This particular site is subject to pronounced seasonal variations as illustrated by the difference between average summer and winter generation. Daily and diurnal variations in the wind resource are also present (not shown).

cost/benefit analysis

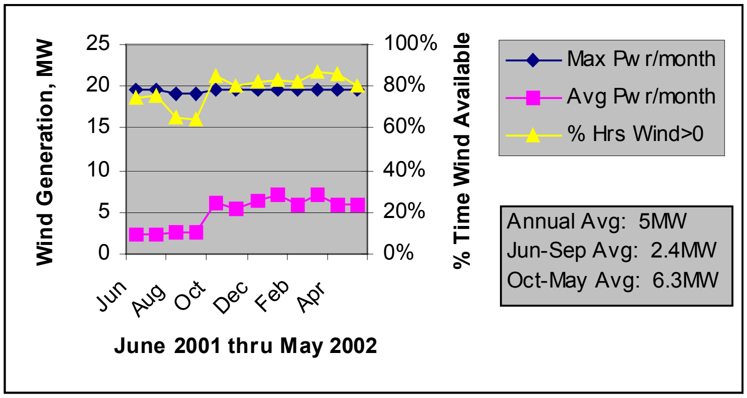

Figure 4-1. Summary of Hourly, Year-long Wind Test Data

To ascertain the value of incorporating energy storage within the wind farm, an optimization calculation using hourly wind data and the above electricity rates was conducted to first identify the maximum revenue stream for the wind farm without incorporating energy storage (wind-only), and then with energy storage (wind+ES). This process showed that the wind generator would maximize revenue with an on-peak firm power supply contract of 1.9MW for wind-only. The optimal on-peak contract amount is increased to 4.4MW when 17.2MWh energy storage capacity per cycle is incorporated. The value of energy storage for these conditions is represented by the incremental benefit in annual revenue summarized in Table 4-5.

Table 4-8. Economic Benefit of Energy Storage for Wind Stabilization

Energy Rates	**Rates, $/MWh**	**Wind-Only, MWh/yr**	**Wind+ES, MWh/yr**	**ES Benefit, K$/yr**
On-Peak Energy (sell)	120	6242	14454	986
On-Peak Energy (buy)	144	(3140)	(3717)	(83)
On-Peak Non-Firm Energy (sell)	60	9468	5963	(210)
Off-Peak Energy (sell)	20	22015	17921	(82)
Off-Peak Energy (buy)	21	0	(1319)	(28)
Semi-Peak Energy (sell)	40	9041	9041	0
Transmission Charges	**Rates, $/kW-mo**	**Wind-Only, MWh/yr**	**Wind+ES, kW-mo**	**ES Benefit, K$/yr**
Transmission Tariff	3	(22800)	(52800)	(90)
	Net Energy Storage Benefit, K$/yr			**493**

Since examination of data also shows that the energy storage system is not being used about 25% of the time, including AGC functions during those periods can further increase its value. This value element would increase annual revenue by $58K, assuming operation in AGC mode for 16 hours per day, 90 days per year. On this basis, the NPV of the NAS system without consideration of AGC is negative ($0.1M) and with AGC it is positive ($0.6M). Costs and benefits for these options are summarized as follows:

Table 4-9. Cost/Benefit of Wind Stabilization Applications

	Base Case Wind Stabilization	**Alternate Wind & AGC**
Initial Installed Cost, M$	3.7	
Total Cost, M$ (Note 1)	6.2	
Total Benefits, M$ (Note 2)	6.1	6.8
NPV, M$ (Note 3)	(0.1)	0.6

Notes:

(1) Total Costs: Present value of initial capital, operating, replacement, taxes and insurance costs

(2) Total Benefits: Present value of avoided costs and revenues

(3) NPV: Total Benefits minus Total Costs

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EPRI Energy Storage Handbook: Superconducting Magnetic Energy Storage Chapter

December 2002

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1. Technology Description

Introduction

Superconducting Magnetic Energy Storage (SMES) is based on three concepts that do not apply to other energy storage technologies:

- Some materials (superconductors) carry current with no resistive losses.
- Electric currents produce magnetic fields.
- Magnetic fields are a form of pure energy, which can be stored.

The combination of these fundamental principles provides the potential for the highly efficient storage of electrical energy in a superconducting coil. Operationally, SMES is different from other storage technologies in that a continuously circulating current within the superconducting coil produces the stored energy. In addition, the only conversion process in the SMES system is from AC to DC. As a result, there are none of the inherent thermodynamic losses associated with conversion of one type of energy to another.

SMES was originally proposed for large-scale, load levelling, but, because of its rapid discharge capabilities, it has been implemented on electric power systems for pulsed-power and system-stability applications. Figure 1 is an example of the only SMES unit commercially produced at present (American Superconductor's D-SMES – see Section 2). This chapter emphasizes these existing applications of SMES. However, it includes descriptions of some of the extensive design and development programs for large-scale SMES plants that were carried out mostly in the 1970s and 1980s. Figure 2 shows such a plant that has a 500-MW power rating and stores enough energy to deliver this energy for 6 to 8 hours. Though there is no scale on the drawing, the coil is about 1000 m in diameter and is buried deep enough for the surrounding rock to support the magnetic load in the coil. Finally, this chapter includes summaries of several studies for other applications. An extensive bibliography and appendices with additional information are included at the end of the report.

Figure 1
A trailer mounted D-SMES unit with 3MW and 16 MVA capacities (Picture supplied by American Superconductor)

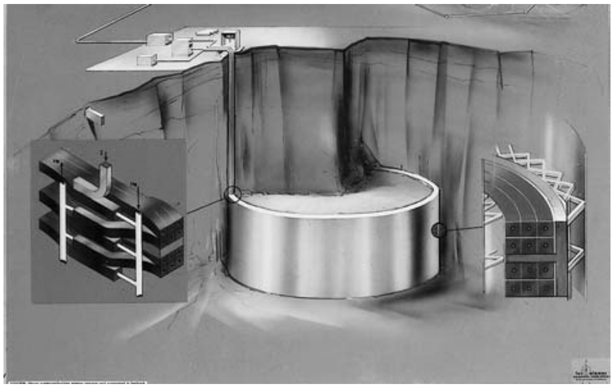

Figure 2
Artist concept of a diurnal SMES system that is constructed underground

System Components

The peak power capacity and the maximum stored energy in a SMES system are determined by application and site-specific requirements. Once these values are set, a system can be designed with adequate margin to provide the required energy on demand. It is apparent from Figures 1 and 2 that SMES units have been proposed over a wide range of power capacities (1 to 1000 MW) and energy storage ratings (0.3 to 10,000,000 kWh). Independent of capacity and size, however, a SMES system always includes a superconducting coil, a refrigerator, a power conversion system (PCS), and a control system as shown in Figure 3. Each of these components is discussed in this section. A description of the magnetic basis for the energy storage of SMES systems and a discussion of mechanical support for the superconducting coils are included in the Appendix. These are included to give additional insight to those interested in some of the details of SMES technology.

The Coil And The Superconductor

The superconducting coil, the heart of the SMES system, stores energy in the magnetic field generated by a circulating current. Since the coil is an inductor, the stored energy is proportional to the square of the current, as described by the familiar equation:

$$E = \frac{1}{2} LI^2,$$

where L is the inductance of the coil, I is the current, and E is the stored energy.

The total stored energy, or the level of charge, can be found from the above equation and the current in the coil. The maximum stored energy, however, is determined by two factors.

- The size and geometry of the coil, which determines the inductance. The larger the coil the greater the stored energy.
- The characteristics of the conductor, which determines the maximum current. Superconductors carry substantial currents in high magnetic fields. For example, at 5 T, which is 100,000 times greater than the earth's field, practical superconductors can carry currents of 300,000 A/cm^2.

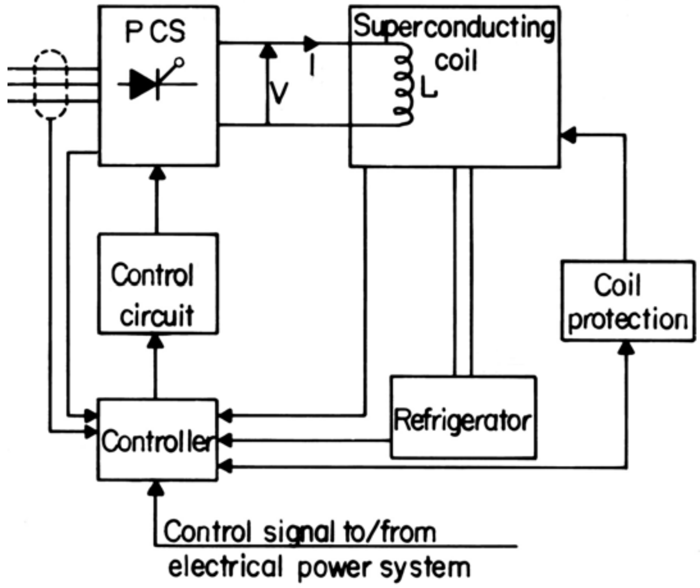

Figure 3
A simplified block diagram of a SMES system showing major components.

All practical SMES systems installed to date use a superconducting alloy of niobium and titanium (Nb-Ti), which requires operation at temperatures near the boiling point of liquid helium, about 4.2 K (-269°C or -452°F) – 4.2 centigrade degrees above absolute zero. Typical conductors made of this material are shown in Figure 4.

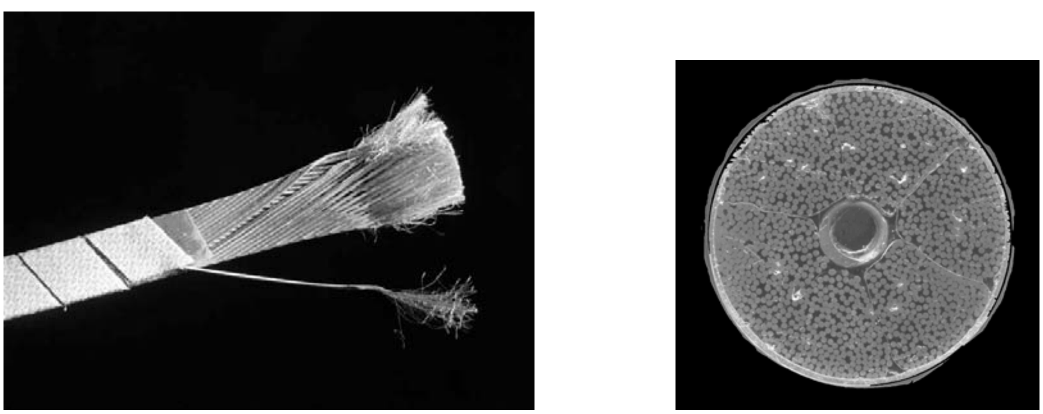

Fig. 4a Fig. 4b

Figure 4
Typical conductors made of the superconductor Nb-Ti (LBNL & LLNL)

Figure 4a, on the left, is a flattened cable made of 30 composite strands wrapped in an insulator made of Kapton and epoxy-fiberglass. Each strand is 0.7 mm in diameter and contains several thousand, 6 μm diameter Nb-Ti filaments extruded in a copper matrix. Figure 4b, on the right, is a CICC cable made of several hundred of these strands in a stainless steel conduit. During operation, helium is in direct contact with the superconducting strands and, in the CICC shown, the helium flows through the central tube. Lawrence Berkeley National Lab (LBNL) and Lawrence Livermore National Lab (LLNL) supplied figures 4a and 4b, respectively.

Many tons of Nb-Ti alloy are fabricated worldwide each year for applications such as magnetic resonance imaging (MRI) magnets and accelerators for nuclear physics research. In addition, the aerospace industry uses considerably more of a slightly different Nb-Ti alloy each year for rivets that hold the aluminum skin in place on the bodies and wings of most commercial and military aircraft. Some research-based SMES coils use high-temperature superconductors (HTS). However, the state of development of these materials today is such that they are not cost effective for SMES. An evaluation HTS for SMES was made for EPRI in 1998 (See Bibliography for this and other reports on HTS SMES research).

Since the superconductor is one of the major costs of a superconducting coil, one design goal is to store the maximum amount of energy per quantity of superconductor. Many factors contribute to achieving this goal. One fundamental aspect, however, is to select a coil design that most effectively uses the material. This is generally accomplished by a solenoidal configuration, as in the two SMES installations shown in Figures 5 and 6. Figure 5 shows the 30 MJ superconducting coil developed by the Los Alamos National Laboratory (LANL) and installed by the Bonneville Power Administration at the Tacoma substation. Figure 6 is a small, 1 MJ SMES coil.

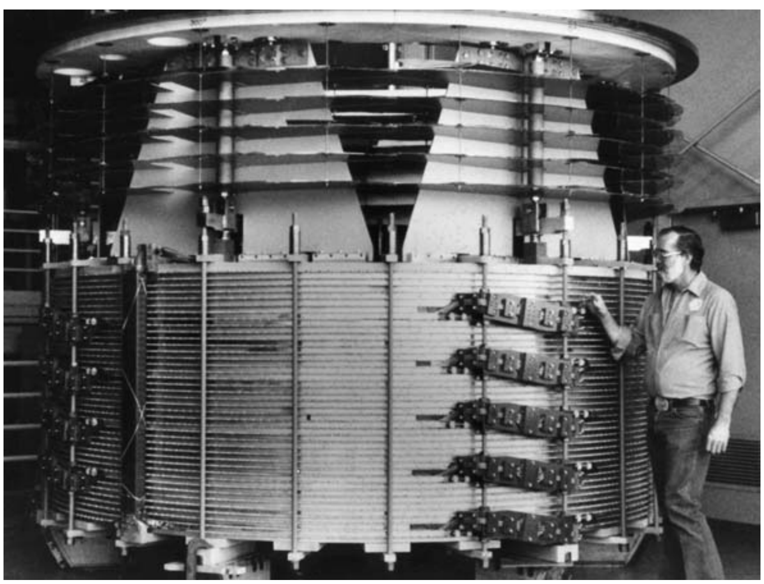

Figure 5
The 30 MJ superconducting coil developed by the Los Alamos National Laboratory (LANL)

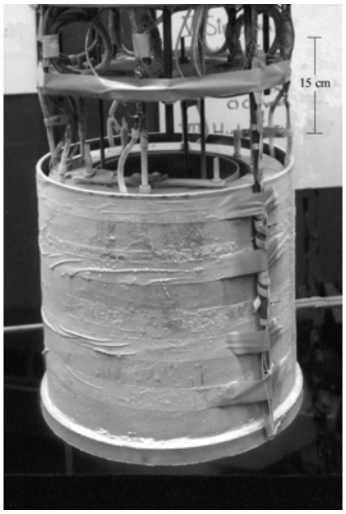

Figure 6
A small, 1 MJ SMES coil in a liquid helium vessel (LANL)

Since only a few SMES coils have been constructed and installed, there is little experience with a generic design. This is true even for the small or micro-SMES units for power-quality applications, where several different coil designs have been used.

A primary consideration in the design of a SMES coil is the maximum allowable current in the conductor. It depends on: conductor size, the superconducting materials used, the resulting magnetic field, and the operating temperature. The magnetic forces can be significant in large coils and must be reacted by a structural material. The mechanical strength of the containment structure within or around the coil must withstand these forces. The coil shown in Figure 5 has stainless straps within the cabled conductor for this purpose. The baffle structure at the top of the coil limits gas circulation and maintains a temperature gradient from the liquid helium bath around the coil to the ambient-temperature top plate. See the Appendix for a discussion of structural requirements. Another factor in coil design is the withstand voltage, which can range from 10 kV to 100 kV.

Cryogenic Refrigerator

The superconducting SMES coil must be maintained at a temperature sufficiently low to maintain a superconducting state in the wires. For commercial SMES today this temperature is about 4.5 K (-269°C, or -452°F). Reaching and maintaining this temperature is accomplished by a special cryogenic refrigerator that uses helium as the coolant. Helium must be used as the so-called "working fluid" in such a refrigerator because it is the only material that is not a solid at these temperatures. Just as a conventional refrigerator requires power to operate, electricity is used to power the cryogenic refrigerator. Thermodynamic analyses show that the lower the temperature, the greater power required to remove heat from the coil. Including inefficiencies within the refrigerator itself, between 200 and 1000 watts of electric power are required for each watt that must be removed from the 4.5 K environment. As a result, there is a tremendous effort in the design of SMES and other cryogenic systems to lower losses within the superconducting coils and to minimize heat flow into the cold environment from all sources.

Both the power requirements and the physical dimensions of the refrigerator depend on the amount of heat that must be removed from the superconducting coil. The refrigerator consists of one or more compressors for gaseous helium and a vacuum enclosure called a “cold-box”, which receives the compressed, ambient-temperature helium gas and produces liquid helium for cooling the coil. The 30 MJ coil shown in Figure 5 required a dedicated refrigerator that occupied two small trailers, one for the compressor and one for the “cold box”. The coil was tested at 4.5 K and then removed from the cryostat while still cold, which leads to the ice on the surface of the helium vessel. The coil is approximately the size of early power quality SMES coils, such as those fabricated by American Superconductor Inc. and Intermagnetics General Corp.

Small SMES coils and modern MRI magnets are designed to have such low losses that very small refrigerators are adequate. Figures 7 and 8 show cryogenic refrigerators of different capacities. In Figure 7, a small cryogenic refrigerator (the 30 cm section) and a cold-finger extension that would be appropriate for recondensing liquid helium to cool a superconducting coil are shown. This refrigerator can remove about 5 W at 4.5 K, which is the heat load that might be expected in a micro-SMES for power-quality applications. Such refrigerators usually operate with the cold finger pointing downward but other orientations are possible. Figure 8 shows a large liquid helium refrigerator at the Japanese Atomic Energy Research Institute (JAERI). Such a refrigerator would be appropriate for the diurnal SMES installation shown in Figure 2. It can remove about 10 kW of heat from a large magnet operating at 4.5 K.

Power Conversion System

Charging and discharging a SMES coil is different from that of other storage technologies. The coil carries a current at any state of charge. Since the current always flows in one direction, the power conversion system (PCS) must produce a positive voltage across the coil when energy is to be stored, which causes the current to increase. Similarly, for discharge, the electronics in the PCS are adjusted to make it appear as a load across the coil. This produces a negative voltage causing the coil to discharge. The product of this applied voltage and the instantaneous current determine the power.

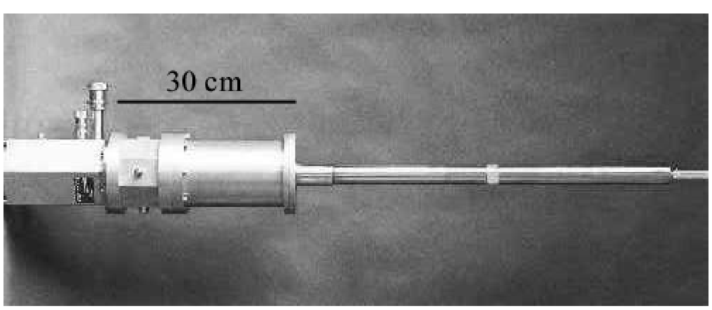

Figure 7
A small cryogenic refrigerator and cold-finger extension (Cryomech Inc.)

Figure 8
A large liquid helium refrigerator (JAERI)

SMES manufacturers design their systems so that both the coil current and the allowable voltage include safety and performance margins. Thus, the PCS power capacity typically determines the rated capacity of the SMES unit. In particular, as energy is removed from the coil, the current decreases. As a result, the PCS must be designed to deliver rated power at the lowest operational coil current, which is about half of the maximum current. Equivalently, about a quarter of the stored energy remains in the coil at the end of a typical discharge (see the equation for energy stored in a coil in Section 1).

The PCS provides an interface between the stored energy (related to the direct current in the coil) and the AC in the power grid. Several different designs have been suggested for the PCS, depending on the application and the design of the SMES coil. The power that can be delivered by the SMES plant depends on the charge status (the current I) and the voltage capability of the PCS, which must be compatible with the grid.

Control System

The control system establishes a link between power demands from the grid and power flow to and from the SMES coil. It receives dispatch signals from the power grid and status information from the SMES coil. The integration of the dispatch request and charge level determines the response of the SMES unit. The control system also measures the condition of the SMES coil, the refrigerator, and other equipment. It maintains system safety and sends system status information to the operator. Modern SMES systems are tied to the Internet to provide remote observation and control.

Technology Attributes

Capacity

The power capacity for a SMES system is dictated by the application, e.g., power quality, power system stability, or load leveling. The manufacturer uses this to select system design and components. In general, the maximum power capacity is the smaller of two quantities:

- The PCS power rating.
- The product of the peak coil current and the maximum coil withstand voltage.

The manufacturer must design the SMES plant so that the current in the superconducting coil and the operational voltage are adequate for the power delivery requirement.

The capacities of existing individual micro-SMES installations range from 1 MW to about 3 MW. These are discussed under technology status in the next section. A much larger unit is now being installed by the Center for Advanced Power Systems (CAPS) at the National High Magnetic Field Laboratory (NHMFL) in Tallahassee, Florida. The PCS for this coil will initially have an installed capacity of 5 MW. Future enhancement to 25 MW is planned. The superconducting coil, however, was designed to deliver 100 MW, i.e., the product of the design current and design voltage is 100 MW.

Energy Storage Rating

The stored energy in the SMES plant depends on the requirements of the application. It is the product of the power capacity and the length of time the installation is to deliver this power. The micro-SMES plants listed above deliver 3 to 6 MJ (0.8 to 1.6 kWh) somewhat more than a lead-acid automotive starting battery. Because the power capacity of these units is so high, this entire quantity of energy can be delivered (i.e., the coil can be fully discharged) in a second or so. The larger, 100 MW coil to be installed at NHMFL, mentioned above, was originally designed for a one-second discharge in conjunction with the unified power flow controller (UPFC) operated by American Electric Power (AEP) at its Inez Substation. This coil thus stores about 100 MJ (28 kWh). When the converter at NHMFL is upgraded to 25 MW, the coil will be discharged in about 4 seconds.

Physical dimensions of the SMES installation

The physical size of a SMES system is the combined sizes of the coil, the refrigerator and the PCS. Each of these depends on a variety of factors. The coil mounted in a cryostat is often one of the smaller elements. A 3 MJ micro-SMES system (coil, PCS, refrigerator and all auxiliary equipment) is completely contained in a 40-ft trailer.

Efficiency

The overall efficiency of a SMES plant depends on many factors. In principle, it can be as high as 95 % in very large systems. For small power quality systems, on the other hand, the overall system efficiency is less. Fortunately, in these applications, efficiency is usually not a significant economic driver. The SMES coil stores energy with absolutely no loss while the current is constant. There are, however, some losses associated with changing current during charging and discharging, and the resulting change in magnetic field. In general, these losses, which are referred to as eddy current and hysteresis losses, are also small.

Unfortunately, other parts of the SMES system may not be as efficient as the coil itself. In particular, there are two potentially significant, <u>continuous</u> energy losses, which are application specific:

- The first is associated with the way SMES systems store the energy. The current in the coil must be flow continuously, and it circulates through the PCS. Both the interconnecting conductors and the silicon-based components of the PCS are resistive. Thus, there are continuous resistive losses in the PCS. This is different from batteries, for example, where there is current in the PCS only during charge and discharge.
- The second is the energy that is needed to operate the refrigerator that removes the heat that flows to the coil from room temperature via: a) conduction along the mechanical supports, b) radiation through the vacuum containment vessel, and c) along the current leads that extend from ambient temperature to the coil operating temperature.

The overall efficiency of a SMES plant depends on many factors. Diurnal (load-leveling) SMES plants designed 20 years ago were estimated to have efficiencies of 90 to 92%. Power quality and system stability applications do not require high efficiency because the cost of maintenance power is much less than the potential losses to the user due to a power outage. Developers rarely quote efficiencies for such systems, although refrigeration requirements are usually specified. A 3 MJ/3 MW micro-SMES system, for example, requires about 40 kW of continues refrigeration power.

2. Status

D-SMES

Today the only commercial SMES product is the D-SMES unit produced by American Superconductor. The individual, trailer-mounted D-SMES units consist of a magnet that contains 3 MJ of stored energy (see Figure 1). They can deliver 3 MW for about 1 second and 8 MVAR continuously. This is accomplished by a PCS that has full 4-quadrant control and uses IGBT based inverters. There is an instantaneous overload capability of 2.3 times continuous (2.3x) for reactive power in the inverter so that the dynamic reactive output can be as high as 18.4 MVAR for up to 1 second. Three networked systems with a total of 9 units have been installed, as indicated in Table I. An additional unit has been ordered.

Table I
Installed D-SMES Units

Installation Date	Host Organization	Installation Location	Installation Purpose
June 2000	Wisconsin Public Service	Northern Wisconsin	Transmission Loop Voltage Stability - 6 Units, installed at distributed locations
July 2000	Alliant Energy	Reedsburg, WI	Transmission Voltage Stability
May 2002	Entergy	North Texas	Voltage Stability - 2 Units
June 2002 (ordered)	BC Hydro	Ft. St. James, BC Canada	Voltage Sag Protection

Power Quality or μ-SMES

Prior to the development of the D-SMES concept, American Superconductor supplied several small power quality SMES units, which are still operational. Designated "micro"-SMES, these units have been installed around the world in mostly industrial settings to control voltage sag problems on the electrical grid. These are listed in Table II.

SMES Test and Evaluations

In 1992 the Defense Advanced Research Projects Agency (DARPA) issued a request for proposals to build an intermediate sized SMES system for a utility application. There was some consideration/discussion of dual use with a military pulsed power application. As finally released, there was no requirement for a military application as part of the design. A contract was awarded to Babcock and Wilcox (B&W) to build and then install a 0.5 MWh, 20 MW plant in Anchorage, Alaska. However, a variety of factors resulted in several changes in direction of the program. It eventually evolved into a program for BWX Technologies to build a 100 MJ (0.028 MWh) coil for the National High Magnetic Field Laboratory (NHMFL) in Tallahassee, Florida. This coil is expected to be completed in 2003 and will be installed at the Center for

Advanced Power Systems (CAPS), a part of NHMFL and Florida State University. The coil will be initially operated with a 5 MW converter, which is appropriate for the local power system. It is designed, however, to accommodate power flows of up to 100 MW.

Table II
Existing Installations of Micro-SMES

Commissioned	Customer	Location	Description of Load
May 1992	Central Hudson G&E	Fishkill, NY	Semiconductor Testing Facility
December 1993	Tyndall AFB	Panama City, FL	Five General Military Buildings
March 1993	CYANCO	Winnemuca, NV	400 HP/4160V Motor at Chemical Plant
May 1995	Brookhaven National Laboratory	Upton, NY	Light Source Research Center Ultra-violet Light source, ring, and experiment station
May 1995	McClellan AFB	Sacramento, CA	Semiconductor Chip Mfg. Lab Fiber Optic Mfg. Facility Removed when Base Closed
July 1996	U.S. Air Force	Tinker AFB, OK	DC Link Support for two 800 kW/1000kVA Ups
June 1997	U.S. Air Force	Tinker AFB, OK	DC Link Support for two 800 kW/1000kVA Ups
April 1997	SAPPI - Stanger	Stanger, South Africa	1000 kVA Paper Machine
May 1997	AmeriMark Plastics	Fairbluff, NC	Plastic Extrusion Plant Removed when plant sold
May 1999	STEWEAG	Gleisdorf, Austria	Automotive Parts Foundry
June 2002	Edison/STM	Agrate, Italy	Semiconductor Processing Facility Voltage Sags - 2 Units
April 2002	EDF	Paris, France	Voltage Sag Protection

SMES Status Summary Tables

Table III describes the status of three different aspects of SMES development.

Table III
Technology Status of SMES

Application	MicroSMES for Power Quality	D-SMES for System Stability	SMES for Load Leveling
Status	Commercial: several units installed as described in Table 1	Demonstration	Theoretical
Funding organizations	Private funding in US. Some government funding of potential applications by Japan and Germany	American Superconductor, Wisconsin Power System	None at present; previously: EPRI, US DOE, US DNA
Vendors	American Superconductor	American Superconductor	None at present
Major demonstrations	See Table II	Northern Wisconsin power system	None
Lessons learned	Critical issues in terms of the power output and response time.	Early data indicates that D-SMES is effective in the Wisconsin application. Additional information is required on these and other installations.	Long-term development and societal commitment is required for large systems that cost over a billion dollars and take more than ten years to complete.
Major development trends	American Superconductor has several units in the field at this time. However, they have standardized on the D-SMES installation as the standard product. At present there is only one developer.	American Superconductor is prepared to deliver additional units and is actively searching for customers	None
Unresolved issues	Costs of SMES units relative to other PQ technologies.	Cost effectiveness of this application compared to other solutions.	Costs, and costs compared to other load leveling technologies

Developmental costs

The original development of SMES systems was for load levelling as an alternative to pumped hydroelectric storage. Thus, large energy storage systems were considered initially. Research and then significant development were carried out over a quarter century in the US, beginning in the early 1970s. This effort was mainly supported by the Department of Defense, the Department of Energy, and EPRI. Internationally, Japan had a significant program for about 20 years, and several European countries participated at a modest level. The Defense Department - sponsored Engineering Test Model program funded $72 M worth of design, engineering and test work between 1988 and 1994. In addition, we estimate the total international R&D related labor on SMES for load levelling up to the present to be about 500 person years. Using a fully loaded annual charge of $150,000 (in 2002 funds) per person per year, this comes to $75M. Since no practical devices have been constructed or installed, material and construction costs will not increase this value significantly.

At several points during the SMES development process, researchers recognized that the rapid discharge potential of SMES, together with the relatively high energy related (coil) costs for bulk storage, made smaller systems more attractive and that significantly reducing the storage time would increase the economic viability of the technology. Thus, there has also been considerable development on SMES for pulsed power systems. Though EPRI and government organizations have supported some of this effort, a great deal has been internally supported by industry. The total labor R&D in this area has been about 250 person years. In addition, several devices have been fabricated. We estimate that the combined international effort is on the order of $50M for SMES systems for pulsed power, system stability, and for other rapid discharge applications.

3. Applications

SMES has been proposed for several different T and D applications. A summary of these applications as described in EPRI report 1006795 is listed in the bibliography and is summarized in the appendix. Three applications are evaluated in this and the following section. They have been selected because there has been sufficient developmental effort to discuss costs and, at some level, potential benefits. The first two, system stability and power quality are included because commercial SMES installations of these devices exist, see Figure 1. The third, load leveling, is included because of the extensive development that was carried out, because several designs were developed and the information on these designs is available, and because this application is often proposed as the ideal application for SMES. The three applications are summarized in Table IV.

System Stability and Damping

Large power systems may experience instabilities associated with the delivery of power over long distances when there are abrupt changes in operating conditions, e.g., when a large load is applied or when a generator or line is lost. Perhaps the best-known case of this type of instability is in the north-south power corridor on the West Coast of the United States. A great deal of power (several thousand Megawatts) is generated in the Pacific Northwest and is delivered to middle and southern California via multiple transmission lines. One characteristics of the system in this region is that a north-south power oscillation can occur with a frequency of about 0.3 Hz. That is, power flow increases and decreases with a period of about 3 seconds. These oscillations are generally insignificant. Under certain conditions, however, the system has exhibited undamped oscillatory power flow with amplitudes of 300 MW, as shown in Figure 9.

This phenomenon is associated with several components of the power grid. Generators have feedback systems to maintain frequency control and transmission lines have high levels of series capacitors that provide VAR compensation. In some cases, these two components form a resonant circuit. When the feedback between theses two parts of the system becomes significant, there can be a Sub-Synchronous Resonance, SSR, which limits power flow. The impact of SSR on the grid is to reduce the transfer capability of the transmission lines.

System stability issues and SSR occur in many areas. In general, however, they are anticipated and additional control systems, generation, or additional transmission capability is installed to reduce the sensitivity of the grid to resonant conditions. Northern Wisconsin's power transmission system is limited in capacity by instabilities that occur under certain operating conditions, even though the thermal limits of the transmission lines are considerably above power demands in all operating scenarios. Stability in this system can be achieved by adding additional transmission lines, but at the expense of raising all the issues associated with rights of way, environmental permissions, etc. It can also be achieved by the addition of a distributed network of energy storage and increased VAR compensation at the point of storage.

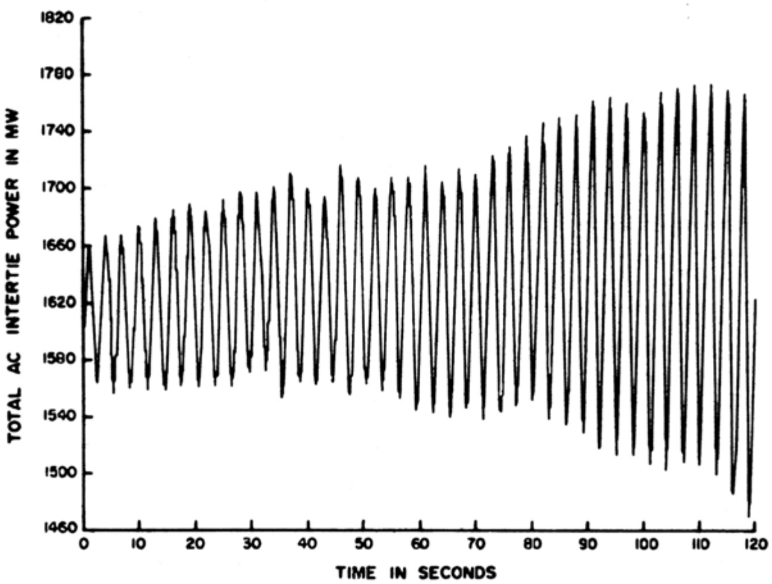

Figure 9
Negatively damped oscillations observed on August 8, 1974, on the BPA Pacific HVAC Intertie.

Power Quality

A variety of loads--ranging from modest industrial installations to substations of significant capacity--require energy to provide power quality and backup power. This energy is used for a variety of conditions such as when momentary disturbances require real power injection to avoid power interruptions. In the case of industrial customers, a local source of power may be required when there is an interruption of power from the utility. This power source may function until the power feed from the utility is restored, until a reserve generator is started, or until critical loads are shut down in a safe manner. In the case of a substation, a variety of momentary disturbances such as lightning strikes or transmission flashovers cause power trips or low voltages. The total energy storage requirement is greater and there may be a need power flow separation to insure continuous power to important customers.

Load leveling

Demands for electric power vary both randomly and with predictable variations. Perhaps the most significant variation of power demand is the diurnal change associated with the functioning of an industrial society. Both commercial and residential demands are greater during the day than at night. On the other hand, many power plants operate most efficiently and have longer lives if they operate continuously near their maximum power output. One method of accommodating users' power demands and the characteristics of these plants is to install an energy storage system that can accept energy at night and can deliver it back to the grid during periods of high demand. The value of this type of storage is based on the difference in marginal cost of off-peak power and the price paid for power during the peak. An additional impact of diurnal storage is that it can replace or defer the installation of extra generation capacity to accommodate.

Table IV Summary of SMES Technologies For Three Applications.

Application	**Size**	**Duration**	**Plant Capacity**	**Response Time**	**Duty Cycle**	**Round-trip Efficiency**	**Plant Foot-print***	**Environ-mental Impact**
units	kWh		MW	ms	Events per year		m^2 (ft^2)	
System Stability	1.7	< 1 sec	3 (8 MVAR)	8	Weekly or more	NA	45 (484)	None
Power quality	0.28	1-3 sec	1	8	Tens to 100 per year	NA	30 (323)	None
Load levelling	4,000,000	4 Hours	1000	8	daily	0.9	1,000,000 (10,760,000)	External/ stray magnetic field

*Footprint of entire system or, for load leveling, area included in fence based on allowable magnetic field

4. Costs and Benefits

SMES Plant Costs

There are two approaches for developing SMES costs. One is to obtain prices from vendors and use them directly or adjust them to fit the details of the application. This method is used below for the System Stability and the Power Quality applications, which are based on vendor data. The second is to carry out a "bottoms-up" calculation that begins with a design and applies cost data for materials, labor, separate components and fabrication processes. It requires knowledge of how a plant will be constructed. Bottoms up cost calculations are the fundamental method for estimating projected costs for technologies that are not yet commercially available. It is used to estimate costs for the load-leveling SMES application. This latter approach is discussed and applied to estimates for load-leveling systems. This discussion is presented before presenting commercial system costs because the information developed is instructive for understanding SMES costs in general since the components are somewhat different from those of other technologies.

The SMES system consists of the components discussed in section 1 of this chapter: i.e., a superconducting coil, a refrigerator, a power conversion system, and a control system. The cost of the control system is small for all SMES systems and is almost independent of size. That is, controllers for a PQ system and one for a diurnal storage system would be in the range of $20,000. PCS requirements, and thus their costs, depend on the power demands of the customer. However, they can be estimated from known electronic converter costs from other applications. The cost will depend somewhat on size, but is projected to be in the range of $125/kW to $175/kW for nth of a kind (NOAK) installations. The cost for the refrigerator depends on amount of cooling required. The cost is roughly proportional to the room temperature power required for operation. Refrigerators with cooling capacities appropriate for each of the three applications considered in this section are commercially available.

The cost of the superconducting coil is somewhat more complicated to determine. It includes several components, each of which must be developed and integrated into a coherent, consistent design. Here we discuss each of these components and then give a formula for calculating total costs. The key to the operation of the SMES plant is the superconductor, which is available in commercial quantities for other applications. The amount of conventional Nb-Ti conductor to be purchased can be specified in several different units. Typically, the final user purchases the conductor by the meter, which can carry a specified current (in kA) at a specified field (usually about 5 T). This is referred to as the cost in $/kAm. This metric is convenient because it is a natural output of the magnetic design of a SMES system. Whereas in most applications the amount of material needed is linearly proportional to the stored energy, in the case of SMES, the superconductor requirement is less than a linear function of the stored energy. Specifically, if the total stored energy increases by a factor of 10, the amount of conductor only increases by a factor of 5. As a result, the cost per unit if stored energy ($/kWh) decreases as the total amount of stored energy increases.

The second component of the coil system is the cryogenic enclosure or cryostat. Details of the cryostat depend on several design choices. However, the driving force in the cryostat design is the need to maintain a coil operating temperature near absolute zero and to reduce heat flow via conduction, convection and radiation from ambient temperature to the coil. The cryostat is usually a double-walled system with vacuum separating the two vessels.

The magnetic field produced during charging produces a force on the coil. This force must be resisted by a mechanical structure. This is the third component in the cost coil component. In small coils, such as those for D-SMES and for PQ applications, the strength of the superconducting wire is sufficient to withstand this force. As the size of the coil increases, the total outward force on the conductor becomes large enough that additional structure is required. This material can be estimated based on the amount of stored energy for large systems, and the costs are similar to those for structural components of flywheel or surface mounted compressed air systems.

These costs may be combined into an equation:

$$C_{SMES} = C_{superconductor} + C_{structure} + C_{refrigerator} + C_{cryostat} + C_{PCS} + C_{BoP} + C_{controller}\,.$$

This equation may be simplified by recognizing that superconductor is a significant fraction of the storage related cost and is related to the stored energy (E) as discussed above. Most other energy related costs are linearly proportional to the stored energy as with other systems. Thus, we can estimate the cost variation as a function of stored energy by a rather straightforward functional relation:

$$C_{SMES} \approx C_1 \cdot E + C_2 \cdot E^{2/3} + C_3 \cdot P + C_{controller}$$

where E is given in kWh and P in kW. The value of C_1 relates to the cost of structure and most of the balance of plant, C_2 relates to the superconductor and the enclosure, and C_3 relates to the power capacity of the plant i.e., the PCS cost. In summary, the costs are energy-related, power-related, or fixed. There are no major replacement costs for a SMES system with a 20-year life. All normal maintenance expenses are included in the O&M cost.

Developments of the costs of large SMES plants for load levelling are included in several publications listed in the Bibliography. The costs of SMES plants for the three different applications under consideration are given in Table V for present costs and VI for NOAK costs. In these tables, the fixed costs are either ignored because they are small, or are included in one of the other terms. NA indicates there are no data available. Fixed O&M costs are estimated from annual service contracts for the small SMES systems, and from industry estimates for the large, load-leveling SMES.

Table V
Present-day Costs for SMES plants.

Application	Type	Plant Capacity	Energy Storage (kWh)	Capital Cost – Power Related ($/kW) or ($/kVAR)	Capital Cost – Energy Related ($/kWh)	Total Capital Cost ($)	O&M Cost – Fixed ($/(kW+ kVAR) /yr)	O&M Cost – Variable ($/kWh)
System Stability	D-SMES	8 MVAR (3 MW)	1.667	300	360,000	2.4M	3	NA
Power quality	μ-SMES	1 MW	0.28	500	1,000,000	800K	5	NA
Load leveling	SMES	1,000 MW	4,000,000	300 - 500	NA	NA	NA	NA

Table VI
Nth of a Kind (NOAK) Costs for SMES plants.

Application	Type	Plant Capacity	Energy Storage (kWh)	Capital Cost – Power Related ($/kW) or ($/kVAR)	Capital Cost – Energy Related ($/kWh)	Total Capital Cost ($)	O&M Cost – Fixed ($/(kW+ kVAR) /yr)	O&M Cost – Variable ($/kWh)
System Stability	D-SMES	8 MVAR (3 MW)	1.667	175	360,000	2M	3	NA
Power quality	μ-SMES	1 MW	0.28	175	850,000	420K	5	NA
Load leveling	SMES	1,000 MW	4,000,000	125	220*	1,005M	1	NA

* Based on the use of steel support structure

Estimated Benefits

Table VII shows the estimated benefits for the use of SMES in the three application categories. These estimates are based on a review of estimates made by other analysts, as shown in the references below the table.
The three application benefits were estimated as follows:

- System stabilization, as provided by D-SMES, provides benefits primarily by the avoidance or deferral of new transmission. The cost of new transmission is used as the benefit value.

- Power quality benefits result primarily from reliable service, i.e., the avoidance of outages. The cost of outages varies, of course, by user, and is estimated by events. The high and low in this case result from a small number of events of low-value events per year to a significant number of high-value events.
- Load-leveling benefits, or arbitrage benefits, result from the differential between the cost of on-peak and off-peak power. This varies widely by location and season. Typical values are quoted.

Table VIII shows Benefit/Cost Ratios based on the Present Value of Benefits listed in Table VII and costs listed in Tables V and VI. Present Value was calculated for the specific system ratings indicated using a discount rate of 7%..

Table VII
Estimated Benefits for SMES T&D Applications

	Low Estimate	Low Ref	High Estimate	High Ref
System Stabilization (transmission deferral)	\$20/kW/year	1	\$150/kW/year	3
Power Quality (reliability)	\$50/kW/yr	2	\$250/KW/yr	4
Load-levelling	\$65/kW/year	5	\$1000/kW/year	6

Table VIII
Benefit Cost Ratios for fixed-size SMES in T&D Applications

Application	Present -day or FOAK Cost, \$	NOAK Cost, \$	NPV Benefits, Low, \$	NPV Benefits, High, \$	BC Ratio, FOAK or Present	BC Ratio, NOAK
System Stability	2.4 M	2M	6.36×10^5	4.77×10^6	.265 - 2.0	.32 - 2.38
Power quality	800 K	420 K	5.30×10^5	2.65×10^6	.66 - 3.31	1.26 - 6.31
Load leveling	NA	1,005 M	6.89×10^8	1.06×10^{10}	NA	.685 - 10.55

References for Benefits Table VII
1. J. DeSteese, et al "Benefit/Cost Comparisons of SMES in System-Specific Application Scenarios," Proc. World Congress on Superconductivity, Munich, Germany, September, 1992.
2. S. Schoenung, "Superconducting Magnetic Energy Storage Benefits Assessment for Niagara Mohawk Power Corporation," report prepared for Oak Ridge National Laboratory, DE-AC05-840R21400, 1994.
3. Zaininger, SAND98-1904 (SMUD Wind and PV study)
4. Calculations by P. Symons for private-sector client

5. “The Market Potential for SMES in Electric Utility Applications,” prepared by Arthur D. Little for Oak Ridge National Laboratory, Report No. ORNL/Sub85-SL889/1, 1994.
6. S. Schoenung, J. Badin, J. Daley, “Commercial Applications and Development Projects for Superconducting Magnetic Energy Storage,” Proc. of the American Power Conference, Chicago, 1993.

5. Bibliography

A series of conferences and journals contain innumerable articles on superconductivity and SMES technology, including:

The Applied Superconductivity Conference is held in North America every even year. The proceedings of recent conferences are published in the IEEE Transactions on Applied Superconductivity. They contain considerable information on applicable superconducting materials and on SMES technology.

The Material Research Society meets at least once per year and the proceedings of these meetings contain considerable information on the status of basic research in the area of superconductivity.

The American Physical Society (APS) has several national and regional meetings each year that include sessions on LTS and HTS materials. In addition, there are several journals published by the American Institute of Physics, of which the APS is a member, that include articles on superconductivity.

Seminal Articles and Books

The first paper on the phenomenon of superconductivity was:

H. K. Onnes, *Leiden Comm*. 120b, 122b, 124c (1911)

The first paper on high temperature superconductivity was

J. G. Bednorz and K. Mueller, *Z. Phyzik* B64, 189 (1986)

The first published paper on SMES was:

M. Ferrier, "Stockage d'energie dans un enroulement supraconducteur", in Low Temperature and Electric Power, London, England: 1970, Pergamon, pp. 425-432."

The accepted book that is used to develop magnet and conductor designs is:

Martin N. Wilson, Superconducting Magnets Oxford Science Publications, Oxford, UK, 1983.

The original article that related stored energy and support structure was:

R. Clausius, "On a Mechanical Theorem Applicable to Heat," Phil. Mag. S-4, Vol. 40, pp 12-127, 1870.

Early Articles and Papers On SMES

Early articles and papers on SMES include the following:

E.F. Hammel, W.V. Hassenzahl, W.E. Keller, T.E. McDonald, and J.D. Rogers, "Superconducting Magnetic Energy Storage for Peakshaving in the Power Industry," Los Alamos Scientific Laboratory Report LA-5298-MS, 1973.

H. A. Peterson, N. Mohan, and R. W. Boom, "Superconductive Energy Storage Inductor-Convertor Units for Power Systems", IEEE Trans. Power Systems", IEEE Trans. Power App. Syst., Vol. PAS-94, No. 4, July-August 1975.

W.V. Hassenzahl, "Will Superconducting Magnetic Energy Storage be Used on Electric Utility Systems?" IEEE Transactions on Magnetics, MAG-11, No. 2, 1975, pp. 482-88 (LA-UR-74-1470).

J.D. Rogers, W.V. Hassenzahl, and R.I. Schermer, "1 GWh Diurnal Load levelling Superconducting Magnetic Energy Storage System Reference Designs," Los Alamos Scientific Laboratory LA- 7885-MS Vols. I-VIII, September 1979.

William V. Hassenzahl, "Superconducting Magnetic Energy Storage," Proc. of the IEEE, 71 (September 1983), pp. 1089-98.

The first report that considered a diurnal SMES plant for other utility applications (in this case spinning reserve) was:

W.V. Hassenzahl, B.L. Baker, and W.E. Keller, "The Economics of the Superconducting Magnetic Energy Storage Systems for Load levelling: a Comparison with Other Systems," Los Alamos Scientific Laboratory Report LA-5377-MS, September 1973.

Early reports on the need for energy storage and the use of SMES for system stability include:

R. L. Cresap, W. A. Mittelstadt, D. N. Scott, and C. W. Taylor, “Operating Experience with Modulation of the Pacific HVDC Intertie”, IEEE PAS Summer Meeting, Mexico City 1977.

J. D. Rogers, M. H. Barron, H. J. Boenig, A. L. Criscoulo, J. W. Dean, and R. I. Schermer, "Superconducting Magnetic Energy Storage", Proc. 1982 ASC, IEEE Trans. Magnetics, Vol. MAG-19, May 1983, pp. 1078-1080, and E. Hoffman, J. Alcorn, W. Chen, Y. H. Hsu, J. Purcell, and R. Schermer, "Design of the BPA Superconducting 30-MJ Energy Storage Coil", Proc. 1980 ASC, IEEE Trans. Magnetics, Vol: Mag-17, Jan. 1981.

EPRI supported a series of studies on SMES in the early 1980’s. In 1986, EPRI decided to pursue the design and construction of an engineering test model ETM that stored about 100 MWh. This model stored about 2 percent of the energy of a full-scale diurnal SMES. At about the same time, the Strategic Defense Initiative (SDI) required a pulsed energy storage system with capacities greater than 1000 MWh and with discharge times of about 30 minutes. Much of the development of the diurnal SMES application over the next 6 years was based on a dual use concept. Several reports and papers related to this effort are given below.

W. V. Hassenzahl, "Superconducting Magnetic Energy Storage", IEEE Trans. on Magnetics Vol. 24 No.2, March 1989, pp 750-758.

Hassenzahl, W. V., R. B. Schainker, and T. M. Peterson, "The Superconducting Energy Storage ETM", Modern Power Systems Review, Vol. 11-3, pp 27-31, March 1991, London.

George Ullrich, "Summary of the DNA SMES Development Program," IEEE Trans. Appl. Superconductivity, Vol. 5, No. 2, June 1995 pp 416-421.

Other Articles In The Design And Use Of SMES

Other articles of interest in the design and use of SMES include:

Facts with Energy Storage: Conceptual Design Study, EPRI, Palo Alto, CA: 1999. TR-111093

W. V. Hassenzahl, "Considerations against force compensated coils", IEEE Trans. on Magnetics, Vol. 24 No.2, March 1989, pp 1854-1857.

J. F. Picard, C. Levillain, P. G. Therond (Electricité de France, R&D division), SCENET, "Advantages and perspectives of SMES", 2nd Workshop on Power Applications of Superconductivity, November 1997.

C. Levillain, P. G. Thérond (Electricité de France), 'Minimal Performances of High Tc Wires for Cost Effective SMES Compared with Low Tc's", IEEE Transactions on Magnetics, Vol. 32, No. 4, July 1996.

The SSD: A Commercial Application of Magnetic Energy Storage, W. E. Buckles, M. A. Daugherty, B. R. Weber, and E. L. Kostecki (Superconducting, Inc.), IEEE Transactions on Applied Superconductivity, Vol. 3, No. 1, March 1993.

Micro Superconducting Magnetic Energy Storage (SMES) System For Protection of Critical Industrial and Military Loads, A. K. Kalafala, J. Bascuñan, D. D. Bell, L. Blecher, F. S. Murray, M. B. Parizh, M. W. Sampson, and R. E. Wicox (Intermagnetics General Corporation), IEEE Transactions on Magnetics, Vol. 32, No. 4, July 1996.

Operation of a Small SMES Power Compensator, K. P. Juengst, H. Salbert (Forschungszentrum Karlsruhe, Institut für Technische Physik), O. Simon (Elektrotechnisches Institut (ETI), Universität Karlsruhe), Proceedings from European Conference on Applied SC, July 1997, Eindoven.

High Temperature Superconductors for SMES

Since their discovery in 1986, high temperature superconductors have been proposed for SMES applications. Some of the papers on the subject are listed here:

Prospects for the Use of High T_C Materials for Superconducting Magnetic Energy Storage, William V. Hassenzahl, Proceedings of EPRI Workshop on High-Temperature Superconductivity, April 1988, EPRI EL/ER-5894P-SR

Conceptual Design Study of Superconducting Magnetic Energy Storage Using High Temperature Superconductors, S. M. Schoenung (W. J. Schafer Associates), R. L. Fagaly, M. Heiberger, R. B. Stephens, J. A. Leuer, R. A. Guzman, E. R. Johnson (General Atomics), J. Purcell, L. Creedon, J. R. Hull (Advanced CryoMagnetics), Final Report to DOE February 1993, DOE/CE/34019-1

Superconducting Magnetic Energy Storage (SMES) Using High-Temperature Superconductors (HTS), Susan M. Schoenung, Robert L. Bieri (W. J. Schafer Associates), Final Report for Sandia National Laboratory May 1994, Subcontract AG-5265

S. S. Kalsi, D. Aided, B. Connor, G. Snitchler, J. Campbell, R. E. Schwall (American Superconductor Corporation), J. Kellers (American Superconductor Europe), Th. Stephanblome, A. Tromm (Gesellschaft für Innovative Energieumwandlung und Speicherung GmbH), P. Winn (Applied Engineering Technologies), "HTS SMES Magnet Design and Test Results", IEEE Transactions on Applied Superconductivity, Vol. 7, No. 2, June 1997.

R. Mikkonen, M. Lahitnen, J. Lehtonen, and J. Paasi (Tampere University of Technology), B. Conner, S. S. Kalsi (American Superconductor), "Design Considerations of a HTS μ-SMES", European Conference on Applied SC, July 1997

W. V. Hassenzahl, "An Assessment of High Temperature Superconductors for High Field SMES Systems", EPRI report 110719, December 1999. Note: this report contains a complete bibliography of HTS SMES through 1998.

Conference Proceedings

As mentioned earlier, one of the riches sources of information on SMES development are the proceedings of the Applied Superconductivity Conferences. The most recent conference was August 4-9, 2002, and the proceedings will be published by the IEEE in April of 2003. Titles of some of the papers on SMES in this conference are given below.

A 100 MJ SMES Demonstration at FSU-CAPS, C.A. Luongo, T. Baldwin, FSU-CAPS; C.M. Weber, P. Ribeiro, BWX Technologies.

Magnet Power Supply with Power Fluctuation Compensating Function Using SMES for High Intensity Synchrotron, T. Ise, Y. Kobayashi, S. Kumagai, Osaka University; H. Sato, T. Shintomi, KEK.

Impact of Micro-SMES on Power Flow, J. Liu, M.M.A. Salama, R.R. Mansour, University of Waterloo.

Design of a 150 kJ High-Tc SMES for a 20 kVA Uninterruptible Power Supply System, R. Kreutz, H. Salbert, D. Krischel, A. Hobl, C. Radermacher, ACCEL Instruments GmbH; N. Blacha, AEG SVS GmbH; P. Behrens, EUSGmbH; K. Dütsch, E.ON Netz GmbH.

Fabrication and Test of a Superconducting Coil for SMES System, H.J. Kim, K.C. Seong, J.W. Cho, S.W. Kim, Y. K. Kwon, Korea Electrotechnology Research Institute.

Fabrication of a 4kJ High-Tc Superconducting Pulse Coil Wound with a Bi2223 Wire for SMES, H. Hayashi, H. Kimura, Y. Hatabe, K. Tsutsumi, Kyushu Electric Power Co., Inc; M. Iwakuma, K. Funaki, Kyushu University; A. Tomioka, T. Bohno, Y. Yagi, Fuji Electric Co., Ltd.

A 5 kJ HTS SMES Magnet System with Temperature Variation, X.H. Jiang, Y.C. Lai, Dept. of Electrical Engineering, Tsinghua University; J. Yang, N.Q. Jin, Institute of Electrical Engineering, Chinese Academy of Sciences; Z.G. Cheng, Baoding Tianwei Group Co. Ltd.

HT-SMES Operating at Liquid Nitrogen Temperatures for Demonstrating Power Conditioning, A. Friedman, N. Shaked, E. Perel, F. Gartzman, M. Sinvani, Y. Wolfus, Y. Yeshurun, Center of Superconductivity, Bar-Ilan University.

Refrigeration Systems

The two articles below show the cost vs. size dependence of the refrigeration systems for superconducting magnets.

T. R. Strowbridge, IEEE Transactions on Nuclear Science, NS-16, No.2, P1104 (1969)

M. A. Green, R. A. Byrns, and S. J. St. Lorant, "Estimating the Cost of Superconducting Magnets and the Refrigerators Needed to Keep Them Cold". Advances In Cryogenic Engineering, Vol 37, Feb, 1992 Plenum Press, New York.

Coil Geometries

Several different geometries have been considered for SMES. They are described in the report below. In general, the solenoid is simplest to build and is the lowest price. However, other designs might be more effective for specific applications, particularly those where the stray magnetic field is important.

W. V. Hassenzahl, "A Comparison of the Conductor Requirements for Energy Storage Devices Made with Ideal Coil Geometries", IEEE Transactions on Magnetics, VOL. 25, No.2 March 1989.

Recent Assessments

A recent assessment of SMES applications by Power Systems Engineers is available in an EPRI report.

"Reassessment of Superconducting Magnetic Energy Storage (SMES) Transmission System Benefits", Power Systems Engineers, EPRI Report 1006795, March 2002.

6. Appendices

Magnetic field description of SMES

As implied in the name, the stored energy can be calculated from the total magnetic field:

$$E = \frac{1}{2\mu_0}\oint B^2 dV ,$$

where the field B is integrated over all space, and μ_0 is the permeability. Note that the stored energy depends on the square of the magnetic field. Thus, the size of the storage device can be reduced considerably by increasing the magnetic field.

Structural requirements of SMES

The various figures in this chapter of SMES devices do not show the structural characteristics of the coils. The interaction between the current in the coil and the magnetic field produce an outward force that must be contained by structural material. This material provides an opposing force that is associated with its internal strain. A detailed set of calculations is required for each coil design to provide adequate structure and to position it properly. There is, however, a fundamental relationship between the mechanical stored energy in a system and the minimum quantity of material required for its support. This relationship is referred to the virial theorem, and it applies equally to magnetic energy storage, kinetic energy storage (flywheels) and compressed air energy storage (CAES). The fundamental equation is:

$$\int \vec{x} \cdot \vec{F}\, dV = -\int \vec{x} \cdot \nabla \overline{\overline{S}}\, dV ,$$

where $\vec{x}$ is the distance moved, $\vec{F}$ is the force that causes the motion, and $\overline{\overline{S}}$ is the elastic strain tensor. These can be solved to produce an expression with validity for all mechanical systems. The straightforward expression of the formulation is given in the following relationship:

$$E = \kappa \cdot \sigma \cdot V = \frac{\kappa \cdot m \cdot \sigma}{\rho} \geq \frac{m \cdot \sigma}{\rho} ,$$

where κ is a number that is related to the geometry and is greater than or equal to 1, V is the volume of structural material, σ is the working stress in the material, and ρ is the density of the material.

The application of this relation to a SMES system depends on its size. In a solenoid, for example, the thickness of the superconductor needed to produce a certain field is essentially constant, independent of the size of the coil and the total energy stored. In practice, the copper and superconductor in small coils, e.g. those storing a few megajoules, require no additional structure. Larger coils with the same field—and thus the same thickness of superconductor—that have diameters of 2 meters or more, almost always require additional structure for support.

For coils of this size or larger, the structural mass is proportional to the stored energy. Thus, the cost for structure is directly proportional to the stored energy. On the other hand, since the thickness of the windings is constant, the larger the coil, the smaller the cost of superconductor per unit of stored energy.

Extensive History of SMES

The following are steps along the way to the development of SMES technology. They include technical developments and studies prepared to show the effectiveness of SMES technology and the costs and value of the system. These studies and devices are generally listed in chronological order. The exception to this rule is where a review of several related studies contains relevant summary information that makes the review of greater value than any of the individual pieces. Many reports that related to these studies are contained in the Bibliography.

As is true of many technologies, early concepts that drive the approach of the research community for a period may be found to have a very limited contribution to the eventual development of commercial systems. Some specific instances are described here.

1969 Ferrier of Electricité de France proposed a large superconducting magnet that would accommodate a great deal of the load levelling needs for France. His intent was to use a toroidal coil that was several hundred meters in diameter with a peak field greater than 10 T. It was later found that the various superconducting materials have optimum (least expensive) fields and temperatures for their use. Most SMES devices in operation today operate at a peak field of 5 to 6 T.

1971 Boom, Peterson and Mohan of the University of Illinois conceived of a direct connection of a large, DC energy storage coil to the electric power grid via a 3 phase SCR based inverter/converter. This approach has been the core of the design of the power component of the SMES system, though improvements in silicon based power conversion systems have advanced the functionality of the PCS on modern SMES plants.

1972 Hassenzahl of the Los Alamos National Laboratory proposed the use of *in situ* rock to support the magnetic forces in a large SMES for load levelling and the operation of the SMES coil in superfluid helium. These two changes in a large system eliminate about half the total plant cost. The cost of structure as a fraction of total cost depends on the amount of stored energy, but is roughly 30% of the cost of a very large SMES. In 1972, the cost of the superconductor was estimated to be about half of the total system cost, which was cut in half. Both of these suggestions increased the cost of the refrigerator, which must remove heat that is carried along the supports between the coil and the warm rock and must have a greater capacity when operating at the lower temperature required by superfluid. It increased from 2% of the total cost to about 4%. The overall impact of these two design conditions was a cost reduction of about 40 %. Since very large SMES plants were never built, neither of these concepts has been applied to the technology.

1973 Hassenzahl of Los Alamos suggests the addition of excess converter capacity to adapt a load-levelling device to a system with multiple benefits, specifically spinning reserve.

1974 Los Alamos proposes construction of a 100 MJ SMES coil as a test of SMES system requirements and to accommodate power fluctuations in the local utility power system. This was the first suggestion of the construction of a specific SMES installation.

1976 Cresap and Mittelstadt of the Bonneville Power Authority and Hassenzahl of Los Alamos propose a 30 MJ pulsed SMES to damp the power oscillations that have been observed on the HVAC Intertie. The system was designed and constructed by a team lead by Rogers of Los Alamos and was installed at the Tacoma substation in 1981, where it operated briefly. The unit was plagued by difficulties caused by damage that had occurred to the refrigerator when it was originally shipped to Los Alamos in 1979. As a result the personnel attention and the O&M requirements increased by a factor of ten or so. This difficulty and a unique, pre-existing component of the West Coast power grid eventually led to the SMES unit being shutdown after only a limited service period. A DC power transmission line had been installed about 10 years prior to the SMES system. Its purpose was to transmit part of the power generated by hydroelectric plants in the Pacific Northwest to the load centers in Southern California. Just as SCR-based converters were used on the SMES, they were also used on DC transmission lines. An SCR converter with a capacity of 50 MW and 50 MVA was added to the diode based rectifier at the north end of the DC Link. Control of this converter provided the same damping as the 10 MW SMES coil. Perhaps the most important lesson learned from this installation was that first of a kind installations of new technology must work. Otherwise, the chance of integration of the technology into the operation of an electric utility is reduced considerably. No future new technology using superconductors should be installed if it does not have a high degree of success. One other item of considerable interest is that the southern termination of the DC link was damaged by an earthquake and took several years to be completely repaired. This potential limitation of power flow because of a natural disaster was nearly sufficient to maintain the SMES device at Tacoma as a backup, just in case.

1979 Rogers of Los Alamos led a team consisting of national laboratories, industries, and universities that developed a 1000 MWh Reference Design. This design effort took the concepts that had been developed over the previous decade and applied them to an engineering design with details of construction, installation, coil winding, etc. This collaboration produced a reference design for large scale, diurnal SMES plants that became the basis for design work during the decade of the 1980's. One critical result was that when detailed cost estimates developed in the study were compared with the costs of pumped hydroelectric plants the group concluded that if SMES plants were used only for load levelling, they would have to be store 5000 MWh or more in order to be cost-competitive with pumped hydro.

1981 EPRI initiated a study of diurnal SMES. The effort was carried out by Bechtel and several contractors, but included some utility, national laboratory and university participation. It initially addressed load levelling only, but eventually included an attempt to measure the value of a SMES plant with some additional capabilities. EPRI continued to support diurnal SMES development over the next decade.

1986 EPRI supported studies concluded that SMES could be a contributor to electric power systems and determined that a 100 MWh model, the Engineering Test Model (ETM), would be an appropriate size to test the concept.

1987 The Strategic Defense Initiative was developing large directed energy devices and needed energy sources in the 1000 MW range for periods of 1 hour. They joined with EPRI and supported the design of a dual-use ETM. Bechtel and EBASCO were chosen to lead teams that followed two different paths for manufacturing large-scale SMES.

1987 The need for pulsed power (megawatts for seconds) to establish power quality for industry, utility and military applications stimulated the formation of the company Superconductivity Inc., which began the development of micro-SMES systems. Much of the effort in this period was supported by the Power Conditioning and Continuing Interface Equipment (PCCIE) office of the US Air Force at McClellan Air Force Base in Sacramento, CA.

1993 DARPA established funds for a SMES installation. The original plan was for Babcock and Wilcox (B&W), now BWX Technologies (BWXT), to design and construct a 30 MW, 0.5 MWh unit and install it in Anchorage, Alaska, to enable spinning reserve on the Alaska Railbelt electric system. After several changes in plans, a smaller coil, 100 MJ, was selected as a size that could be accommodated within the new budget. The smaller coil was to have been installed at American Electric Power's Inez Substation to support operation of their unified power flow controller (UPFC), but again changing budgets and program goals for the partners in the project resulted in a mutual decision to cancel it at AEP. In about 2000 BWXT licensed the coil design to the Center for Applied Power Systems (CAPS) at Florida State University (FSU). The coil is nearly completed and it should be installed in early 2003 at CAPS.

1993 Several studies of the impact of SMES systems for system stability are carried out. They were supported by the US Department of Energy. Torre described these and other studies in an EPRI report 1006795. One of the studies eventually led to the concept of an energy storage system that is distributed across a wide area of a power system but which responds to system in an integrated fashion.

1994 The US Navy initiated a study of energy storage systems associated with a move to an all-electric ship. SMES was one of the storage systems studied. Westinghouse constructed a 50 MJ coil that has been transferred to FSU for future system evaluation.

1997 American Superconductor's subsidiary, Superconductivity Inc. began the development of D-SMES devices and established a program to install 6 devices in northern Wisconsin.

There are small installations of SMES test facilities in Europe and Japan. None of these devices has the capacity of the larger units in use today in the United States and South Africa. The Japanese have maintained a program of SMES development. They have generally had a wait and see approach to construction, but have constructed several small industrial and university systems. The structure of the SMES effort in Japan in 1999 is given at the end of the Bibliography.

Summary of Potential SMES Applications

Power Systems Engineers recently completed a review of previous SMES studies on a variety of applications. This effort is available in the EPRI report referenced below.

"Reassessment of Superconducting Magnetic Energy Storage (SMES) Transmission System Benefits", Power Systems Engineers, EPRI Report 1006795, March 2002.

A summary of applications from this report is summarized below.

System Stability-Damping

Large power systems may experience instabilities associated with the delivery of power over long distances when there are abrupt changes in operating conditions, e.g., when a large load is applied or when a generator or line is lost. Perhaps the best-known case of this type of instability is in the north-south power corridor on the West Coast of the United States. A great deal of power (several thousand Megawatts) is generated in the Pacific Northwest and is delivered to middle and southern California via multiple transmission lines. One characteristics of the system in this region is that a north-south power oscillation can occur with a frequency of about 0.3 Hz. That is, power flow increases and decreases with a period of about 3 seconds. These oscillations are generally insignificant. Under certain conditions, however, the system has exhibited oscillatory power flow with amplitudes of 300 MW, as shown in Figure 8.

Load levelling

Demands for electric power vary both randomly and with predictable variations. Perhaps the most significant variation of power demand is the diurnal change associated with the functioning of an industrial society. Both commercial and residential demands are greater during the day than at night. On the other hand, many power plants operate most efficiently and have longer lives if they operate continuously near their maximum power output. One method of accommodating users' power demands and the characteristics of these plants is to install an energy storage system that can accept energy at night and can deliver it back to the grid during periods of high demand. The value of this type of storage is based on the difference in marginal cost of off-peak power and the price paid for power during the peak. An additional impact of diurnal storage is that it can replace the installation of extra generation capacity.

Transient Voltage Dip

Major disturbances on power systems, such as loss of generation or of a line or, in some cases an abrupt increase in load, can cause transient voltage dips that may last for 10-20 cycles. Typically, control of this effect is accomplished today by limiting power transfer. If this is required on critical power lines then they must operate well below their thermal limits. Reduction of this effect on the grid to can defer construction of transmission lines.

Dynamic Voltage Instability

Dynamic voltage instability is a condition that can occur when a loss of generation or transmission line and insufficient dynamic reactive power is available to support voltages. As a result, line voltage in all or part of the system will degrade. This process may occur over a period of minutes and result in voltage collapse.

Spinning Reserve

Operating guidelines for major power systems demand that some excess power capacity is available for immediate power delivery in case of loss of a major generator or transmission line.

In general, the requirement for this reserve is the larger of 7 % of total capacity or the size of the largest operating generator. It must accommodate the largest single contingency on the system and provide power within a period measured in cycles or seconds depending on the requirement.

Underfrequency Load Shedding

Loss of transmission lines and generators may lead to a decrease in system frequency as the available generation attempts to supply the load. This condition will continue until a balance between generation, transmission capability and load are reached. If this balance does not occur rapidly (e.g., by the overall system generation increasing to accommodate the existing load), load shedding (dropping customer load) may be required to avoid loss of synchronism and system blackout.

Circuit Breaker Reclosing

Power line faults cause circuit breakers to open, thereby isolating the fault and eliminating or reducing any damage. Once the fault is cleared, the circuit breakers are reclosed and the isolated section is returned to service. If the separated sections of the power system are not otherwise tightly connected, they will drift in phase while the circuit breaker is open. If the power angle difference across the breaker is too large, protective relays will prevent it from closing. The injection of real power while the circuit breaker is open can reduce the time for reclosure.

Power Quality and Backup Power

A variety of loads--ranging from modest industrial installations to substations of significant capacity--require energy to provide power quality and backup power. This energy is used for a variety of conditions such as when momentary disturbances require real power injection to avoid power interruptions. In the case of industrial customers, a local source of power may be required when there is an interruption of power from the utility. This power source may function until the power feed from the utility is restored, until a reserve generator is started, or until critical loads are shut down in a safe manner. In the case of a substation, a variety of momentary disturbances such as lightning strikes or transmission flashovers cause power trips or low voltages. The total energy storage requirement is greater and there may be a need power flow separation to insure continuous power to important customers.

Sub synchronous Resonance

Long-distance, high-power transmission lines typically have high levels of series capacitors that provide VAR compensation. Generators directly connected to the transmission lines can become a part of what is called Sub-Synchronous Resonance SSR when their feed back or control systems cause them to form a resonant circuit with the transmission lines and associated capacitors. The impact of SSR on the grid is to reduce the transfer capability of the transmission lines.

SMES Activities in Japan

There are differences between US and Japanese efforts in SMES development. The US has been generally project focused, i.e., a specific application and site are chosen and one or more teams develop plans and perhaps devices to meet the project goal. In Japan, the developments are generally part of a program that has a variety of players and is coordinated by a national committee.

A conference on HTS SMES was held in Japan in December 1998. The proceedings are in Japanese. Summaries of some of the papers are given here.

I Masahiro Yamamoto provided an overview of the ISTEC/SMES Project,

The SMES system can store energy as electricity and has a highly efficient energy storage capability. Moreover, it allows high-speed input and output of energy, which means both real and reactive power can be controlled independently. Other features determine that it has high capabilities, not only in energy storage capacity aspects (kWh), but also in aspects of instantaneous output of electric power. It is anticipated that the SMES system will fulfill a significant role in future electric power systems in terms of load-leveling of power, load change compensation, improving system stabilization, etc.

Due to these factors, the Japanese government, electric power companies, manufacturers, and research groups concerned with superconducting energy storage are engaged in investigation, research, and conceptual design work on its utility.

The Agency of Natural Resources and Energy, Ministry of International Trade and Industry, has taken the first step toward full-scale development of SMES in Japan. It is conducting a project 'Study of Factors and Technology Development for Superconducting Electric Power Storage System' during fiscal years 1991-1998 to establish the necessary technological basis for building a small-scale SMES pilot plant. As shown in Table IX, ISTEC is consigned to implement this with the participation of electric power companies and manufacturers. In addition, in order to promote effective research, an advisory committee of experts in the field has been set up to examine and review the content of the studies.

Table IX
Implementation SMES Structure/Organization in Japan

Technical area	Responsible Entity
Superconducting coil	Chubu Electric Power
Quench protection	Tohoku Electric Power
AC to DC converter equipment	Dengen Kaihatsu (Electric Utility Development) Co.:
Persistent current switch and direct current circuit breaker	Dengen Kaihatsu (Electric Utility Development) Co.:
Optimal system research	Kyushu Electric Power
Utility system effects of SMES operation	Central Research Institute of the Electric Power Industry
Testing and evaluating HTS materials	Osaka Science and Technology Center—New Materials Center
Coil testing	Toshiba

EPRI Energy Storage Handbook: Flywheels

December 2002

Haresh Kamath and Tom Key
EPRI PEAC
Knoxville, TN

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Description

History of Flywheel Systems

Flywheels rank among the earliest mechanical energy storage mechanisms discovered by mankind. The principal was probably first applied in the potter's wheel, a device used to produce symmetrical ceramic containers. The millstone, a contrivance used to grind grain into flour, is another form of flywheel.

Beginning in the early years of the Industrial Revolution, flywheels found their way into various contrivances to smooth the delivery of mechanical power. In handlooms, for instance, flywheels were used to store mechanical energy applied in pulses by the operator. Flywheels allowed the development of more complex power machines such as steam engines and internal combustion engines by enabling the delivery of constant, continuous power from a pulsating power source. Flywheels continue to have a broad variety of applications in mechanical systems.

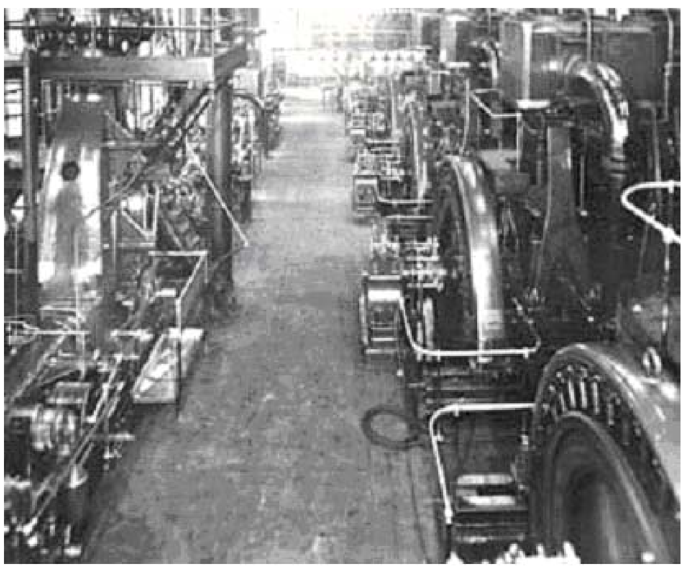

Figure 1
Vertical Reciprocating Steam Engines Drive Westinghouse Flywheel Electric Generators In Pittsburgh's Railway Station, From 1902 Until 1950's (*Courtesy Of Smithsonian Institute*)

Probably one of the first application of flywheels to large-scale electric power systems was for smoothing the output of low-speed steam piston engine driving flywheel generators, shown in Figure 1. Waterwheel generators also benefit from the flywheel action of large salient-pole rotors. Heavy steel wheels are commonly integrated into electric motor/ generator sets. In the event of pulsating or interrupted propulsion the additional momentum of the flywheels smooths the output and helps to maintain desired operating frequency. This direct flywheel contribution has improved quality and has provided ride through capability during momentary, less than one second, interruptions.

The evolution of efficient inverters and rectifiers in the 1960s and early 1970s meant that frequency could be controlled even when the generator was not spinning inside the desired operating range. This allows the utilization of a higher percentage of a flywheel's momentum, thus delivering more energy and adding time in ride through applications. With this development, flywheels began to be considered as independent energy storage devices, especially for applications in the transportation and electric utility industries.

The energy crises of the 1970s accelerated development of flywheel technology, bringing to the fore new technologies such as carbon composite rotors and magnetic bearings, which allowed higher energy densities. Development slowed in the 1980s, but utility deregulation and increased public concern over environmental issues revived interest in energy storage technologies in the next decade. The 1990s saw the emergence of a number of small companies dedicated to the commercialization of flywheel energy storage systems. A few larger companies also applied their resources to the technology.

Commercialization efforts continue today, with mixed results. Conservative versions of the technology, using steel wheels at low-rotational speeds, have managed to penetrate the power conditioning market in UPS and power quality applications. More advanced flywheel technologies, however, have not found widespread acceptance, due to technical and economic obstacles, both real and perceived. Table 1 lists some of the major advantages and disadvantages of flywheel energy storage systems relative to other energy storage technologies.

Table 1
Advantages And Disadvantages Of Flywheel Energy Storage Relative To Other Energy Storage Technologies

Advantages	Disadvantages
Power and energy are nearly independent	Complexity of durable and low loss bearings
Fast power response	Mechanical stress and fatigue limits
Potentially high specific energy	Material limits at around 700M/sec tip speed
High cycle and calendar life	Potentially hazardous failure modes
Relatively high round-trip efficiency	Relatively high parasitic and intrinsic losses
Short recharge time	Short discharge times

Theory of Flywheel Operation

Energy Storage Capacity

Flywheels store energy in the form of the angular momentum of a spinning mass, called a rotor. The work done to spin the mass is stored in the form of kinetic energy. The amount of kinetic energy stored in a spinning object is a function of its mass and rotational velocity:

$$E = \tfrac{1}{2} I \omega^2 \qquad \textbf{(1)}$$

Where E is the kinetic energy, I is the moment of inertia (with units of mass-distance^2), and   is the rotational velocity (with units of radians/time). The moment of inertia is dependent on the mass and geometry of the spinning object. It can be shown that for a solid disc rotating about its axis, stored kinetic energy is described by the equation:

$$E = \tfrac{1}{4} M r^2 \omega^2 \approx \tfrac{1}{4} M v^2 \qquad (2)$$

Where M is the mass of the disc, r is its radius, and v is the linear velocity of the outer rim of the cylinder (approximated by r). Equation (2) shows that increasing the rim speed is more effective than increasing the mass of the rotor in improving the energy capacity of a flywheel, see Figure 2.

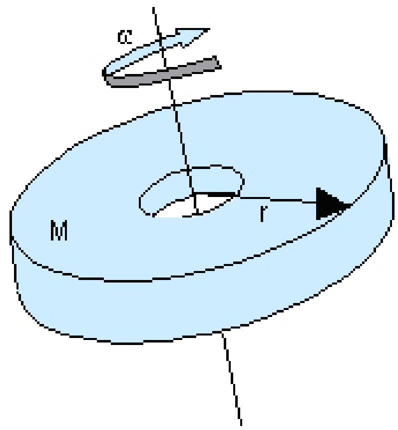

Figure 2
Physical Factors In Energy Storage Capacity

Rotor Stresses and Failure Modes

By the analysis above, flywheels with large radius rotating at very high speeds, so as to maximize rim velocity, would be favored when high-energy capacity is desired. In practice, however, flywheel design is limited by the strength of the rotor material to withstand the stresses caused by rotation. If the rotor spins too quickly, it will fly apart, ending the useful life of the flywheel and possibly causing harm to personnel and damage to nearby equipment in the process.

Energy Conversion

Flywheels store kinetic energy while the end-use applications of interest in this handbook will use electric energy. Conversion from kinetic to electric energy is simply accomplished via electromechanical machines. Many different type machines are being used in available flywheel systems. The key is to match the decreasing speed of the flywheel during discharge and the acceleration when recharged with a fixed frequency electrical system. Along with electromechanical machines, two methods are used to match system frequencies, mechanical clutches and power electronics. The trend is toward a power electronic frequency conversion, with mechanical clutches only seen in the larger low-speed machines.

Friction and Energy Losses

In any real flywheel system, there are forces that act against the spinning wheel, causing it to slow down and lose energy. These forces arise from friction between the rotor and surrounding environment, between the rotor bearing and its support, and from the stresses and strains within the rotor itself. In addition to these energy losses through friction, the minute stress differentials within the spinning rotor and induced magnetic currents in the motor/generator can also cause energy losses.

The mechanical bearings, which support the flywheel rotor, are a significant source of friction. Many developers have introduced magnetic bearings into the flywheel system, which remove load from mechanical bearings and reduce frictional losses.

The fluid surrounding the rotor is also a source of frictional loss. At higher speeds, this loss can be very large indeed. Most developers have addressed this problem by enclosing the rotor within a vacuum or low-viscosity fluid.

Thermal Effects

The energy lost during rotation is transformed into heat, which raises the temperature of the flywheel rotor. If heat accumulates it must somehow be removed to prevent damage to the rotor and other components. Material considerations will define a maximum temperature for the rotor. One way to reduce heat is to limit the operating speed of the flywheel system so that the steady-state temperature of the rotor is within a safe margin of the maximum temperature. This speed limitation will also reduce the energy density of the flywheel system.

The answer to this problem has been low-loss bearing technology, which has kept thermal effects from being a limiting factor in most practical flywheel systems. Vacuum containment and magnetic bearings can significantly reduce friction, and therefore reduce the amount of heat that must be removed. The trade-off is that they also can make it difficult to remove the heat that remains. In flywheels with bearing enhancements, thermal energy normally leaves the rotor only through radiation, sometimes requiring special heat removal methods within the enclosure.

Some manufacturers have chosen to include active cooling systems in their products, through the use of a low viscosity gas in the containment system. Some investigators have suggested hydrogen cooling, similar to the technique used for large electric generators.

Subsystem and Components

A flywheel has several critical components. These components will be discussed in further detail in the following subsections (See Figure 3).

- **Rotor** – a spinning mass that stores energy in the form of momentum
- **Bearings** – pivots on which the rotor rests
- **Motor-Generator** – a device that converts stored mechanical energy into electrical energy, or vice versa

- **Power Electronics** – an inverter and rectifier that convert the raw electrical power output of the motor/generator into conditioned electrical power with the appropriate voltage and frequency
- **Controls and Instrumentation** – electronics which monitor and control the flywheel to ensure that the system operates within design parameters
- **Housing** – Containment around the flywheel system, used to protect against hazardous failure modes. It is sometimes also used to maintain a vacuum around the rotor to reduce atmospheric friction.

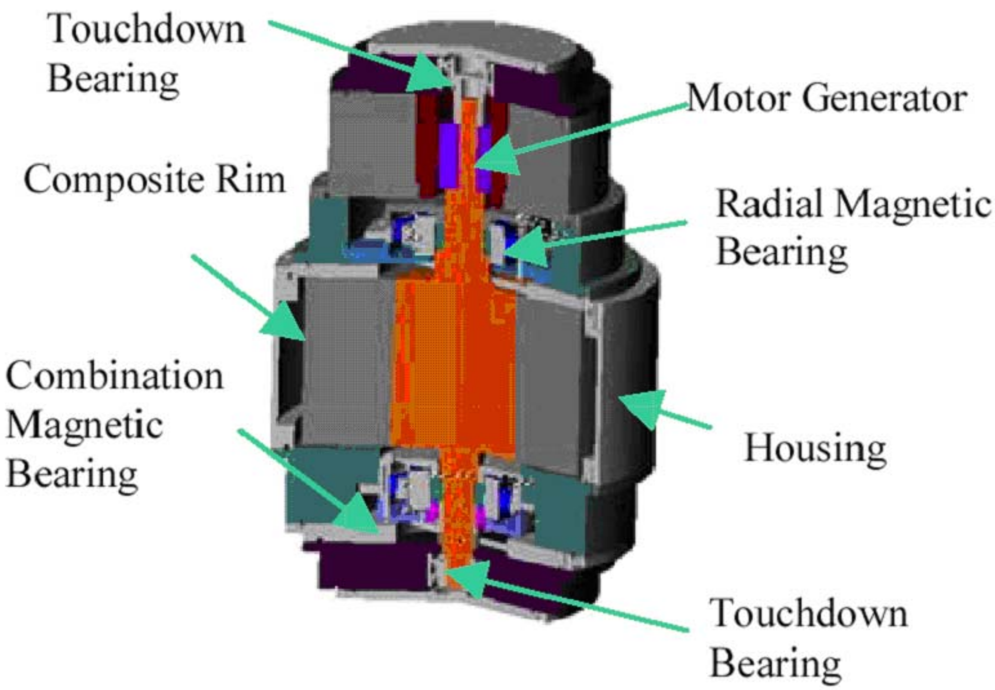

Figure 3
Cross-Section Of A Flywheel Module (*Courtesy NASA Glenn Research Center*)

Rotor Design and Construction

The rotor, as the energy storage mechanism, is the most important component of the flywheel energy storage system. The design of the rotor is the most significant contributor to the effectiveness and efficiency of the system. As described above, rotors are designed to maximize energy density at a given rotational speed, while maintaining structural integrity in the face of rotational and thermal stresses.

Rotor designs can be divided into two broad categories of low-speed, vertical or horizontal shaft and high-speed, usually vertical shaft rotors. Examples of each are illustrated in Figure 4 and Figure 5. Both types of rotors have advantages and disadvantages, and the two find uses in different applications.

Figure 4
Low-Speed Horizontal-Shaft Steel Flywheel ***(Courtesy Of Satcon Power Systems)***

Figure 5
High-Speed Vertical-Shaft Composite Power Flywheel

High-speed rotors typically use more exotic materials such as graphite composites and fiberglass, which are lighter but stronger and allow much higher rotational velocities. These wheels typically spin at speeds above 10,000 rpm, and some designs exceed 100,000 rpm.

The physical construction varies with vertical and horizontal shafts, flywheel speeds, and simply from one manufacture to another. Figure 6 shows the relative physical size and profile of several commercially available flywheel systems. Note that the Satcon unit profile also includes a standby generator, which is connected on the same shaft as the flywheel and generator.

Rotor Bearings

The bearings support the flywheel rotor and keep it in position to freely rotate. The bearings must constrain five of the six degrees of freedom for rigid bodies, allowing only rotation around the axis of the rotor. The construction of the bearings is important in flywheel performance. Speed of the flywheel is limited in large part by the friction on the bearings, and the resulting wear on the bearings often defines the maintenance schedule for the system.

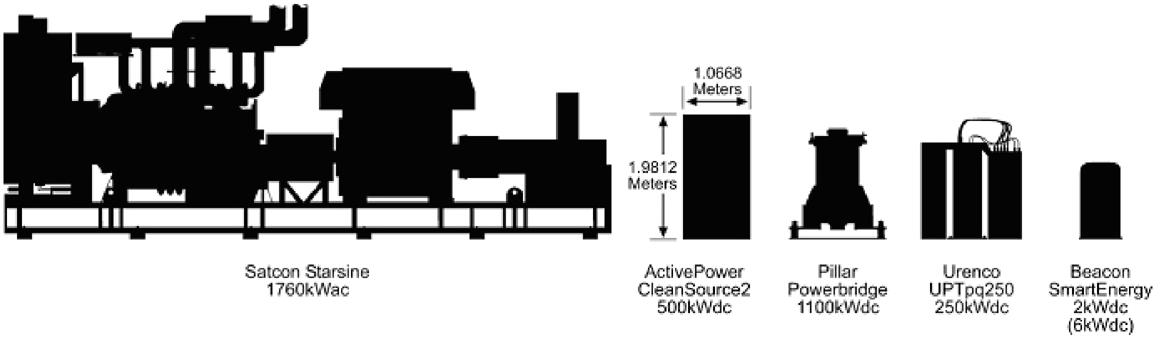

Figure 6
Silhouettes Of Several Commercially Available Flywheel Systems

There are several types of bearings used in flywheel construction. Mechanical bearings are the simplest form of flywheel bearings. These might be ball, sleeve, roller, or other type of mechanical bearing. These bearings are well understood, reliable, and inexpensive, but also suffer the most wear and tear, and produce the largest frictional forces, inhibiting high rates of rotation.

Magnetic bearings are required for high-speed flywheel systems. These bearings reduce or eliminate frictional force between the rotor and its supports, significantly reducing the intrinsic losses. There are several types of magnetic bearings. Passive magnetic bearings are simply permanent magnets, which support all, or part of the loads on the flywheel. Active magnetic bearings, on the other hand, use controlled magnetic fields, where field strength on the bearing axes is varied to account for the effect of external forces on the rotor. Superconducting bearings are passive magnetic bearings, which use superconducting materials to produce the magnetic repulsive force to support the rotor assembly. These materials operate at very low temperatures, and so require cryogenic cooling systems to maintain.

Magnetic bearings do not completely eliminate power drain. The geometry and variance in the magnetic fields of the bearing will cause some loss factor in the rotor speed. Magnetic bearing failure must also be taken into consideration, especially for active bearings. In most designs, magnetic bearings are used in conjunction with mechanical bearings. The mechanical bearings prevent damage in the event that the magnetic bearings fail, while the magnetic bearings reduce friction and wear and tear resulting from the mechanical bearings.

It is important to remember that bearings may cause both intrinsic and parasitic drains on the energy stored in the flywheel system. For example, superconducting bearings produce eddy currents, which cause intrinsic pseudo-frictional losses in the rotor speed, and they require power to maintain their low temperature.

Motors and Generators

Motors convert electrical energy into the rotational mechanical energy stored in the flywheel rotor during charge, and generators reverse the process during discharge. In many modern flywheels the same rotating machine serves both functions. The machine is called a motor alternator or motor generator and consists of a wound- or permanent-magnet rotor, usually revolving within a stator containing electrical winding through which charge (or discharge) current flows. Note that this machine, along with any power electronics, limits the power rating of the flywheel system. And in some practical systems the generator for discharging the wheel is higher power than the recharging motor. Thus at full power charging the wheel will require more time than discharging.

The starter motor and alternator or generator are connected to the flywheel via the same steel shaft and may be either a single machine or two different machines. In both cases the rotor becomes part of the flywheel mass. When separate, the starter motor is typically a simple induction motor that is able to produce starting torque. When combined in one synchronous motor/alternator, with either permanent magnet or wound rotor, electronics are required to spin up the flywheel. In this configuration the power electronics are also used to convert the variable output frequency to a constant 60-Hz frequency. Figure 7 shows both arrangements.

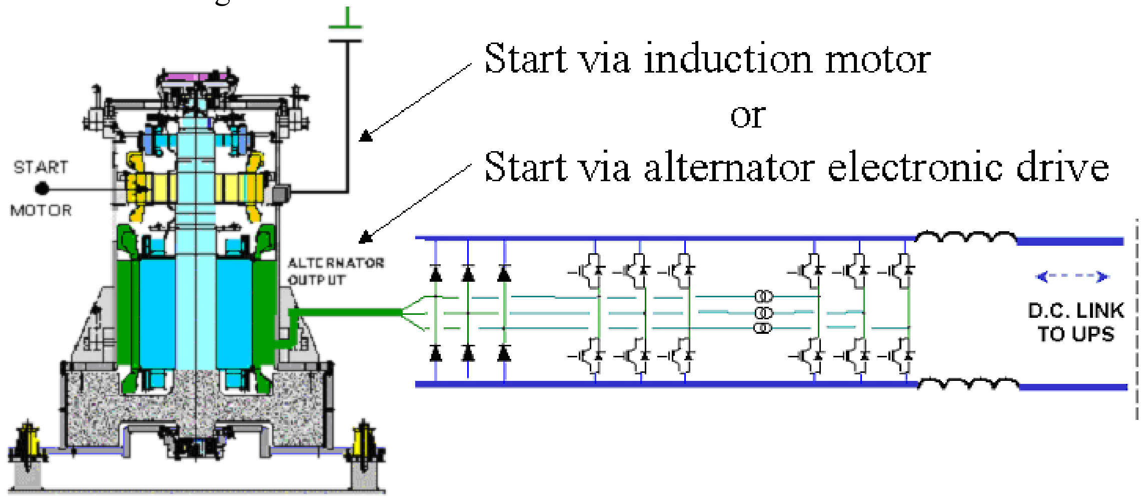

Figure 7
Two Possible Flywheel Charging Configurations: Induction Motor Starter And Power Electronics For Starting And Frequency Control. ***(Courtesy Of Piller Premium Power System)***

Further integrating is obtained in some models where the magnets in the machine rotor are embedded within the flywheel rotor itself, which rotates around a stator containing the electrical windings. This arrangement usually improves the energy and power density of the system, but challenges the cooling, by combining the two components into one.

Power Electronics and Electro-Mechanical Couplings

Most flywheel energy systems have some form of power electronics that convert and regulate the power output from the flywheel. As the motor-generator or alternator draws on mechanical energy in the rotor, the rotor slows, changing the frequency of the ac-electrical output. These power electronics, in the form of rectifiers and inverters, compete with electromechanical methods, such as the eddy-current clutch and induction coupling, to convert the changing flywheel speed to dc or to constant frequency ac power.

Power electronics have won this competition in all the high-speed wheels on the market. However several high-power, low-speed systems use electromechanical couplings to isolate the shaft and effectively couple an accelerating and decelerating flywheel with a constant-speed generator. Whether electronic or mechanical the main function of these devices is to allow energy to be taken from the wheel before its frequency and power output drop below usable levels. In fact the low-end (i.e., end-of-discharge) cutout speed at which the flywheel is considered discharged is primarily dependent on the current carrying capability of the electronics (or electromechanical coupling) and the size of the load. For example, most flywheels have output current proportional to load and inversely proportional to speed. This means a lighter load can go to a lower speed before the system cuts out on maximum current. The flywheel system can actually deliver 1.5 to 2 times more energy at light load than high load as can be seen in performance curves. While for different reasons, in this feature the flywheel is similar to a conventional lead-acid battery.

When power electronics are used the variable frequency, ac output of the flywheel alternator is simply rectified providing a dc voltage and current. From this point a power electronic inverter may be used to recreate ac at the desired waveform, frequency and voltage. So the function of the power electronics is to couple the fixed-frequency ac electrical grid with the variable-speed flywheel and also to invert, regulate, and provide wave shaping for the ac electrical output of the system. By reversing the process the power electronics are also able to draw power from the ac line connection, and drive the flywheel motor to spin up and recharge the wheel. In some cases a power electronics system recharges the flywheel and can use energy drawn from the electric grid. The most common power electronic systems use two matching bi-directional or 4-quadrant converters to carry out all of the functions described here.

Controls and Instrumentation

Flywheel systems require some controls and instrumentation to operate properly. Instrumentation is used to monitor critical variables such as rotor speed, temperature, and alignment. Rotor speed and alignment are also often controlled variables, through active feedback loops. The latter is especially important for systems with magnetic bearings, and most magnetic systems have complex controls to reduce precession and other potentially negative effects on the rotor.

In many systems, other instrumentation is used to monitor performance or design parameters related to failure modes. In some composite flywheel systems, for example, instrumentation is used to measure deformation of the rotor over time, alerting operators when the rotor shape indicates possible failure in the future.

System Packaging

Nearly all-modern flywheel systems have some type of containment for safety and performance enhancement purposes. This is usually a thick steel vessel surrounding the rotor, motor-generator, and other rotational components of the flywheel. In the event of catastrophic failure, the containment vessel would stop or slow parts and fragments, preventing injury to bystanders and damage to surrounding equipment.

Containment systems are also used to enhance the performance of the flywheel. The containment vessel is often placed under vacuum or filled with a low-friction gas such as helium to reduce the effect of friction on the rotor. Figure 8 illustrates a typical system packaging approach.

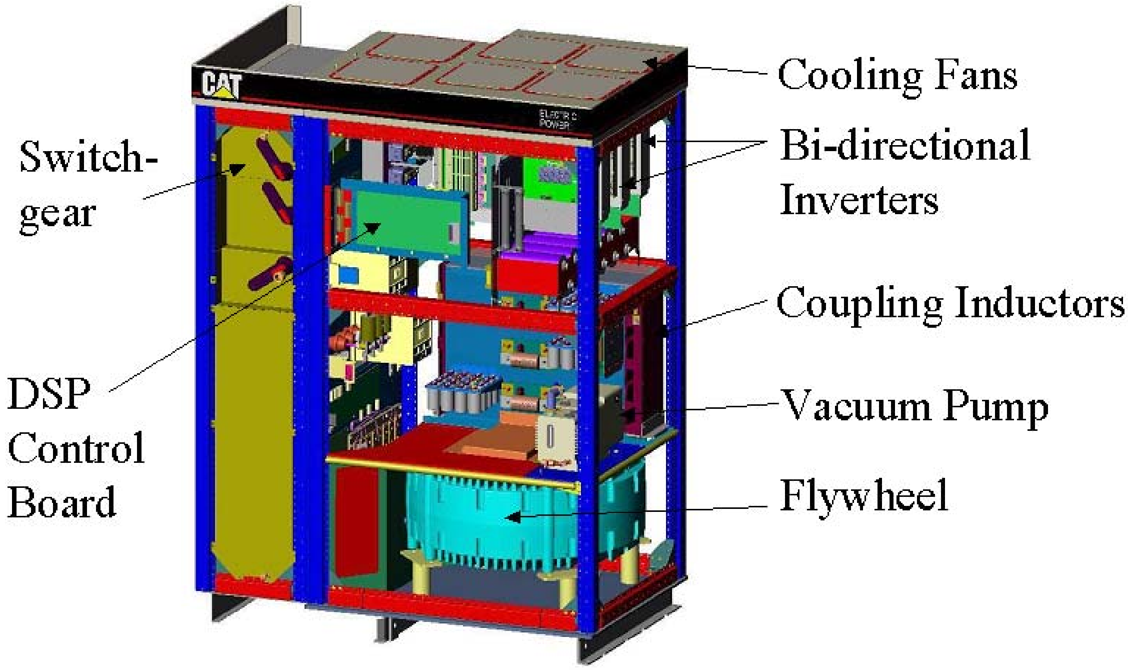

Figure 8
System Packaging Includes All Power Conditioning, Controls And Switchgear *(Courtesy Of Caterpillar)*

Features and Limitations

The advantages and disadvantages of flywheel systems relative to other energy storage systems were listed in Table 1. The specific features and limitations of flywheel systems are examined in the sections below.

Power Capacity

As noted above, the energy stored by a flywheel is determined solely by the mass and speed of the rotor, while the maximum power is determined more by the characteristics of the motor-generator and power electronics. This means that the energy and power characteristics of a flywheel system are more or less independent variables, allowing optimization of both characteristics independently. This is in contrast with most other energy storage devices. In batteries, for instance, both energy and power are determined by the size and shape of the battery electrodes.

Because of this independence, flywheel systems can, in theory, be designed for any power and energy combination. In practice, technical limitations such as rotor strength and weight, and resource limitations such as cost limit design characteristics.

Flywheel systems are typically designed to maximize either power output or energy storage capacity, depending on the application. Low-speed steel rotor systems are usually designed for high-power output, while high-speed composite rotor systems can be designed to provide either high power or high-energy storage.

When designed for power, where electric power conversion is adequately sized, flywheels can deliver relatively high kW for a short period of time. Most power flywheel products presently available provide from 100 to 500kW for a period of time ranging between 5 and 50 seconds. The power capability of flywheel systems can be far larger than these commercial systems, however. The largest flywheel built to date is an 8000MJ system built by the Japan Atomic Energy Research Institute (JAERI) for use in fusion energy research. This system uses a steel wheel to deliver up to 340MW for as long as 30 seconds.

Energy and Efficiency

Energy depends on mass and rotational velocity. High RPM, sometimes considered a measure of technical sophistication, is only part of the equation for high energy. For flywheels, the important parameter is rotational velocity or rim surface speed, which is circumference times RPM. For example, a small 0.5 kWh flywheel has a relatively small diameter rotor and may spin at 100,000 RPM; whereas a heavier 6-kWh flywheel has a bigger diameter rim and maintains the same rim surface speed at only 20,000 RPM. Therefore flywheel systems designed for high energy as opposed to high power tend to be larger diameter, taking advantage of weight and increased rim speed. However this advantage is physically limited to a speed of about 2 km/second by practical material strengths.

Round-trip efficiency and standby power loss become critical design factors in energy flywheel design since losses represent degradation of the primary commodity provided by the storage system (energy). However, they are largely irrelevant in power flywheel design (although standby losses could be an “operating cost” factor in comparison with other power technologies that have significantly lower losses). For these reasons, energy flywheels require more advanced technologies than power flywheels. These energy flywheels usually have composite rotors enclosed in vacuum containment systems, with magnetic bearings. Such systems typically store between 0.5 and 10 kWh. The largest commercially available systems of this type are in the 2-6 kWh, with plans for up to 25 kWh.

Round-trip efficiency for energy flywheels is between 70 and 80%. The standby losses are very small, typically less than 25W per kWh of storage and in the range 1 – 2% of the rated output power.

Calendar and Cycle Life

The nature of flywheel systems means that there is at least one moving part, the rotor itself. As might be expected, the most important life-limiting parts are the bearings on which the rotor rests. Continuous operation of a flywheel, even if it is not cycled, will eventually lead to deterioration of these bearings. Some designers have attempted to mitigate this life-limiting issue by either augmenting or entirely replacing mechanical bearings with magnetic bearings.

Flywheels generally exhibit excellent cycle life in comparison to other energy storage systems. Most developers estimate cycle life in excess of 100,000 full charge-discharge cycles. The rotor is subject to fatigue effects due to the cyclical application and stress during charge and discharge. The most common failure mode for the rotor is the propagation of cracks through the rotor over a period of time. Crack propagation can be difficult to detect in steel rotors, and hazardous failure modes are possible in which large chunks of steel break off from the rotor during operation. Appropriate design and operation precautions must be taken in order to ensure safe operation (see Safety, below).

In graphite rotors, cracks tend to propagate longitudinally, or result in de-lamination of the concentric layers of material. This phenomenon causes the rotor to gradually deviate from normal operation. Thus, monitoring of suitable operating parameters will ensure that the device can be removed from service before a hazardous failure mode occurs.

Recharge Time

Like electrochemical capacitors and SMES, flywheels have the advantage of relatively quick recharge times. Recharge times are comparable to discharge times for both power and energy flywheels designs. High-power flywheel systems can often deliver their energy and recharge in seconds, provided that adequate recharging power is available. Bi-directional power conversion facilitates this two-way action. On the other hand, in stabilizer applications the controls may be designed to provide a negative feedback where the rate of charging and discharging depend on voltage or frequency. In this case charging may occur quickly and discharge slowly or vice versa and most of the time no charging or discharging is required.

Standby Power Loss

Flywheel systems may have both intrinsic and parasitic power losses which cause the energy stored to be gradually used up. A certain amount of power must be applied to maintain a high level of charge if the flywheel is used in a standby mode. The magnitude of the power loss is dependent on the design of the flywheel, and may have both intrinsic and parasitic components.

Intrinsic power losses include friction and other forces that cause the rotor to slow down, and are common to all flywheel designs. Intrinsic power losses can be reduced through the use of techniques such as vacuum containment and magnetic bearings, but can never be reduced to zero.

Parasitic power losses include power provided to active magnetic bearings or cooling for superconducting bearings. Unlike intrinsic losses, parasitic power losses are independent of the speed of the flywheel. Not all flywheel systems have parasitic power losses.

Electrical Interface

The electrical interface, where the flywheel mechanical or kinetic energy is converted to electrical energy, and vise versa, can vary greatly with different flywheel types and applications. There are a number of rotating machine technologies that can be used in flywheels for generating (during discharge) and restarting (after discharge). These include permanent magnet alternators as well as dc, synchronous, wound-rotor induction, and written-pole motors and generators. Additional variety comes when these various machine technologies are mixed with different forms of power electronic and electromagnetic frequency conversion technologies. Also in the mix are application-specific filtering or conditioning, paralleling, isolation, transfer, and back up generator equipment. This results in the practical reality that no two-flywheel systems on the market in 2002 use exactly the same electrical interface.

The parameters that determine electrical interface design are flywheel speed (high, medium or low), electrical loading (ac or dc), response time (seconds or fractions of a second), parallel or series connection, need to interface with an alternate source, and the need for high power or high energy. With all these variables the variety in electrical interface is understandable. Still, in all cases, energy loss is a critical parameter that must be minimized, partly through electrical interface design. Thus, the interface design of most of the flywheels on the market allow suppliers to claim above 90% overall system round trip efficiency with standby losses of less than 3%. Table 2 provides an overview of the combinations of equipment that are typically used in the flywheel electrical interface.

Table 2
Typical Combinations Of Electrical Interface Equipment In Flywheels

Size Range	Rotor Speed	Mech. To Electric Converter	Frequency Converter	Load Type	Recharge Starter	Eff. %
<500 kW	High	PM[1] Alternator	Rectifier/Inverter.	AC	PM Motor/ASD[2]	95
<500 kW	High	PM Alternator	Rectifier	DC ASD	Induction Motor	92
<500 kW	Med.	DC Generator	Rectifier/Inverter.	AC	DC Motor	95
<500 kW	Low	Written-pole Gen	Variable Poles	AC	Induction motor	85
>1 MW	Low	Synchronous Generator	WR Induction Coupling	AC	Synchronous Motor	97
>1 MW	Low	WR[3] Alternator	Rectifier	DC	Induction Motor	93
>1 MW	Low	Wound Rotor (WR) Induction Generator	Double output Induction Generator	AC	WR Induction Motor	96
>1 MW	Low	WR Alternator	Rectifier/Inverter.	AC	Synchronous Motor/ASD[2]	96

[1] The permanent magnet (PM) machines are preferred in high-speed applications because they are more durable than electrical winding under mechanical forces on the spinning rotor.
[2] An adjustable speed drive (ASD) allows speed matching between the power source moving magnetic field (MMF) and the machine rotor poles. In the case of a PM alternator or synchronous machine, the machine only produces torque when the source MMF matches the rotor pole speed. This is not the case in induction machines, which produce torque (for starting) at zero rotor speed.
[3] Wound rotor (WR) machines are preferred in low speed applications where larger structures are needed to obtain high energy.

A good example of the application influence on the flywheel electrical interface is the bridge power system. In this application, when prime power is lost the flywheel system takes over and must operate as a standalone generator, with load following, voltage and frequency control until an alternate power source is available. At that point the flywheel system electrical interface synchronizes and transfers the load to the alternative source and begins the recharging sequence. This interface is typical for systems that have an integrated diesel engine or other backup generation.

Safety

As with any energy storage technology, hazardous conditions may exist around operating flywheels. Considerable effort has gone into making flywheels safe for use under a variety of conditions.

The most prominent safety issue in flywheel design is catastrophic failure of the flywheel rotor. In large, massive rotors, such as those made of steel, failure typically results from the propagation of cracks through the rotor, causing large pieces of the flywheel to break off during rotation. Unless the wheel is properly contained, this type of failure can cause serious damage to surrounding equipment, and injury or death to people in the vicinity. Large steel containment systems are employed to prevent high-speed fragments from causing damage in the event of failure.

Composite flywheels have other failure mechanisms, usually through gradual delaminating of the concentric layers of the rotor, or through vertical delaminating, or crack propagation parallel to the axis of rotation. In most cases, these failure mechanisms cause noticeable deviations from normal operational behavior long before catastrophic failure, and control mechanisms are often used to catch impending failure conditions. Nonetheless, the possibility of hazardous failure modes cannot be completely ruled out, and containment systems are also applied to composite flywheel systems, in part to enhance the perceived safety factor for such devices. Some systems are installed underground to further improve containment.

As with any electrical equipment, care must be taken to avoid accidental electrical discharge. Standard electrical codes and procedures can be applied to flywheel construction to prevent these failure modes from occurring.

Environmental

In contrast to many other energy storage systems, flywheel systems have few adverse environmental effects, both in normal operation and in failure conditions. Neither low-speed nor high-speed flywheel systems use hazardous materials, and the machines produce no emissions.

The most important environmental constraint for flywheel systems is noise when in operation. Many large flywheel systems, especially low-speed systems, are quite loud, often reaching noise levels in excess of 70dB at 6 feet. On the other hand, high-speed systems with vacuum containment are considerably quieter, and those that are installed underground can be unnoticeable.

Status

There is an ever-growing selection of new flywheel products on the emerging on the coattails of advances in technology. Consequently there are also a number of applications that now propose using flywheels as the energy storage medium. These include inrush control, voltage regulation and stabilization in substations for light rail, trolley, microturbine and wind generation. Still the majority of products currently being marketed by national and international-based companies are targeted for power quality (PQ) applications. And the number one application in power quality is short-term bridging through power disturbances or from one power source to an alternate source.

Flywheels are being marketed as environmentally safe, reliable, modular, and high-cycle life alternatives to lead-acid batteries for uninterruptible power supplies (UPSs) and other power-conditioning equipment designed to improve the quality of power delivered to critical or protected loads.

Major Manufacturers and Systems

Although the majority of products being sold and marketed today fit into the PQ niche market, there are a number of key areas where electric utilities can directly benefit from the use of available flywheel systems. These include hybrid distributed energy resources (wind and flywheel, photovoltaic and flywheels, etc.), T&D grid stability (e.g., mass transit substation support), and potentially diurnal load leveling (peak shaving). This section focuses on existing and emerging flywheel products that may have applicability to utility T&D operations and will address product availability, performance characteristics, cycle life, and expandability/modularity.

Table 3 lists the best-known manufacturers of flywheel systems for utility applications at present, along with the names and characteristics of their main products.

The following sections describe these manufacturers and the special features of their products with respect to other flywheel systems.

Active Power

Active Power, located in Austin, Texas, manufactures low-speed power flywheel systems to provide a brief ride-through or bridge to a standby generator when voltage is low or power is not available. The company was founded in 1996 with private funding from various venture sources, and has since issued public stock, trading on the NASDAQ exchange under the ticker symbol ACPW.

Active Power is rather unusual among flywheel manufacturers in having a steel wheel design that incorporates many of the features of higher speed composite wheels. The flywheel operates in a low and relatively wide speed range from 7700 to 2000 rpm, and is contained in a near vacuum environment. According to the company, the decision to go with steel rotors was made to avoid the technical difficulties and expense associated with composite rotors, magnetic bearings, complex controls, and containment systems required at high rotor speeds.

Table 3
Major Flywheel Manufacturers And Their Products

Manufacturer	Product Name	Rotor Type[1]	Nominal Standby Rotor Speed (rpm)	Rotor Environment	Bearing Type	Power Rating (kW)	Discharge Time	Recharge Time	Standby Power Loss[2]
Active Power	CleanSource	Steel	7,700	Rough vacuum	Magnetic & Mechanical[3]	250	13.5 sec	2.5 min @ 100A	0.76%
Piller	Powerbridge	Steel	3,600	Helium	Magnetic & Mechanical[3]	1100	15 sec	60 sec	4.5%
Hitec (formerly Holec)	Continuous Power Supply (CPS)*	Steel	3,600	Air	Mechanical	275 - 2000 kVA	10 sec	10 sec	2.5%
SatCon	Starsine Rotary UPS*	Steel	1,800	Air	Mechanical	315 - 2200kVA	12 sec	12 sec	2.3%
AFS Trinity	M3A	Graphite Composite	40,800	Vacuum	Active Magnetic	100	15 sec	15 sec	0.70%
Pentadyne	PPC 120	Graphite Composite	55,000	Vacuum	Active Magnetic	120	20 sec	20 sec	0.10%
Urenco Power Technologies	pq250	Graphite Composite	36,000	Vacuum	Magnetic	250	30 sec	26 sec	0.28%
Beacon Power	SmartEnergy BHE-6	Graphite Composite	22,500	Vacuum	Active Magnetic	2	3 hrs	2.5 hrs @ 4kW	3.5%

[1] Products are listed based on likely application with higher power flywheels listed first followed by higher energy systems.
[2] Standby power loss is given as a percent of rated power. Where rated power is a range, the maximum power is used for this calculation.
[3] These systems use electro-magnets for lifting of a vertical shaft wheel to reduce the weight on lower mechanical bearings.

The heart of the CleanSource2 is a 14” high, 32” in diameter integrated motor, generator and flywheel storage system that is capable of storing and delivering up to 250kW of DC power to the DC bus of a UPS. The flywheel stores energy as angular momentum in a single piece, forged 4340 steel wheel rotating in a near vacuum. The motor/alternator, characterized as a “homo-polar induction alternator,” has a novel design. There are no permanent magnets used, nor are there wound rotor type coils or magnets on the rotor. No brushes are employed. A field coil structure above and below the wheel magnetizes the rotor and produces characteristics of a salient pole generator. By driving higher current in the upper coil the magnetic structure supports most of the rotor weight via integral upper and lower magnetic ring bearings. This unloads the mechanical bearings to about 100 lbs and greatly extends their life.

Active Power has strategic relationships with several large manufacturers, including Caterpillar, PowerWare, and General Electric Digital Energy. Caterpillar is currently marketing the Caterpillar UPS, a battery-free UPS system using Active Power’s technology. PowerWare, a subsidiary of Invensys, markets the PF2 Flywheel Energy Storage system, which uses Active Power’s flywheel technology. Active Power also sells complete AC systems, which combine one or two flywheels in a cabinet with AC inverters to provide three-phase power.

Active Power plans to expand its line of flywheel systems. The Company recently released a lower power 150kW system, and expanded its UPS systems to include 150 kVA and 1200 kVA modules in addition to the existing 250 kVA through 900 kVA units marketed by Caterpillar. Active Power is also developing a high-inertia microturbine to replace battery packs in telecommunications power applications. The latter device is reminiscent of more conventional steel flywheel systems.

AFS Trinity

AFS Trinity, based in Medina, Washington, is the result of a merger between American Flywheel Systems (AFS) and Trinity Flywheel Power in 2000. The company has licensed composite flywheel technology from Lawrence Livermore National Laboratories to produce their short discharge time flywheel system.

The AFS Trinity system uses a high-speed, high-strength carbon composite rotor contained within a vacuum housing and is mounted on active magnetic bearings. The AFS Trinity system is unusual in the “inside-out” configuration of the motor/generator: permanent magnets are fixed in the core of the rotor, and revolve with the rotor around a stator inside the core. This system eliminates the shaft connecting the flywheel to the generator.

AFS Trinity has plans to market two products, the M3A and the M4A. The former, scheduled to become commercially available in late 2002, is a 100kW DC power flywheel system for use in power quality and short ride through applications. The M4A is a larger, 250kW device, planned to become available at an unspecified later date.

Beacon Power Corporation

Based in Wilmington, Massachusetts, Beacon Power was formed in 1997 when SatCon spun off its Energy Systems Division. Beacon became a separate entity in 1998, trading on the NASDAQ exchange under the ticker symbol BCON.

The company initially focused on energy storage flywheels for telecom applications, and developed the highest stored-energy, commercially available flywheel products in the world. Its high-energy telecom flywheel systems are operating in about a dozen field locations in North America, South Africa and Israel. Beacon recently began marketing high-power flywheel systems for UPS applications. Beacon is also proposing an innovative flywheel power station that can deliver megawatts for high-power distributed generation applications. Beacon offers flywheel technologies over a range of low and high power, from 2 kW to 250 kW.

For low power, they have a 6-kWh flywheel that delivers up to 2 kW, for a long period of time–up to 3 hours at full rated load for remote terminal telephone and cable applications, longer at reduced power. These flywheels are designed for very low power loss (~60 W) and totally maintenance free operation for 20 years. The system uses a composite rotor on magnetic bearings, spinning in a patented self-contained vacuum environment and operating at 22,500 rpm in float. Because of the low power applications, these flywheels can efficiently deliver power down to approximately 7,000 rpm. The flywheel is typically installed underground, which minimizes real estate requirements and provides increased security.

For high power, Beacon offers a 250 kW flywheel that delivers high power for short duration. This flywheel is designed to economically provide longer run-time than other available flywheels; up to 25 seconds at 250 kW vs. the typical 12-15 seconds. This type of flywheel delivers a relatively small amount of energy (e.g. 250 kW for 25 sec is only 1 kWh). The rotor is considerably smaller than the 6 kWh wheel used in the low power, long duration telecom applications. This family of flywheels operates at a float speed in the 36,000-rpm range. Depending on the load, the cut-off speed is limited by current draw through the electronics and ranges between 18,000 and 24,000 rpm.

Hitec Power Protection

Hitec (formerly known as Holec Power Protection) is a Dutch company that has been manufacturing its Continuous Power Supply (CPS) for over thirty years. Recent versions of the CPS have incorporated an unusual system using a flywheel within an inductive coupling to provide bridging power.

The CPS is composed of four parts: a diesel engine, a free-wheel clutch, an induction coupling, and a synchronous generator. The generator is connected to the AC utility line in parallel with the load. The clutch disengages the generator from the diesel engine, allowing the generator to spin, as a motor when utility power is available. The generator is connected mechanically to the induction coupling, which consists of two concentric rotors. The outer rotor is directly connected to the generator on one side and to the diesel engine, via the clutch, on the other, and contains ac and dc windings that couple it to the freewheeling inner rotor.

When the ac windings are energized the outer rotor, spinning at 1800 rpm, becomes a two-pole stator as in an induction motor. And this induction acts on the inner rotor, spinning it up to nearly 5400 rpm, where it acts as a flywheel. When utility power is lost the dc windings of the other rotor take over and hold the generator shaft at 1800 RPM by coupling with the inter rotor and controlling the slip as it is decelerating. This provides enough time for the diesel generator to turn on, come up to speed and pick up the load via the eddy current clutch, providing power for as long as the fuel holds out or until utility power becomes available.

Pentadyne

Pentadyne Power Corporation of Chatsworth, CA is a manufacturer of high-speed graphite composite flywheel systems for high-power applications. Paul Craig, former CEO of Capstone Turbine Corporation, founded the company in 1998. The company owns technology from Rosen Motors (now defunct), which had developed flywheel technologies for use in electric and hybrid-electric vehicles.

Pentadyne is marketing a product called the PPQ 120, a battery replacement / augmentation for a UPS system, which targets the power quality market. The PPQ 120 is a high-speed power flywheel system, which provides 120kW for up to 20 seconds. It applies a synchronous reluctance motor-generator with a power electronic rectifier/inverter to provide a regulated DC output. As of this writing, Pentadyne has secured Series B financing and is searching for beta test partners for its PPQ 120 unit.

Piller Premium Power Systems

Piller Premium Power Systems of Middletown, New York, is a member of the RWE family of companies, which is headquartered in Germany. Piller builds a low-speed power flywheel system for ride-through applications, which it calls the Powerbridge. The Powerbridge unit consists of a massive steel wheel that discharges from a nominal speed of 3600 rpm down to 1800 rpm, and is contained within an enclosure surrounded by helium. Piller is somewhat unusual among low-speed flywheel manufacturers for using magnetic lifting in the vertical shaft system to reduce the weight on the mechanical lower bearing in its system.

Piller also uses power electronics in a different way than others. The flywheel is built into their Powerbridge product, which can be combined with other equipment such as the Piller Uniblock-T UPS. Included in the UPS are the flywheel with alternator and starter motor, a rectifier/inverter, and a vertical shaft synchronous motor/generator. For the Uniblock-TD product Piller substitutes a horizontal shaft M-G and adds a diesel generator. In the event that utility power fails, the Powerbridge system provides ride-through power long enough for the diesel generator to start up and take over.

Like several other manufactures of >1MW flywheels, Piller physically separates the flywheel housing from the generator housing. However Piller applies a unique approach of coupling the flywheel and ac generator via power electronics. In this configuration the power electronics serve as the frequency converter, but leave power conditioning, wave-shaping, and regulation functions to the output of a conventional synchronous ac generator.

SatCon Power Systems

SatCon Power Systems a Division of SatCon Technology Corporation is based in Worcester, MA where they manufacture flywheel systems from 315 to 2200 kVA. The first systems were being tested in Fall 2002 and are expected to be ready for delivery February 2003. SatCon's first entry in the field is the large low-speed flywheel system incorporated into a rotary UPS that includes a back up diesel generator, called the

Starsine Rotary UPS. The Starsine uses a large steel wheel that operates between 1980 and 1620 rpm and discharges via an induction generator using rotor power electronics to compensate for the speed change. They are targeting applications that provide continuous power for process industries. However, with some modifications to the power electronics and rotor current rating, the system may be suitable for higher powers for 1-2 seconds in a utility scale stabilizer application.

The SatCon UPS product will operate in a fashion similar to other bridge-power devices, providing 12 seconds of ride-through power to cover short power quality events or momentary service interruptions, and relying on the diesel engine to cover longer interruptions. SatCon is unique among flywheel manufactures in their use of power electronic controls integrated into an induction generator, sometimes referred to as a doubly fed or double-output induction generator. This technology provides a soft interface between the variable speed flywheel or diesel generator and the fixed frequency of the load bus. Because of the interface SatCon expects to be able to parallel several flywheels without added paralleling switch gear and control.

Urenco Power Technologies

Urenco is a British company best known for uranium enrichment processes, for which they have developed and manufactured high-speed, composite gas centrifuges over the past thirty years. Urenco's flywheel technology is a direct spin-off from this experience and is being commercialised in a subsidiary called Urenco Power Technologies (UPT). Like the centrifuge the UPT flywheel uses a composite rotor and the same type bearing system that has allowed many of Urenco’s early centrifuges to run continuously for over twenty years.

For the power quality market, UPT builds two models; one sized to provide 100kW and a more recent version capable of providing 250kW. Both systems provide full power for about 30 seconds. It should be noted that this high-speed flywheel provides as much power as many of the low-speed flywheel ride-through devices, for a longer period of time and in a much smaller flywheel package. On the other hand auxiliary electronics and cooling add to the package size and weight. UPT's flywheel is a DC output device and can be coupled with an inverter/rectifier if AC power is required. Beacon Power has plans to market a system incorporating a UPT 250kW flywheel together with an inverter/rectifier, under the Beacon label as the SmartPower BHP-250.

The UPT flywheels are also being used in power management applications where the requirement is for repeated charge/discharge cycles. Examples include voltage support and energy saving in mass transit systems and power smoothing with wind turbines.

Recent Developments in Flywheel Technology

There are two major avenues of research in flywheel technology at present: improved passive magnetic bearings, and improved wheel materials. Research into these avenues is being conducted in various facilities, including universities, government laboratories, and in industry. Table 3 lists important flywheel technology developers and the technology they are best known for developing.

Table 3
Major Flywheel Research Groups

Developer	Development Area
Boeing Phantom Works	High Temperature Superconducting Bearings
Lawrence Livermore National Laboratories	Passive Magnetic Bearings
Pennsylvania State University	Composite rotor materials
University of Texas	Composite rotor materials

Magnetic Bearings

Research into new magnetic bearings is a significant part of flywheel research at present. New developments in active magnetic bearing technology have built hopes that similar advances in passive magnetic bearings may be possible. Passive bearings have the advantage of greater stability and reliability, and potentially lower parasitic loads than active bearings.

Two groups are leading the field in research on bearings: Boeing Corporation, and Lawrence Livermore National Laboratories. Boeing is better known for its airplanes and defense contracts than its flywheel technology, but the Boeing Phantom Works, the R&D branch of the company, has a flywheel program geared in part towards electric utility applications.

In 1998, the Department of Energy awarded Boeing a contract to develop flywheels with high-temperature superconductor (HTS) magnetic bearings. These bearings are made from superconducting materials that operate at somewhat higher temperatures than regular superconductors, although they still require cryogenic cooling with liquid nitrogen. The energy required to cool the materials is expected to be less than that required by conventional active magnetic bearings.

Using this technology, Boeing has built 15kW, 2.5 kWh energy-storage flywheels for both aerospace and utility energy storage applications. The flywheels have graphite composite rotors spinning in a vacuum. With further development, the company hopes to achieve 10kWh flywheels, and eventually develop megawatt-hour systems for utility energy storage applications.

It can be argued that modern flywheel technologies began at Lawrence Livermore National Laboratories (LLNL) in Livermore, CA, where Dr. Richard Post first proposed advanced flywheel systems for electric vehicles in the early 1970s. Later work at LLNL resulted in composite flywheels in place of the metal wheels predominant at that time. Much of LLNL's technology – particularly its Halbach motor/generator technology – was licensed to Trinity Flywheel Power (now a part of AFS Trinity).

LLNL's present work in flywheel technology is concentrated on the development of passive permanent magnetic bearings. Permanent magnets, arranged asymmetrically in such a way as to minimize instability and losses, can form stable room-temperature magnetic bearings. These bearings would enable much smaller standby losses than even HTS bearings, and would greatly increase the reliability and simplify the control systems of high-speed flywheels.

Composite Materials

Another area of intense interest to flywheel developers and manufacturers is the use of new composite materials in flywheel design. The term “composite material” is used to describe materials which have complex microstructures, often consisting of several materials in combination, and which defy classification by composition, crystal structure, or physical properties. The key point is that composites have a higher tensile strength and are lighter than steel. The expected benefit in flywheel applications is an order of magnitude increase in the practical wheel speed.

In the case of flywheels, the most common composite materials under consideration are graphite fiber composites and glass fiber composites. Both these materials are typically composed of fine fibers in a parallel arrangement, held together by a binder. This arrangement produces low-weight materials with very high tensile strength - often greater than that of steel - in the direction of the fibers. In flywheel applications, the lighter weight reduces the hoop and radial stresses within a spinning rotor at a given radial velocity, and the higher tensile strength allows a much higher maximum stress before yield. These effects combine to allow composite rotors to achieve much higher rotational speeds (and therefore, higher energy storage potential) than steel rotors.

At present, the specific research with respect to flywheels is generally dedicated to characterization, adaptation and qualification of new materials to a rotary application. Composite materials do not act linearly. As a result they tend to be much more difficult to characterize and understand than materials such as steel. The adaptation of such materials to rotary applications can also be difficult. For example, fiber composite rotors cannot be cut out of a block of existing material; they must be constructed in such a way that fibers are wound around the circumference of the rotor, to absorb maximum stress. For these reasons, research into new rotor materials can be costly and time-consuming.

Research Activities

There are three major directions in flywheel rotor material research. The first is towards stronger, lighter materials, which allow higher rim speeds and energy density. The second is towards cost reduction of composite rotors. The third is towards more effective and more repeatable manufacturing techniques, producing safer and more reliable rotors. In general, all the material developments involve these three directions to some degree.

The Composites Technology Center at Pennsylvania State University in University Park, PA has concentrated its efforts in flywheel technology on the development of lighter, stronger, and cheaper composite rotors. Penn State investigators are working on perfecting a carbon filament winding system, which will improve the strength of rotors while allowing the use of cheaper carbon materials. They have also been involved in investigations into the use of exotic materials such as carbon filaments, carbon nanotubes, and higher temperature materials, all of which can improve flywheel performance in the future.

The University of Texas Center for Electromechanics in Austin, TX has focused on modeling and characterization as steps towards the development of a significant prototype project, a 2MW, 480MJ flywheel for the Advanced Locomotive Propulsion System (ALPS). University of Texas investigators have made significant progress into software modeling of the stress and dynamics characteristics of composite rotors. They have also developed new non-destructive characterization tools to understand performance of new materials and geometries. They are now investigating other effects on high-speed flywheels, such as the effect of thermal conditions, particularly in a near-vacuum environment, and behavior under non-standard conditions such as magnetic bearing failure.

Applications

Flywheels have inherent appeal due to the sheer simplicity of storing kinetic energy in a spinning mass. For decades piston engines have used this concept to smooth power output and operation. In short-duration electrical applications they are competitive with traditional energy-storage technologies such lead-acid batteries. Advances in power conversion technologies coupled with advances in flywheel designs have paved the way for new applications for flywheel-based energy storage. Today flywheel systems are capable of supplying megawatts for a few seconds with very fast response and low energy losses.

This section describes two primary applications related to utility transmission and distribution operations that are likely to benefit from emerging flywheel (or other) energy storage technologies. The first application is energy storage for voltage support or grid stabilization. The second is energy storage as a supplemental source of current to serve power demand of highly fluctuating loads.

A third application is mentioned here for completeness, but is not further developed. The application is bridging power for uninterrupted power to critical substation loads. This is somewhat rare in that most substation critical loads, except telecom loads, are supported by station batteries. In this application the energy storage is usually configured to provide short-term bridging power that carries the load from loss of primary power until a standby generator can be started, or until, recovery of the primary source.

Voltage Stabilization Support to the Electric Grid

Problem Description

Need for system stability, in both central and distributed power systems, as well as the specific functions of reactive power supply and frequency regulation support, are considered here. The reactive power control application solves the problem of VAR control to maintain power flow and voltage stability. The frequency regulation application solves the problem of controlled injection needed to regulate system frequency. The later is particularly relevant for improving stability of relatively weak areas in the T&D. These applications are cited as ancillary services in FERC order 888 1996, and will eventually carry a location dependent market value in a restructured utility situation.

The technical criteria for grid stabilization, identified here as a "mini-facts" application, will be somewhat site and utility system specific but likely will fall within these parameters:

- **Application –** Reactive power supply and frequency regulation support of T&D
- **Power Rating –** 2 to 40 MVA (power may be real, reactive, or both)
- **Energy Capacity –** .5 to 10 kWh at MVA rating
- **Duration –** Corrective action for cycles up to a few seconds
- **Response Time –** 5 to 100 Milliseconds
- **Duty Cycle –** Variable depending on conditions, may be a continuous problem
- **Roundtrip Efficiency –** 80 to 90% (assumes less than 10% duty cycle)
- **Standby Losses –** 3 to 4%
- **Plant Footprint –** .05 MW/m^2 (assumes siting in low density area)
- **Environmental Issues –** EMI

Other, non energy storage alternatives for solving this problem are: overexcited synchronous motors and generators, switched capacitors, as well as fast acting static var compensators (SVCs). Also, utilities traditional options to improve voltage regulation and control frequency are upgrading transformer and feeder capacity, and cycling power plants.

Stored Energy for "Distributed-Mini FACTS" Controllers

The energy storage application for improved stability is based on benefits of active power injection coupled with dynamic reactive power exchange with thee power system. The need for dynamic reactive power compensation ("fast VARS") as opposed to fixed or mechanically switched capacitor banks have long been recognized as a way to improve T&D system stability and increase power transfer limits. This concept has been applied in large-scale inverter-based Flexible AC Transmission Systems (FACTS). These systems have the ability to affect changes of 10 to 100 MVAR and respond in less than one-quarter of a cycle and they have brought about a new way of thinking regarding active and reactive power.

An example is the STATCOM, which outpaces switched passive capacitors, reactors, and LTC transformers in the rapid voltage regulation. STATCOM responds even faster than conventional generators, SVCs, or synchronous condensers, which in the past were the main supplier of "fast VAR" to the electric systems. Also, this type of dynamic reactive compensation is better at supporting voltage during system contingencies than conventional capacitor banks that loose capacity when system voltage decreases, (See Figure 9).

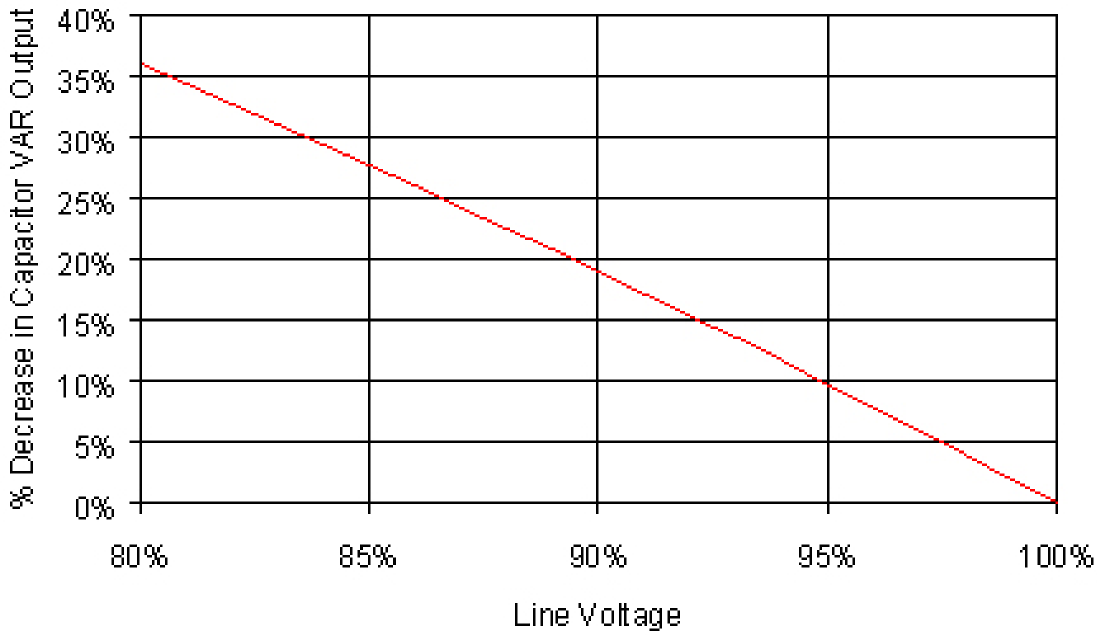

Figure 9
Loss Of Capacitor VAR Output As A Function Of Line Voltage

Combining energy storage with FACTS controllers offers three distinct advantages:

1. Energy storage devices can provide system damping while maintaining constant voltage following a system disturbance.
2. Energy storage increases the dynamic control range allowing the interchange of small amounts of real power with the system.
3. Distributed energy storage can maintain the speed of locally connected induction motors during a power system disturbance, thus helping to prevent a voltage collapse in areas where there is a large concentration of induction motors.

An EPRI study [1] found that adding energy storage (in this case, SMES) to a FACTS device increased the control leverage of the reactive power modulation of a FACTS device by 33% (i.e., operating the FACTS + energy storage in four-quadrant, reactive plus real power mode provided 33% greater transmission enhancement). Figure 10 shows the results of a study conducted by Siemens on the effectiveness of short-term energy storage with a FACTS controller in damping low frequency power oscillations that could not have been achieved with the STATCOM plus post oscillation damping (POD) alone.

"The results illustrate that a STATCOM alone (i.e. no POD) will regulate voltage in the post contingency period but will not naturally add much damping to power oscillations. The STATCOM with POD signal applied to its voltage reference may damp swing oscillations following a disturbance however this is achieved at the expense of voltage regulation. The combination of STATCOM plus SMES with POD modulating the SMES output will allow the system to both regulate voltage and provide oscillation damping." [2]

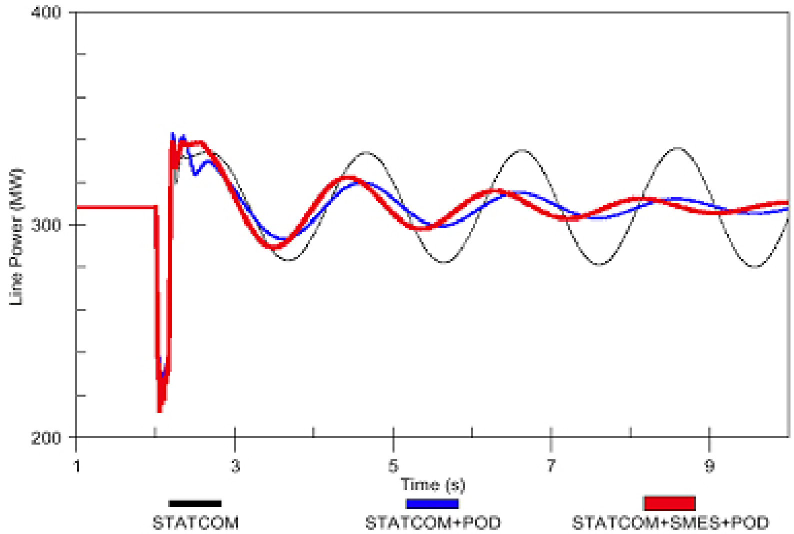

Figure 10
Damping Of Post Fault Oscillation With And Without Energy Storage

The use of large-scale (100 MVAR or more) FACTS controllers to provide dynamic reactive compensation has already been demonstrated through several landmark projects. However, because of high initial cost, the alternative of a smaller scale, modularized, distributed real, and reactive VAR injection has recently received considerable attention.

The key to this application is the injection of real energy storage to maintain speed of motor, which in turn reduces the inrush current for feeders heavily loaded with motor loads. This minimizes bus voltage depression and thus helps with both rotor angle and voltage stability. By providing a critical boost to the system both during faults and following the clearing of faults helps avert instability. This type of distributed dynamic reactive compensation with energy storage is particularly suitable for solving transient voltage stability problems in a weak portion of the network with a high concentration of induction motor loads during peak loading conditions.

The advantage of energy storage under these conditions is mainly in reducing the maximum transient voltage dip, which is a measure of the dynamic performance of the system Based on Western Systems Coordinating Council (WSCC) criteria as shown in Figure 11, the voltage at any load bus should not dip below 20% of the initial value for more than 20 cycles.

Estimating the total portion of induction motor loads is becoming a critical issue for power system stability. This was recognized in a study conducted for model validation and analysis of WSCC System Oscillations following Alberta Separation on August 4, 2000. Figure 12 shows the modeling result of the system oscillation following the separation for different percentages of induction motor loads. Based on this study, one of the recommendations was to increase the portion of induction motor load representation in selected areas for future system stability study models.

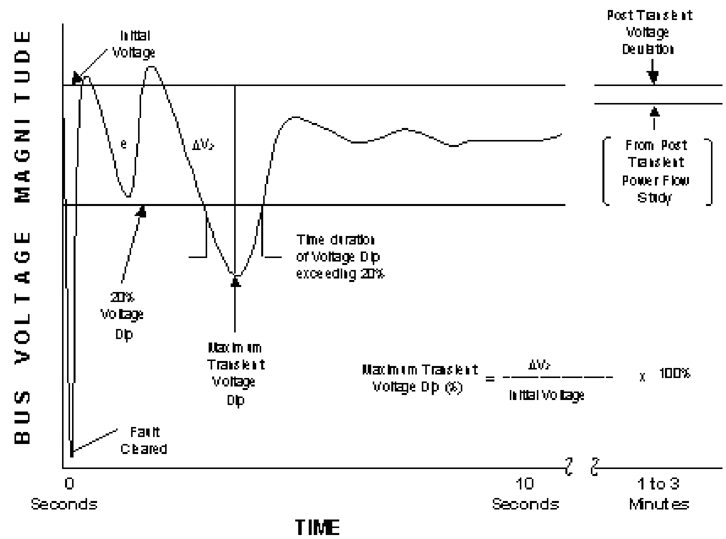

Figure 11
Voltage Performance Parameters From WSCC

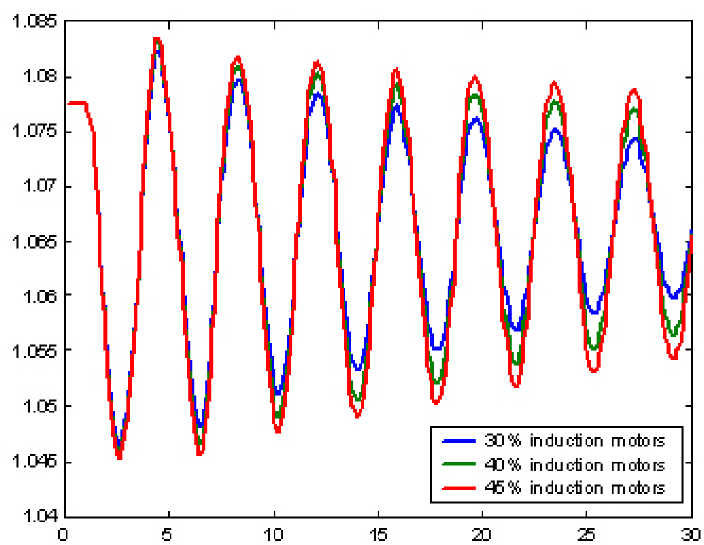

Figure 12
Impact Of Induction Motors On System Oscillation

Potential for Flywheel Energy Storage Mini FACTS in T&D Circuits

Combining flywheel energy storage with appropriate bi-directional electronic power conversion provides a legitimate implementation of the distributed mini-FACTS controller. No such system has been built. Figure 13 shows a conceptual block diagram of a flywheel-based mini FACTS controller system. This system may be controlled to act as a stabilizer for distribution feeders, acting on post-disturbance voltage to assist in returning the voltage and frequency to an equilibrium status within one second. The advantages of the flywheel-based storage system over conventional lead-acid battery are relatively high-power density and cycle life as well as inherently lower maintenance and tolerance to temperature. The potential advantage of the flywheel over SMES, a technology that has been used successfully in grid stabilization, is likely to be modularity in size selection and lower cost. Currently the main disadvantage is cost.

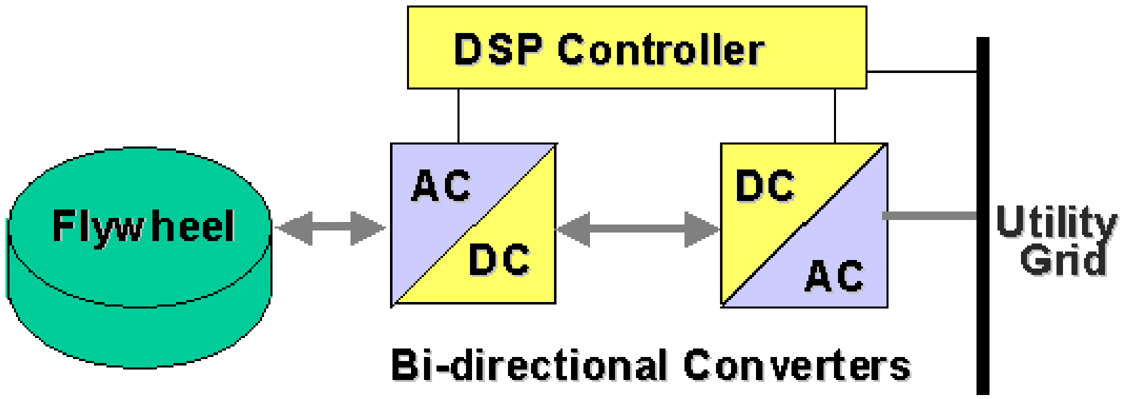

Figure 13
Concept Of Flywheel-Based, Utility Grid Coupled Mini-FACTS Controller

Enhance Service to Fluctuating Loads

Problem Description

The opportunity described here is related to the difficulty for electric distribution companies to serve highly fluctuating end-user load equipment. For example distribution service to car- or rock-crusher operations, pulsing amusement park rides, large electric welders, mini steel mills with melting operation, or electric mass transit may experience a fluctuating load problem. This problem is manifested in voltage variations that can affect performance of the fluctuating load or other load equipment connected nearby. The most common complaint related to voltage fluctuations is visual irritation from flickering lights. In addition, high-inrush loads cause voltage dips that may cause stalling of motors or disturbance of sensitive electronic equipment. Standards have been published, such as IEEE 1453 and IEC 61000-3-7, which set minimum requirements for end users and utilities and help to assign responsibility for corrective actions.

The technical criteria for this application will depend on the fluctuating load and the characteristics of the local power system but likely will fall within these parameters:

- **Application** – Provide local starting inrush current and absorb excess energy while mitigating bus voltage sags and swells
- **Power Level** – Depends on the size of the fluctuating load, .5-5 MVA (both real and reactive power required for ac load and only real power for dc load)
- **Energy Capacity – .**2 to 20 kWh
- **Duration** – Less than 30 seconds
- **Response Time** – 100 to 200 Milliseconds

- **Duty Cycle –** Variable depending on type of fluctuating loads and power sources, may be a continuous duty such as for automatic welding equipment.
- **Roundtrip Efficiency –** >90% (assumes less than 10% duty cycle)
- **Standby Losses -** < 3%
- **Plant Footprint –** .1 MW/m^2
- **Environmental Issues –** EMI, EMF, Aesthetics

Non-energy storage alternatives for solving this problem in the distribution system or at end-user facilities include dynamic voltage restorer or related ride-through power conditioning equipment, increased service size, and modifying or isolating fluctuating loads. In the transmission system and at higher voltage levels alternate feeders may be used to separate offending loads; substation static VAR compensators and FACTS can compensate for momentary reactive power demand; and utilities have the option to add faster regulators and beef up transformer and feeder capacity to reduce voltage fluctuations.

Stored Energy Solution for Inrush Current and Voltage Control

The most direct approach to mitigate fluctuating loads is to provide distributed or local compensation. This relieves the rest of the power system of momentary overloads and related line losses for power delivery. Reactive power compensation, such as fixed shunt capacitors is usually the most economic compensation. Series capacitors have also been successfully applied for compensating fluctuating reactive loads. However, when fluctuations are caused by high power factor loads, such as a resistive welder, than the most effective compensation must have a real power component.

Distributed energy storage interfaced via power electronics offers real and reactive power compensation capability. Also, if four-quadrant (real, reactive, bi-directional) power electronics are used it is possible to source or sink power acting as a stabilizer for the electric grid. In this case the system can be sized for the aggregate of expected local load and source fluctuations, and thereby provide local stabilization. Assuming moderate series impedance, and a lag time in the response from other grid sources, a simple voltage-based control will pick up momentary voltage excursions and feedback demand for sourcing or sinking power with the grid. A conceptual diagram of this dynamic voltage regulator and current inrush controller is shown in Figure 14.

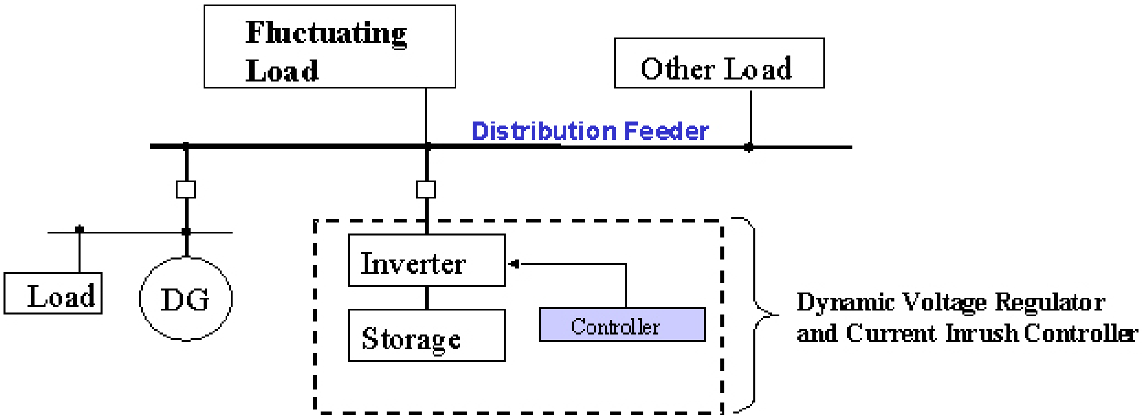

Figure 14
Block Diagram And Electrical Schematic Of Stabilizer Application In Distribution

Flywheel Energy Storage Solution for Serving Fluctuating Loads (NYPA Case)

In many ways the flywheel-based dynamic controller is a natural for this application. Flywheels are a proven technology for fast response and excellent dynamic damping characteristics. When designed for power, the kW output rating can be quite high relative to their size and weight. When several flywheel modules are required to match the fluctuating load, paralleling is straightforward.

Electric service to light rail, subway trains, or trolley systems is an interesting application of this energy storage solution. Load fluctuations are related to electric trains starting up and stopping, with opportunity of demand reduction and energy recovery via regenerative braking. A practical case in point is a prototype installation in New York City, where NYPA is financing a flywheel energy storage system connected to the subway. The site is on New York City Transit (NYCT) premises. The installation is on Broad Channel, near the recently constructed bay equalizer site at the Far Rockaway Test Track, see Figure 15.

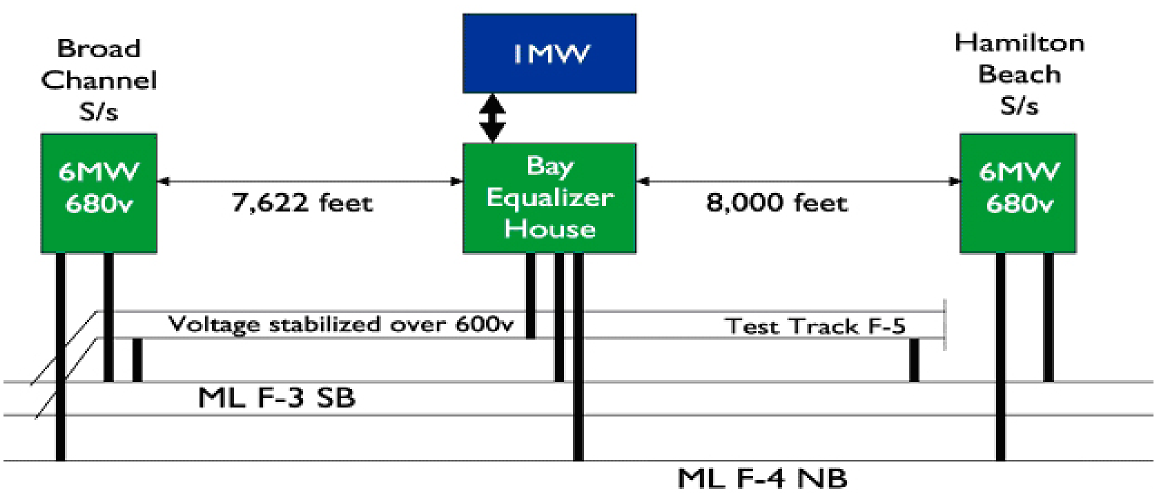

Figure 15
Two 6-MW Substations (NYPA) and 1MW Storage (NYCT) Service Far Rockaway Line

This site was selected so that power from the flywheel equipment may be utilized to support performance testing of new technology trains on the test track. Testing requires a stable track voltage, which has not been available at this site. As shown in Figure 16 average voltage is approximately 672 Vdc at light load, however excursions well above and below this level are were common during train operations. The existing substation spacing along the Far Rockaway Line at Broad Channel makes the voltage requirements for performance testing (600V maintained) difficult to meet.

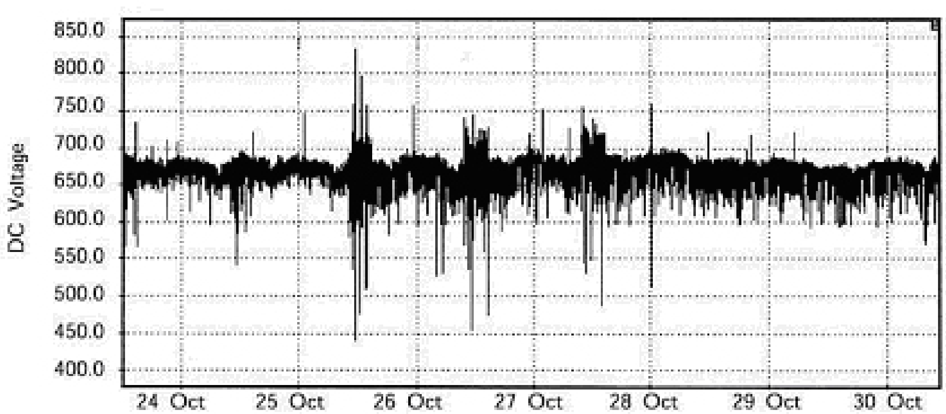

Figure 16
Typical Voltage Profile At The Far Rockaway Test Track In October 2001

The prototype installation consists of ten individual high-speed flywheels of 100-kw each, connected together to provide one-megawatt capacity, see photo in Figure 17. Together the flywheels store about 5 kWh in kinetic energy and could be expected to operate as often as every 2 minutes during peak hours, and average about every 6 minutes during normal operating hours. A complete cycle of the flywheels consist of a 20 second discharge triggered by reduced voltage during train accelerations and a recharge at approximately the same rate if trains are regeneratively braking in the vicinity. Otherwise the recharge is controlled based on track voltage during the several minutes between trains.

Figure 17
Flywheel Installation At NYCT Bay Equalizer Location, 10 1-MW Units In New Building

The power control for the system is based on the dc-track voltage. By controlling the power electronics the system can provide zero to maximum power in 5 millisecond. A typical power profile for this application, Figure 18, contains three distinct control regions: discharge, recovery and charge, and shows typical voltage levels for a no load situation.

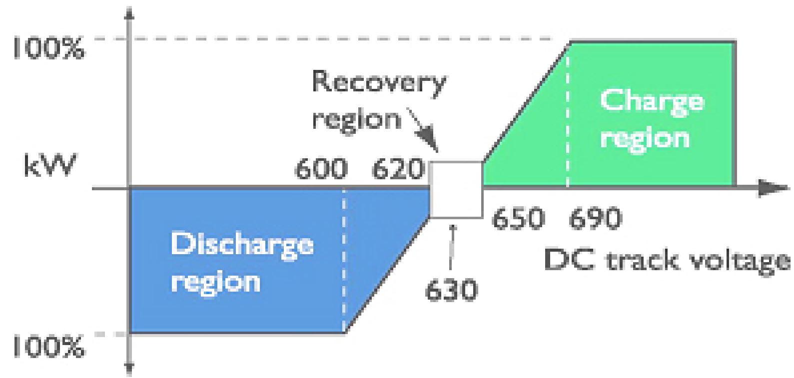

Figure 18
Typical Power Profile Based On A Nominal Track Voltage Of 630Vdc

Energy recapture depends on the coincidence of trains. In cases where trains in the vicinity are accelerating and braking at the same time the energy is exchanged between trains and the flywheel is not cycled or is only partially cycled. From the above operating schedule trains pass by approximately 10 times per hour over 6000 hours per year. If the flywheels recapture 15% of the time approximately 45,000 kWH are saved.

NYCT recognizes three distinct benefits from utilizing this kinetic energy storage system.

1. Through proper parameter settings, improvement in the third rail voltage regulation is achieved. The flywheel output voltage is a constant voltage (for the duration of which the flywheels have power available to discharge). Thus, higher DC voltages may be realized during the short acceleration events (10 secs.) of trains, allowing operation of new more efficient AC trains.

2. Cost savings in substation capacity and in NYTCs power bill are realized because peak power demand at neighboring substations is reduced by the timely contributions made from the energy storage equipment. Demand charges currently make up over 40% of electric cost. Estimated reduction at the two involved substations may be 33%.

3. Energy savings from regenerative braking trains that would normally be dissipated in braking resistors and tracks during periods of non-receptivity may be stored and put to use later on by accelerating trains recapturing in the range of 7-25%.

For NYPA the benefits are related to reduction in substation capacity, better utilization of existing T&D assets, and deferral of construction of new capacity for the new, higher power demand AC trains. This installation also provides a new design criterion for optimum placement of substations in traction applications. Application of the flywheel energy storage provides added flexibility in sub station placement, increased distance s between substations, and better utilization of available T&D investment dollars.

Costs and Benefits

This section defines the variables that determine typical costs and benefits for flywheel energy storage applied to transmission and distribution. Costs are based on currently available high speed and low speed flywheel technology, in multi module configurations. For this analysis the low-speed system is estimated to be used for grid stability in the proposed distributed mini FACTS application. The high-speed system is estimated for service to provide fluctuating load stabilization in the railroad traction application. In fact, either the high or low speed flywheels can be applied in these T&D applications.

Cost data is also provided for expected near-term development of the high-speed flywheel. This development will increase the flywheel capacity by 2.5 times in the same physical package.

Cost Assumptions

The following are the assumptions related to these variables and the relevant applications.

1. For the grid stabilization application the low-speed flywheel equipment first cost are assumed to be $400 per kW. For the traction application the high-speed flywheel equipment first cost is assumed to be $600 per kW for current hardware and $400 per kW for future high-capacity hardware.
2. The installation cost is a one-time expense that includes ancillary electrical power integration and wiring, panel board and switchgear, and system foundation and enclosure equipment. HVAC is required for the low speed flywheel and this cost is included as additional part of the installation cost.
3. The system footprint or real-estate cost is a fixed cost based on the square-footage required to house the flywheel modules and related equipment. For this cost and benefit analysis, it is assumed that the area required is 500 square feet for all three applications and the cost per square foot per year is $25.00.
4. Annual operating expenses include cost of energy, routine maintenance, inspection, and any scheduled replacements. The HVAC energy cost is a continuous expense and is a function of the system efficiency. Only the grid stabilization application is expected to require HVAC for system controls.
5. The energy used by the flywheel system to maintain rotor speed is a function of the system efficiency and duty cycle. For example, for some applications, the duty cycle might be once per week, while for more demanding applications, the duty cycle might be once per hour. The efficiency is greatest for light duty cycle applications and typically reaches 97 percent, or 3% loss at no load. However, for high-duty cycle applications, the efficiency typically reduces to 90 percent.

Cost Analysis

Costs depend primarily on the flywheel technology and the specification for the application. The primary applications discussed previously are AC grid stabilization and traction load stabilization. The information in Table 4 below summarizes the significant cost elements for these different applications and selected flywheel technologies.

Table 4
Summaries Of Costs By Application And Variation Of Technology

Technology Variant	T&D Application	Size* MW	Stg Capacity kW-hours	A. Power-Related Equipment Cost	B. Energy-Related Equipment Cost	C. Installation-Related Cost	Total Capital Costs (A + B+ C)	Annual Estimated O&M Costs
Low Speed Flywheel	AC Grid Stabilization	1.5	5.00	$393,120	$120,960	$104,567	$618,647	$67,447
Low Speed Flywheel ($/kW)	AC Grid Stabilization	1.5	5.00	$262	$81	$70	$412	$45
High Speed Flywheel	Traction Load Stabilization	1	8.33	$409,500	$220,500	$105,000	$735,000	$66,398
High Speed Flywheel ($/kW)	Traction Load Stabilization	1	8.33	$410	$221	$105	$735	$66
Increased Capacity High Speed Flywheel	Traction Load Stabilization	1	8.33	$189,000	$231,000	$63,000	$483,000	$50,320
Increased Capacity High Speed Flywheel ($/kW)	Traction Load Stabilization	1	8.33	$189	$231	$63	$483	$50

*Note: Multiple flywheel systems can be connected in parallel to produce a larger system rating. For example, for some applications, multiple 250kW flywheel units might be easier to site, build, and install than one single 1.5MW unit.

Cost and Benefit Comparison

The cost and benefit comparison using the net present value (NPV) method depends on the specific application. The major benefit associated with grid stability includes VAR control to maintain power flow and voltage stability of the T&D system. This is difficult to quantify, however it may be possible to defer some other T&D upgrade investments which will certainly show a clear financial value to the utility. The approach is to apply usual practices or service standards as the criteria to say if an investment is required.

In the case of end-use load stabilization, or load fluctuation control, the major benefit to the utility is similar to grid stabilization, and is to defer investments and operating cost of the T&D. In some special cases, where the stabilizing equipment is near the end user such as the DC railroad traction case described here, there may be other quantifiable benefits for the end user. These are improved operations and energy efficiency of end-use electrical equipment such as AC motors and reduced peak power demands at nearby electrical substations.

Table 6 shows the NPV of the costs, the benefits and their combination for each major application. The parameters used in the NPV calculation include:

1. Time period for calculation is 20 years
2. Escalation rate is 2%
3. Inflation rate is 2%
4. Discount rate adjusted for inflation is 5%

The benefit assumptions used for each application include:

1. For AC grid stabilization the assumption on benefits is based on substation upgrade deferral. The value of deferral is assumed to be $840,000 for the first 10 years and $1.68 million for the second 10 years. The deferral savings must be based on specific site conditions and estimated costs. The rationale for these numbers is that they are in the range of substation upgrade costs.
2. The railroad traction load stabilization gives value to both the utility and to the end user, such as city, municipal operator or transient authority.
    a. Assumptions for value to the utility is in reducing the size or number of substations required in a new installation or in deferring the upgrade of existing substation in the case of increased train operations or new and more demanding train loads. In this specific case of a small substation supporting the subway operations deferral was valued at $340K for the first ten years and $780K there after.
    b. Value to the end user includes improved voltage regulation to maintain the train operations and allow the use of new AC drive trains, with improved overall energy efficiency. In addition, storing of energy flattens the peaks and valleys of demand, which reduces the demand charges. Typical benefits assumed in this case are an energy (kWh) savings of 15% of flywheel rating, based on 6000 hours per year @ $.06/kWh. Also the

customer based on demand reduction at the meter expects an additional 13% savings in the power bill.

Table 5
Benefit/Cost Ratio Comparison Based On NPV Assessment.

Technology Variant	T&D Application	Size* MW	Stg Capacity kW-hours	NPV(Costs)	NPV(Benefits)	NPV (Total)	Benefit/Cost Ratio
Low Speed Flywheel	AC Grid Stabilization	1.5	5.00	$1,529,145	$1,445,026	($84,119)	0.9
Low Speed Flywheel ($/kW)	AC Grid Stabilization	1.5	5.00	$1,019	$963	($56)	N/A
High Speed Flywheel	Traction Load Stabilization	1	8.33	$1,519,974	$1,841,082	$321,108	1.2
High Speed Flywheel ($/kW)	Traction Load Stabilization	1	8.33	$1,013	$1,227	$214	N/A
Increased Capacity High Speed Flywheel	Traction Load Stabilization	1	8.33	$1,080,217	$1,841,082	$760,865	1.7
Increased Capacity High Speed Flywheel ($/kW)	Traction Load Stabilization	1	8.33	$720	$1,227	$507	N/A

*Note: Multiple flywheel systems can be connected in parallel to produce a larger system rating. For example, for some applications, multiple 250kW flywheel units might be easier to site, build, and install than one single 1.5MW unit.

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EPRI Energy Storage Handbook: Compressed Air Energy Storage (CAES) Chapter

December 2002

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Bellevue, Washington

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1. Description

Compressed air energy storage (CAES) offers a method to store low-cost off-peak energy in the form of stored compressed air (in an underground reservoir or an aboveground piping or vessel system) and to generate on-peak higher-priced electricity by:

1. Releasing the compressed air from the storage reservoir
2. Preheating the cool, high-pressure air
3. Directing the preheated air into an expansion turbine driving an electric generator

The concept for a typical CAES plant is shown in simplistic diagram in **Figure 1**. Since the compressor and expander operate independently and at different times, CAES offers significant advantages over a conventional simple-cycle combustion turbine system, where approximately 55-70% of the expander power is used to drive the compressor.

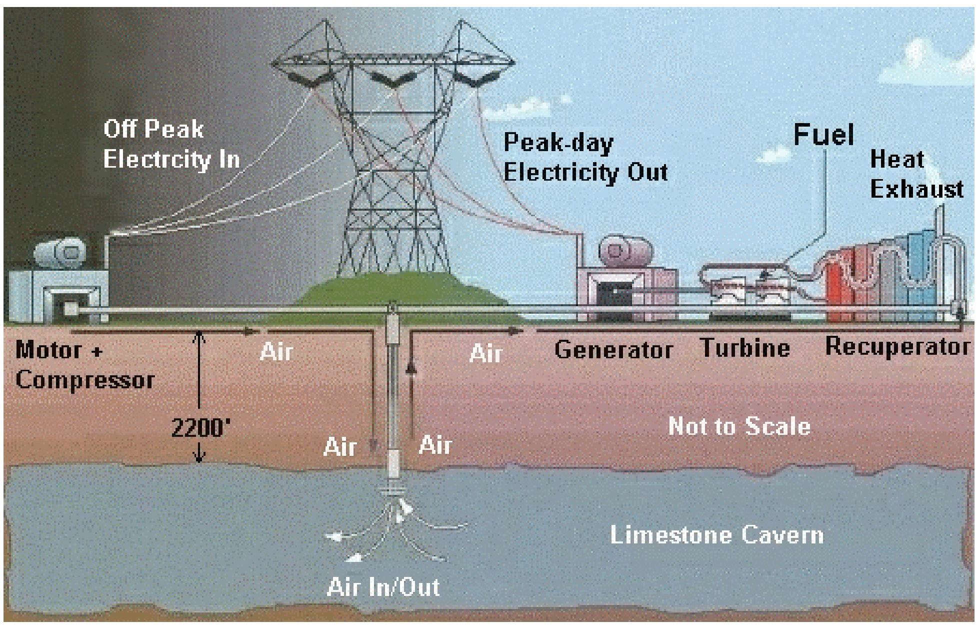

Figure 1
Typical Compressed Air Energy Storage Plant (The Plant Shown Is One Planned By Norton Energy Storage LLC)

Brief History

The technological concept of compressed air energy storage is more than 40 years old. CAES was seriously investigated in the 1970s as a means to provide load following and to meet peak demand while maintaining constant capacity factor in the nuclear power industry. CAES technology has been commercially available since the late 1970s. One commercial CAES plant has been operating successfully for over 24 years, and another has been operating successfully for 11 years. In addition, many other CAES plants have been investigated via siting, economic feasibility, or design studies.

Operating CAES Plants

The first and longest operating CAES facility in the world is near Huntorf, Germany. The 290-MW_e Huntorf plant has operated since 1978, functioning primarily for cyclic duty, ramping duty, and as a hot spinning reserve for the industrial customers in northwest Germany. Recently this plant has been successfully leveling the variable power from numerous wind turbine generators in Germany.

The only CAES facility in the U.S., a 110-MW_e plant near McIntosh, Alabama, has been in operation since 1991. The McIntosh plant performs a wide range of operating functions; namely,

- Load management
- Generation of peak power
- Synchronous condenser duty
- Spinning reserve duty

Past CAES Development Efforts

Many other CAES plants have been designed and/or investigated but were not built for a variety of reasons. Examples of such plants follow:

- During the Soviet era, a 1,050-MW_e CAES plant using salt cavern geology formations for the air storage was proposed for construction in the Donbas area of Russia. Underground geological development of the air store using salt domes was initiated, but when the Soviet Union collapsed, the construction was terminated.
- Israel studied several CAES facilities, including a 3 x 100-MW_e CAES plant facility using fractured hard rock aquifers [1].
- Luxembourg designed a 100-MW_e CAES plant sharing an upper reservoir for a water compensation system with a pumped hydro plant located in a hard rock cavern at the Viendan site [2].
- Soyland Electric Cooperative, headquartered in Decatur, IL contracted for the construction of a 220-MW_e hard rock based plant. Plant engineering and the cavern sample drilling/rock analysis was completed and all major equipment had been purchased when the project was terminated due to non-technical considerations arising from a change in the Board of Directors at the utility. ABB had been selected to manufacture the turbomachinery [2], and Gibbs & Hill, Inc. had been selected as the plant engineering company.

CAES Technology

In CAES systems, electricity is used to compress air during off-peak hours when low-cost generating capacity is available. For power plants with energy storage in excess of approximately 100 MWh, the compressed air is most economically stored underground in salt caverns, hard rock caverns, or porous rock formations. A CAES plant with underground storage must be built near a favorable geological formation. Aboveground compressed air storage in gas pipes or pressure vessels is practical and cost effective for storage plants with less than about 100 MWh of storage.

For a conventional CAES plant cycle (as illustrated in **Figure 2**), the major components include:

- A motor/generator with clutches on both ends (to engage/disengage it to/from the compressor train, the expander train, or both)
- Multi-stage air compressors with intercoolers to reduce the power requirements needed during the compression cycle, and with an aftercooler to reduce the storage volume requirements
- An expander train consisting of high- and low-pressure turboexpanders with combustors between stages
- Control system (to regulate and control the off-peak energy storage and peak power supply, to switch from the compressed air storage mode to the electric power generation mode, or to operate the plant as a synchronous condenser to regulate VARS on the grid)
- Auxiliary equipment (fuel storage and handling, cooling system, mechanical systems, electrical systems, heat exchangers)
- Underground or aboveground compressed air storage, including piping and fittings

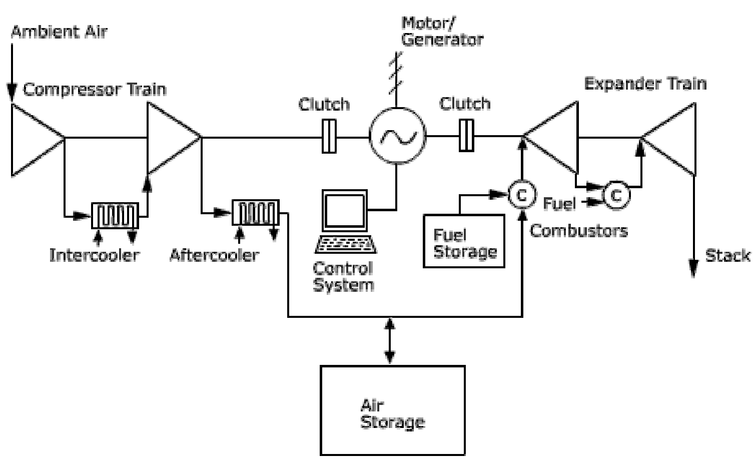

Figure 2
Conventional CAES Cycle

In the compressed air storage mode, the low cost off-peak electricity from the grid is used to operate the motor-driven compressor train to compress the air and to send it into an underground storage facility. In single-shaft CAES plant configurations, the shaft power to start the compressor may be supplied partially or completely by the expander. In the power generation mode, the compressed air is withdrawn from the storage reservoir, preheated in the recuperator, sometimes heated further via fuel burning in a combustor, and then expanded through the reheat turboexpander train to drive the generator to provide peak power to the grid.

While combustion turbines are standardized power plant equipment, CAES plants are optimized for specific site conditions such as the availability and price of off-peak energy, cost of fuel, storage type (and the local geology if underground storage is used), load management requirements, peaking power requirements and capital cost of the facility. By converting off-peak energy from the grid to compressed air and storing it for electric power generation during peak periods, utilities can defer or avoid capital-intensive generation, transmission, and distribution upgrades, yet they can still meet the peak electricity demand from their load centers.

The combustor can be designed to operate on a variety of fuels, including natural gas, oil, and hydrogen. Since the CAES plants use a fuel during the air discharge generation cycle, a CAES plant is not truly a "pure" energy storage plant such as pumped hydro, battery, and flywheel storage systems. In general, since fuel is used during a CAES plant's generation cycle, a CAES plant provides approximately 25-60% more energy to the grid during on-peak times than it uses for compression during off-peak times (the exact figure for this percentage is determined by the specific CAES plant design selected by the plant owner). In addition, as was mentioned above, the power output of an expansion turbine used in a CAES plant provides 2 to 3 time more power to the grid than the same expansion turbine would provide to the grid if it were a part of a simple-cycle combustion turbine plant. This explains the exceptionally low specific fuel consumption (heat rate) of a CAES plant as compared to a combustion turbine. For example, if the expansion turbine element from a 100-MW_e simple cycle combustion turbine were used in a CAES plant configuration, it would provide roughly 250 MW_e to the grid.

Compressed Air Energy Cycles

A variety of different thermodynamic cycles may be applied to the CAES plant design. The selection of any of the following cycles is driven by specific site conditions and operating requirements and has a significant impact on the plant costs, selection of plant components, and overall plant operating/performance characteristics:

- Conventional Cycle [3] – The conventional cycle illustrated in **Figure 2** consists of the intercooled compressor train, reheat expander train, motor/generator, control system, and the air storage along with auxiliary equipment (fuel storage and handling, heat exchangers, mechanical systems, and electrical systems). The stored air is expanded through a reheat turboexpander train where the air is heated (via combustion of fuel) sequentially in the high-pressure and low-pressure combustors before entering the corresponding high-pressure and low-pressure expansion turbines. Such a configuration is used by the German Huntorf plant and is characterized by relatively high heat rate (approximately 5,500 Btu/kWh) compared to more recent CAES plant designs, as described below. This type of plant is best suited for peaking and spinning reserve duty applications.

- Recuperated Cycle [3] – This is the conventional CAES thermal cycle with an additional component (the recuperator), as illustrated in **Figure 3**. A recuperator recovers the low-pressure turbine waste heat to preheat the stored air before it goes into the high-pressure combustor. This reduces the fuel consumption of the plant (as compared to the conventional plant above) by about 25%. This configuration was used in the Alabama McIntosh plant that was designed for primary operation as a source of peak power and as a load-management storage plant. The recuperator is a necessary component to reduce costs of the peak power.

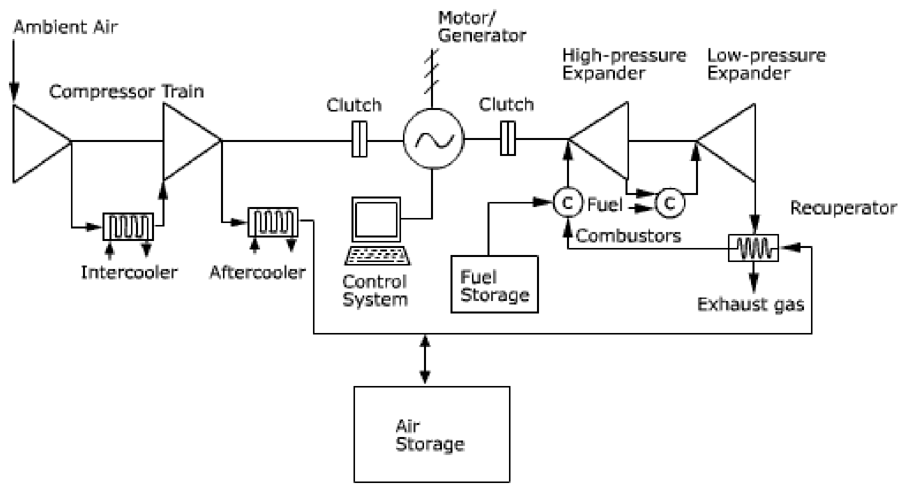

Figure 3
Recuperated Cycle

- Combined Cycle [4] –This is the conventional cycle with addition of a Heat Recovery Steam Generator (HRSG) and steam turbine (**Figure 4**). The exhaust heat from the low-pressure expander is recovered in the HRSG to produce steam, which in turn drives a steam turbine and provides additional power from the plant. Due to the thermodynamic inertia of the bottoming cycle equipment, the additional power generated by the bottoming steam cycle will reach full capacity in approximately one hour after the CAES plant start-up. Therefore, this concept is applicable for cases that need additional peak power for continuous long-term operations. Compared to the conventional cycle, this cycle reduces specific storage volume per kWh produced with a corresponding reduction in the storage reservoir costs.

- Steam-injected Cycle [3] – This is the conventional cycle adapted to use the HRSG to recover waste heat for steam production, as illustrated in **Figure 5**. The steam is added to the airflow from the storage reservoir to increase the mass flow through the expansion turbine during the generation cycle, thereby increasing the output power level from the plant. The mass of air needed to be stored per unit of power output is significantly reduced due to steam injection with corresponding reduction of the storage volume and costs. Similar to combined cycle gas turbine plants, the additional power associated with the steam injection lags the power almost instantly produced by the air expansion turbine. Like any steam-injected system, this concept uses demineralized water; the cost of the water has to be included in economic feasibility studies for this type of plant.

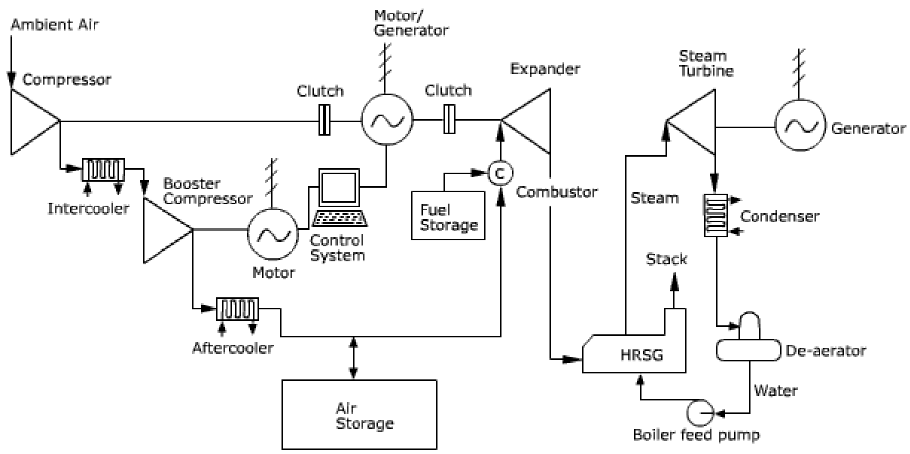

Figure 4
Combined Cycle with HRSG and Steam Turbine

- Compressed Air Storage with Humidification (CASH) [3, 4] – As shown in **Figure 6**, the stored air is humidified in an air saturator before being injected into the combustion turbine. The mass of air needed to be stored per unit of power output is significantly reduced due to humidification. Thus, the size of the air storage reservoir required is much smaller than other types of CAES cycles. The dynamics of this concept are better than those for the combined cycle and steam injection concepts. This concept also uses water, although this water does not require demineralization.
- "Adiabatic" CAES Cycle – In this CAES cycle, the thermal energy recovered during the compression cycle is stored and used later to reheat the stored air during the generation cycle to reduce or even eliminate any fuel consumption. As illustrated in **Figure 7**, this type of cycle uses sensible or latent heat storage and recovery materials (e.g., basalt stone/thermal oils and phase change salts, respectively). Many such plants have been analyzed [5, 6]. Taken to the limit, the result is the so-called "adiabatic" CAES plant where no fuel is used during the plant's generation cycle.

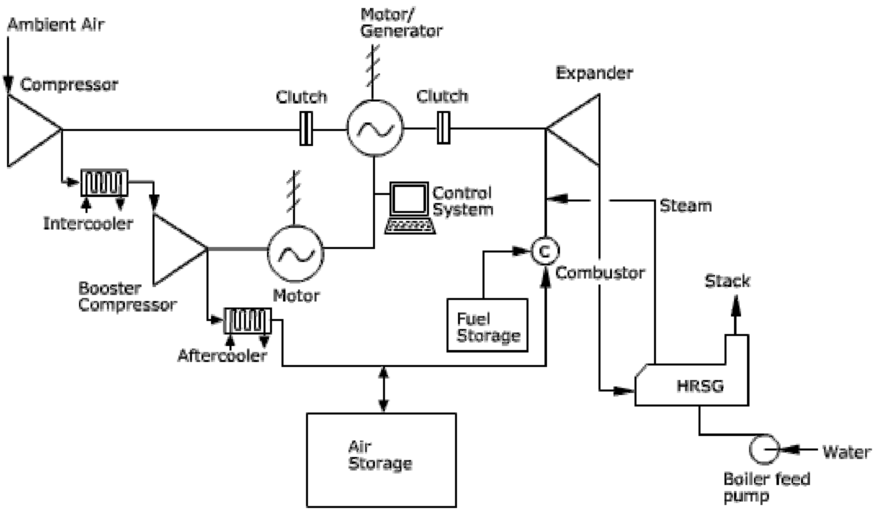

Figure 5
Steam-injected Cycle

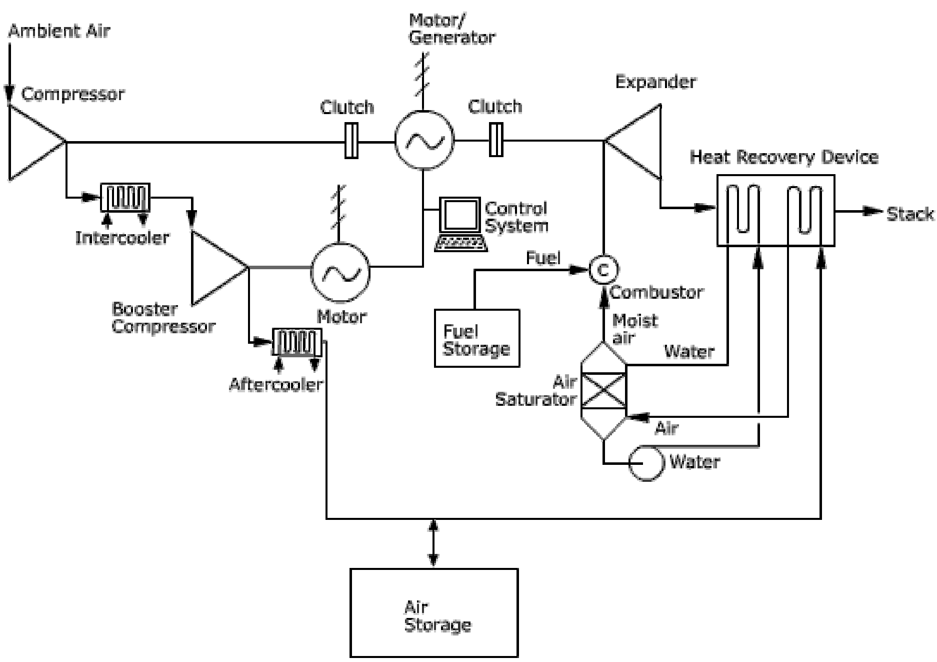

Figure 6
Compressed Air Storage with Humidification (CASH)

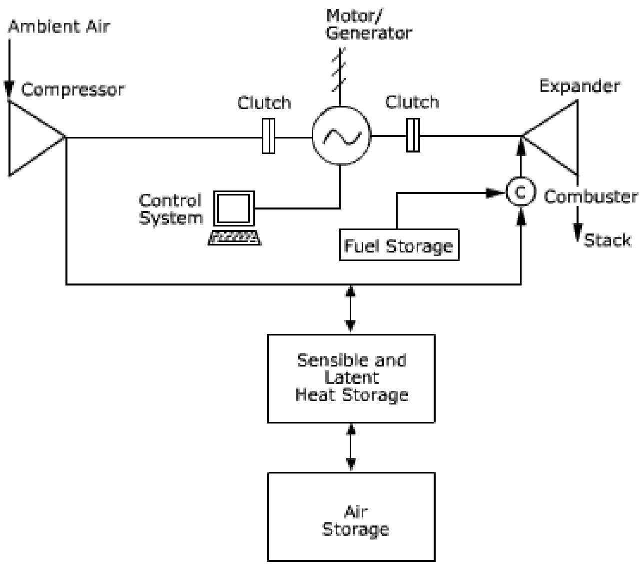

Figure 7
"Adiabatic" CAES Cycle

Compressed Air Storage Underground Facilities

The compressed air for the CAES plant may be stored underground, near the surface, or aboveground. Underground storage media may be in any of the following man-made and naturally occurring geological formations:

- Salt caverns created by solution mining (which typically costs about $1/kWh of energy stored) or dry mining (which typically costs about $10/kWh stored [7, 8]).
- Underground rock caverns created by excavating comparatively hard and impervious rock formations (either through new excavation for the CAES plant or in existing hard-rock mines) (which typically costs $30/kWh stored [9]).
- Naturally occurring porous rock formations (e.g., sandstone, fissured limestone) from aquifers or depleted gas or oilfields (which typically costs only $0.10/kWh stored [10]). It should be noted the aquifers used for CAES contain non-potable salt water.
- Abandoned limestone or coalmines (which typically cost about $10/kWh stored [11]).

In general, a geological formation suitable for underground air storage must meet the following requirements:

- The formation must have sufficient depth to allow safe operation at the required air pressure.

- For porous rock formations, the storage zone must be sufficiently porous to provide the required storage volume at the desired pressure and sufficiently permeable to permit the desired airflow rates. In addition, the over-burden and adjacent geological formations must have sufficient structural integrity to contain the air vertically and laterally; that is, the storage zone must be overlain by an impermeable rock layer to prevent the air from leaving the storage zone and escaping to the surface. All of these types of characteristics are the same as those used for over 80 years in the aquifer-based natural-gas storage industry.
- Porous rock formations need to possess a mineralogy that does not result in rapid chemical consumption of the oxygen in the stored air through oxidation reactions.

Geologic opportunities for CAES plants in the U.S. are shown in **Figure 8**, which indicates that over 80% of the U.S. territory has geological formations suitable for the underground storage.

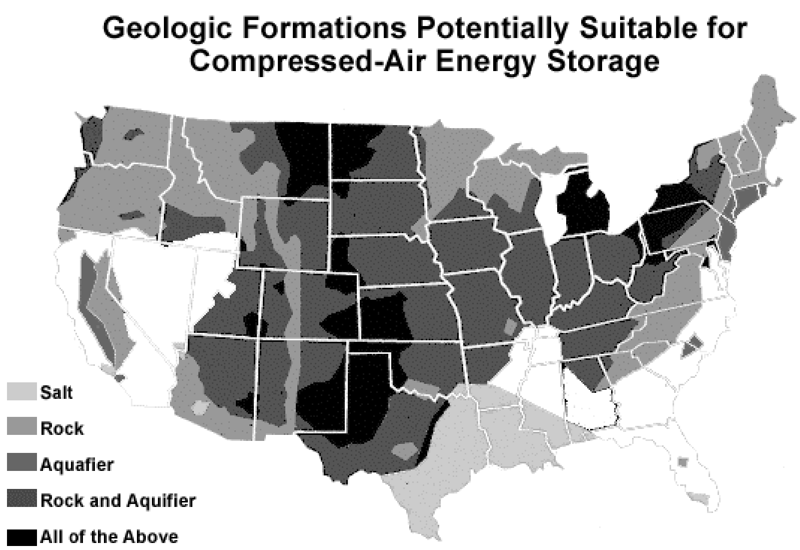

Figure 8
Geologic Opportunities For CAES Plant Sites In The U.S.

Deep underground caverns may be operated with or without hydraulic compensation. With hydraulic compensation, water at the bottom of the storage cavern is connected to a surface reservoir. Thus, the storage pressure is always at or near the hydrostatic pressure of the water column to the surface.

For caverns operated without hydraulic compensation (e.g., salt caverns), the air pressure varies between the two design pressure levels associated with the CAES plant. In addition, it is generally better to operate the surface turbomachinery at a constant pressure that is slightly lower than the lowest pressure in the cavern.

The Hybrid Plant Concept

As conceived by Dr. Michael Nakhamkin in 1998 under EPRI sponsorship, a hybrid CAES plant can be operated in a variety of modes [12]. The concept allows the plant to operate continuously as a base-load combustion turbine and, when necessary, to operate at increased power during peak hours to supply intermediate/maximum peak power as needed. This plant concept is particularly well suited for distributed power generation applications. At present, the only hybrid plant configuration developed is based on the Rolls Royce Allison Company's KM7 combustion turbine [13]. As such, the following is a brief description of the major operating modes of the hybrid concept sized using the KM7 turbine:

- Base load operation – The plant is operated as a conventional combustion turbine with 100% of the expander flow provided by the compressor. The turbine supplies a net power output of 4.8 MW_e at 11,700 Btu/kWh.
- Intermediate peak load operation -- The expander flow and power are increased because the expander receives compressed air flow from the storage reservoir in addition to the full airflow from the main compressor. It is estimated that, when 20% additional airflow comes from the storage reservoir, the net output power will be 7.9 MW_e for 3 hours at 8,300 Btu/kWh.
- Maximum peak load operation -- The compressor is disengaged, and the full flow of the compressed air from the storage reservoir goes into the expander. The power output is approximately 16 MW_e at a heat rate of approximately 4,000 Btu/kWh.
- Storage-charging mode of operation --The off-peak power feeds both the motor-driven main compressor and the separate motor-driven boost compressor. For the KM7, 12.2 MW_e of off-peak power is required to drive the compressors.
- Self-charging operation -- 78% of the main compressor's flow is sent to the expander to generate electric power to drive the booster compressor to fill the storage reservoir. This requires about 3.5 hours of charging time, with no power going to or from the grid.
- Synchronous condenser mode of operation – By opening the clutch between the compressor and the motor/generator, and between the expander and the motor/generator, the motor/generator is synchronized to the grid and is operated as a synchronous condenser, providing power factor correction. In this mode, the motor/generator works to stabilize line voltage and frequency, ease grid power transitions, and provides reactive power to assist in providing high quality electrical power to the grid.

Key Features and Limitations

The key features of compressed air energy storage offer several advantages over alternative energy storage technologies.

- The CAES plant is the only technology that can provide significant energy storage (in the thousands of MWhs) at relatively low costs (approximately \$400 to \$500/kW_e). The plant has practically unlimited flexibility for providing significant load management at the utility or regional levels.
- Commercial turboexpander units range in size from 10 MW_e (Rolls Royce-Allison) to 135 MW_e (Dresser-Rand) to 300-400 MW_e (Alstom).

- The CAES technology can be easily optimized for specific site conditions and economics.
- CAES is a proven technology and can be delivered on a competitive basis by a number of suppliers.
- CAES plants are capable of black start. Both the Huntorf and McIntosh plants have black-start capability that is occasionally required.
- CAES plants have fast startup time. If a CAES plant is operated as a hot spinning reserve, it can reach the maximum capacity within a few seconds. The emergency startup times from cold conditions at the Huntorf and McIntosh plants are about 5 minutes. Their normal startup times are about 10 to 12 minutes.
- CAES plants have a ramp rate of about 30% of maximum load per minute.
- As mentioned above, the nominal heat rate of a CAES plant at maximum load is about 2.5 times lower than the heat rate of a comparable combustion turbine plant using the same turbine expander. CAES plants also excel at part load. Their heat rate at 20% of maximum load is 80% of the nominal heat rate at maximum load. This is very good and unique, since all other oil, gas, and coal power plants have poor efficiency at 20% of maximum load, making them uneconomical for operation at part load for normal duty. This characteristic of CAES plants make them very useful (and efficient) for ramping, part load, and regulation duty.
- A CAES plant can (and do) operate as a synchronous condenser when both clutches are opened (disconnecting the motor-generator from both the compressor train and the expander train), and the motor-generator is synchronized to the grid. VARS can be injected and withdrawn from the grid by modulating the exciter voltages. Both the Huntorf and the McIntosh plant are used in this manner. Since this operation does not require the use of stored air, the plant operator can choose to operate the plant in this mode for as long as necessary.

Given all these advantages, one could ask why there are so few CAES plants. The main reason is probably the lack of awareness of this option by utility planners. In addition, for those that are aware of this option, the underground geology is likely perceived as a risk issue by utilities, even though oil and gas companies have been storing hydrocarbon-based fuels in similar underground reservoirs for over 80 years. Finally, very few utility engineers are aware of the fact that about 80% of the U.S. has suitable CAES sites.

The various storage options offer specific advantages and disadvantages. Underground storage can be designed to allow 10-20 hours of operation at full power in the range of 100-200 MW_e. Site selection is somewhat limited (see next paragraph) by the presence of mines, caverns, and certain geological formations. In contrast, aboveground storage allows only a few hours of operation at 10-20 MW_e, but the site selection is much more flexible.

The project lead times for CAES plants are typically not more than three years, including development, design, construction, and startup. For example, the contract for the 110-MW_e McIntosh plant was signed on June 1, 1988, and the plant was commissioned on June 1, 1991.

For smaller plants, the construction time is about one year. **Table 1** shows some of the common parameter ranges for CAES plants. **Table 2** shows typical ranges for air compression and electricity generation in CAES plants.

Table 1
Key Features

Feature	Parameter Range
Space requirements	100-MW_e plant needs about 1 acre
Effective Efficiency	85% (using the battery or pumped hydro analogy)
Life	30 years
Maintenance requirements	Same as simple cycle combustion turbine: about $0.30/MWh generated
Environmental impact	Minimal (NOx is below 5 ppm)
Auxiliary equipment needs	Water if wet cooling is used; no water if dry cooling fans are used
Power conditioning needs	None

Table 2
Typical Charging And Discharging Characteristics (Based On 110-Mw_e Mcintosh Plant)

Characteristic	"Charging" (Compression Mode)	"Discharging" (Generation Mode)
Electrical energy input	0.75 kWh input for every 1 kWh of output	N/A
Heat consumption with fuel	N/A	4,000 Btu/kWh of the net plant output
Storage capacity	2,100 MWh	2,600 MWh
Response time, standby to full power	4 minutes	Nominal: 10-12 minutes Emergency: 5-7 minutes
Response time (to switch from full power in compression mode to full power in generation mode)	Approx. 20 minutes (if solid-state drive is used, about 3 minutes)	N/A

2. Status

There are presently only two operational CAES plants in the world. Two additional CAES plants are currently under development in the U.S.

Current and On-going Development Efforts

CAES plants differ from other energy storage technologies in that they cannot be "mass-produced". Each project is individually developed, designed, and funded. There are two existing CAES plants in the world (Huntorf and McIntosh) and two additional plants under development (Norton and Matagordo). **Table 3** provides project information and design features for each of these three CAES plants.

Huntorf Plant

The Huntorf plant (**Figure 9**) is the first compressed air storage power station in the world; it began commercial operation December 1978. Today, E.ON Kraftwerke of Bremen, Germany owns the 290-MW_e CAES plant in Huntorf, Germany [14]. ABB (formerly BBC) was the main contractor for the plant. The compressed air is stored in two salt caverns between 2,100 and 2,600 feet below the surface with a total volume of 11 million cubic feet. The caverns have a maximum diameter of about 200 feet and a height of 500 feet. The cavern air pressure ranges from 620 to 1,010 psi. At the compressor airflow rate of 187,000 scfm (108 kg/s), the plant requires 12 hours for full recharge. At full power, the turbine draws 720,000 scfm (417 kg/s) of airflow from the caverns for up to 4 hours. After that, the cavern pressure is too low to allow generation at 290 MW_e and the airflow supplied by the caverns decreases (although the plant will produce power at an exponentially declining power level for over 10 more hours).

McIntosh Plant

The 110-MW_e McIntosh plant (**Figure 10**), owned by the Alabama Electric Cooperative, is the second CAES power plant in the world, and the first in the United States [18]. Dresser-Rand designed and constructed the entire turbomachinery train. The overall plant (turbomachinery, building, and underground cavern) was constructed in 30 months for a cost $51 million (1991 dollars) and was completed on June 1, 1991 [18]. The air is compressed in three stages, each followed by an intercooler. The compressed air is stored in a salt cavern between 1,500 and 2,500 feet below the surface with a total volume of 19 million cubic feet, yielding a power generating duration of 26 hours at full power and at 267,000 scfm (340 lb/s). The cavern air pressure ranges from 650 to 1,080 psi during normal operation. The reheat turboexpander train has high- and low-pressure expanders with high and low pressure combustors and drives the electric motor/generator to produce peak electric power. Dual-fuel combustors are capable of burning natural gas or fuel oil [19]. An advanced recuperator is used to extract thermal energy from the low-pressure expander exhaust to preheat inlet air from the storage cavern before it goes to the inlet of the high-pressure combustor. The recuperator reduces fuel consumption by approximately 25%.

Table 3
Current And On-Going CAES Development Efforts

Characteristic	Huntorf Plant [14]	McIntosh Plant	Norton Plant	Matagordo Plant [15]
Major Players	ABB, KBB (Cavern)	Dresser-Rand, PBKBB (Cavern)	Norton Energy Storage LLC	Ridge Energy Storage, Dresser-Rand
Partners and Investors	E.ON Kraftwerke (owner), NWK/Prussia Electric	Alabama Electric Cooperative	Haddington Ventures[1a] CAES Development Company LLC[1b] Haddington Energy Partners and Haddington Chase Energy Partners[1c]	-----
Amount Invested (2002 dollars)	$116 million[2]	$63 million ($570/kWe)[3]	$1.2 billion ($444/kWe [16])	$243 million ($450/kWe)
Schedule	Commissioned December 1978	Commissioned June 1, 1991[4]	Expected 2003[5] [17]	-----
Hurdles	Materials problems in the production string pipe sections	-----	-----	-----
Applications	(1) Peak shaving (2) Spinning res. (3) VAR support	(1) Arbitrage (2) Peak shaving (3) Spinning reserve	(1) Peak shaving (2) Arbitrage	(1) Arbitrage (2) Peak shaving
Rated output	290 MWe	110 MWe (minimum output of 10 MWe)	2,700 MWe	540 MWe (minimum output of 60 MWe)
Duration	4 hours	26 hours	30 hours (estimate)	-----
Availability	90% [17]	95%[6] [17]	-----	-----
Starting reliability	99%	99%[7]	-----	-----
Power Requir'mt.	0.82 kWin/kWout	0.75 kWin/kWout	-----	-----
Normal Start	8 minutes	6 minutes	-----	14 minutes

NOTES:
1. (a) Investor; (b) Developer; (c) Backers.
2. Based on an estimate of $400/kWe.
3. Based on $51M in 1991 dollars with 2%/year escalation. (Note: Today's turbomachinery cost is less than in 1991, thus actual cost today is about $360/kWe for salt geology).
4. Actual construction time was 2.5 yrs.
5. Approval process began in early 2001; first 300 MWe expected to be operational in 2003.
6. During 2000-2002; overall availability since commissioning is 90% due to earlier problems now remedied.
7. In the years 2000 to 2002

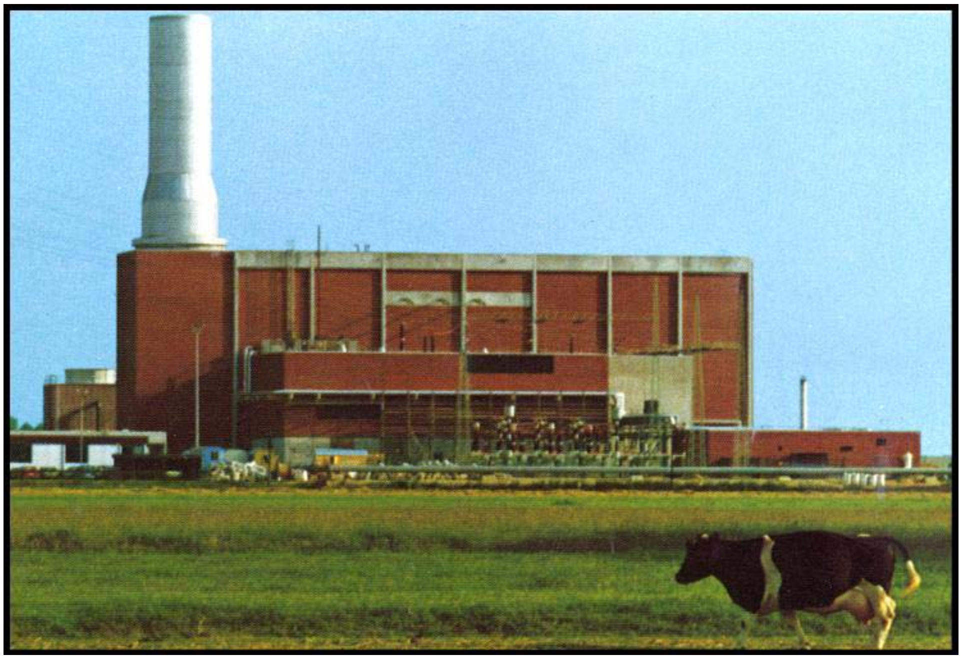

Figure 9
Huntorf Plant

Figure 10
McIntosh Plant

Norton Plant

The Norton CAES power plant (illustrated in **Figure 11**) will be the world's largest at 2,700 MW_e when it is fully completed. It is anticipated that the first 300-MW_e unit will come on line in 2003 [20]. Norton Energy Storage LLC is constructing this CAES plant in Norton, Ohio. The site and the limestone mine were purchased in October 1999, four years before the anticipated startup date. The compressed air is stored in an abandoned limestone mine at a depth of 2,200 feet below the surface with a total volume of 338 million cubic feet. The cavern air pressure will range between 800 to 1,600 psi during operation. A team from Sandia National Laboratory and The Hydrodynamics Group LLC has performed a geotechnical study that concluded that "the mine will likely hold air at the required storage pressures and will work well as an air storage vessel for the CAES power plant" [20].

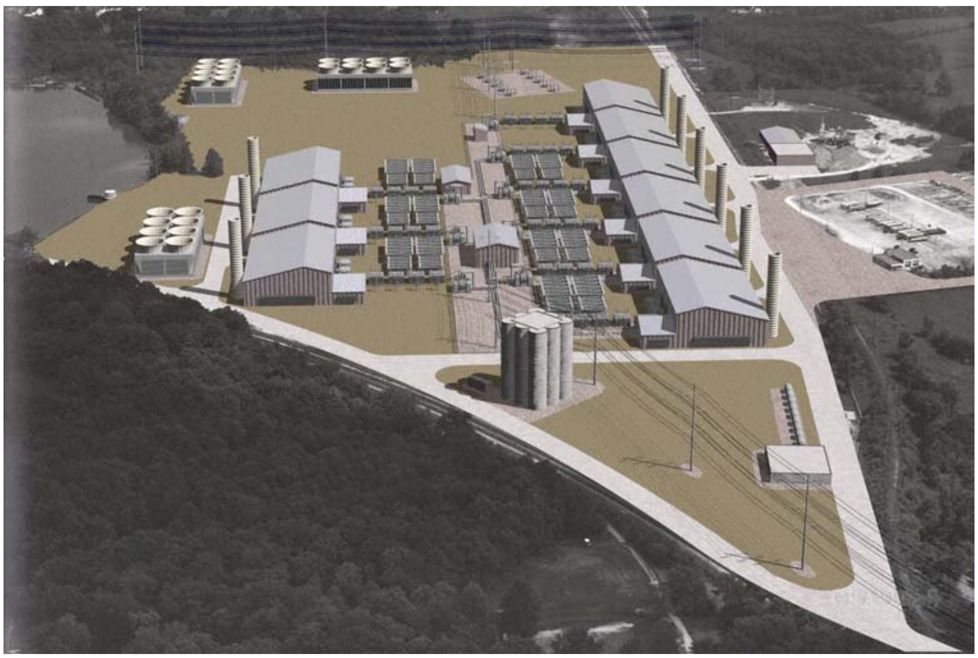

Figure 11
Norton Plant (Artist's Rendering)

Matagordo Plant

Houston-based Ridge Energy Storage recently began the development process for a 540-MW_e CAES plant in Matagordo, Texas. The plant will use an upgraded version of the Dresser-Rand design utilized at the McIntosh plant. The design calls for four independent 135-MW_e power train modules; each can reach full power in 14 minutes (or 7 minutes for an emergency start). The compressed air will be stored in a previously developed brine cavern and delivered to the expander at a pressure of 700 psi and a flow rate of 400-407 lb/sec. The heat rate of the Matagordo plant at full load is 3,800 Btu/kWh. At 20% of full load, the plant heat rate is still very favorable at 4,100 Btu/kWh. The total cost of the plant is estimated to be $243 million or $450 per kilowatt.

Other Ongoing Development Efforts

Several companies in the U.S. are committed to the development of CAES projects:

- CAES Development Company, the parent of Norton Energy Storage, is actively seeking other suitable CAES locations in the U.S.
- Strata Power owns the reservoir rights to numerous aquifers near Chicago; several CAES plants are under consideration at these sites.
- Ridge Energy Storage has an exclusive agreement with Texas Brine Company for access to several brine production sites in the U.S. that Texas Brine Company owns or has under lease. Ridge Energy hopes to utilize these brine caverns for the development of CAES plants.
- The New Energy Foundation (NEF) has led CAES development in Japan with the construction of a 2-MW_e, 4-hour CAES pilot plant in Kamisunagawa-cho, Sorachigun, Hokkaido. Compressed air is stored at 580-1,160 psi in a shaft of an old coalmine. Research is ongoing to perform a comprehensive evaluation of the performance of the pilot plant. NES is also collaborating with the Japanese utility Electric Power Development Company Ltd. (EPDC) to develop a 35-MW_e, 8-hour CAES plant.

Current developers and vendors

As mentioned above, several companies have been formed to focus on the development of CAES projects. The major components, the intercooled turbocompressor and reheat turboexpander trains, are commercially offered by a number of suppliers:

- Dresser-Rand offers a 135-MW_e turboexpander.
- Alstom (that acquired ABB) offers a 300-400 MW_e turboexpander.
- Dresser-Rand and Sulzer offer full turbocompressor trains.

These companies are driving technical aspects of the CAES technology, and all have significant experience in this field:

- Dresser-Rand supplied the complete 110 MW_e turbomachinery train for the McIntosh plant.
- ABB supplied the turboexpander for the Huntorf plant.
- Sulzer supplied the turbocompressor for the Huntorf plant.

The other components for CAES plants are obtained from vendors of conventional equipment items such as electric motors/generators, small air compressors, recuperators, etc. **Table 4** provides a list of CAES developers and equipment vendors.

Field Tests

Before a CAES project can be developed, it is important to conduct field tests to determine the feasibility of a site for a full-scale plant. For example, significant drilling work and probe analyses were conducted before the McIntosh plant was constructed to determine the salt characteristics and the configuration of the salt dome.

Table 4
Current Developers And Vendors

Company	Role
Allison	10-20-MW_e turboexpander train
Alstom/ABB	300-400-MW_e turboexpander train manufacturer
Dresser Rand	135-MW_e turboexpander train manufacturer
Mitsubishi	30-150-MW_e turboexpander train manufacturer
CAES Development Company	Project developer, U.S.
Reliant	Project developer, U.S.
New Energy Foundation	Project developer, Japan
Ridge Energy Storage	Project developer, U.S.
Strata Power	Project developer, U.S.
Westinghouse/Siemens	150-300-MW_e turbomachinery
PBKBB	Salt geology air stores
Geo-Stock	Porous media, salt geology

Several companies and/or organizations have conducted CAES field tests to determine the competency of reservoirs or to demonstrate pilot plants. **Table 5** provides details of three such examples in Japan, Italy, and the U.S.

Japan

In Japan, the Energy Storage Engineering Development Center (under the New Energy Foundation) has constructed a 2-MW_e pilot CAES plant in a tunnel in the former Sunagawa Coal Mine in Kami-sunagawa Town, Sorachi-gun, Hokkaido Prefecture. Constructional and operation research has been conducted since 1990 to evaluate plant performance for load leveling [21]. The air is stored in a 187-foot long tunnel lined with 2.3 feet of concrete and a synthetic liner tunnel, which has an inside diameter of 19.7 feet. The aboveground equipment consists of the following:

- Oil-less, 4-stage reciprocating compressor
- Single cylinder combustion chamber

- Simple open-cycle single-shaft gas turbine
- Gas turbine power generator
- Steel-finned tube regenerator to preheat the combustion air using exhaust heat recovery
- Cooling water system with air-cooled radiator
- No NO_x reduction equipment

Table 5
CAES Field Tests

Characteristic	Location		
	Japan [21]	Italy	Pittsfield
Sponsor	New Energy Foundation	ENEL	Strata Power, EPRI, Nicor
Storage	Variable pressure using synthetic lining in concrete shaft put in coal mine tunnel	Porous rock	Porous sandstone caverns
Design parameters	2 MW_e 10 hours compression 4 hours generation 1,100 psi 57,000 cubic feet	25 MW_e	Testing successfully completed to measure and cycle stored compressed air
Status	On-going project	Testing Successful (geologic formation was “disturbed” by a geothermal event and the testing was stopped somewhat prematurely)	Testing successful [22]

Italy

ENEL operated a small 25-MW_e CAES research facility plant in Italy using a porous rock storage zone that previously held a carbon dioxide “bubble”. Although the testing was successful, the testing was stopped somewhat prematurely when the geologic formation was “disturbed” by a geothermal event (which was probably induced by a nearby geothermal field extraction process).

United States

Several parties, including Strata Power, EPRI, Nicor, and U.S. DOE, have tested the porous sandstone caverns in Pittsfield, Illinois to determine the feasibility of the porous rock formations for holding and cycling compressed air. The tests that EPRI performed at the Pittsfield site (after taking over the project from DOE) indicated that compressed air could be stored and cycled successfully in the St. Peter sandstone underneath the Pittsfield site. However, if air is left in this sandstone for more than three months before it is cycled, the stored air starts to react with local pyrites in the sandstone, causing a reduction in the concentration of oxygen. It has been hypothesized that, at some point, the oxidation process would be self-limiting at the site.

Lessons learned

During construction and initial operation of the McIntosh and Huntorf plants, the project participants conducted a number of optimization studies and analyses related to various aspects of the CAES plant engineering and operations. The lessons learned – some of them of a conceptual nature and some related to engineering details – have been presented in technical publications [23] and EPRI reports.

The generic conceptual findings are summarized as follows:

- CAES plants can be built within estimated funds and schedule.
- The plants confirmed the expected high efficiency, reliability, availability, and competitive economics.
- The underground storage caverns were developed using well-established techniques and were completed on time within budgeted funds.
- Careful optimization of the CAES plant design can significantly enhance plant economics. For example, the McIntosh plant was optimized based on specified off-peak and peak hours, off-peak and on-peak power costs, fuel costs, and cost equations describing equipment and storage costs as a function of major cycle parameters.
- The recuperator requires a particular care in its design. The so-called Advanced Recuperator [11] is used to prevent the tubes from operating at temperatures below the dew point.
- Underground storage reservoirs can achieve negligible leak rates.
- The negligible amount of sodium chloride in the compressed air drawn from salt caverns does not cause corrosion problems in the aboveground turbomachinery equipment.
- The role of the house engineer involved in the CAES project is very important because there is no standard CAES plant. To minimize plant costs and to enhance the plant performance and operations, the house engineer should integrate and optimize the aboveground and underground components and systems for the specific site conditions and economic parameters of the plant owner.
- CAES plants can be constructed using commercially available equipment; mainly components developed for the combustion turbine and oil/gas industries over that last 50 years.

Unresolved issues

Several advances in the CAES technology have yet to be demonstrated or tested in the field environment. The following concepts offer significant theoretical advantages but require practical validation:

- Demonstrate air storage in porous rock and in hard rock storage formations
- Demonstrate surface piping for air storage CAES application
- Demonstrate the storage of thermal energy -- recover the thermal energy from the heat of compression to reheat the air withdrawn from storage many hours later
- Demonstrate a “hybrid” CAES plant

Summary of Innovative Development Efforts

The conventional single-shaft configuration for a CAES plant was used for the McIntosh and Huntorf projects. The compressors, motor/generator, and expanders are all on the same shaft, separated by clutches. This low initial capital cost concept requires only a single motor / generator that supports both the compression and power generation cycles. The expanders can be used to start the compressor train. The advanced recuperator used in the McIntosh plant is a necessary component to reduce the heat rate, and the plant is operating much of the time. Dresser-Rand is a promoter of the conventional configuration as well as other plant configurations.

OEMs and developers are also promoting several innovative CAES plant concepts; the innovation lies in the use of present day turbo-expanders, compressors, new thermal cycles, different turbomachinery configurations, and different component selection. The innovative development efforts are summarized in **Table 6** and described in the text below.

- Innovative Concept 1 -- This multi-shaft concept includes a reheat expander train (with a recuperator) driving the electric generator for peak power generation and a number of parallel independently operating motor-driven intercooled compressors trains for charging the underground storage. This concept has higher capital costs but provides significant operating flexibility. This concept is currently under consideration for a number of projects. Both Dresser Rand and Alstom commercially offer this configuration.
- Innovative Concept 2 – In this concept, a high-pressure recuperator is used instead of the high-pressure combustor in the expansion train. The only combustor is a conventional low-pressure combustor installed upstream of the low-pressure turbine. This concept eliminates the high-pressure combustor, which is a relatively new and technically challenging component and is a significant source of NO_x emissions. Alstom is promoting this concept for 300-400-MW_e CAES plants.

Table 6
Innovative Development Efforts

Characteristic	Innovative Concept 1	Innovative Concept 2	Innovative Concept 3	Innovative Concept 4
Feature	Multiple independent compressor trains	High-pressure recuperator	Preheat air upstream of combustion turbine	Compress air using wind power
Status	Commercially available	Commercially available	Design being marketed	Being studied
Target market	Plants requiring operating flexibility	300-400-MW_e plants requiring high reliability	Plants requiring high peak power and operating flexibility	Wind farms
Potential Funding	EPRI, DOE, IPPs, venture capitalists	EPRI, DOE, IPPs, venture capitalists	EPRI, DOE, IPPs, venture capitalists	EPRI, DOE, IPPs, venture capitalists
Vendors	Dresser-Rand, Alstom	Alstom	Alstom	Dresser-Rand, Alstom
Demonstrations	Funded in the future	Funded in the future	Funded in the future	Funded in the future
Lessons learned	TBD	TBD	TBD	TBD
Development trends	Operational flexibility	Produces lower emissions	Provides higher peak power	Integration with wind energy
Issues	High first cost	Reliability of high-pressure recuperator	System control and heat balance	Power fluctuation from wind, cost of aboveground compressed air storage

- Innovative Concept 3 -- Alstom is marketing the concept of adding an air turbine upstream of the combustion turbines [24]. A recuperator recovers the heat in the low-pressure expander exhaust and preheats the compressed air from the cavern to approximately 900 °F. The preheated compressed air is expanded through an air turbine to drive a generator in addition to the power generated by a GT24/GT11 combustion turbine. The combustion turbine and the air turbine can generate more power than the combustion turbine alone. The compressor train consists of a number of motor-driven intercooled compressors operating in parallel to charge the underground storage. This concept has the advantages of high peak power, proven components, excellent operating flexibility, reliability, and availability, and competitive costs.

- Innovative Concept 4 -- There are a number of studies investigating the integration of wind farms with small capacity CAES plants. The concept is to use the wind power (primarily during night hours) to compress the air for storage in above ground piping and/or other pressure vessels. During peak hours of electric demand, the compressed air supplies a combustion turbine to generate electric power for sale at premium prices. Since the compression is independent of the power generation, this hybrid plant can operate continuously to provide base load power in addition to the intermittent peak load.

3. Applications

CAES plants designed for specific applications can provide economic benefit to owners and/or operators of power generation facilities, and transmission and distribution (T&D) facilities. The benefits of using a CAES plant to support power generation include the following:

- Increase use of generation facilities during off-peak hours (i.e., during the storage plant charging cycle)
- Provide ramping, intermediate, and peaking power during the day.
- Store nighttime wind energy for delivery during the higher priced daytime hours (a remote wind farm would be an excellent application for CAES since air can be compressed at night when excess wind energy is most available).
- Provide frequency regulation (CAES can provide much better frequency control than a base-load power plant).

The benefits of using a CAES plant for T&D support include the following:

- Provide VAR support (e.g., by operating the CAES plant to supply reactive power in the synchronous condenser mode). A CAES plant can be operated 24 hours a day in the synchronous condenser mode, since it does not require any air from the storage reservoir.
- Provide peak shaving to enable deferment of T&D upgrades (e.g., by siting surface-based CAES plants near load centers). This application has a very large benefit-to-cost ratio.
- Provide area control to reduce energy imbalances between grid regions.
- Provide spinning reserve. This application has twice the spinning reserve capability (MW) during the charging cycle time since the grid operator gets credit for the power off-loaded during the charge cycle in addition to the plant generation capacity.
- Provide supplemental reserve. This application has twice the spinning reserve capability (MW) during the charging cycle time since the grid operator gets credit for the power off-loaded during the charge cycle in addition to the plant generation capacity.
- Provide off-peak-on-peak arbitrage

- Provide ramping power when the demand on a feeder or substation increases at a higher rate than the other generating capacity can ramp.
- Absorb excess generating capacity with its compressor during times of rapidly decreasing demand. This application is particularly useful when base nuclear, hydro, or fossil capacity is available at very low prices during off peak time periods.

In the classical configuration, a CAES plant needs to be connected to a grid that has access to off-peak charging energy from a power generating plant that is underutilized during the off-peak hours. However, at least one of the advanced CAES cycles uses the plant itself to charge the air storage media.

T&D Applications

The following describes how CAES plants could be used for six examples of T&D applications. With the ongoing deregulation of the utility industry, the price differential between on- and off-peak electricity is much greater than it used to be. For example, in California during the 2001 energy crisis, the off-peak electricity price was in the range of $10-20/MWh and the on-peak electricity price was in the range of $1,000-5,000/MWh. Finally, it is important to know that one CAES plant can be designed to meet the needs of many of these applications. That is, a plant can provide multiple benefits simultaneously (e.g., peak shaving, spinning reserve, dynamic ramping duty, and arbitrage).

VAR Support (Reactive Power Supply)

CAES can provide reactive power support and voltage control for the T&D system. The motor/generator can easily be declutched from the expander and compressor system and can be controlled using the exciter to perform synchronous duty operation. As a result, the plant can supply reactive power (plus or negative), voltage control, and voltage support.

Peak shaving

Like all storage plants that have at least 15 minutes of storage, CAES can provide real power support during peak demand times. Peak shaving allows the utility to generate when the demand is high and avoid purchasing expensive power from the spot market. The peak-shaving concept is to replace expensive energy needed during the peak operating hours (typically 8:00 A.M. to 8:00 P.M.) with inexpensive energy produced and stored off-peak by the CAES plant. In peaking applications, the CAES system is usually operated only during peak demand periods, implying relatively low generating hours (e.g., 500 hours per year) and high avoided-peak-time electricity prices. The potential benefits of CAES in peaking applications include the option to defer investments in additional T&D capacity and the avoided costs of purchasing high-priced electric power during high demand periods.

Energy Imbalance (Distributed Resource for Area Control)

CAES can provide energy to correct the energy imbalance that results when the supply to a distribution feeder or substation is insufficient to meet the demand or when the demand on a feeder or substation approaches the physical limits of the equipment. CAES generators can help correct such imbalances by supplying power needed during these times. CAES plants can be especially useful when operated in a complementary manner with distributed generation. While the distributed generation unit operates continuously at full power, the CAES plant can store energy when demand is low and supply the intermediate and peaking power.

Emergency Spinning Reserve

CAES can provide emergency spinning operating reserve. Spinning reserves are generation resources that are energized and synchronized to the grid, responsive to frequency changes, and capable of reaching a specified electric power demand within 10 minutes. A CAES plant can provide spinning reserve capacity greater than its plant size when it is in compression mode and spinning reserve equal to its plant size when it is idle. For example, at a 200-MW_e plant, the plant operator can switch from drawing 100-MW_e for compression mode to supplying 200-MW_e in generation mode in less than 15 minutes; therefore, the grid operator credits the plant with 300 MW_e of spinning reserve capacity.

Supplemental Reserve

CAES can provide supplemental operating reserve. Supplemental reserves are generation resources that do not need to be operating and synchronized, but that can be interconnected and serve demand within about 15 minutes. CAES plants can provide supplemental reserve capacity since they can be brought on-line within 10 minutes (by using the stored compressed air to spin up the turbine rapidly).

Arbitrage (Price Hedging)

Arbitrage is the purchase of electricity in one market and its sale in the same or another market in order to exploit price differentials during different times of the day. CAES plants allow this operation to occur where the owner of the CAES plant determines the time differential between purchase and sale to maximize the profit. Electric power can be purchased during the night (when electric rates and demand are low) and sold to customers or other utilities during peak hours of the day (when electric rates and demand are high). If the CAES plant owner also owns other generating facilities, the owner might choose to operate these other generating facilities at higher power output during the night to generate the power used by the CAES plant in compression mode instead of purchasing the power.

Technology Evaluation

Table 7 provides typical parameters for CAES plants designed for the six T&D applications described in Section 3. These six plant designs will be used in later sections to illustrate the typical costs and benefits of applying CAES technology to T&D applications.

Table 7
Example CAES Plant Performance Characteristics For Various Applications [25], [13]

T&D Application of Plant	Size (MW_e)	Cycle Duration	Plant Capacity (MWh)	Response Time	Duty Cycle	Effective Efficiency[1]	Yearly Operation (hours/yr)[2]
VAR Support	200 MVAR	Zero to Continuous Operation	Can Be Any Value	1/60 sec	Continuous reactive power exchange	99%	8,640
Peak Shaving	20	3 hr	60	1 min	Continuous 250 events/ year	85%	750
Energy Imbalance	200	15 min	50	1 sec	charge/ discharge	85%	2,000
Spinning Reserve	200	15 min	50	1 min	Continuous charge/ discharge	85%	2,000
Supple-mental Reserve	200	30 min	100	10 min	Continuous charge/ discharge	85%	2,000
Arbitrage	200	10 hr	2,000	15 min	250 events/ year	85%	2,500

NOTES:
1. Effective efficiency is based on the analogy to a battery or pumped hydro plant
2. Assuming a maximum of 360 days of operation and 5 days of downtime for maintenance per year.

For the CAES plants designed for the six T&D applications described in Section 3 (and **Table 7**), **Table 8** provides a summary of the technology evaluation. The environmental impacts of CAES plants tend to be low, both aboveground and underground. The advantages generally outweigh the limitations. The cost and financial benefits are considered in the next section.

4. Costs and Benefits

The benefits of transmission and distribution (T&D) applications of CAES plants depend on a number of factors, with one of the most critical being cost.

Capital Cost

The capital cost of a CAES plant is a function of the storage medium, the plant capacity (power), and the energy stored in the storage medium. **Table 9** below gives approximate values for the capital cost components of CAES plants as a function of some of the plant variables. For example, the typical plant cost for a 200-MW_e CAES system for salt geology is about \$360/kW_e with a 10-hour discharge storage reservoir.

Table 8
Summary Of Technology Evaluation

T&D Application of Plant	Environmental Impact	Advantages	Limitations (Other Than Plant Size)
VAR Support	Negligible	Supply reactive power continuously	None
Peak Shaving	Low emissions, noise	Charge during off-peak, Provide real power for extended time, Defer T&D investments	Hours of operation limited by plant capacity (MWh)
Energy Imbalance	Low emissions, noise	Supply real power as needed, Support DG and renewables	Response time
Spinning Reserve	Low emissions, noise	Available during charging and discharging times	Negligible
Supplemental Reserve	Low emissions, noise	Use compressed air for more rapid turbine start	Negligible
Arbitrage	Low emissions, noise	Plant operator is free to select best time interval between power purchase and sale	Hours of operation limited by plant capacity (MWh)

Table 9
CAES Plant Costs For Various Storage Media And Plant Configurations

Storage Media for CAES Plant	Size (MW_e)	Cost for Power-Related Plant Components [25] ($/kW)	Cost for the Energy Storage Components [7, 9, 10] ($/kWh)	"Typical" Hours of Storage for a Plant	Total Cost ($/kW$_e$)
Salt	200	350	1	10	360
Porous Media	200	350	0.10	10	351
Hard Rock (new cavern)	200	350	30	10	650
Surface Piping	20	350	30	3	440

Operating Cost

As a rule of thumb for a "generic" CAES plant, the operating cost per kWh delivered during power generation mode is 0.75 times that of the incremental cost per kWh of off-peak power purchased during the compression mode, plus the cost of the fuel (in $/MMBTU) times 4,000 Btu/kWh generated [2].

Cost of electricity generated ($/kWh) = (0.75) (Incremental cost of electricity purchased, $/kWh) + (Cost of fuel purchased, $/MMBtu) (4,000 Btu/kWh) / (1,000,000 Btu/MMBtu)

The factor "0.75" includes the ratio of generated electricity to purchased electricity and the energy lost to pipe friction, air leakage, pressure regulation, and compressor/expander component efficiencies. The heat rate of 4,000 Btu/kWh is typical for an expander-generator set operating without the compressor during the generation mode.

Cost information

Table 10 shows the typical size, capacity, response time, and capital cost per kW_e for hypothetical CAES plants designed for the six T&D applications described in Section 3 (and **Tables 7 and 8**). The fixed O&M costs for CAES plants are projected to be in the range of $4/$kW_e$ to $7/$kW_e$, and the variable O&M costs in the range of $0.001/kWh to $0.002/kWh. In these examples, the fixed and variable O&M costs, the electricity in Vs. out, and the heat rate were chosen to be the same for every plant:

- Fixed O&M costs — $6.00/$kW_e$ per year [17]
- Variable O&M costs — $0.002/kWh [17]
- Electric Input/Output — 0.75 [2]
- Heat Rate (HHV Btu/kWh) — 4,000 [2]

Benefits information

In this sample benefits analysis, the hypothetical CAES plants designed for the six T&D applications described in Section 3 (and **Tables 7, 8, and 10**) are analyzed in five situations. It is assumed that a utility is comparing the cost the CAES situations with the alternatives. In each situation, the economic benefit of the CAES plant is compared to the situations listed in **Table 11**.

For each plant, **Table 12** shows the assumptions and **Table 13** shows the quantifiable benefits of the CAES plants delineated for each application. The quantifiable benefits are presented as net present values for the five situations. The benefits will, of course, depend upon local and site specific conditions associated with each plant type applied to each case. In addition, there are unquantifiable benefits of each application of CAES (e.g., customer satisfaction on power quality, reduced wear and tear from operating equipment near or over limits). Note that for all five situations, many of the hypothetical CAES plants will not meet the power and duration requirements (and are marked N/A in **Table 13**).

Table 10
Cost Summary

T&D Application of Plant	Size (MW_e)	Cycle Duration	Plant Capacity (MWh)	Response Time	Power-Related Capital Cost ($\$/kW_e$) [25]	Energy-Related Capital Cost ($/kWh)	Total Capital Cost ($\$/kW_e$)
Reactive Power Supply (VAR Support)	200 (100 MVAR)	8 hr	1,600	0.25 sec	350	30 (hard rock cavern) [9]	590
Peak Shaving	20	3 hr	60	1 min	350	1 (salt cavern) [7]	353
Energy Imbalance (Area Control)	200	15 min	50	10 sec	350	1 (salt cavern) [7]	350
Spinning Reserve	200	15 min	50	1 min	350	30 (above ground)	358
Supplemental Reserve	200	30 min	100	10 min	350	1 (salt cavern) [7]	351
Price Hedging (Arbitrage)	200	10 hr	2,000	30 min	350	0.10 (natural porous rock) [10]	351

Table 11
Situations Analyzed in Benefits Calculation

Situation	Alternative
T&D deferral	Adding T&D capacity
Peak shaving	Installing a simple-cycle combustion turbine plant
Load shedding	Inaction
Arbitrage	Inaction
Spinning reserve credit	Inaction

Table 12
Assumptions Used For Benefits Calculation

Parameter	Situation				
	T&D Deferral	Combustion Turbine Plant for Peak Shaving	Load Shedding	Arbitrage	Spinning Reserve Credit
Additional capacity required (MW_e)	200	20	20	200	200
Cycle duration required (hr)	3	3	3	10	0.25
Annual operating hours	1,500	750	750	2,500	2,000
Power-Related Installed Equipment Cost ($\$/kW_e$)	2,000	800	0	0	0
Electric Input/Output	1.02	0	N/A	N/A	N/A
Heat rate (HHV Btu/kWh)	N/A	10,000	N/A	N/A	N/A
Plant life (yr)	10	20	20	20	20
Annual variable maintenance cost ($/kWh)	0	0.01	0	0	0
Annual fixed maintenance cost ($\$/kW_e$)	0.1	0	0	0	0
Demand charge ($/kW per month) [2]	N/A	10.30	10.30	10.30	N/A
Spinning Reserve Credit ($/kW per year)	N/A	N/A	N/A	N/A	40

Table 13
Benefits Summary (NPV Of Using The CAES Plant Developed For Each Application In Table 10 For The Five Situations Shown Across The Top)

Original T&D Application of Plant	Situation				
	Deferral of T&D Construction	Peak Shaving	Avoided Load Shedding	Arbitrage	Spinning Reserve Credit
Reactive Power Supply (VAR Support)	$72M	n/a	n/a	n/a	n/a
Peak Shaving	n/a	$7M	$38M	n/a	n/a
Energy Imbalance (Area Control)	n/a	n/a	n/a	n/a	$42M
Spinning Reserve	n/a	n/a	n/a	n/a	$41M
Supplemental Reserve	n/a	n/a	n/a	n/a	$42M
Price Hedging (Arbitrage)	$120M	n/a	n/a	$580M	$42M

The following five cases are considered:

- T&D Deferral – The baseline is for the utility to construct new T&D facilities during the first year. The CAES alternatives are for the utility to use the CAES plants delineated in **Table 10** to defer the construction of T&D for ten years. The cost of constructing the new T&D facilities in ten years is included as part of the CAES situation, but the economic value of the CAES plant beyond ten years is neglected. A benefit to the utility is achieved if the CAES plant has a lower net present value than the T&D construction.
- Peak Shaving – The baseline is for the utility to construct a new simple-cycle combustion turbine power plant during the first year to meet the demand. The CAES alternatives are to provide the power required with the CAES plants defined in **Table 10**. A benefit is achieved if the CAES plant has a lower net present value than the combustion turbine power plant construction.
- Load Shedding – The baseline is for the utility to do nothing to avoid lost sales due to load shedding. The CAES alternatives are to provide the power required to avoid load shedding

with the CAES plants defined in **Table 10**. A benefit is achieved if the CAES plant concept has a positive net present value.

- Arbitrage -- The baseline is for the utility to do nothing. The CAES alternatives are to purchase power a low cost and sell power at a higher cost using the CAES plants defined in **Table 10**. A benefit is achieved if the CAES plant concept has a positive net present value.
- Spinning reserve -- The baseline is for the utility to do nothing to meet the requirement for spinning reserve. The CAES alternatives are to provide the required hot spinning reserve with the CAES plants defined in **Table 10**. A benefit is achieved if the CAES plant concept has a positive net present value.

The following parameters were the same for every case:

- Average off-peak wholesale electricity price paid by utility [2] $0.01/kWh
- Average wholesale electricity price paid by utility [2] $0.04/kWh
- Average peak electricity selling price received by utility [2] $0.047/kWh
- Fuel cost [2] $3.00/MMBtu
- Discount rate [2] 5%
- Inflation rate [2] 2%
- Cost escalation rate 2%

The major benefits of CAES are the arbitrage and deferral of T&D investments. Demand charges and spinning reserve credits dominate the economic benefit when they can be applied, and demand charges are particularly lucrative for arbitrage. Although CAES may not avoid the need for T&D construction in the long term, it can buy time until other problems can be solved or until a more accurate assessment of potential solutions are completed. For example, a CAES facility may suffice while the route for the new transmission line goes through the environmental permitting and public approval process. In addition, a CAES facility can be added to a system in relatively small capacity increments, allowing the system capacity to follow the demand closely. In contrast, new T&D capacity is usually added in large capacity increments, resulting in several years of underutilized capacity while the load grows to meet the new capacity.

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Glossary

Glossary list.

See key words below

Porous Media

Key words

List of index key words.

CAES

Energy Storage

Spinning Reserve

Dynamic Benefits

Peak Shaving

VAR Control

T&D Deferral

EPRI Energy Storage Handbook:

Electrochemical Capacitors

December 2002

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Introduction

Discovered by Henrich Helmholtz in the 1800s, electrochemical capacitors were first practically used in 1979 for memory backup in computers and are now manufacturer by many companies. Electrochemical capacitors are distinguished from other types as "double-layer capacitors[1]." Manufactured products have also been given names including "super," "ultra," "gold," "pseudo," as well as "electric double-layer" capacitors.

Double layer electrochemical capacitors differ from other types by having capacitance and energy density values several orders of magnitude larger than even the largest electrolytic-based capacitor. They are true capacitors in that energy is stored via electrostatic charges on opposing surfaces, and they can withstand a large number of charge/discharge cycles without degradation. They are also similar to batteries in many respects, including the use of liquid electrolytes, and the practice of configuring various size cells into modules to meet power, energy, and voltage requirements of a wide range of applications.

The first products were rated at two to five volts and had capacitance values measured in fractions of a Farad to several Farads. Although early applications were primarily computer memory backup, the technology has evolved to larger scale applications. Today's devices range in size up to hundreds of thousands of Farads at low voltage and, in some applications, systems voltages (multiple series-connected capacitors) are above 600 V. The technology has grown into an industry with an annual sales estimated to be $100 million. It is poised for rapid growth in the near future with higher energy and higher voltage devices suitable for power quality and advanced transportation applications. With the advent of distributed power generation, capacitors are being considered for fuel cell and micro-turbine load inrush support, and for leveling fluctuating energy flow from natural sources like wind turbines or solar.

Capacitor Fundamentals

A capacitor is a device used for storing electrical charge. There are three distinct types of capacitors: electrostatic, electrolytic, and electrochemical, see appendix for a description of each type. The simplest capacitor is a parallel-plate electrostatic. It has two conductors of area *A* separated by a distance *t*. The region between the plates is usually filled with air, paper or other dielectric material, which increases the stored energy in the device. The charge, *Q*, that is stored in the device, is proportional to the voltage applied to the conductors. This proportionality constant is the capacitance. The capacitance C is equal to the dielectric constant times the area divided by the separation.

[1] There is some uncertainty within the industry on the exact name for capacitors with massive storage capability. This is in part due to the many names of products by different manufacturers, but also due to the relative newness of the industry and recent advances. An electrochemical capacitor commonly stores energy through non-faradic processes (electrostatic). However, faradic processes (electron transfer due to chemical or oxidation state changes) can and do occur. Because both processes can occur, the generic term electrochemical is more appropriate than double-layer electrochemical capacitor, which also excludes the mixed-metal-oxide capacitor technology. In general, this report uses the generic term electrochemical capacitor as suggested by A. Burke and endorse by B. Conway and J. Miller.

The energy E, that is stored in an ideal capacitor at voltage V, is equal to:

$$E = 0.5\ CV^2$$

The energy increases as the square of the applied voltage. When charged at a constant current, the voltage of an ideal capacitor rises linearly with time. When charged at a constant power, the stored energy rises linearly with time. In reality, the first order model of a capacitor is a series combination of an inductor, a resistor, and a capacitor (see Appendix for additional modeling details). The fundamental equations for all types of capacitors are summarized in Table 1. Note that R_s, the series resistance, is also referred to as the equivalent series resistance, ESR.

Table 1 Fundamental equations for all capacitors including electrochemical capacitors.

Stored Charge, Q	Q = CV	C = capacitance
Stored energy, E, ideal case	$E = ½\ CV^2$	V = applied voltage
Capacitance of parallel plate capacitor, C	C = εA/t	ε = dielectric constant A = area of the capacitor plate T = separation of the plates
Self-resonant frequency, f_o, for RLC circuit	$f_o = \dfrac{1}{2\Pi\sqrt{LC}}$	L = inductance
Maximum power, P_{max}	$P_{max} = V^2/4R_s$	R_s = series resistance (ESR)
Resistive charge or discharge efficiency, η	$\eta = \dfrac{100R_L}{R_L + R_S}$	R_L = load resistance
Constant current charge or discharge efficiency, η	$\eta = \dfrac{100(V_r - I_o R_S)}{(V_r + I_o R_S)}$	Vr = rated voltage I_o = fixed current

For most practical applications in the utility industry, the inductance in the series-RLC circuit can be ignored because operation is well below the self-resonant frequency. Thus, a simple series-RC circuit is a good first-order model for the real capacitor.

It is important to understand the effect of the capacitor internal resistance (R_s) on the efficiency of discharge. For example, modeling the capacitor as series-RC circuit being discharged into a resistive load R_L the efficiency of discharge in percent is equal to $100R_L/(R_S + R_L)$. Thus the efficiency is nearly 100% when the load resistance, R_L, is much greater than the internal resistance, R_S. On the other hand, the efficiency is exactly 50% for the matched load, that is when $R_L = R_S$. That is, for a matched load half the delivered energy is dissipated in the capacitor itself and not in the load. Similar efficiency relationships can be calculated for constant current charge or discharge, as listed in Table 1.

Electrochemical Capacitor Characteristics

What Is a Double-Layer Capacitor?

Electrochemical capacitors consist of two electrodes, a separator, electrolyte, two current collectors, and packaging. Within the electrochemical capacitor, charge is stored electrostatically, not chemically as in a battery. It has, as a dielectric, an electrolyte solvent, typically potassium hydroxide or sulfuric acid, and is actually two capacitors connected in series via the electrolyte. It is called a ***double-layer capacitor*** because of the dual layers within the structure, one at each electrode as shown in Figure 1.

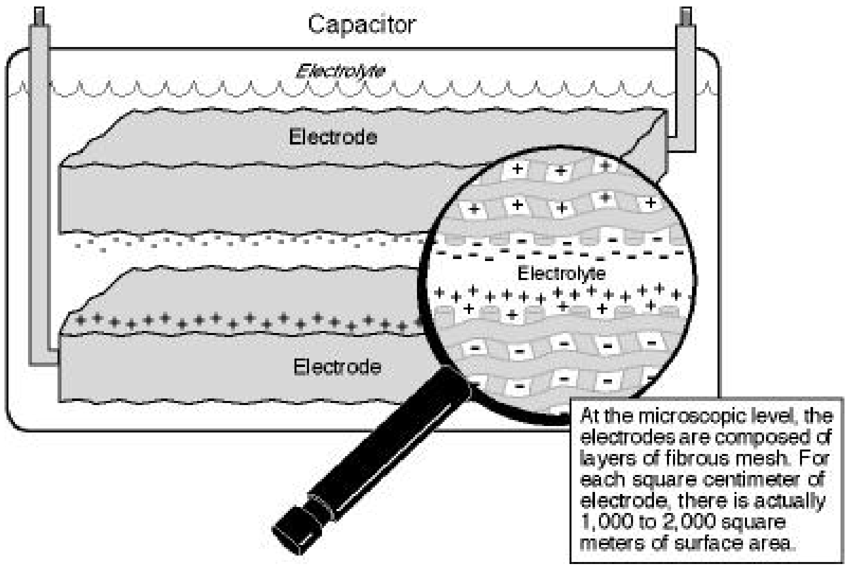


Figure 1. Construction of a flooded electrochemical capacitor with a double-layer

As in any capacitor, the amount of capacitance is directly related to the surface area of the electrode. Carbon is the element almost uniquely suited for fabrication of electrodes within electrochemical capacitors. When fabricated into felt or woven into a fabric, it makes an excellent electrode structure having both mechanical integrity and electrical conductivity. The surface area of a carbon electrode is very large at 1000 to 2000 m^2/cm^3. This large surface area is the reason for very high characteristic capacity and energy density.

Evolution of Double-Layer Technology

Electrochemical capacitor technology has evolved through four distinct design types, each with its own development time line. Symmetric designs, where both positive and negative electrodes are made of the same material with approximately the same mass, and are available with aqueous or organic electrolytes. Asymmetric designs have different material for the two electrodes, with one of the electrodes having much higher capacity than the other. The asymmetric are currently available with aqueous electrolytes and the asymmetric organic electrolytes are in development. There are significant differences in the characteristics and performance of these four types leading to a wide range of products with many different possible applications.

The first devices, type I, use a symmetric design with activated carbon for the positive and negative electrodes, each with approximately the same mass and similar capacitance values. The choice of electrolyte is an aqueous solution, usually high-concentration sulfuric acid or potassium hydroxide. Because of the aqueous electrolyte, operating voltages are limited to ~1.2 V per cell, with nominal ratings of 0.9 Vdc.

Second to come along was a type II electrochemical capacitor that is similar to the first, but with an organic rather than an aqueous electrolyte. The organic electrolyte typically is an ammonium salt dissolved in an organic solvent such as propylene carbonate or acetonitrile, which allows operation at higher unit cell voltages. Type II products are the most common type in use today and are rated at voltages in the range of 2.3 to 2.7 V/cell, depending on manufacturer.

Operation at higher voltages offers distinct advantages for energy and power density, but with some offsetting disadvantages. The dielectric constant of the organic solvent is less than that of water; the double layer thickness (plate separation) is greater because of the larger solvent molecules; the effective surface area of the electrode is somewhat diminished because the larger ion sizes cannot penetrate all pores in the electrodes; and the ionic conductivity of the electrolyte is much less than that of aqueous electrolytes, particularly at low temperatures. Stable, long term operation at higher voltages requires extremely pure materials: trace quantities of water in the electrolyte, for instance, can create problems. Thus, the device must be packaged in such a way that water does not enter the capacitor.

The net effect of using an organic electrolyte in the type II device is increased energy density over type I. However, there often is a reduction in power performance over that exhibited by the type I devices, even though each cell operates at higher voltage.

The type III design, referred to as asymmetric, is the most recent available. They are comprised of two capacitors in series, one being an electrostatic capacitor and the other a faradaic pseudocapacitor. The electrostatic capacitor is exactly like those used in the symmetric type I and II devices. It consists of a high-surface-area electrode with double layer charge storage. The faradaic-pseudocapacitor electrode relies on an electron charge transfer reaction at the electrode-electrolyte interface to store energy. This is very similar to an electrode in a rechargeable battery.

In this design the capacity of the faradaic-pseudocapacitor electrode is typically many times greater than the capacitance of the double layer charge storage electrode. Thus the depth of discharge of the faradaic-pseudocapacitor electrode is very small during operation, allowing higher cycle life. Different asymmetric capacity ratios have been built to tailor the capacitor for specific applications. Asymmetric electrochemical capacitors have an important advantage of voltage self-balancing, which will be discussed in the section on series connecting cells to create high-voltage systems. None of the other types of capacitors offer this feature.

Comparison of the three product types is provided in Table 2.

Table 2 Comparison of functionality of electrochemical capacitor designs

Electrochemical Capacitor Types	**Type I Symmetric /aqueous**	**Type II Symmetric /organic**	**Type III Asymmetric /aqueous**
Energy Density	Low to Moderate	Moderate to High	High to Very High
Power performance	High	High	Low to High
Cycle life	High	High	High
Self-discharge rate	Low	Low	very Low
Low-Temp. performance	Excellent	Good to excellent	Excellent
Packaging	non-hermetic	hermetic	Non-hermetic, resealable vent valve
Voltage balance	resistor/active	resistor/active	self limiting/active
Cell voltage	< 1 V	2.3 - 2.7 V	1.4 - 1.6 V

A type IV electrochemical capacitor is currently not available in a commercial product, however there are active research programs directed toward development of such devices. These devices use an asymmetric design with an organic electrolyte. This combination provides the opportunity for the faradaic-pseudocapacitive charge storage with the higher operating voltage afforded by the organic electrolyte. For example, the design could mate an electrostatic electrode with a faradaic pseudocapacitive electrode that operates by intercalation, similar to one electrode in a lithium ion battery. Or, there could be charge storage in an electrochromic polymer such as a polythiophene. There are many faradaic electrode materials that can be used with the double layer electrode, again using a large capacity ratio as previously described to obtain high cycle life.

Double-Layer Technology Comparisons

Table 2 compares some general properties of each type capacitor. Type IV products are not described because of their present early state of development. As listed, type I products have low to moderate energy density, type II products have moderate to high energy density, and type III products have high to very high energy density. Power performance can be very high for type I products because of the use of high-conductivity aqueous electrolytes. Type II products can be high in power, and type III products, depending on optimization, can be low to high.

Cycle life can be high for all types of capacitors. Self-discharge rates for type I and II designs are generally low because they use balancing resistors. These resistors are included to help maintain voltage uniformity in series-strings of cells. The self-discharge rate of the type III capacitor is very low, usually less than a commercial lead-acid battery.

Temperature performance is excellent for type I and type III designs because of the low freezing points of the sulfuric acid or potassium hydroxide solutions used for the electrolyte. The low temperature performance of type II capacitors depends intimately on the exact solvent used in the electrolyte and cell design details. Performance can be good to excellent.

Packaging of the different type products varies considerably. Two of the commercial type I capacitor products use bipolar construction, which involves sealing a stack of cells using a potting material around the stack perimeter. The stack is then placed within an epoxy or metal package. Type II products invariably are well sealed, often using a hermetic design that involves welded metal packaging with glass-to-metal seals. Because this package is completely sealed, it usually contains a rupture valve that is designed to burst at a specified overpressure condition. This is used to prevent the cell from exploding due to internal gas generation during abuse situations. The use of a rupture valve in the hermetic packages should be mandatory for safe operation of these devices.

The type III product is a single cell design with a plastic package similar to that of an aircraft nickel cadmium battery. The cell is not hermetically sealed, but has a resealable safety valve to permit gas release during severe over-voltage conditions.

Voltage balance for a series string of capacitor cells can involve active or passive systems. A passive system is generally a parallel string of resistors attached to the capacitor string at each cell. The active systems include cell voltage monitoring and in some cases forces individual cells to charge or discharge and bring voltage uniformity to the string. Type III electrochemical capacitors have natural voltage balancing when connected in a series string. This is due to several reasons, one being that the device can operate on an oxygen cycle just like sealed lead-acid or NiCd batteries. A second reason is that the leakage current of this design has a well defined, fixed electrolyte decomposition potential. So, it is very difficult to over-voltage a type III cell.

Cell operating voltage for a type I device is generally < 1 V. For type II devices, it presently is 2.3 to 2.7 V and is expected to increase to perhaps 3.0 V after further developments. Type III devices presently are comprised of a nickel oxyhydroxide positive electrode mated with an activated carbon negative electrode. This system operates at between 1.4 V and 1.6 V per cell, depending on the optimization of the device. Type IV designs have voltages reported to exceed 4 V for some material systems.

Asymmetric capacitor designs have led to higher energy densities and symmetric designs usually have higher peak power. Today's types I and II electrochemical capacitors are in the 1 to 7 Wh/kg range. Commercial capacitors of the type III design are available with energy densities of 10 Wh/kg. Energy densities as high as 19 Wh/kg are reported in patent examples covering this technology. In comparison, lead-acid batteries have an energy density in the range of 25 to 45 Wh/kg depending on design.

Electrochemical Capacitor Construction

The carbon electrodes used in both symmetric and asymmetric electrochemical capacitors consist of a high-surface-area activated carbon having area on the order of 1000 m^2/g or more in particulate or cloth form. The carbon electrode is in contact with a current collector. A material that prevents physical contact (shorts), but allows ion conduction, separate the electrodes. One design for type II products utilizes particulate carbon in a spiral-wound configuration. Such construction can be performed on a high-speed winding machine, which introduces minimal labor content. While this construction lends itself to a right-cylinder product, it can also form rectangular packaging. This form factor is more desirable in some applications. Type III electrochemical capacitor cells are constructed in a similar fashion to the type II product. The first commercial products used a nickel-oxyhydroxide positive electrode with an activated carbon cloth negative electrode.

The electrolyte of an electrochemical capacitor is an important constituent. Properties most desired include high conductivity and high voltage stability. Little can be done to change the conductivity and voltage characteristics of aqueous-based electrolytes used in type I or type III products, but major improvements should be possible for type II products. Higher-conductivity electrolyte yields increased power performance, and high voltage stability allows stable operation at high voltage. These properties are important for energy and power since each measure scales as the square of the voltage. Organic electrolytes allow operation above two volts, the exact upper limit depending on the solvent and salt, their levels of purity, the desired operating temperature, and component design life.

The electrolyte in a type II capacitor is one of its more expensive constituents. It must have low concentrations of water at the time of manufacture and over the life of the product. This adds manufacturing costs in addition to material costs. Type II electrolytes are generally comprised of an ammonium salt with a solvent such as propylene carbonate, dimethyl-carbonate, or acetonitrile. At the present time, acetonitrile is the most popular solvent in large capacitors. It offers higher power operation, but at the expense of using a toxic and flammable material.

One feature common to all electrochemical capacitors is the requirement that some pressure be applied to the cell so that its electrodes remain in contact with the separator, that the electrodes are in contact with the current collectors, and that everything is wetted with electrolyte. The amount of pressure required depends on the design and electrode form. Winding pressure is typically used for type II products. External pressure plates are usually used for type I and III products.

Performance Features and Limitations

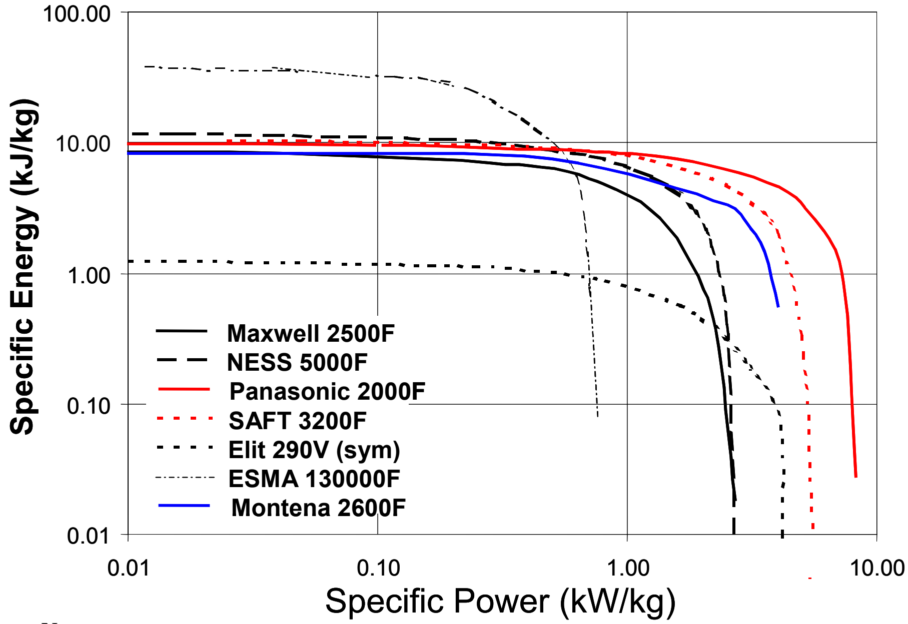
Power-Energy Relationships (Ragone Plots)

A convenient way to compare various energy storage technologies is to use so called Ragone plots. These plots show energy available (work performed) as a function of power level. Relative units for energy and power are used such as specific energy in Wh/kg or power density in kW/ liter. At low power levels essentially all of the energy is available to perform work. Less energy is available as the power level increases, until a maximum power value is reached.

This behavior is typical for all sources of energy and is therefore useful for comparison purposes. For example, a horse that is walking (at low power output) can likely perform more work until fatigue than one that is running (at high power output). This behavior is true for capacitors. More energy is released at slow discharge rates than at faster rates. Losses increase and efficiency drops off significantly at high rates thus reducing the amount of energy that can be delivered in any particular application. The Ragone plots are particularly useful for matching application requirement with various energy storage technologies. When using Ragone plots it is important to keep in mind that attributes other than power and energy such as cycle life, self-discharge rate, operational life and safety are not considered. These other factors may also be key to selection of the best technology for a particular application.

Ragone Plots for Available Capacitors

There are many ways to compare capacitor products. One way is to examine their power-energy behavior. Figure 2 shows Ragone plots of several large electrochemical capacitors available as commercial products or as fully packaged prototype products. Most of the devices were tested as single cells. However, the ELIT was tested as a multi-cell module rated at 290Vdc. The operating voltage window was from rated voltage *Vr* to one-half rated voltage, which represents 75% of the stored energy in an ideal capacitor.



Notes:
1. Calculated using equivalent circuit models and voltage window of V_r to 0.5 V_r
2. Module and cell voltages vary, Elit 290 V, ESMA 1.6V, others are rated at 2.3 - 2.7 V
3. Montena has since been acquired by Maxwell

Figure 2 Energy and power relationships for several large electrochemical capacitors (i.e., Ragone plots)

As shown in Figure 2, at low power levels different capacitors types tend to group, depending on their design. For instance, energy performance at low power of the type II capacitors are all approximately 10 kJ/kg (3 – 4 Wh/kg). The type I (Elit) capacitor is at a lower energy value of ~1 kJ/kg (~0.3 Wh/kg). The type III (ESMA) capacitor is at a higher level ~35 kJ/kg (~10 Wh/kg). This type III is a "traction" type capacitor, which has been optimized for, high-energy density applications. Note that the type I capacitor is rated at 290V and is comprised of hundreds of cells connected in series. This product uses bipolar construction as opposed to individual cell construction. The voltages of individual cells in the series stack have been de-rated to allow for the unique high voltage module.

On the other hand, capacitor power performance is not well grouped, but widely spread. For the type II capacitors, this suggests that these commercial devices have different types of carbons with different electrode thickness. The electrolyte for all of these type II capacitors is believed to be acetonitrile based. Even with the larger mass and volume required to achieve the higher voltage rating, the type I capacitor shows good specific power and power density, albeit at lower energy density and specific energy.

The asymmetric capacitor design can offer energy density advantages over symmetric designs, as explained under Operating Principles below. Another advantage of an asymmetric capacitor is that it can reliably operate above 1.2 V (the breakdown voltage of water) without gas evolution, even when employing an aqueous electrolyte. Operation above 1.2 V is possible because reaction kinetics for gas evolution are slow. Therefore available asymmetric capacitors products can operate at 1.4 to 1.6 Vdc for the same reason lead-acid batteries can operate at 2.05 V per cell with an aqueous electrolyte.

Pulse Ragone Plots

For many applications, it is useful to determine the energy delivered by a capacitor during a given discharge time. This relationship, for instance, can express the energy delivered by a capacitor during one 60 Hz cycle. In this case, the effective energy density of the capacitor has to be measured at the pulse width of one cycle. Figure 3 is pulse discharge data for several large electrochemical capacitors. The discharge is from rated voltage to 90% of rated voltage, and the pulse lengths are from very long, 100 s, down to 1 ms. This plot shows the energy per mass that can be delivered by the capacitor for different length pulses.

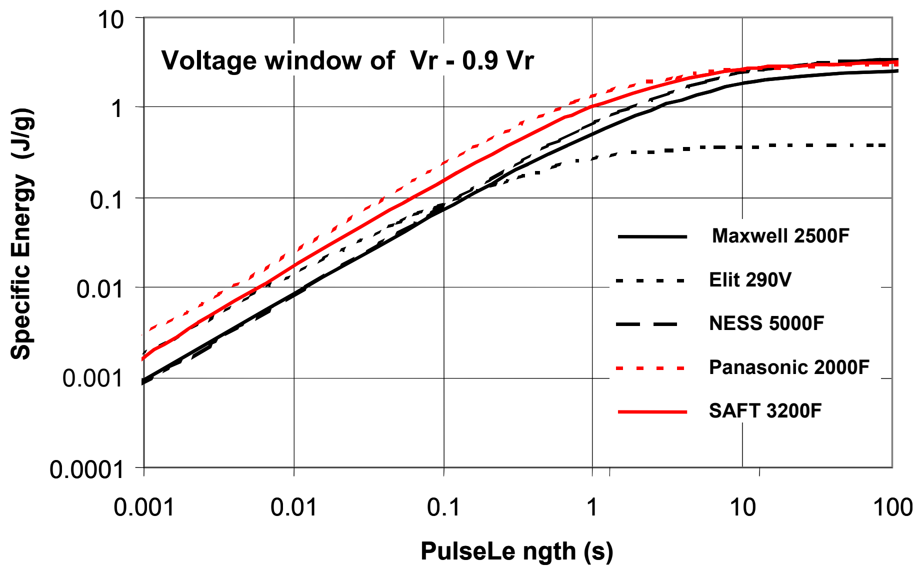


Figure 3 Pulsed Ragone plot for several large electrochemical capacitors

As shown in this figure, several of the capacitors have an effective specific energy of approximately 3 J/g for long pulse lengths. At shorter pulse lengths, for example at 1s, the effective energy drops by a factor of three or more per decade for the majority of these capacitors. The effective energy density continues to drop as the pulse length becomes shorter. This behavior is characteristic of a multiple-time-constant circuit as exists with electrochemical capacitors. The shape of the curve depends on the capacitor design. It is possible to design the capacitors for either higher long pulse length or higher short pulse length performance. It is not possible to predict the energy delivered by a capacitor at short discharge times based on total specific energy alone.

Temperature Performance

Electrochemical capacitors provide good operating performance over a wide range of temperatures. Upper temperature limits are generally below 85 C, depending on the product. Lower temperature limits are as low as -55 C in some products. Capacitor properties, in particular leakage current, are affected by temperature. Property changes observed with increased temperature are fully reversible if the temperature is not excessive. Self-discharge rates increase dramatically with temperature and often establish a practical upper operating temperature limit. Correspondingly, product life decreases at high temperatures since mechanisms responsible for the leakage current are often chemical side-reactions.

Such undesired chemistry in type II capacitors results from electrochemically active impurities that were originally present in the package (water, for instance), and new impurities that are created during capacitor operation due to electrolyte decomposition or arise from permeation into the package through seals. One common method to counteract the elevated leakage current levels and thus increase operating life of type I and II cells is to reduce the average voltage applied to a cell. This reduces the effective energy density of the capacitor but can substantially increase operating life.

Exceptional low-temperature performance can usually be expected in all electrochemical capacitors. This is possible because, unlike batteries, reaction kinetics do not limit the charge or discharge rate of an electrochemical capacitor. Instead, the limit is usually established by the electrolyte conductivity. Thus, capacitors can operate with good performance at very low temperatures. Generally, but not always, aqueous electrolyte electrochemical capacitors (types I and III) have the least change in performance at low temperatures compared with room-temperature values.

Combining Cells into Modules

Unlike conventional electrostatic and electrolytic capacitors, electrochemical capacitors are inherently low voltage devices. The maximum voltage of a single cell in a commercial product is 2.7 V. Thus, to meet the 600- to 800-V requirements of a utility application, hundreds of cells are series-connected and a dc-to-dc boost converter may also be employed.

Failure of just one cell in a series string can lead to failure of the entire storage system. A cell can fail as an open circuit or as a short circuit. The most common failure is an open circuit. Of course, if the failure is an open circuit, the entire system will stop working. On the other hand, if a single cell short circuits, then other cells in the string will experience higher voltage, which may stress them. This stress could lead to accelerated aging of those remaining and premature failure of another cell, and so on. Thus, one cell failure in this scenario could start a cascade situation where the entire string of cells would rapidly become a short circuit.

For long life, each cell in a series-string must remain below its maximum voltage rating under all conditions, which includes charge/discharge as well as float operation. The three key parameters affecting the cell voltage are variability in capacitance, internal resistance, and leakage current. Each of these parameters can lead to voltage imbalance among cells in a string. Thus, the construction of the cell, and its normal variability, will affect the reliability of a high-voltage string.

Cell Over Voltage in a Series String

Preventing cell over voltage is particularly critical for type I and II symmetrical capacitors. When gas is generated due to over voltage in a symmetric electrochemical capacitor there is no means for recombination and pressure rises inside the package. Some small capacitors have crimp seals for pressure relief that can vent small amounts of gas, eventually leading to dry-out and failure. Hermetically sealed packages may swell as the pressure rises and the package can eventually rupture causing a catastrophic loss of electrolyte and failure of the cell, usually as an open circuit. Before total failure these conditions may cause additional voltage stress on the remaining cells and lead to unusual performance of the series string.

Voltage de-rating, decreasing the average cell voltage in the string, is often applied as an effective way to avoid cell overvoltages. That is, the average voltage, V_{ave}, on each cell in the string must be below its maximum allowable value. This means the number of cells connected in series need to operate at voltage V must be greater than V/V_{ave}. As described, this will prevent a single cell in the string from reaching the maximum voltage and causing problems. The resultant effect is lower power (more cells in series means higher series resistance), less energy storage (more cells means less capacitance), and higher cost.

The type III asymmetric are more tolerant to overvoltages. In this case the recombinant mechanism seen in some aqueous batteries[2] helps to maintain voltage balance in a series string. When the string is charged with a controlled current, cells that first reach over-voltage conditions start to evolve oxygen. They do not rise in voltage while the lower charge cells "catch up." For healthy cells this condition continues until all of the cells reach full voltage. Provided the rate of oxygen generation is not too high compared to the rate of gas recombination, there is practically no loss of electrolyte. Therefore, type III electrochemical cells have a valuable self-leveling characteristic.

Like recombinant batteries, these devices can operate at a slight overpressure and normally release no gas. Nevertheless, commercial products have a pressure release safety valve similar to that used on batteries. At higher over voltage conditions, there can be gas releases with consequential loss of electrolyte, but without damage to the cells. Because of the valve there is generally no swelling of the cells and no deterioration in performance. If overvoltage conditions continue and lead to excessive consumption of electrolyte, then the cell will fail as an open circuit due to electrolyte loss.

Type III capacitors differ from type II devices with respect to cell voltage de-rating. In fact, it is undesirable to de-rate the voltage of an asymmetric aqueous capacitor. It is best to operate series-strings of such cells with average voltage equal to their rated value, which helps maintain cell voltage uniformity. Restated, in contrast with type I and II electrochemical capacitors, type III capacitors should not be de-rated when series connected to form high-voltage series strings.

Cell Balancing in a Series String

Series connecting a number of electrochemical capacitor cells usually requires an active or passive voltage leveling system. For example attaching a parallel string of precision resistors to help pin the voltage of each cell. Typically, resistance values are selected so that the current flowing through the resistor string is approximately ten times the current flowing through the capacitor string. With this ratio, and during static operation, the

[2] There is a fundamental difference between aqueous batteries and symmetric electrochemical capacitors. Such rechargeable batteries can be subjected to conditions that might lead to over voltage, but they do not actually rise in voltage. Instead, the high voltage causes the evolution of oxygen gas at the positive electrode of the cell. The gas travels to the negative electrode and recombines to form water. This mechanism is used in recombinant lead-acid batteries as well as in sealed nickel cadmium and sealed nickel metal hydride batteries.

resistor string establishes the individual cell voltages. A disadvantage of this passive approach is high self-discharge rate, since the string of resistors will discharge the capacitor. A related approach to provide cell balance but without the self-discharge problem is to use a parallel string of Zener diodes. Such devices appear as open circuit below a specified voltage, and a short circuit above that voltage. These methods add cost and complexity to the system.

There are also active approaches for balancing cell voltages where each cell is monitored. This information can be used to report over-voltage problems that may occur in series strings, or it may be used to actually control the voltage on each cell by charging or discharging individual cells in the string. Active balancing has been used with batteries and some electrochemical capacitors in the past. It is often used at the cell level, but sometimes this balancing is only needed between modules in a multi module system.

Note that balancing is normally at a low level, that is a few hundred milliamps during float conditions. If dynamic cell balancing is needed for a particular application a much higher rated leveling circuit will be required for the higher currents. This may add substantial cost to the system. Nevertheless, such an approach can be effective for raising the voltage of capacitors in a string to an average value that is closer to the maximum possible value, increasing energy density and perhaps offsetting the additional cost.

Temperature Variations in a Series String

Even with highly uniform cells there are still potential problems when cells are connected in series that have temperature non-uniformities. If a large module is warmer at the center due to cycling or warmer at the perimeter because of environmental factors, a temperature gradient will exist and could create cell voltage imbalance. This situation is true for all electrochemical capacitor designs. The solution to this problem is to engineer the system so that every cell within the system is held to within some specified temperature tolerance. Without this consideration, cells that are from a theoretically perfect manufacturing line (no variability) still may have cell voltage balance problems when operated within a series string.

Power Electronics Requirements

A unique characteristic of a capacitive energy storage system is that the state of charge of the system is always known–it is determined by the voltage. This is very different from most battery storage systems. It is usual to exploit this feature when charging and discharging a capacitor.

The sloping discharge of a capacitor, however, does present problems in applications that demand a constant voltage. In this case, power electronics are needed to boost the voltage of the discharging capacitor to a higher, constant value. Generally, a capacitor storage system will have very large capacitance, small inductance, and small resistance. Thus, it can act as its own filter during charge. The single limitation is that self-heating from its charging source must not create over-temperature conditions in the cells. Heat dissipation depends on the value of the ripple current, the value of the charging current, and the cell equivalent series resistance. Thus, low-cost charging sources can be employed, ones that are typically unsuited for battery charging.

A practical difference between the power source used for charging a capacitor and that used for charging a battery is the power level. Charging can be much faster for a capacitor than for a typical lead-acid battery design since they have minimal chemical reactions for charge storage. Capacitors generally can be charged at any rate provided overheating does not occur. This means that higher power chargers can be effectively used for capacitors since they can be charged in seconds to minutes, not hours. Similarly, their discharge rate can be high and is only limited by the series resistance of the capacitor. However, high-rate charge and discharge, particularly with cycling, can lead to internal heating of the capacitor, which without dissipation, can lead to over-temperature conditions and system failure as described previously. Shorting an electrochemical capacitor generally does not cause damage provided maximum temperatures are not exceeded. Type III and IV capacitors generally cannot be left in a shorted state without damage. Also they have a minimum operating voltage before damage may occur.

Health, Safety, and Environmental Issues

Safety issues can be grouped into several categories. One relates to electrical, a second to chemical, and a third to fire and explosion hazards. Electrical hazards are similar to those of batteries, not any better and not any worse. Hazards from chemical burns and chemical exposures can be similar to some batteries. Fire hazard is essentially nonexistent for type I and III products, which have aqueous electrolyte. For type II capacitors, fire hazard should be similar to some organic electrolyte batteries. An unknown safety related issue arises because acetonitrile is contained in the electrolyte of some large type II capacitors (see discussion under Chemical Hazards about acetonitrile). This situation has not been fully evaluated for potential problems it may create in larger scale utility or automotive applications.

To consider these issues, it is helpful to identify the exact materials used in each type of capacitor. Large type I capacitors use potassium hydroxide electrolyte, carbon electrodes, and generally nickel or steel current collectors or conductive polymer bipolar plates. Packages are generally steel or epoxy. The Elit and the ECOND companies make capacitors using this construction.

Type II electrochemical capacitors use carbon electrodes, paper or polymer separators, aluminum current collectors, and usually an acetonitrile solvent containing an ammonium salt for the electrolyte. Manufacturers of large type II capacitors include Maxwell, Panasonic, NESS, and EPCOS.

Type III electrochemical capacitors use nickel-oxyhydroxide positive electrodes, carbon negative electrodes, potassium hydroxide electrolyte, polyethylene case, polymer separator, and module packages generally of steel or a polymer. ESMA is the manufacturer of commercial products of this type.

Type IV devices are under development. They use carbon for one electrode and various types of battery electrodes for the second electrode. Electrolytes typically are various salt-containing organic solvents including acetonitrile-based solutions in some cases.

Electrical Hazards

Series-strings of the electrochemical capacitor cells often have voltages at lethal levels. These systems are similar to any voltage source with respect to electrical operating safety. Electrochemical capacitor systems are capable of delivering very high currents, higher than comparable lead-acid battery systems for instance, which can cause severe electrical burns from inadvertent short circuit. Safe operation procedures are exactly like those for battery systems of the same voltage and capacity.

Chemical Hazards

Aqueous electrolyte type electrochemical capacitors contain potassium hydroxide solutions at approximately 30-wt % concentration. This is similar to the electrolyte used in nickel metal hydride and nickel cadmium batteries, and in primary alkali cells. It is a common electrolyte, but it can cause chemical burns if contacted to bare skin as well as eye injuries. Safe operating procedures are similar to those for battery systems with the same electrolyte.

Some of the large type II capacitors contain acetonitrile solvent in their electrolyte. The synonym for the chemical acetonitrile is methyl cyanide. This chemical can create severe health problems from exposure due to respiration, ingestion, or skin contact. The amount of acetonitrile used in the electrolyte varies. The material specification data sheets (MSDS) will state percentages. Some type IV products under development also are reported to contain acetonitrile solvent.

Fire and Explosion Hazards

Whenever there is a concentrated quantity of stored energy, the possibility always exists of creating high temperatures that can lead to combustion. Type I and III products generally do not have fire hazard problems because they use an aqueous electrolyte. Type II products, with organic electrolytes may present a potential fire hazard problem. For example acetonitrile solvent is highly volatile and has flammability like kerosene and depending on the application may be classified as a fire hazard.

All commercial electrochemical capacitors should be designed so that they are safe and will not explode under any operating or use condition. Type I devices having aqueous electrolyte will become hot and vent steam under extreme conditions, but they should not explode. Type II products usually have a hermetic package. If they have a functioning safety pressure release valve, then they should vent before package rupturing. Type III products are expected to use water-based electrolytes and to be packaged in plastic containers with a resealable pressure release valve. Thus they present little hazard from explosion. Type IV products are presently in the research and development stage so it is not possible to comment on their safety. The issues of fire and explosion will be based on product designs and materials, which are not in their final form.

Disposal and/or Recycling

There are presently no recycling programs for electrochemical capacitors. There is no motivation to recycle some symmetric capacitors because they contain little high-value material. Proper disposal may be an issue for type II products containing acetonitrile because this solvent is classified as a toxic material for waste reporting purposes. Type III products contain high value and reclaimable nickel, very much like the nickel used in nickel metal hydride and nickel cadmium batteries. Nickel current collectors are used in some type I products. There are well-established programs for recycling these nickel-containing batteries. It is possible that recycling of the battery-like electrode and nickel collectors could be accommodated into these programs, once such capacitor products come into general use. The carbon electrodes and aqueous electrolyte in these capacitors present no specified disposal issues.

Cell Life Prediction

The life of a particular type of capacitor cell can be determined by testing a number of cells at a variety of temperature and voltage conditions. Capacitor failure is usually defined as a certain percentage loss of capacitance, increase in series resistance, or increase in leakage current. Also complete failure can occur due to an open or short circuit. Note that charge/discharge cycling is not a first-order determinant of cell life unless the cycle rate causes cell overheating. See the Appendix for a discussion of predicting capacitor life and cell failure mode flow charts.

Development History, Status, and Plans

Brief 25-year Product History

The concept of storing electrical energy in the electric double surface layer that is naturally formed at the interface between an electrolyte and a solid has been known since the late 1800's. General Electric reported the first two-terminal device based on this charge-storage mechanism in 1957. In 1962, Standard Oil of Ohio filed a patent application for a practical energy storage device based on charge storage in an electric double layer. The patent, awarded in November 1966, formed the basis for subsequent patents and eventual licensing. New ideas with configurations ruled to be outside these early patents have resulted in patents by numerous business entities around the world.

One of the earliest electrochemical capacitor products to be introduced was by Nippon Electric Corporation (NEC) under license from Standard Oil of Ohio (SOHIO) in August 1978. NEC created the name Supercapacitor and has used it as the name of their electrochemical capacitor product family. Production proceeded with the start of mass production in January, 1980, and sales to the Japanese market. In 1982, NEC introduced a new line of electrochemical capacitors having a different design optimization. This was repeated again in 1983, in 1987, and again in 1988. In general, each of these type I product lines was optimized for a different application. Large capacitors now under development by NEC are aimed at the automotive market.

One very interesting feature of the NEC product is the use of bipolar construction. NEC developed processes to assemble six or more cells in a series-stack and successfully seal the perimeter of the device. This is significant because it eliminated the need for external cell interconnects as is required with single-cell construction. This same approach has been used in large capacitors manufactured by ECOND and ELIT.

Panasonic started manufacturing their Goldcap electrochemical capacitor in 1978. The two major differences between the Panasonic and the NEC products were the electrolyte and the construction. The Panasonic Goldcap has a type II design. It uses an organic electrolyte with a spiral-wound single-cell construction.

Early Panasonic products were rated at <2 V/cell. In the middle 1980's, their products were available in sizes up to several Farads. Panasonic began manufacturing much larger electrochemical capacitors in the 1990's, with early products having 470 or 1500 Farad ratings at 2.3 Volts. These devices were extensively tested by the DOE for possible use in electric vehicle load leveling. Subsequent advances increased the capacitance of the 470 Farad-size products to 700 Farads, and ultimately to 2000 Farads and with a rating of 2.5 Volts.

Maxwell Technologies began development efforts on electrochemical capacitors in the early 1990's after receiving a DOE contract to develop an advanced electric vehicle load-leveling capacitor. Development was initially confined to type I products, then switched to type II products in an effort to obtain higher energy density. Maxwell has developed 8-kJ cells using an accordion-fold design with carbon cloth electrodes and organic electrolyte. They presently are developing a spiral-wound design using particulate carbon.

At about the same time in Japan, the Okamura Laboratory begin working on a type II design that used active power electronics for controlling and leveling multi-cell modules. Several patents have been obtained in Japan and the US. Results of this work were first published in English at the electric vehicle conference, EVS-13 in 1996, and some time later at the International Seminar on Double Layer Capacitors held annually in south Florida. The design technique, under the trademark ECaSS, has led to relatively high reported specific energies in the 4-6 Wh/kg range. Several Japanese manufactures including Shizuki Electric, Nissan Diesel and Power Systems Ltd, offer either capacitor modules or products that use this design.

The first reported activity on type III capacitors was from Russia. The Elit Company made asymmetric capacitors based on nickel oxyhydroxide and carbon electrodes with potassium hydroxide electrolyte. These devices were used to power wheel chairs and subsequently, children's toy cars. This company later concentrated on, and has widely commercialized a type I carbon/carbon electrochemical capacitor.

The Russian company ECOND presented a paper in the US in late 1993 that described type I electrochemical capacitors much larger in size than any device then available or under development in the US. Their capacitors were described as the power source for starting diesel internal combustion engines of sizes up to 3000 horsepower, including locomotive engines. The 1993 paper was certainly an eye-opener for some US researchers involved in the development of 1.8 MJ electric vehicle load-leveling capacitors. As with ELIT, this work was a giant step ahead of research that had been reported in the US and provided encouragement to many capacitor developers.

Type III development activities continued in Russia and were greatly expanded by the Joint Stock Company ESMA, a Moscow-based developer and manufacturer. This company reported using type III capacitors to power electric buses and electric trucks in 1997, with capacitors being the sole energy source in the vehicles. These 30 MJ capacitor storage systems far surpassed the size of any previously reported system. ELTON, the ESMA parent company, has patents that cover the asymmetric capacitor concept, i.e. type III and IV designs.

There is considerable development activity today on type IV capacitor products. These include use of lithium battery intercalation electrodes in combination with activated carbon double-layer charge storage electrodes. Development along this line has progressed rapidly due to the exploitation of material advances made on Li-ion battery technology.

Today's Manufacturers and Products

There are only a limited number of manufacturers now making large electrochemical capacitor products. A brief description of each company and their large capacitor products is given in Table 3.

Table 3 Manufacturers of Large Capacitor Products

Manufacturer	Country	State of the Technology	Typical Energy Storage and Voltage Ratings	Technology Volts/Cell	Website
ECOND	Russia	commercial products	40 kJ, 14-200 V modules	type I, .9	www.tavrima.com
Elit Stock Company	Russia	commercial products	50 kJ, 14-400 V	type I, .9	www.elit-cap.com
EPCOS AG	Germany	commercial products	15 kJ, 2.5 V 40 kJ, 14 V	type II, 2.5-2.7	www.epcos.com
ESMA Joint Stock Company	Russia	commercial products	20 kJ – 1.2 MJ, 14 V 30 MJ, 180 V modules	type III, 1.4-1.6	www.esma-cap.com
Maxwell Technologies, Inc.	USA	commercial products	8 kJ, 2.5 V	type II, 2.3-2.5	www.maxwell.com
NESS capacitor Company	Korea	commercial products	18 kJ, 2.7 V	type II, 2.5-2.7	www.nesscap.com
NEC Tokin	Japan	development	8 kJ, 14 V	type I, .9	www.nec-tokin.com
Okamura Laboratory, Inc. with license of ECaSS to Shizuki, Nissan, etc.	Japan	commercial products	1350-1500 F, 2.7V 35 F, 346V, 75 F, 54V	type II, 2.5-2.7	www.okamura-lab.com
Panasonic	Japan	commercial products	6 kJ, 2.5 V	type II, 2.5-2.7	www.maco.panasonic.co.jp
Saft	France	advanced prototype	10 kJ, 2.5 V	type II, 2.5-2.7	------

ECOND

The ECOND capacitor made in Moscow, Russia, has bipolar construction with KOH electrolyte. It is a cylinder approximately nine inches in diameter, and, depending on energy, a height from several inches up to more that two feet. Capacitor energies range up to 45 kJ in size. Equivalent series resistances are typically in the milliohm range. Voltages up to 200 V are common. Their RC time constant is below one second, considerably less than many competitive products. This capacitor technology has not changed significantly from when it was first described in the US in 1993.

ECOND products have been used in many demonstration systems including diesel truck starting and in hybrid electric vehicles. ECOND capacitors were used in the first large-scale hybrid bus demonstration in North America that had capacitor energy storage. This 40-ft-long city transit bus was a gas/electric hybrid system that contained a 1.5 MJ, 400 V capacitor system. ECOND capacitors are available from their North American distributor, Tavrima Canada, Inc.

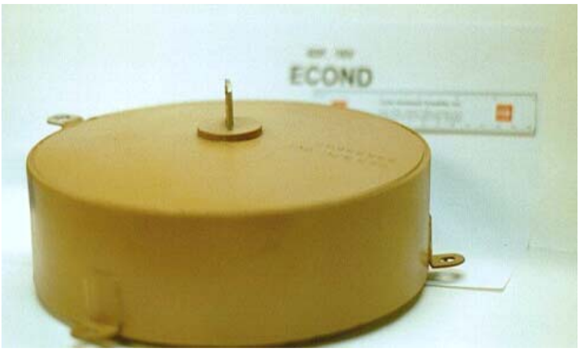


Figure 4 ECOND capacitor 60F, 16V (six inch ruler also shown)

ELIT

The ELIT Company started operation in 1990 in Kursk, Russia. Their early devices were designed to power wheel chairs and subsequently for children’s toy cars. ELIT has concentrated on carbon-carbon electrochemical capacitors, which led to the development of a broad line of type I products having significant sales volume in the US. Capacitors with voltages as high as 400 V are now available.

A reader’s letter to *Battery International* from Alexey Beliakov in early 1993 corrected information in an earlier issue by pointing out the existence of their large electrochemical capacitors. Pictures of 30 and 50 kJ, 12 and 24 V capacitors were shown. He described the testing they had done on such capacitors and mentioned delivery of 600 kJ capacitor systems. Capacitors of such size and sophistication were totally unheard of at that time in the US. The complete line of ELIT capacitor products is available from their factory in Kursk, Russia.

Figure 5 Elit capacitor 0.8 F, 310 V, 19 kg (six inch ruler also shown)

EPCOS

EPCOS licensed electrochemical capacitor technology from Maxwell Technologies in the late 1990’s and offered identical products to the European market for several years. They now have developed a new family of products, which range from 1000 F to 5000 F at 2.3 V or 2.5 V. EPCOS capacitors are type II products with accordion-fold carbon cloth or, for the new family, spiral-wound pasted carbon construction. Some contain acetonitrile in their electrolyte. Some have both terminals at one end of the package, but their newer products have a terminal at each end. EPCOS capacitors (of this new design only) are available in North America through their Munich, Germany office.

Figure 6 EPCOS family of EC capacitors and modules from 5000F at 2.5V to 150F at 42 V

ESMA

ESMA products were first described in the US during a conference presentation in 1997. Photographs of buses and trucks that were powered solely by electrochemical capacitors were shown. Many members of the audience missed the point that these vehicles actually had no batteries or an engine, only capacitor energy storage. These vehicles stored approximately 30 MJ of energy in capacitors, perhaps the largest-size capacitor system then in use. The capacitor storage technology used by ESMA was type III, which they referred to as an asymmetric capacitor. Since this first report, they have presented many technical papers that further describe and explain this mating of a battery-like Faradaic charge storage electrode with a capacitor-like double layer charge storage electrode.

Products sold by ESMA range from 20-kJ, 14-V modules up to multi-MJ, 600 V systems. Cell construction is similar to that of aircraft NiCd batteries, but with activated carbon substituted for the cadmium in the negative electrode. ESMA capacitors have a flooded cell design, which provides the ability to voltage-balance cells when connected in a series string.

ESMA has optimized their capacitors for either pulse or traction applications. The pulse capacitor is intended for discharges of a few seconds like needed for starting an internal combustion engine. The traction capacitor is designed to power electric vehicles like fork lifts, utility vehicles, trucks, buses, etc. These devices can be charged much quicker than a battery, in 12 to 15 minutes with a high-power supply, and then be discharged over a period of an hour or longer. ESMA capacitors and systems are available from their factory in Troitsk, Russia. Private-labeled capacitors for the starting of commercial trucks are available from their distributor, Kold-Ban International in Lake in the Hills,

Illinois.

Figure 7 ESMA 10 cell module 1000F @ 14.5V (six inch ruler also shown)

Maxwell

Maxwell Technologies had a broad line of high-voltage electrostatic capacitor products when they were awarded a contract by the US Department of Energy for electrochemical capacitor development in 1991. The goal was to develop a powerful energy storage technology that would be suitable for electric vehicle load leveling. The desired capacitor would store 500 Wh (1.8 MJ) of energy, deliver 50 kW of power, be rated at 300 V or higher, weigh less than 100 kg, and have material costs below $1000. Maxwell initially worked with Auburn University on this project. Their approach was a type I capacitor product that used a metal/carbon fiber composite electrode with potassium hydroxide electrolyte. Later efforts were directed to a type II design to increase device energy density. In the mid 1990’s Maxwell moved this project from Auburn to its manufacturing plant in San Diego, where it is located today.

Maxwell is the leading US producer of large electrochemical capacitors. They manufacture capacitor cells up to 2700 F. Their packaging is well engineered with welded metal construction, and in some products, glass-to-metal seals for electrical feed through. Their large devices have been used in numerous demonstration programs including in hybrid vehicles, power quality applications, and engine starting. Maxwell licensed their technology to the German company EPCOS in the late 1990s.

They recently acquired the Swiss company Montena that has extensive winding technology capabilities. In the middle of 2002, they announced, but have not introduced, a new product line having a pasted electrode in a spiral-wound design. This technology should allow substantially lower material and production costs. Major markets for the large Maxwell capacitors are in vehicle and telecommunication power applications.

Maxwell has undertaken a vigorous cost reduction program for their large capacitors. This effort involves replacing the carbon cloth electrode material with a particulate carbon, and using these electrodes in a spiral-wound assembly. Maxwell capacitor products are available from their main offices in San Diego, California.

Figure 8 Maxwell Capacitor 2700F, 2.5 V

Montena

Montena is a Swiss company that produced spiral wound, type II electrochemical capacitors in addition to capacitor manufacturing equipment. Maxwell Technologies acquired Montena in 2002, and their product lines have been merged.

NEC Tokin

The Japanese company NEC was one of the first to commercialize double layer products. They still sell the small capacitors under the name "Supercap." NEC Tokin is now developing larger "Hypercap" capacitors, primarily for the automotive market. These are type I design, using sulfuric acid electrolyte, prismatic in form, and available either optimized for high energy or for high power. Special large capacitor products from NEC Tokin are available through their Japanese factory. Figure 22 shows two samples.

Figure 9 Samples of NEC Tokin products

NESS

NESS electrochemical capacitor technology is a spin-off from the Korean DAEWOO Group in 1998. They have rapidly created a broad product line of electrochemical capacitors and developed automated capacitor manufacturing capability. NESS capacitors include type II products with a spiral wound cell construction. Their first commercial shipment of capacitors to the US market was in mid-2000. NESS presently makes cells up to 5000 farads in size, some rated at 2.7 V, among the highest voltage ratings available. Their larger capacitor cells have prismatic packages for efficient stacking in modules. NESS recently introduced a 42-V capacitor module for the emerging automotive market. NESS capacitor products are available from their Korean home office.

Figure 10 NESS CAP 5000 F, 2.7 V (six inch ruler also shown)

Okamura Laboratory, Inc. (ECaSS)

Capacitor systems based on an Okamura Lab design approach consist of large electrochemical capacitors with active electronic voltage control. These have been reported at professional meetings and were recently presented in the company web site. The distinguishing feature is that active voltage control is integral to the capacitor system and only operates to adjust the maximum charging voltage of individual cells, a technique called monitoring and initializing. The advantage is that the adjusting current for each capacitor cell will converge to the level of the leakage current, which is negligible in terms of energy consumption.

The Okamura Laboratory is located in Japan and does not sell capacitors directly. They partner with other capacitor manufactures, apply their design expertise to the cell design, and then add active controls to modules. The individual capacitor cells are typically prismatic geometry, of type II design, and do not contain acetonitrile in the electrolyte. Okamura has reported that a number of their systems are in use for demonstration projects associated with vehicular and UPS applications at several hundred volts. Figure 24 shows three of their manufacturing partner's products.

Figure 11 ECaSS commercial capacitors, from left, Nissan Diesel (346Vdc, 35F, 6.3Wh/kg), Shizuki Electric "Faradcap" (FML-2A, 54V, 75F, 30Wh), Power Systems (HO2A, 54V, 65F, 6.5Wh/kg)

Panasonic

The Panasonic "Goldcap" capacitor, introduced in 1978, was initially developed for memory backup applications to replace the unreliable coin cell batteries in use at that time. It was not until the 1990s that Panasonic began manufacturing much larger electrochemical capacitor prototypes in Japan. In 1999 Panasonic introduced their UpCap capacitor for transportation applications, such as needed for hybrid vehicles. One version of the UpCap is rated at 2000 farads and 2.5 V. It is a type II device that has been very well engineered. It uses a sophisticated double-seal arrangement in the crimped package, a lower cost approach than welded construction for preventing water entry into the package. It has essentially many tabs to the spiral-wound foils at each end of the package, which helps in reducing the series resistance. Furthermore, this arrangement helps to extract internally generated heat, which is important for applications like a hybrid vehicles where there are continuous repetitive charge/discharge cycles. The UpCap is currently available in high-power and high-energy versions, and under evaluation for many applications.

These products are available from Panasonic Automotive Electronics Company in Southfield, Michigan.

Figure 12 Panasonic 2000 F, 2.3 V (six-inch ruler also shown)

Saft

Saft's electrochemical capacitor program compliments their large lithium ion battery products. Saft manufactures their large capacitors in France. The product is available in two variations: high energy and high power. The products are of type II design, have cylindrical geometry with a terminal on each end, and are available with capacitance values up to 3200 F. The manufacturing is at the stage of advanced prototype. These capacitor products may be purchased from the Saft's Cockeysville, Maryland office.

Figure 13 Saft 3200 F, 2.5 V (six-inch ruler also shown)

Current Technology Developments

Development thrusts in the year 2002 generally relate to capacitor design, manufacturing cost reductions, and electrode materials development. Capacitor researchers apparently see performance or other advantages of the asymmetric design and are making it popular. Numerous research papers have been presented on this concept since it was first described in 1997. Patents are appearing with various descriptions of type III and IV materials and construction. For example, of the ~45 papers presented at the 2002 Spring meeting of the Electrochemical Society, 18 were related to asymmetric electrochemical capacitors. There were few if any presented on this topic at previous meetings. Electrochemical Society meetings represent a forum where professionals often first present major developments and new technology directions.

Another current development thrust relates to technical issues surrounding capacitor thermal management. Here interest originates from the need to create large, high-voltage energy storage systems capable of rapid cycling. Such systems require uniform voltage among the many capacitor cells in series-connected strings for reliable operation. This motivates increased emphasis on cell temperature uniformity and efficient heat removal from cells. Although charge/discharge efficiency is generally high for capacitors, they nevertheless dissipate energy, which can cause excessive internal temperature rise without appropriate heat removal techniques.

An important issue related to the creation of reliable high-voltage strings of cells is cell uniformity. So reducing manufacturing variability is certainly important. Improving control of the production process is an ongoing effort for many companies according to recent reports. Still another issue in capacitor design relates to product cost reduction. For example, Maxwell has reported on their cost-reduction program. They are developing spiral-wound cell construction capability using particulate-carbon electrode materials pasted on current collectors. This is in contrast with the carbon cloth used with a manual, accordion-fold design.

Development thrusts in electrode materials include examining the performance of various activated carbons to find lower-cost materials. Some new carbon materials are being implemented. Several companies are attempting to find replacements for activated carbon cloth material, which is much more expensive than the particulate carbon, especially particulate materials that have a natural origin. Other electrode materials that have been investigated include metal-oxides of ignoble elements, ones having good performance without associated high-costs typically found in the platinum group metals. There has been some development activity using nano-structured materials, both for carbons in symmetric double layer capacitors, and in the pseudocapacitor electrode of an asymmetric capacitor.

The third major development thrust has been with the electrolyte. Work has been reported on using polymer electrolytes for both aqueous and non-aqueous designs. Also, there has been some effort to find replacement materials for the acetonitrile-based electrolytes used in many type II products. The performance of these electrolytes is very good but its use creates concerns because of toxicity and safety issues.

The thrusts for the asymmetric capacitor activity have expanded from the nickel oxyhydroxide/carbon system to other systems including a lead oxide/carbon system and a MnO_2/carbon system. Reports of device performance using these other material systems are most encouraging. A major advantage of these systems is low materials cost. Yet another system that has been described in several papers recently is a lithium-titanate electrode in combination with a carbon electrode and an organic electrolyte. This design offers higher voltage than can be obtained in present symmetric organic electrolyte capacitors, and it is referred to as a type IV electrochemical capacitor.

Yet another design that has been described in the literature is a graphite/carbon capacitor. This type IV capacitor relies on charge intercalation in the graphite of one electrode and double layer charge storage on activated carbon in the other electrode. The electrolyte for this system is an organic solvent with a lithium salt. This particular system has an operating voltage approaching 4 V. None of these advanced devices are commercially available at this time.

Technology in the Next Ten Years

It is interesting to speculate about the future performance of electrochemical capacitors. In the next three to five years, type II capacitors cells are predicted to achieve stable operation at 3.0 V. This represents a significant increase in energy density over the present products, perhaps 50% higher than is available today. With this higher operating voltage will come increased stability, possibly increased operating temperature, and perhaps with suitable emphasis in organic electrolyte development, creation of a non-toxic type II electrolyte capable of high power performance.

Type III capacitors in the next several years should approach an energy density of 70 kJ/kg, which represents a 100% increase in energy density over products available today. There could also be significant cost reductions as a result of the introduction of lower cost designs that are described in the patent literature.

Longer term, type II capacitors will probably remain fixed at 3.0 V operation because further increases in electrolyte and electrode purity will become cost prohibitive. Furthermore, emphasis by small-capacitor developers on increasing cell operating voltage will wane since the portable electronic applications will decrease to below 3.0 V. But improved stability at the 3-V level is anticipated, particularly at elevated temperatures. Type IV electrochemical capacitors should become commercially available, for example the graphite/carbon system and the lithium-titanate system. Energy densities of 100 kJ/kg may become available, which is solidly placed in the range of today’s lead acid batteries.

Which type will become the dominant capacitive energy storage technology in the future? This is impossible to predict with any certainty. However, for applications where cost is a major issue, the dominant technology will probably have an aqueous electrolyte. This lowers the cost of materials as well as manufacturing processes. For instance, aqueous electrolyte products generally do not require special conditioned space like dry rooms, or special drying systems to remove water impurities from cells before sealing like what is needed with the non-aqueous electrolytes. Yet another related cost issue is capacitor packaging. Aqueous electrolyte products generally are sealed in a low-cost crimped metal or plastic package to reduce loss of water—the design need not be highly sophisticated. In contrast, organic electrolyte products must be hermetically sealed in a low-permeability container like metal and often incorporate a sophisticated glass-to-metal seal for electrical feed-through. These materials and package designs add considerable costs to a product.

Of the aqueous electrolyte capacitors on the horizon today, type III electrochemical capacitors offer significant performance advantages including higher energy density and voltage balance. So, this particular design is predicted to become the dominant capacitor technology of the future for applications where cost is a driver. Since many utility and transportation applications are cost sensitive, type III capacitors are predicted to dominate these markets.

It is possible to estimate future cost difference between the organic and the aqueous electrolyte products by examining the present cost differences between lithium-ion and nickel-metal hydride batteries. The organic electrolyte battery presently costs about twice as much as the aqueous battery. Both of these technologies are in large-volume production. So cost differences for the capacitor types when in large-volume production may mimic this behavior, i.e., organic electrolyte capacitors will continue to cost more than aqueous electrolyte capacitors, perhaps two-times higher.

Applications

Until recently, most applications for electrochemical capacitors have been in low-voltage circuits such as computer memory backup. Larger capacitor modules with advanced power electronics have expanded the possible applications of energy storage capacitors into electric power systems. Capacitors can now store enough energy to compete with batteries in many short-term energy storage applications. The best fit for capacitors is in applications requiring relatively high cycle life, high round-trip efficiency, wide operating temperature range, maintenance-free operation, quick charge, and high power.

Often these short-term operations compliment other power system components such as weak feeders, small-distributed generators, fluctuating or high-inrush loads, etc. Consequently, effective application of the electrochemical capacitor is expected to help make a wide range of energy system applications more practical. In other words, there are short-term storage applications that were not technically or economically viable in the past that should now be reconsidered because of this new technology.

The applications of interest use energy storage to supplement normal power delivery. One dimension of a power system application is how the delivery is supported or enhanced by using energy storage. Important electrical parameters include voltage (V), current (A), real power (W), reactive power (VA), and energy (Wh).

Baseline for Applying Energy Storage

The cost and performance of lead-acid batteries are well known and provide a practical baseline for comparison with other energy storage technologies. Electrochemical capacitors store less energy per unit mass (or volume) than batteries, but can deliver higher power per unit mass (or volume). This is shown graphically by the hypothetical Ragone curves shown in Figure 14. In this figure, the battery delivers more energy, per unit mass, than the capacitor for discharges longer than 15 seconds, while the capacitor delivers more energy than the battery for discharges less than 15 seconds.

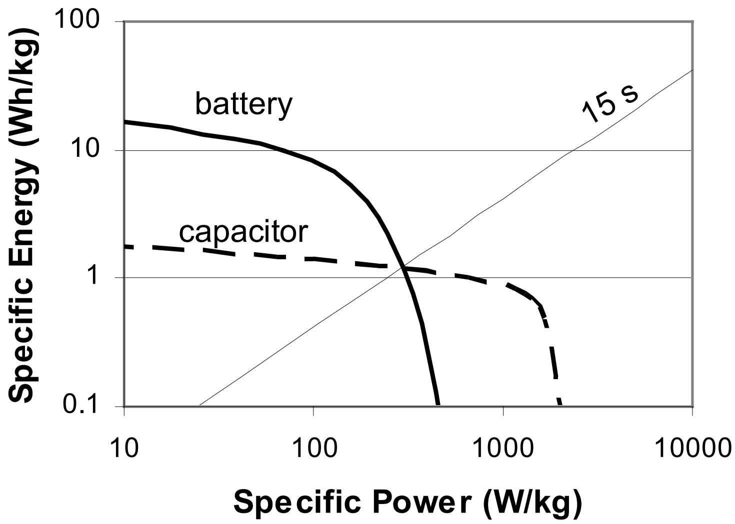


Figure 14 Hypothetical Ragone plots for battery and electrochemical capacitor.

Figure 15 shows a physical size comparison of a 220 kJ, type III electrochemical capacitor and an 83 Ah SLI (starting, lighting, and ignition) lead-acid battery. Which device contains greater useable energy? Since the available energy depends on how quickly it is delivered, the answer to this question depends on the application. In this case, as for the hypothetical Ragone plots of Figure 14, the specific energies of the two technologies, in watt-hours per kg, are approximately equal for a 15-second discharge rate. For times less than 15 seconds, capacitor specific energy is greater than that of the battery, and for times longer than 15 seconds, the battery specific energy is greater.

The energy available from the 27-kg battery, discharging in 15 seconds from 12 volts to 10.5 volts, is 120 kJ (33 Wh). The energy available from the larger, 40 kg capacitor, discharging in 15 seconds from 42 to 21 volts, is 246 kJ (68 Wh). Thus, the larger capacitor provides more energy in 15 seconds. On energy per mass basis the two technologies are nearly the same. On the other hand, if compared over an 8-hour discharge period, the physically smaller battery, rated at 83 Amp-hours, contains 3600 kJ (1000 Wh), and provides about 8 times more energy than the capacitor, which can deliver about 540 kJ (150 Wh) during the longer discharge.

Figure 15 Comparison of physical packages of 12-V, 83A-hour, lead-acid cranking type battery (Delco 1150) and 42-V, 220 kJ, pulse type electrochemical capacitor (ESMA 30EC402)

Voltage responses during charge and discharge are significantly different for capacitors and batteries. Figure 16 shows these characteristics for a 576 V system designed for a 250 kW, 30-second discharge and a 4 kW, one-hour recharge. Note that the capacitor can recharge faster than shown; the recharge time for the capacitor is limited by the size of the charger, which is rated at 4 kW.

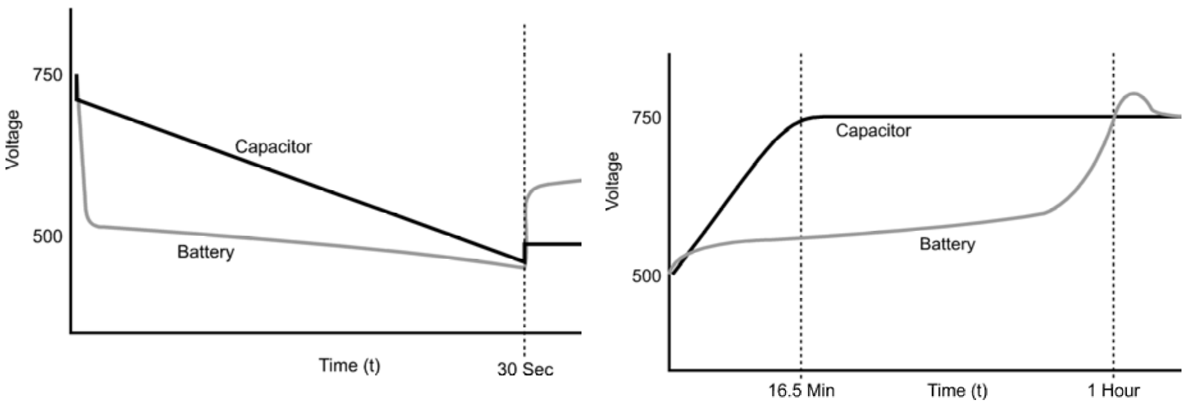


Figure 16 Comparison of Capacitor and Battery discharge and charge characteristics

It is informative to compare the charge/discharge cycle efficiencies of a lead acid battery with a typical electrochemical capacitor. Both exhibit the same type of losses due to ohmic heating during charge and discharge, so-called IR losses. Equations for capacitor discharge efficiency are listed in Table 1. The equivalent series resistance, *Rs*, of a capacitor is constant and independent of its state of charge (i.e., capacitor voltage) while the equivalent series resistance of a battery increases as the battery discharges, becoming highest when the battery is fully discharged. Thus, a capacitor with the same initial equivalent series resistance as a battery, and thus, the same power performance as the battery, will have higher energy efficiency during charge/discharge cycling. Stated differently, the battery will dissipate more energy during charge and discharge than a capacitor of the same peak power rating. Note, these efficiencies should not be confused with standby or self-discharge losses, which both technologies experience at low levels and increase with temperature.

There is a second factor that is even more significant in reducing battery cycle efficiency but does not play a role in capacitor efficiency. This is due to the thermodynamic effect that requires a battery be recharged at a higher voltage than its discharge voltage. For example, a lead acid cell must be charged at a potential of 2.3 to 2.8 V per cell while its theoretical maximum discharge voltage is 2.1 V, and it often is below 2.0 V. This energy loss is independent of the charge rate, and it inherently reduces lead-acid battery cycle efficiency to values below those of a capacitor.

Table 4 shows other characteristics of electrochemical capacitors compared with conventional lead-acid batteries.

Table 4 Comparison of batteries. electrochemical capacitor characteristics to lead-acid batteries

Parameter	Electrochemical-Capacitors	Lead-Acid Batteries[1]
Discharge Time Range	.1 seconds or minutes seconds	Seconds to hours
Recharge Time Range	Seconds to Minutes	Minutes to Hours
Roundtrip Efficiency(1)	90-97%	80%
Typical Cycle Life	≥100,000 cycles	2,000 cycles
Operating Temp. Range, °C	-50 / +50	0 to 26
Cost $/kJ Range(2)	$5 – 40	$0.1 - 1
Technology Status	Emerging	Mature

1. Higher efficiencies occur for longer discharge/recharge cycles
2. First cost over rated discharge time range from longest (lowest cost) to shortest time (highest cost)

Short-term Power Delivery Applications

The required "duration" of energy storage is key to an application and determines whether the application requires a short burst or a longer-term delivery of energy. For example, utility power fault mitigation and transient stability control may require storage of only a few cycles of energy storage. Momentary interruption mitigation requires several seconds to minutes of stored energy. System support functions such as peak shaving and load leveling, where stored energy is dispatched to offset the load during peak periods, may require hours of stored energy. Rescheduling energy for cost or environmental reasons would involve 8 to 12 hours of energy storage.

Capacitors are well suited to deliver short-term power, 15 seconds or less, and may be the preferred choice when the application requires higher specific power, low roundtrip losses, higher cycle life, and wider tolerance to temperature. Figure 17, a comparison of the operating range for high-energy capacitors and lead-acid battery, shows the specific power versus discharge time to the end voltage for a 250 kW system comparing high-energy capacitors and lead-acid battery.

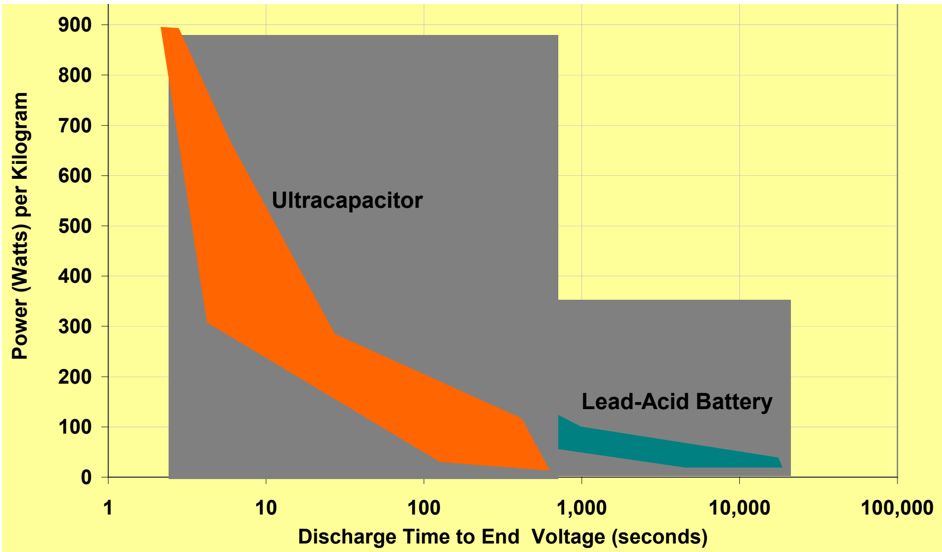


Figure 17 Specific power in watts per kilogram versus discharge time to end voltage in seconds.

For longer-term energy storage applications (greater than 15 seconds), the lead-acid battery is lower cost and the preferred solution. The amount of energy available in the lead-acid battery for these longer durations is more than in capacitors, as shown in Figure 18, and the cost is about 10 times lower.

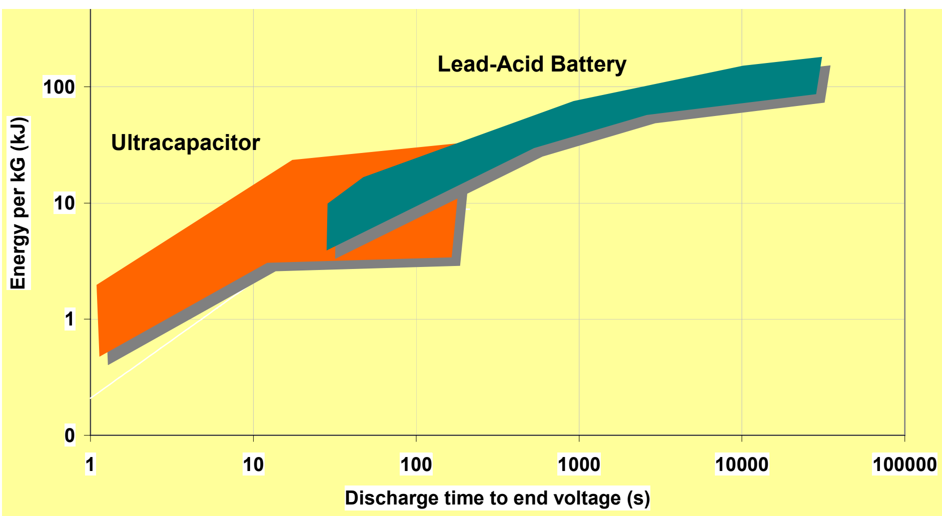


Figure 18 Specific energy in kiloJoules per kilogram versus discharge time to end voltage in seconds.

Application of Electrochemical Capacitors for Utility Power Delivery

Two electrochemical capacitor applications for utility power delivery are grid stabilization in T&D and station battery replacement or reduction in substations. Both applications require short-time delivery of energy for limited time. For grid stabilization stored energy is combined with electronic control and acts to source or sink power for momentary grid support. In this application, energy storage supplements reactive compensation and can improve system stability and power through-put. The second application, providing uninterruptible power for substation critical loads, has two possible solutions. The first solution replaces the substation battery by providing short-term bridging energy to carry critical loads during transfer to an alternate source, or until the primary source returns to normal operation. The second solution supplements the substation battery by picking up high inrush loads, allowing reduction in battery size. These T&D energy storage applications are described below based on the generic need that they serve. Included in the descriptions are technical specifications such as response time, run time, duty cycle and power requirements.

Voltage Stabilization Support to the Electric Grid

Problem Description

Need for system stability, in both central and distributed power systems, as well as the specific functions of reactive power supply and frequency regulation support, are considered here. The reactive power (VAR) control application solves the problem of maintaining power flow and voltage stability. The frequency regulation application solves the problem of controlled injection needed to regulate system frequency. The latter is particularly relevant for improving stability of relatively weak areas in the T&D system. These applications are cited as ancillary services in FERC order 888, 1996, and will eventually carry a location dependent market value in a restructured utility situation.

The technical criteria for grid stabilization, identified here as a “mini-facts” application, will be somewhat site and utility system specific but likely will fall within these parameters:

- **Application –** Reactive power supply and frequency regulation support of T&D
- **Power Rating –** 2-40 MVA (power may be real, reactive, or both)
- **Energy Capacity –** .5-10 kWh at MVA rating
- **Duration –** Corrective action for cycles up to a few seconds
- **Response Time –** 5 to 100 milliseconds
- **Duty Cycle –** Variable depending on conditions, may be a continuous problem
- **Roundtrip Efficiency –** 80-90% (assumes less than 10% duty cycle)
- **No load Losses –** less than 3%
- **Plant Footprint –** .05 MW/m^2 (assumes siting in low-density area)
- **Environmental Issues –** EMI

Other, non-energy storage, alternatives for solving this problem are overexcited synchronous motors and generators, switched capacitors, as well as fast acting static var compensators (SVCs). Also, utilities’ traditional options to improve voltage regulation and control frequency are upgrading transformer and feeder capacity, and cycling power plants.

Stored Energy for "Distributed Mini FACTS" Controllers

This energy storage application is based on benefits of active power injection coupled with dynamic reactive power exchange for improved stability in the power system. The need for dynamic reactive power compensation ("fast VARS") as opposed to fixed or mechanically switched capacitor banks have long been recognized as a way to improve T&D system stability and increase power transfer limits. This concept has been applied in large-scale inverter-based Flexible AC Transmission Systems (FACTS). These systems have the ability to affect changes of 10 to 100 MVAR and respond in less than one-quarter of a cycle and they have brought about a new way of thinking regarding active and reactive power.

An example is the STATCOM, which outpaces switched passive capacitors, reactors, and LTC transformers in rapid voltage regulation. STATCOM responds even faster than conventional generators, SVCs, or synchronous condensers, which in the past were the main supplier of "fast VAR" to the electric systems. Also, this type of dynamic reactive compensation is better at supporting voltage during system contingencies than conventional capacitor banks that lose capacity when system voltage decreases, (See Figure 19).

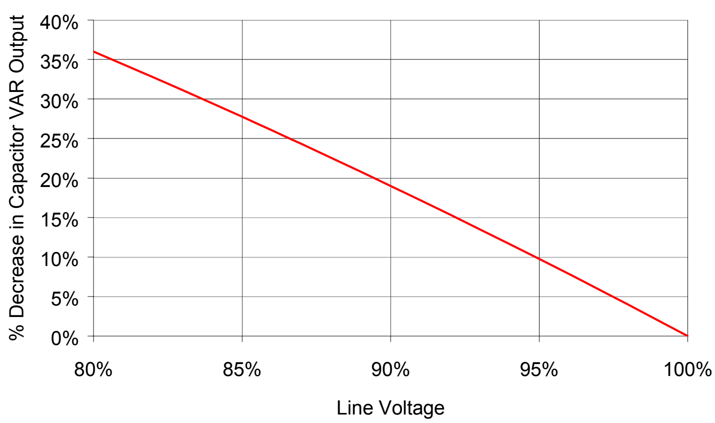


Figure 19 Loss of capacitor VAR output as a function of line voltage

Combining energy storage with FACTS controllers offers three distinct advantages:

1. Energy storage devices can provide system damping while maintaining constant voltage following a system disturbance.
2. Energy storage increases the dynamic control range allowing the interchange of small amounts of real power with the system.
3. Distributed energy storage can maintain the speed of locally connected induction motors during a power system disturbance, thus helping to prevent a voltage collapse in areas where there is a large concentration of induction motors.

An EPRI study [1] found that adding energy storage (in this case, SMES) to a FACTS device increased the control leverage of the reactive power modulation of a FACTS device by 33% (i.e., operating the FACTS + energy storage in four-quadrant, reactive plus real power mode provided 33% greater transmission enhancement). Figure 20 shows the results of a study conducted by Siemens on the effectiveness of short-term energy storage with a FACTS controller in damping low frequency oscillation that could not have been achieved with the STATCOM plus post oscillation damping (POD) alone.

> "The results illustrate that a STATCOM alone (i.e. no POD) will regulate voltage in the post contingency period but will not naturally add much damping to power oscillations. The STATCOM with POD signal applied to its voltage reference may damp swing oscillations following a disturbance however this is achieved at the expense of voltage regulation. The combination of STATCOM plus SMES with POD modulating the SMES output will allow the system to both regulate voltage and provide oscillation damping." [2]

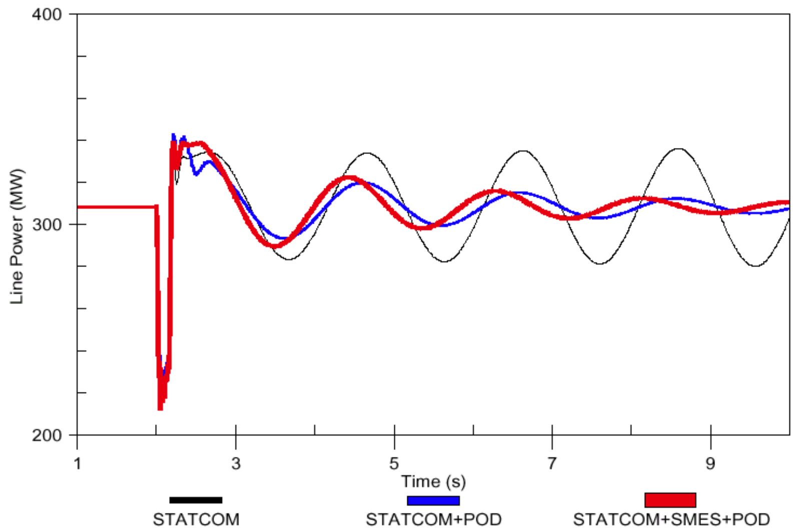


Figure 20 Damping of Post Fault Oscillation with and without Energy Storage

The use of large-scale (100 MVAR or more) FACTS controllers to provide dynamic reactive compensation has already been demonstrated through several landmark projects. However, because of high initial cost, the alternative of a smaller scale, modularized, distributed real, and reactive VAR injection has recently received considerable attention.

The key to this application is the injection of real energy storage to maintain the speed of motors, which in turn reduces the inrush current for feeders heavily loaded with motor loads. This minimizes bus voltage depression and thus helps with both rotor angle and voltage stability. By providing a critical boost to the system both during faults and following the clearing of faults helps avert instability. This type of distributed dynamic reactive compensation with energy storage is particularly suitable for solving transient voltage stability problems in a weak portion of the network with a high concentration of induction motor loads during peak loading conditions.

The advantage of energy storage under these conditions is mainly in reducing the maximum transient voltage dip, which is a measure of the dynamic performance of the system [3]. Based on Western Systems Coordinating Council (WSCC) criteria as shown in Figure 21, the voltage at any load bus should not dip below 20% of the initial value for more than 20 cycles.

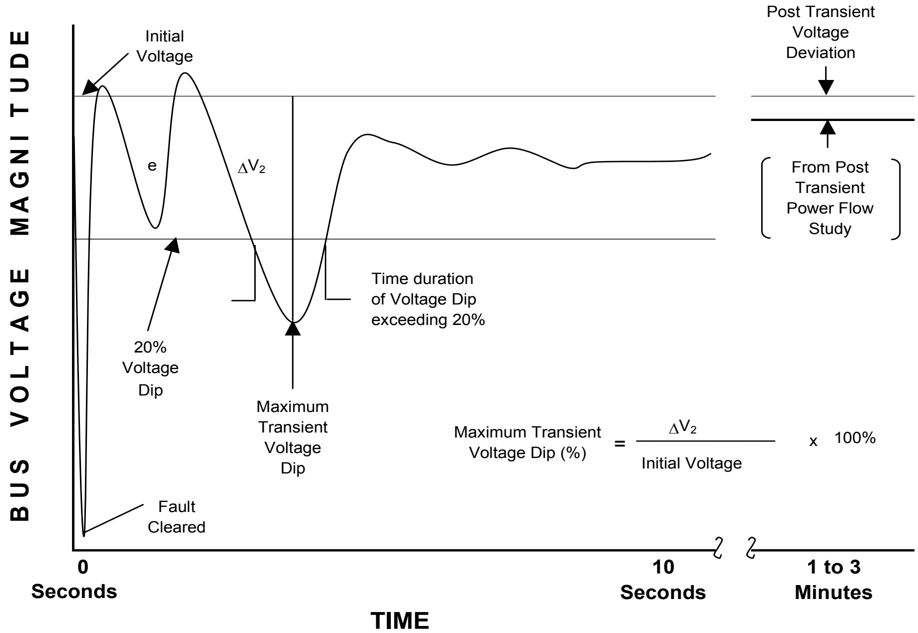


Figure 21 Voltage Performance Parameters from WSCC

Estimating the total portion of induction motor loads is becoming a critical issue for power system stability. This was recognized in a study conducted for model validation and analysis of WSCC System Oscillations following the Alberta Separation on August 4, 2000. Figure 22 shows the modeling result of the system oscillation following the separation for different percentages of induction motor loads. Based on this study, one of the recommendations was to increase the portion of induction motor load representation in selected areas for future system stability study models.

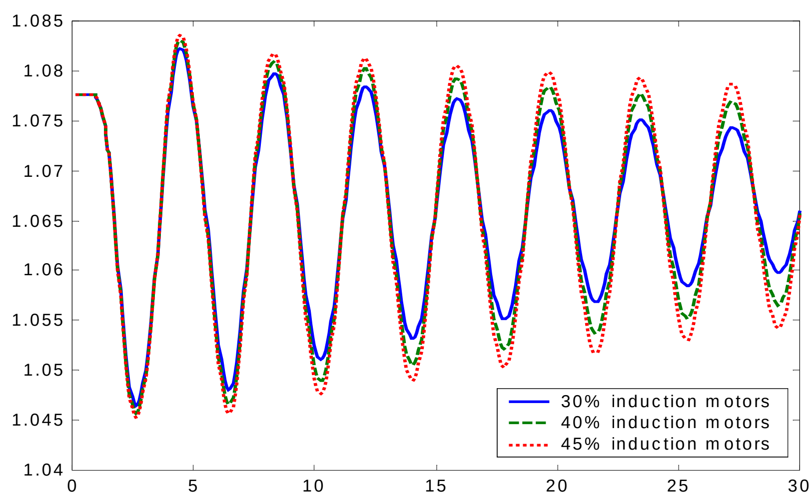


Figure 22 Impacts of Induction Motors on System Oscillation [4]

Combining electrochemical capacitor energy storage with appropriate bi-directional electronic power conversion provides a legitimate distributed mini-FACTS controller. Figure 23 shows a conceptual block diagram of the electrochemical, capacitor-based mini FACTS controller system. This system may be controlled to act as a stabilizer for distribution feeders, acting on post-disturbance voltage to assist in returning the voltage and frequency to an equilibrium status within one second. The advantages of the electrochemical capacitor-based storage system over conventional lead-acid battery are relatively high-power density and cycle life as well as inherently lower maintenance and tolerance to temperature. Currently the main disadvantage is cost. The potential advantage of EC capacitors over SMES, a technology that has been used successfully in grid stabilization, is likely to be modularity in size selection and lower cost.

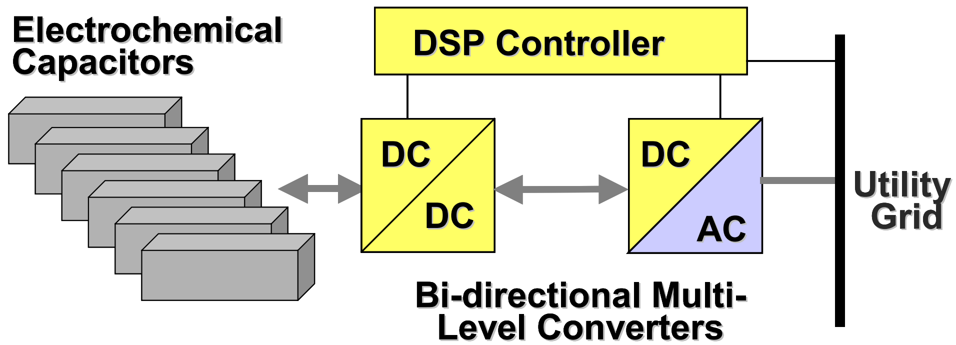


Figure 23 Concept of Electrochemical capacitor-Based Mini-FACTS controllers Coupled to Utility Grid

Uninterrupted Power for Critical Substation Loads

Problem Description

The need to protect substation equipment during momentary power disturbances and longer-term outages depends on the equipment sensitivity, function, and exposure to power disturbance events at the location. Currently, most substations have control and protection equipment that are identified as critical to station functions. By far the most common practice to protect this equipment is the installation of 48-, 125- and 250-Vdc stationary batteries sized for several days of outage protection.

These station batteries require a significant amount of real estate often in the control house of modern transmission and distribution stations. Sixty to 120 cells of large 100- to 400-AH batteries on several battery racks are not uncommon. These typically require environmental space conditioning and periodic maintenance. In some cases, without space conditioning, the expected battery life and its capacity are less. Replacing the batteries with a smaller power protection system that can be installed outdoors is of interest to many utility planners and substation engineers.

One concept that will accomplish this is to provide short-term energy storage with some form of back up generation. The system is designed for a few seconds of bridging power to transfer from the primary supply to on site back up generator. Today most practical generators are internal combustion engines, however new types of generators such as micro turbines and fuel cells, as well as advanced fuels, such as hydrogen and bio diesel are evolving. Short-term energy storage products are currently available and could be applied.

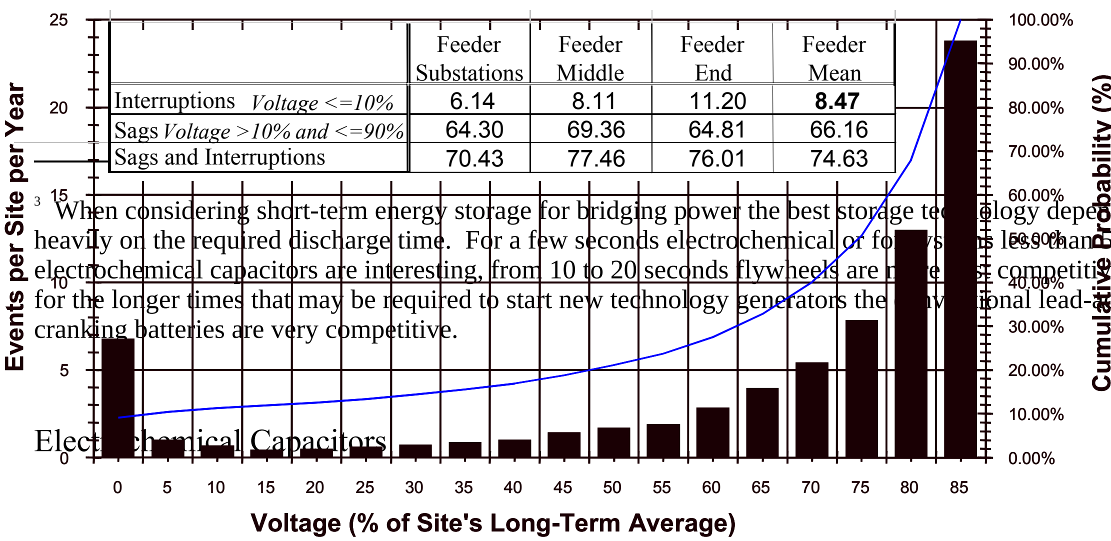
As of this writing no such application has been installed and tested in substations, although a number of utilities are investigating possible demonstrations. These same systems have proven to be reliable in many power quality applications. In the future short-term energy storage such as flywheels, high-energy capacitors, or low-cost cranking batteries, may replace station batteries as a bridge to a fast-start alternate source, such as an engine generator. The options for alternate generators are getting to be more interesting with the possibility of fuel cells, micro-turbines or even hydrogen-fueled IC engines[3]. And the high output power characteristic of many short-term storage technology is particularly complementary to new generation technologies that, when operating alone lack overload capability.

Before any application of power protection equipment is attempted the expected electrical environment should be identified. Monitoring and studies of electric power systems have shown that nearly all locations are exposed to power disturbances such as faults on distribution feeders and momentary or sustained loss of the primary power feed. In the case of substations, the low-voltage power service bus is likely to be affected by all events that take place on the transmission lines serving the station and from all the faults on feeders originating from the station.

EPRI's distribution power quality study has defined the typical electrical environment in terms of number and duration of expected events. Figure 24 shows typical interruption and sag rates from the study [3]. These results are based on monitoring events at 277 locations for 28 months, with 326,000-recorded events. Monitor locations were utility feeders selected to be representative of typical quality of power in the US. The average at each location was 74.6 per year.

The proposed application is Uninterruptible Power for Critical Substation Equipment that will replace existing station lead acid batteries. This is accomplished by a short-term storage device (e.g., high energy capacitor) incorporated into a bridging power system, as described below, to enable seamless transfer to an alternate feeder or power source. The technical criteria for this application will be substation specific but likely will fall within these parameters:

- **Application –** Uninterruptible Power for Critical Substation Equipment
- **Power Rating** – 25 kW (32 kVA)
- **Energy Storage Capacity –** 139 Wh (not including generator output)
- **Duration** – 20 seconds, or until start of back up generator
- **Response Time** – 5 milliseconds



	Feeder Substations	Feeder Middle	Feeder End	Feeder Mean
Interruptions *Voltage <=10%*	6.14	8.11	11.20	**8.47**
Sags *Voltage >10% and <=90%*	64.30	69.36	64.81	66.16
Sags and Interruptions	70.43	77.46	76.01	74.63

[3] When considering short-term energy storage for bridging power the best storage technology depends heavily on the required discharge time. For a few seconds electrochemical or for systems less than 50-kW electrochemical capacitors are interesting, from 10 to 20 seconds flywheels are more cost competitive, and for the longer times that may be required to start new technology generators the conventional lead-acid cranking batteries are very competitive.

- **Duty Cycle –** Infrequent, e.g. 6 times per month, 75 momentary events per year
- **Roundtrip Efficiency** – 70-80% (assumes less than 1% duty cycle)
- **No load Losses** – Less than 3%
- **Plant Footprint** – 50 kW/m^2
- **Environmental Issues –** EMI, Harmonics, Air Quality (if back up diesel is used)

Figure 24 Typical Interruption and Sag Rates as a Function of Voltage Magnitude

There are very few practical non-energy storage alternatives for providing uninterruptible protection of critical loads. Other available power sources or spinning reserves will serve this need. This is usually in the form or a second independent feeder that is accessed within the required response time via an electronic switch. Available of such independent feeders is rare. Also, in this case, the small scale of the application is not likely to justify the cost of such sources.

Battery-less Bridge to Stand by Generator (Standby UPS)

The objective of the bridging power system is to carry the critical load away from an out-of-spec or failing power source, and to a stable alternate source. The system is effectively a battery-less standby UPS. Several key functions are required to accomplish this objective. These are rapid isolation from the failing source, recovery using local storage, energy conversion, synchronization, paralleling and soft transfer switching between the primary and alternative power source. Optional functions that may add value to this application are: additional power conditioning and filtering, full-time reactive and real power stabilization, harmonic cancellation, control and dispatch of distributed generation, interconnection protection and load control. Figure 25 shows each of the basic functions in a generic circuit configuration.

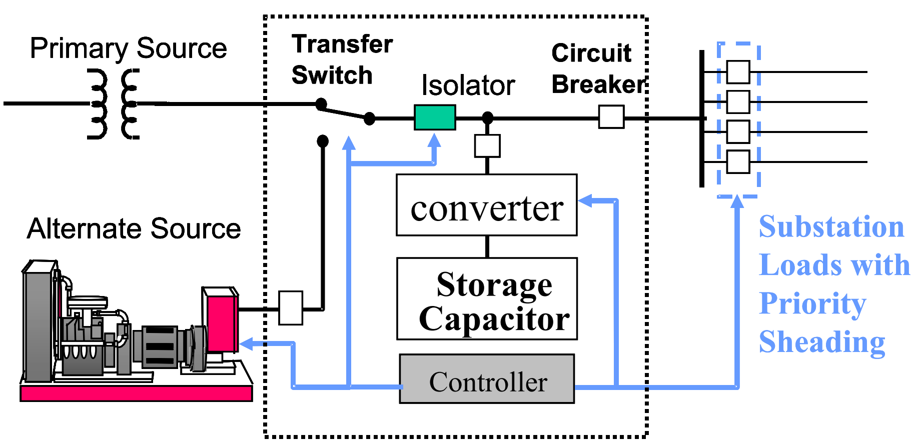


Figure 25 Generic Circuit Configuration for a Substation Bridging Power System

Typically, the bridging application transfers the facility load from the primary power source to a stand-by engine generator set. In addition, the application includes the transfer back to the primary source after power is restored, and these transitions must be seamless without causing any disruption to the source, load or facility. Characteristics of available bridging power systems are:

- Interruption protection within cycles
- Bridging power to alternate source - typically 10–20 seconds
- Synchronized control for paralleling and seamless transfer
- Single and 3-phase systems range from kWs to MWs at low to medium ac voltage
- Interconnection protection and load control may also be provided

Figure 26 shows an electrochemical capacitor bridging power system designed for a 150-kW dc load. The system will carry the load for up to 12 seconds during an outage and will also boost the dc voltage during voltage sags. By applying electrochemical capacitors in a bridging power system there are several potential benefits in addition to outage protection, for example:

- Momentary missing-voltage replacement where electrochemical capacitors system supplements the reduced voltage during a fault or a severe overload condition, without the need to start back-up generation, covers 80-90% of events. Normally the duration of this support is less than 15 cycles or 250 milliseconds.
- Providing required bridging power where the electrochemical capacitors carry and serve the local load, with both real and reactive power, during transfer between alternate power sources. Bridging power is for a few seconds during transfer to a hot standby power source or up to 15 seconds for transfer to a cold-start generator.
- Supplementing a small standby power source as a source of current for starting or for handling other momentary overloads when operating standalone. This allows reduced size and inrush capacity in the alternate source.

Figure 26 Capacitor System, ~2MJ, 133kW for 15-seconds, energy delivered from dc to dc converters at 600 Vdc, from 9 42Vdc, 220 F Modules operating from 42 to 21 Vdc

Matching Batteries for Power and Energy Loads

Problem Description

The need to protect substation equipment during momentary power disturbances and longer-term outages depends on the equipment sensitivity, function, and exposure to power disturbance events at the location. Currently, most substations have control and protection equipment that are identified as critical to station functions. By far the most common practice to protect this equipment is the installation of 48-, 125- and 250-Vdc stationary batteries sized for several days of outage protection.

These station batteries require a significant amount of real estate often in the control house of modern transmission and distribution stations. Sixty to 120 cells of large 100- to 400-AH batteries on several battery racks are not uncommon. These typically require environmental space conditioning and periodic maintenance. In some cases, without space conditioning, the expected battery life and capacity are less. Reducing the size of this battery and increasing the ambient temperature range for effective operation, allowing it to be installed outdoors, is of interest to many utility planners and substation engineers.

The size of this critical load and the period that protection is required varies with the substation design and function. Most substations have requirements from a few hundred watts to several kilowatts, which is well suited for the station battery. Most of the systems installed today tend to be oversized for longer duration protection up 10s of hours. Also contributing to large size is the difficulty to match load power and energy requirement to the battery capabilities. This is because some of the loads are relatively low power for the full duration of the outage, and other loads, such as breaker trip coils, are relatively high power and high inrush, for a very short time. The station battery is effectively oversized to meet both power and energy requirements at the rated voltage.

There is an opportunity to better optimize this system with a hybrid energy storage design. The idea is to match high-powered short-term energy storage with those high inrush loads and to match the longer-term battery storage for the average load. Relieving the station battery of these high inrush loads will allow a significant reduction in size and may extend the life or reduce the cost of the smaller battery because its characteristics can be better matched to the duty.

This application entails segregation or buffering of high-inrush, low-energy loads effectively removing them from the station battery-sizing requirement. While the traditional lead-acid battery is capable of handling these momentary loads it must be sized to do so. The high power energy storage device that will support these high inrush loads will be electrochemical capacitors. Removal of high inrush requirements and added redundancy provided by the capacitor string is expected to allow reduction of the station battery by up to 50%. The technical criteria for this application will be substation specific but likely will fall within these parameters:

- **Application –** High-inrush load support for a 48-kWatt-Hour station battery requirement (3 kW x 8 hours x 2)
- **Voltage Rating –** 120 Volts dc

- **Power Rating –** 36 kW (assumes 1.5 kW load x 12 for inrush)
- **Energy Storage Capacity –** 60 Wh
- **Duration** – 6 seconds
- **Response Time –** 5 milliseconds
- **Duty Cycle –** Infrequent, e.g. 10 times per month, 120 per year
- **Roundtrip Efficiency –** 70% (lower efficiency at maximum power)
- **No load Losses** – less than 2%
- **Plant Footprint** – .5 m^2
- **Environmental Issues –** same as lead-acid batteries

The only alternative to energy storage devices is other available power sources or spinning reserves. This is usually in the form or a second independent feeder that is accessed within the required response time via an electronic switch. Availability of such independent feeders is rare.

High-Inrush Load Support for Substation Batteries

Electrochemical capacitors do not compete well with batteries when a long-duration energy supply is needed. However, they excel when the requirement is high power for a short-duration, such as for starting inrush, as required to operate a trip coil or motor operated switch. The fact that a station battery has to serve auxiliary loads for a long duration, and then at the end of this time period still have the necessary pulse power to operate high inrush loads, leads to over sizing station batteries relative to the average loads served. Another factor contributing to desire for redundancy.

The proposed solution is to add the electrochemical capacitors in parallel on the battery buss via a small dc-to-dc converter to allow voltage matching during both charge and discharge. The conceptual layout is shown in Figure 27. Also required will be a small series impedance (not shown) to assure that the converter and capacitor combination show lower impedance for inrush circuit requirements. Some classification and segregation of load into high power and high energy may help with design and application of this solution.

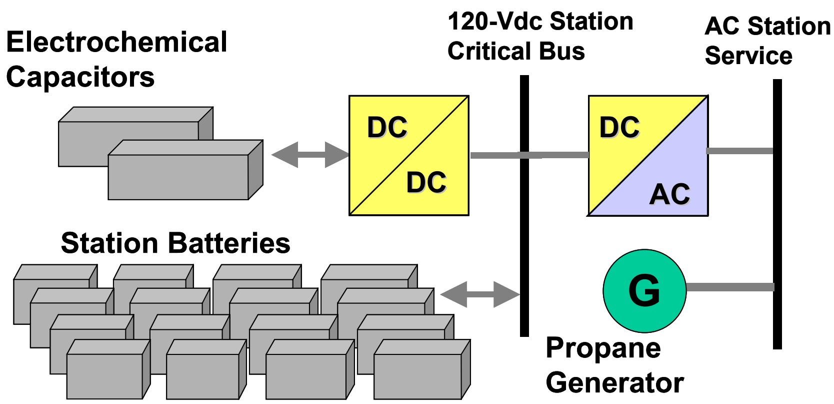


Figure 27 Generic Circuit Configuration for a Substation Battery Support System

Costs and Benefits

This section defines the variables that determine typical costs and benefits for electrochemical capacitor energy storage applied to transmission and distribution. Costs are based on both currently available and emerging electrochemical capacitor technology, in multi-module configurations. For this analysis a type II, pulse duty cells are estimated to be used for grid stabilization in the proposed distributed mini FACTS application and for station battery inrush support. The type III asymmetric traction type cell is estimated for service in the substation batter-less bridging power UPS application.

Cost Assumptions

The following are the assumptions related to these variables and the relevant applications.

1. Type II, pulse duty, electrochemical capacitors cost \$115/Wh, type III, traction duty, capacitors are \$80/Wh.
2. The installation costs are a one-time expense that includes ancillary electrical power integration and wiring, panel board and switchgear. HVAC is required for the grid stability application, but only rated for standby operation and for cooling the control elements. That is, during high duty cycle periods the power components are cooled by movement of ambient temperature air. The first cost of the HVAC is included as part of the installation cost. Operating cost is considered separately.
3. The system footprint or required real-estate leads to a fixed cost based on the annual lease of square-footage required for housing the system. For the cost and benefit analysis, it is assumed that the cost per square foot per year is \$25.00.
4. Annual operating expenses include cost of energy, routine maintenance and any scheduled replacements. The HVAC energy cost is fulltime, based on the no load or standby losses of 2% and part time based on the expected duty cycle of 5% and the full load efficiency of 90%, i.e. 10% losses.
5. Other operation and maintenance costs includes primarily labor, at \$200 per hour for the mini FACTs and \$100 per hour for bridging system, for inspections, exercising and fuel for generator (in UPS case), checking capacitor connections, adjusting and tuning system, etc.

6. Replacement cost assumes complete change out for energy storage and major upgrade of electronics in 10 years for the mini FACTS and. In the comparison of battery vs capacitors for the substation bridging power system the battery is replaced twice and the capacitors once during 20 year life.
7. The energy used by the electrochemical capacitor system to maintain the capacitors and controls is a function of the system efficiency and duty cycle. For example, for some applications, the duty cycle might be once per week, while for more demanding applications, the duty cycle might be once per hour. The efficiency is greatest for light duty cycle applications, and typically reaches 96 percent. However, for high duty cycle applications, the efficiency typically reduces to 90 percent.

Cost Analysis

Costs depend primarily on the electrochemical capacitor technology and the specification for the application. The three applications discussed previously have been analyzed based on the application specification. The results are shown in Table 5 below summarizing significant cost elements for these different applications and the selected electrochemical capacitor technologies.

Cost and Benefit Comparison

The cost and benefit comparison using the net present value (NPV) method depends on the specific application. The table below shows the NPV of the costs, the benefits, and their combination for the three electrochemical capacitor applications described above. The parameters used in the NPV calculation include:

1. Time period for calculation is 20 years
2. Escalation rate is 5%
3. Inflation rate is 2%
4. Discount rate adjusted for inflation is 5%

Technology Variant	T&D Application	Size* kW	Stg Capacity kW-hours	A. Power-Related Equipment Cost	B. Energy-Related Equipment Cost	C. Installation-Related Cost	Total Capital Costs (A + B+ C)	Annual Estimated O&M Costs
Pulse Type II Capacitors	Mini FACTs Controller	3000	1.67	$270,000	$180,000	$180,000	$630,000	$87,627
Pulse Type II Capacitors ($/kW)	Mini FACTs Controller	3000	1.67	$0.09	$0.06	$0.06	$0.21	$0.03
Traction Type III Capacitors	Battery-less Substation UPS	25	0.139	$11,000	$11,000	$3,300	$25,300	$4,594
Traction Type III Capacitors ($/kw)	Battery-less Substation UPS	25	0.139	$0.44	$0.44	$0.13	$1.01	$0.18
Pulse Type II Capacitors	Support of Substation High-Inrush Loads	36	0.060	$1,830	$7,320	$1,373	$10,523	$407
Pulse Type II Capacitors ($/kW)	Support of Substation High-Inrush Loads	36	0.060	$0.07	$0.20	$0.04	$0.29	$0.01

*Note: Capacitor modules are connected in series to achieve the operating voltage and in parallel for increased current capacity and use dc to dc boost converters to achieve the higher voltages needed for a distribution level voltage interface.

Table 5 Summary of system costs by application and variation of technology

The following is an explanation of benefits in each application:

Mini-FACTS Controller - The major benefits associated with grid stabilization, via the mini FACTS, includes VAR control to maintain power flow and voltage stability, and to increase capacity of the T&D system. Grid voltage stabilization, providing fast VAR or watts, can enhance frequency, power flow and voltage stability, and increase power throughput of the T&D. This will increase asset utilization and in some cases defer capital investments for T&D upgrades. This benefit or cost savings is highly site dependent. For illustration purposes it has been estimated at $500/day for this single feeder case.

Battery-less Substation UPS – In this case the benefit was estimated by the life-cycle costs of the UPS/standby generator with the electrochemical capacitors compared to the same UPS/standby generator with a conventional lead-acid battery. Included in the benefit is a savings in space, $25/sqft per year, assuming that the capacitor will be in an outdoor package. Also included is two battery replacements in 20 years compared to one capacitor replacement. As can be seen, the capacitor application is not currently cost competitive with batteries. However the cost tend of batteries, assumed to be level, compared to electrochemical capacitors, which are going down, indicates that there will be a crossover where battery-less will be more economic in near future.

Support of Substation High-Inrush Loads – This application raises some interesting questions for future design of station battery systems. As in other applications the benefits will be very site specific and will depend on the individual utility practices. The benefit calculation in this case assumed a 50% reduction in the battery size. In this case the substation battery was estimated $36k, two parallel (redundant) strings at 250 AH and 120Vdc each. There for the savings was assumed to be $18k. Additional benefits of $500 per year were assumed based on space freed up in the control house. There was not consideration for any differences in operating efficiency. Both the battery and the capacitor are assumed to be replaced after 10 years, or once in a 20-year life.

Table 6 shows the costs and benefits for each application, per kilowatt costs, as well as cost benefit ratios. What is not included in the table is the opportunity for making these applications. For example the mini FACTS benefits are highly site and utility specific, and only a few such applications are likely to available to any one utility. Substation

UPS is limited to 10% or less of all substations. The opportunity for battery size reduction will vary greatly with at utility practices in battery sizing, voltage levels and types of equipment. On the other hand this may be the most significant application because of the large number of substations that have station batteries.

Technology Variant	T&D Application	Size* kW	Stg Capacity kW-hours	NPV(Costs)	NPV(Benefits)	NPV (Total)	Benefit/Cost Ratio
Pulse Type II or Type III Capacitors	Mini FACTs Controller	3000	1.67	$1,882,260	$2,274,353	$392,093	1.2
Pulse Type II or Type III ($/kW)	Mini FACTs Controller	3000	1.67	$0.63	$0.76	$0.13	N/A
Traction Type III Capacitors	Battery-less Substation UPS	25	0.139	$93,451	$90,512	($2,938)	0.97
Traction Type III Capacitors ($/kw)	Battery-less Substation UPS	25	0.139	$3.74	$3.62	($0.12)	N/A
Pulse Type II or Type III Capacitors	Support of Substation High-Inrush Loads	36	0.060	$20,083	$36,387	$16,303	1.8
Pulse Type II or Type III ($/kW)	Support of Substation High-Inrush Loads	36	0.060	$0.56	$1.01	$0.45	N/A

*Note: Capacitor modules are connected in series to achieve the operating voltage and in parallel for increased current capacity and use dc to dc boost converters to achieve the higher voltages needed for a distribution level voltage interface.

Table 6 Cost/Benefit Comparison Based on NPV Assessment.

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[3] System to Improve Voltage Stability, S.Kolluri, Senior Member, IEEE, Entergy Services Inc, New Orleans, LA.

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Glossary

Asymmetric capacitor – See type III capacitor and type IV capacitor

Electrochemical capacitor, double layer capacitor, electric double layer capacitor, supercapacitor, ultracapacitor – common names for the type of capacitor in which electrical energy is stored in an electric double layer by means of separation of charge at an interface between a solid electrode and electrolyte. Ultracapacitor and supercapacitor are trademarked names.

Energy, Capacitor - The ideal (maximum) value of the electrical energy stored in a capacitor. For the first-order model of a capacitor, it is equal to ½ CV^2 where C is the capacitance and V is the working voltage on the capacitor.

Energy, Specific – Energy per unit mass usually expressed as Watt-hours/kilogram or kilojoules/kilogram.

Energy density - Energy per unit volume, usually expressed as Watt-hours/liter or kilojoules/liter.

Equivalent series resistance - The value of the resistance element when a capacitor is modeled as a series RLC circuit. ESR can be measured using current interrupt methods or by AC impedance techniques. It contributes to dynamic losses in the capacitor, that is, losses experienced only during charge or discharge. ESR is a lumped element value that arises from the leads, current collectors, electrodes, separators, contacts, and other resistance elements.

Impedance (Z) – The ratio V/I of a capacitor where V is a voltage (periodic in time) applied to the component and I is the resultant current. Z is a complex quantity, having real and imaginary parts. It represents the current flow response to an applied time-dependent voltage.

Leakage current - The steady-state current drawn by a capacitor after being charged. It is responsible for static energy losses . The leakage current is established by resistor R_p, the equilavent resistance in parallel with the capacitor which is sometimes referred to as the self-discharge resistance. The leakage current is time dependent when the capacitor is held at a constant voltage and the current required to maintain this voltage decreases with time as the capacitor comes to an equilibrium-charge state.

Power (maximum) - The ideal (maximum) value of the power that can be delivered by a capacitor. For the first-order model of a capacitor, it is equal to $V^2/4R$ where V is the working voltage on the capacitor and R is the equivalent series resistance.

Power, Specific – Power per unit mass usually expressed as kilowatts/kilogram.

Power density - Power per unit volume usually expressed as kilowatts/liter.

Pulse Ragone plot – The relationship showing the energy delivered by a capacitor during a given discharge time. This plot shows the effective energy density of the capacitor for different discharge periods.

Ragone plot – The power and energy relationship commonly used to compare different energy storage devices. The plot is usually shown as a log – log scale with specific power for the independent variable and specific energy for the dependent variable.

Symmetric capacitor – See type I capacitor and type II capacitor

type I electrochemical capacitor - The first type of electrochemical capacitors developed. These are of symmetric design and utilizing two activated carbon electrodes with sulfuric acid or potassium hydroxide electrolyte.

type II electrochemical capacitor – The type of electrochemical capacitor with symmetric design utilizing activated carbon electrodes and an organic electrolyte. Organic electrolytes allow operation at higher voltage. Type II electrochemical capacitors are probably the most common type in use today.

type III electrochemical capacitor - The type electrochemical capacitor that is of asymmetric design, using one activated carbon electrode and one high capacity battery-like electrode with an aqueous electrolyte.

type IV electrochemical capacitor - The type electrochemical capacitor that is of asymmetric design, using one activated carbon electrode and one high capacity battery-like electrode with an organic electrolyte. There are no commercial type IV products; this technology is the subject of present research. (Telcordia Technologies, Inc. is sampling an asymmetric type IV capacitor that has a carbon cathode and a Li-titanate anode that uses an organic electrolyte.

Appendix – Electrochemical Capacitor Technology

Traditional Capacitor Types

There are three distinct types of capacitors: electrostatic, electrolytic, and electrochemical.

The electrostatic capacitor was invented first. It is referred to historically as a Leyden jar capacitor and is very similar to the simple parallel-plate capacitor. An electrostatic capacitor is created by two conductors (metals) separated by an insulator (air or paper, for instance). Modern electrostatic capacitors use materials other than paper between the plates, for instance, different types of polymeric films, like Mylar or polypropylene. These films can be made quite thin so the metal plates can be spaced very close together. In fact, instead of metal plates, modern electrostatic capacitors consist of a polymeric film that has been vacuum coated with a thin metal coating on each face, forming a very thin structure that can be spiral wound. The thickness of the film dictates the separation between the plates. The dielectric constant of the film establishes the multiplicative factor previously described. High dielectric constants, very thin films, and high breakdown voltages are desired in such devices. Electrostatic capacitors are available in voltage ratings above 10 kV. Electrostatic capacitors are commonly used in high voltage utility applications, such as flexible AC transmission system (FACTS) devices.

An electrolytic capacitor is more complicated than an electrostatic capacitor. It is comprised of two electrostatic capacitors in series, a cathode capacitor and an anode capacitor, separated by a liquid electrolyte. This electrolyte is an ion conductor but an electron insulator. The motivation for the development of an electrolytic capacitor was to achieve thinner plate separation thus higher energy than can be achieved by using paper or film dielectrics as with electrostatic capacitors.

Electrolytic capacitors store energy across an oxide dielectric layer on a metal surface, an etched aluminum, for instance. A second material sometimes used for electrolytic capacitors is tantalum in the so-called wet-slug capacitor. The tantalum devices are expensive and commonly used only in high reliability applications.

The dielectric of an electrolytic capacitor is anodically formed on the surface of a roughened substrate, for instance, aluminum foil. The dielectric thickness is dependent on the voltage used for its formation. Aluminum, for example, forms a dielectric film approximately 14 angstroms thick per volt applied. Thus the dielectric would be ~140 angstroms thick for a 10 V capacitor, clearly much thinner than possible for a polymer film.

With such a thin dielectric film, it is not practical to apply the second electrode directly onto it. The approach taken is to use an ion-conducting electrolyte to provide this contact so the second capacitor becomes series-connected with the first. This second capacitor is typically created in a similar manner but with a thinner dielectric layer and, therefore, with much higher capacitance. Thus, an electrolytic capacitor consists of two capacitors in series with one having substantially higher capacitance than the other. This makes the capacitance of the device very close to the smaller of the series-connected capacitors, the one formed at higher (positive) voltage.

Electrolytic capacitors are generally constructed in a spiral wound configuration. Besides aluminum, these capacitors can be made using tantalum or niobium. Electrolytic capacitor technology today provides devices rated up to 600 V. These capacitors are widely used in filtering applications (dc) because of their relatively low cost, high energy density, and low power dissipation. These are the upright tubular capacitors that are commonly seen in power supplies.

The third distinct type of capacitor is designated as electrochemical, and has been referred to as electric double layer ultra capacitors. Electrochemical capacitors store energy by charge separation at the interface between a solid electrode and an electrolyte. Individual capacitor cells operate at low voltage (< 2.7 V) compared to electrostatic or electrolytic capacitors. What makes them interesting is that electrochemical capacitors can have much higher energy densities than other types of capacitors. Thus, they can deliver the energy over longer times than electrostatic and electrolytic capacitors of the same physical size. A common application of small electrochemical capacitors is to provide power for computer memory backup during power outage.

The electrochemical capacitor, in its simplest form, is comprised of two double layer charge storage surfaces in series, i.e. two electrostatic capacitors in series. The double layer charge storage surface is formed at the interface between a conductor and an electrolyte when a voltage is imposed across them. Essentially there is an increase in the electrolyte ion concentration, with a change in electrolyte ion orientation, near the surface of the electrode. Charge separation at this interface occurs over a very short distance, ~10 angstroms. Thus, very large capacitance values, on the order of 100 Farads/gram of material, can be obtained with the use of a high surface area conductor like activated carbon. Although the double layer phenomenon has been known for more than 100 years, the first practical device was created in the late 1960's.

Ideal Capacitor and ESR

An ideal capacitor is a fundamental circuit element and has no resistive or inductive components. In reality, the first order model of an actual capacitor is a series combination of an inductor, a resistor, and a capacitor. The series resistance and inductance are intrinsic to the construction of the capacitor and are dependent on the design characteristics of the device, such as its geometry and physical size. Note that series resistance is also referred to as the equivalent series resistance, ESR.

The series-RLC circuit has a characteristic frequency f_o, the self-resonance frequency, at which the magnitude of the impedance is a minimum. This self-resonant frequency occurs when the inductance and the capacitance balance each other to produce an impedance equal to the series resistance value. This frequency occurs at $f_o = 1/\ 2\pi\sqrt{(LC)}$. At frequencies below f_o, capacitive behavior is dominant; above this frequency inductive behavior is dominant. The series resistance can be measured precisely at frequency f_o.

The self-resonant frequency of electrostatic capacitors can be in the MHz or higher range, depending on the size and design of the device. The self-resonance frequency for electrolytic capacitors is generally in the range of kHz to tens of kHz because the capacitance is much larger and the inductance is also higher, making the resonance frequency lower. For large electrochemical capacitors, the self-resonant frequency is generally in the range of 1 Hz to ~ 100 Hz. This occurs because the capacitance itself is very large. The inductance is generally small for this technology. So the frequency range of interest for large electrochemical capacitors is generally below 1 kHz.

Figure 28 shows the magnitude of the impedance versus the frequency for a series-RLC circuit. For large electrochemical capacitors presently available, the frequency at which Xc = ESR, is less than 10 Hz. Thus, these devices are completely unsuitable for 60-Hz power filtering applications. Stated differently, the dissipation factor of large commercial electrochemical capacitors at 60-Hz frequency is greater than 100%, making them behave more as a resistor than a capacitor. Thus, electrochemical capacitor technology does not compete with electrolytic capacitors in common dc filtering applications.

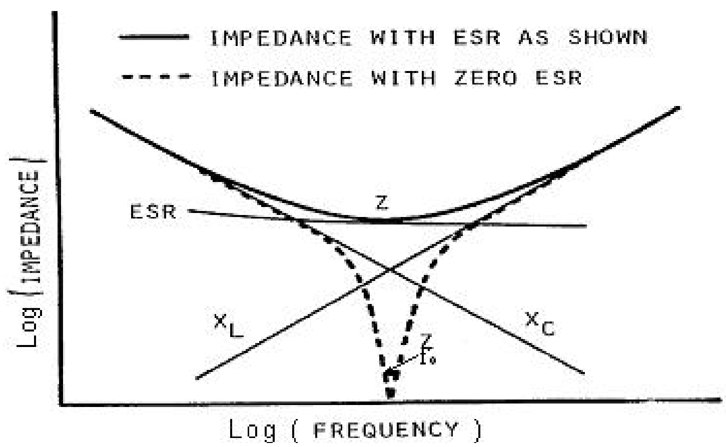


Figure 28 Magnitude of the impedance as a function of frequency for a series-RLC circuit.

As described above, the minimum impedance value occurs at the self-resonant frequency and is equal to the value of the ESR. This ESR value (R_s) along with the operating voltage, determines the maximum power capability of the capacitor. The maximum power (Pmax) that can be delivered by the capacitor into a matched load is Pmax $=V^2/4R_s$. When operating the capacitor at this maximum power point, the amount of energy that is delivered is equal to the amount dissipated internally within the capacitor. For many applications, particularly where efficiency is important, or where repetitive operation may lead to an unacceptable temperature rise, it is undesirable to operate a capacitor at this maximum power condition.

Deviations from Ideal Behavior

Because of the porous electrodes in an electrochemical capacitor, the power-energy relationship is more complicated than that described by a series-RC circuit. The equivalent circuit model used to describe the response of an electrochemical capacitor can be used to derive this energy-power relationship in Ragone plots. For example at very low discharge powers, when P_{ave}/P_{max} is <<1, the real capacitor is well represented by the series-RC circuit, see figure Figure 29. At increased power levels, deviation from the series-RC circuit becomes significant. At a power level of $P_{ave}/P_{max} = 0.1$, the delivered energy to total energy ratio is ~0.6. Slightly more than one-half of the stored energy can be delivered by the capacitor when it is discharged to one-half its rated voltage. In contrast, the series-RC circuit predicts a ratio of ~0.7. Differences between the RC model and the actual performance increase as the power level approaches its maximum value.

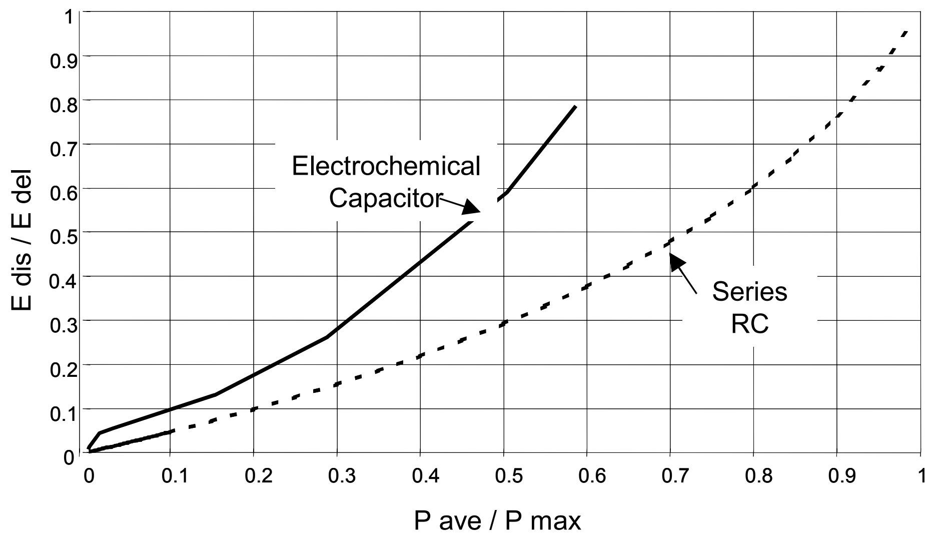


Figure 29 Energy dissipated as a function of power for series RC circuit versus a typical electrochemical capacitor

A rule of thumb for capacitor operation, where efficiency or self-heating is important, is to restrict operation to a P_{ave}/P_{max} ratio of less than 0.1. At this power level, ~90% of the stored energy can be extracted from the capacitor. There are some applications where operation at higher power levels is appropriate. These applications generally are not cyclic in nature since operating at such high levels does cause a temperature rise within the capacitor.

Two-Terminal Response

The behavior of a typical electrochemical capacitor cell can be represented by the equivalent circuit model shown in Figure 30. Circuit elements include a series resistance, R_s, and a capacitor, C, in parallel with a leakage current source. The equilibrium leakage current has exponential voltage dependence, which is observed for all electrochemical capacitors. The series resistance of a cell, R_s, is responsible for establishing the voltage of that cell in a series string during transient operation. During steady state operation, the leakage current element establishes the voltage in a cell. During intermediate rate operation, that is during charge/discharge cycling, all three elements can play a role in establishing the voltage of each cell.

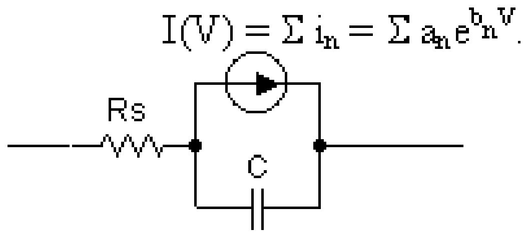


Figure 30 Simple equivalent circuit model showing series resistance and leakage current terms.

It has been estimated that more than 95% of the surface area of activated carbon is within the internal structure of the carbon itself, and that 5% or less is due to the external surface of the particles. This situation provides for a very unique electrical response. At very long times, access to stored charge within the porous network is complete. All of the stored energy is accessible and can be discharged. On the other hand, at very short times (high charge/discharge cycle rated) only the charge on the external surface of the material can be accessed. At intermediate times, charge becomes available deeper into the porous structure as the discharge times increase until full access is obtained for the entire surface area.

The porous network dictates what equivalent circuit model should be used to represent the two-terminal response of the capacitor. For float voltage operation or for very slow charge and discharge cycles, the equivalent circuit for such a porous electrode can be represented as an ideal capacitor in parallel with a leakage current source as described. This leakage current source accounts for the open circuit voltage decay of such a device. On the other hand, at shorter discharge times a series-RC circuit is appropriate. Here the series resistor is a lumped element that represents associated electronic and ionic resistances. The response time in this case is the product R•C. For higher discharge rates less of the stored energy is available immediately. In fact, a multiple time constant equivalent circuit model is necessary to accurately represent the electrical response.

Figure 31 shows such a multiple time constant circuit. This truncated ladder network

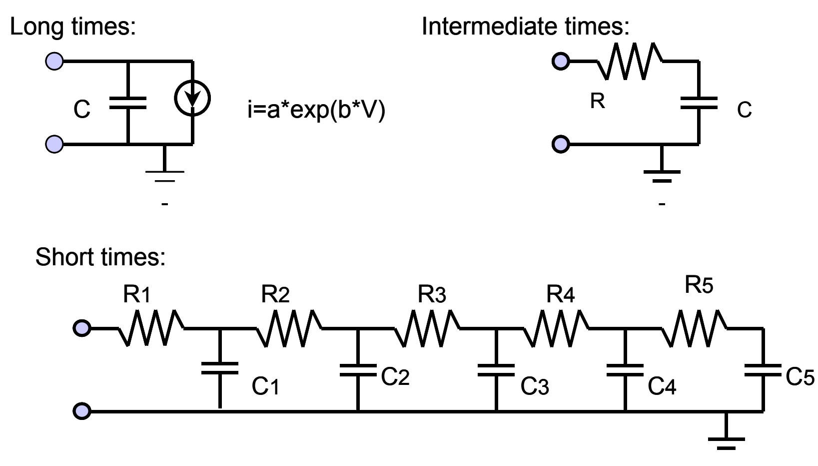


Figure 31 Equivalent circuit model for an electrochemical capacitor.

better represents the dynamic behavior of the capacitor. The fastest response time is the discharge of C1 through R1, the second fastest is the discharge of C2 through R1 + R2, and so on. Because of the distributed charge storage with distributed resistances, the capacitor can release only a small fraction of its total stored energy in very short times. This is evident in the 2500 F example type II capacitor response shown in Figure 32. At longer times, more of the stored energy becomes available until, at very long times, all of the stored energy can be accessed. Impedance data is commonly used to derive multiple time constant equivalent

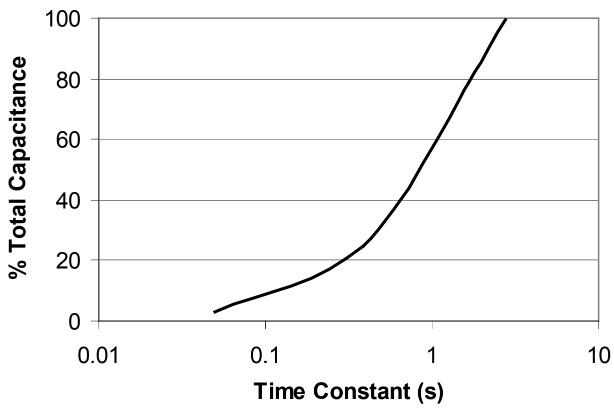


Figure 32 Type II design, 2500F capacitor demonstrates dynamic characteristics of increased capacity with reduced loading and longer discharge times.

Electrochemical capacitor response often has a second effect due to the porosity of the electrodes themselves. Although particles in the electrode are typically large, interstitial space between these particles in thick electrodes creates multiple-time-constant behavior. Consequently, an upper limit on the electrode thickness is usually established by the desired time response of the capacitor.

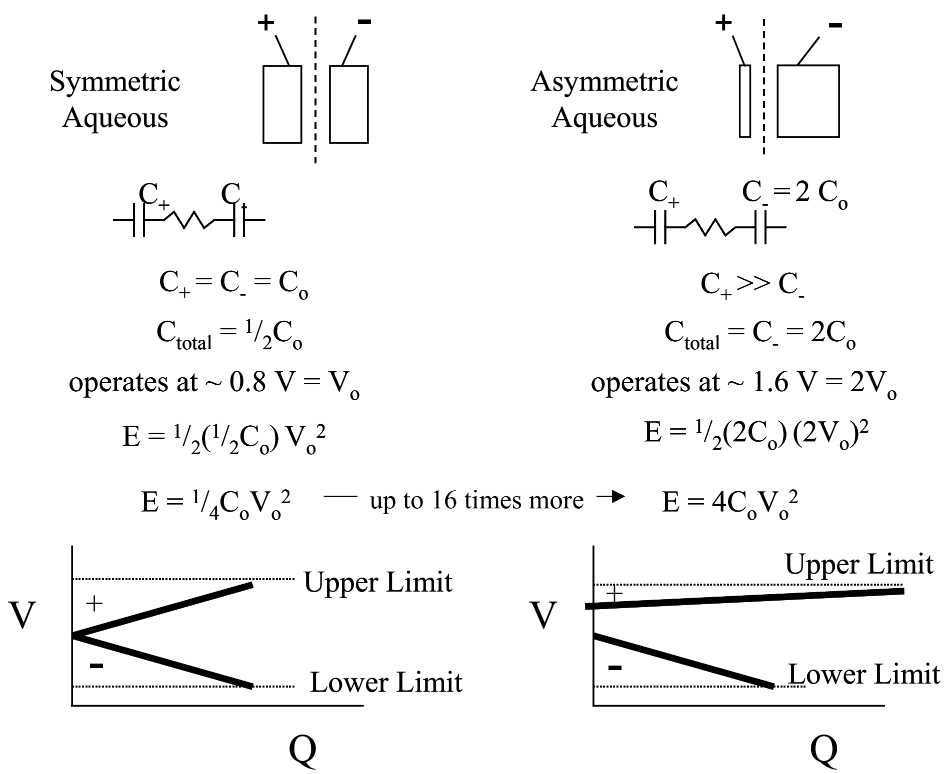
Symmetric and Asymmetrical Electrodes

Figure 33 summarizes some basic differences between the symmetric and the asymmetric capacitor designs using aqueous electrolytes. The symmetric capacitor uses the same material for both positive and the negative electrodes in approximately the same quantity, and produces two identical capacitances, each C_o. Since these two capacitors are connected in series, the total capacitance is 1/2 C_o.

In contrast, the asymmetric electrochemical capacitors, as shown on the right side of Figure 33, have positive and negative electrodes comprised of different materials. In fact, the positive electrode stores charge more like a battery (Faradaic processes) so although physically smaller, its capacity is greater than the opposing double layer charge storage electrode. There is enough space for the negative electrode to be sized for the total capacitance 2 C_o in the single electrode. And, since it is mated with a much larger series capacitor, the total capacitance of this design is 2 C_o. This difference, 1/2 C_o for the symmetric and 2 C_o for the asymmetric, gives a four-fold volumetric capacity advantage to the asymmetric designs.

The voltage versus charge curve for each electrode is also shown in Figure 33. It provides information on the exact operation of the capacitor. As charge is delivered to the capacitor, the positive electrode voltage increases and concurrently the negative electrode voltage decreases, both at approximately the same rate. Provided the rest potential (zero charge) of the electrode material in the electrolyte is midway between its stability limits, both reach their potential limits at the same state of charge. This allows the full operating voltage window to be realized. In practical implementations, the type I capacitors usually do not have a rest potential in the middle of the voltage window and do not have exactly the same capacitance in each electrodes. This reduces the maximum operating voltage in some cases from 1.2 V to below 1 V.

For type II capacitors, with organic electrolytes, voltages are higher and the window is increased. Instead of 0.8V operation as shown in the figure, this voltage could be perhaps 2.3 to 2.7 V. Also, in practical products the non-aqueous symmetric designs make up for



some of the difference in capacitance by choice of electrode material.

Figure 33 Comparison of type I and type III electrochemical capacitor energy calculation[4]

Type IV electrochemical capacitors operate in the same fashion as type III devices except the operating voltage can be higher due to the use of an organic electrolyte. Some type IV capacitors have been reported to operate at 4.0 V or higher in contrast to the 2.7 V value for the highest type II products. Consequently, the V^2 dependence of energy on the operating voltage represents at least a two-fold increase in energy density. The net

[4] The figure is intended to illustrate a fundamental difference between the symmetric and asymmetric capacitor designs. Specific energy in practical products also depends on specifics of the electrode and electrolyte materials, operating voltage per cell, device design life, and type of packaging.

benefit of type IV technology over type II technology, both having non-aqueous electrolytes, is a factor of eight because of these voltage and capacitance effects.

The graph, bottom right of Figure 4, shows voltage as a function of charge for type III and type IV devices. As shown, the positive electrode voltage is relatively flat, independent of state of charge, and the negative electrode voltage decreases towards some lower limit. Of note is the gap at zero state of charge. It indicates that the uncharged capacitor will have a voltage on it.

Figure 4 also depicts the reason why high cycle life can be obtained from type III and IV capacitors even with the use of a battery–like electrode. As shown, the relative change in charge state of the positive electrode is very small due to the asymmetry in electrode capacity. The reported capacity ratio of the electrodes for this type capacitor is at least 3:1 and preferably 10:1. This means that during a discharge cycle the positive electrode only discharges 10% of its capacity while the negative electrode is fully discharged. Consequently, high cycle life is available from such devices due to the low depth of discharge by their battery-like electrode.

Comparison with Ideal RC Behavior

It is useful to examine the power/energy relationship when discharging a series-RC circuit. The energy delivered to a load, E_{del}, at a specified average power P_{ave}, can be derived for a series-RC circuit under various discharge conditions. For a constant current discharge from V_0 to $V_0/2$, the delivered energy to total energy ratio available in that voltage window can be calculated. The equation is:

$$\frac{Edel}{Etot} = \frac{3}{8} + \frac{3}{8}\sqrt{1 - \frac{8}{9}\frac{Pave}{P\max}} - \frac{1}{2}\frac{Pave}{P\max}$$

This relationship is plotted as a dotted line in Figure 34. It applies to any capacitor of any type, provided it can be represented by a series-RC circuit. At low power levels, the value of the delivered energy approaches 0.75 E_{tot}, the total energy stored in the voltage window. As the power level increases to its maximum value, $Pave/P_{max}=1$, E_{del} approaches 0, as expected for a matched load. An important trend to note is that the delivered energy decreases monotonically as the power level rises. For example, Figure 34 shows that operating at 0.5 of the maximum power point will yield an energy delivery ratio of 0.4, about one-half the total energy available in the operating voltage window.

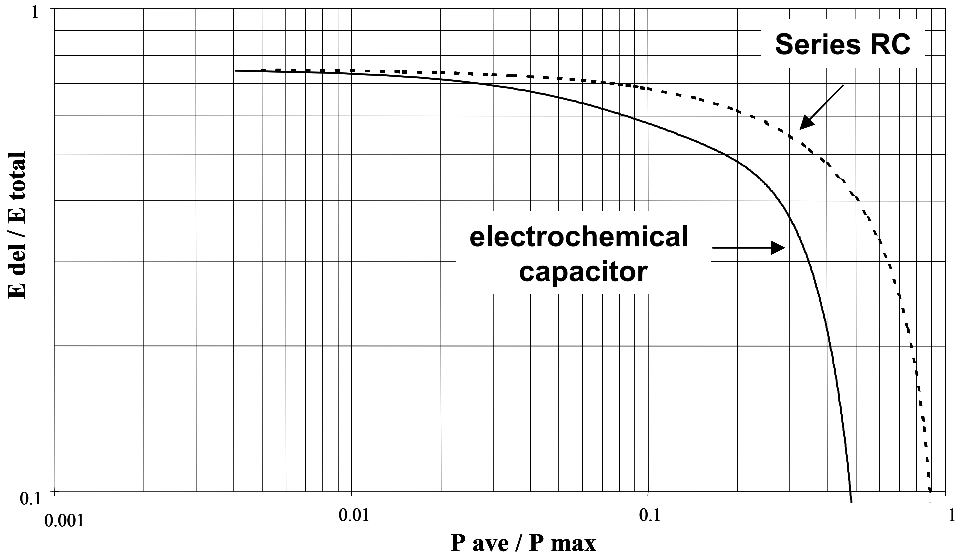


Figure 34 Energy and power relationship for series RC and actual electrochemical capacitor.

The dissipated energy E_{dis} in a series-RC circuit can also be derived for a series-RC circuit during a constant-current discharge from V_0 to $V_0/2$. This equation is:

$$\frac{Edis}{Edel} = \frac{\frac{9}{4}\left[1-\sqrt{1-\frac{8}{9}\frac{Pave}{P\max}}\right]^2}{\left(\frac{Pave}{P\max}\right)}$$

The dotted line in Figure 34 shows this as E_{dis}/E_{del}. In the case of an electrochemical capacitor the figure shows that a relatively high percentage of the total energy may not be available at high power discharge rates.

Distribution of Cell Voltages

It is useful to consider the hypothetical distribution of voltage among cells in a series-connected string as shown in Figure 35. The equations describe the relationship between the average cell voltage, V_a, and the critical voltage, V_c, above which a cell will fail. Since no cell in the string can experience a voltage greater than V_c, the average voltage must be below V_c by an amount that depends on the width of the voltage distribution. So, without active or passive cell voltage balancing, symmetric capacitor cells must be de-rated such that the average cell voltage is $V_a < V_c/(1+T/100)$ where T is the tolerance of the batch of cells in percent. Such de-rating should be kept to the absolute minimum because it decreases the stored energy in the device. For example, energy density is reduced by the factor of $(1 + T/100)^{-2}$ compared to the energy density of a single cell operating at its rated voltage. Thus, when the average cell voltage is de-rated by 10%, the energy density is reduced by over 17%.

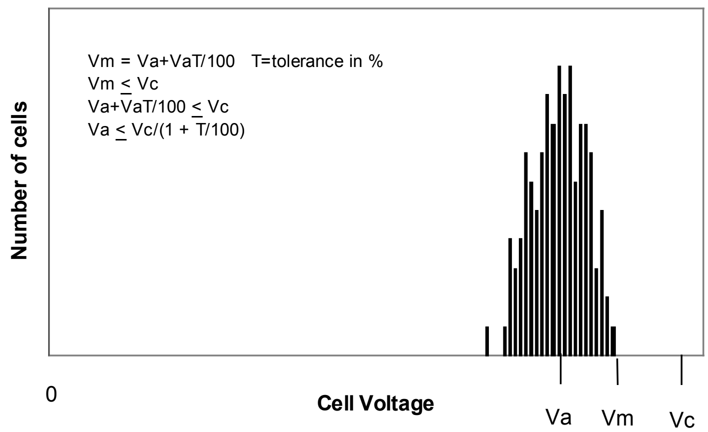


Figure 35 Histogram of individual capacitor voltages in a hypothetical series-connected string.

The tolerance, *T*, used in these derivations can be a "hard" tolerance established by sorting of cells used in a series string. For example, cells could be selected with properties in the range of ±10% of some nominal value. However, for most applications with a large number of cells, it is more convenient to express cell voltages using a continuous, rather than a discrete distribution. A normal distribution defined by a mean and a standard deviation is appropriate for a controlled manufacturing process. The relative standard deviation, *s*, in percentage, is related to the tolerance *T* by $s = T/(sd)$ where *sd* is the number of standard deviations in the tolerance band. The *sd* value determines what percentage of the population is included in the tolerance band. Thus, to include 99% of the population within the normal curve, the *sd* is 2.58, for 99.9 percent of the population the value is 3.29.

The relationship between the energy density of a series string and the *sd* value can be derived. The energy density of a string of cells is greatly reduced from single-cell values as the tolerance increases. The large tolerance in cell properties also adversely affects the manufacturing yield. Figure 36 shows yield versus the number of cells in the string for two *sd* values. Thus, cell sorting may be required for reasonable *sd* values with high-voltage strings of type II cells.

Therefore, without active or passive cell voltage balance, cell in a series-string must have extremely small variability to make a reliable, high-voltage, capacitor.

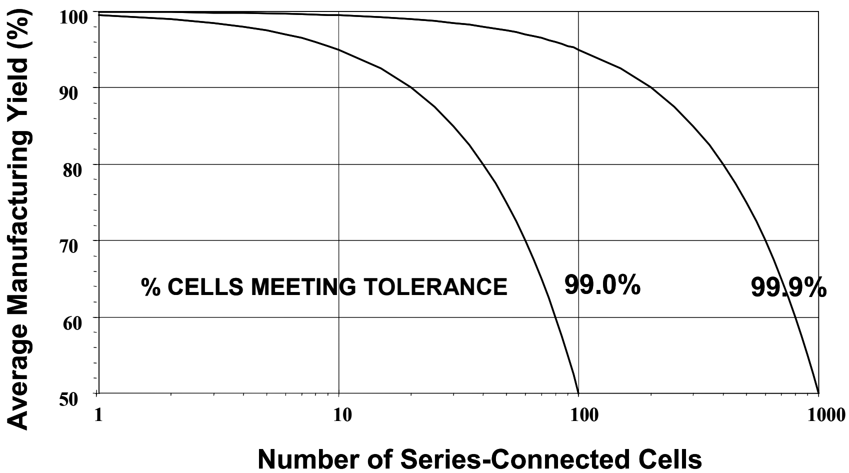


Figure 36 Yield for electrochemical capacitors from two different manufacturing distributions

Cell Failure Modes

The following charts show failure modes for electrochemical capacitors types I, II and III. There is less experience with type III and no experience with type IV. Figures 12 and 13 charts the common failure mode scenario for these capacitors.

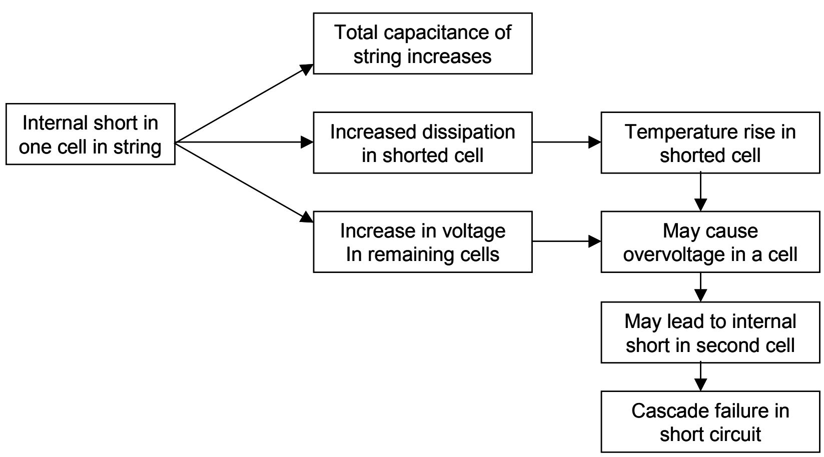


Figure 37 Possible failure mode scenario for Type I electrochemical capacitors

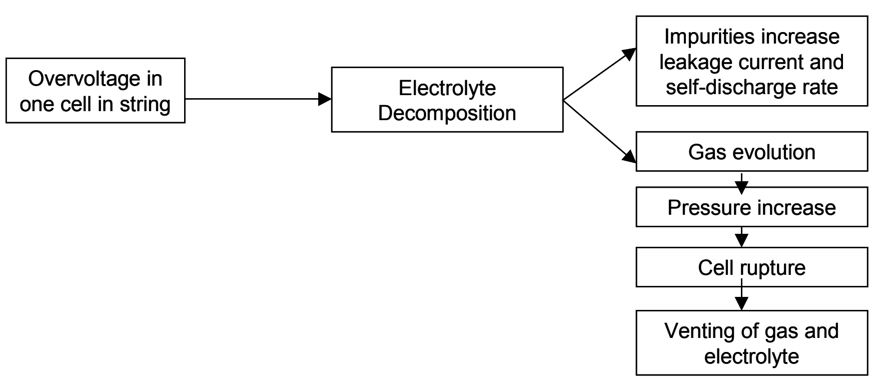


Figure 38 Common failure mode scenario for Type II electrochemical capacitors

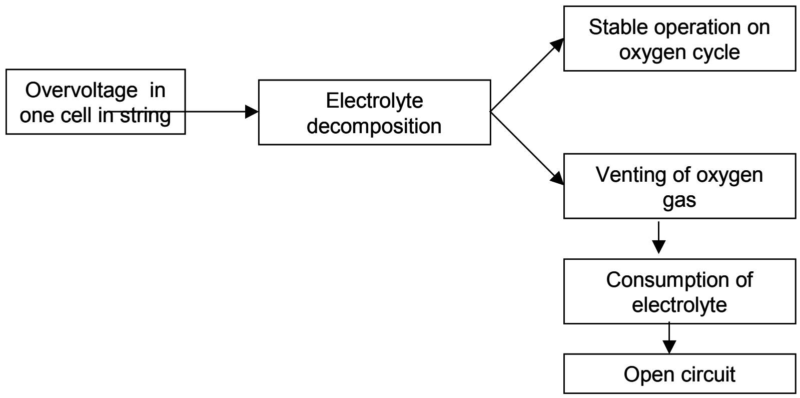


Figure 39 Common failure mode scenario for Type III electrochemical capacitors

Cell Life Predicition

Weibull analysis is a proven approach for predicting capacitor life. The experimental conditions and number of capacitors to test are selected with an experimental design. The results of life testing and reliability for a 0.1 F, 5.5- NEC electrochemical capacitor are shown in Figure 15. These are multi-cell modules using type I design. Capacitance loss occurs faster at the elevated temperatures.

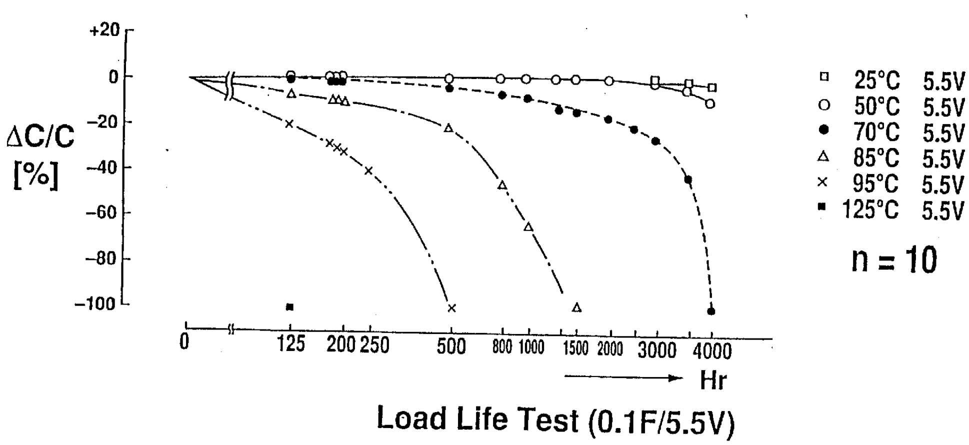


Figure 40 Life performance – capacitance loss as a function of time and temperature (NEC symmetric, aqueous design type)

The straight-line behavior in the Weibull plot of Figure 41 indicates that this model does represent cumulative failures. The slope of the 50 C and 70 C test data are the same, indicating that capacitors at these temperatures have the same failure modes. The 85 C line has a different slope, indicating introduction of a different cell failure mode. The 50 and 70 C test data can be used to derive a temperature acceleration factor for life prediction.

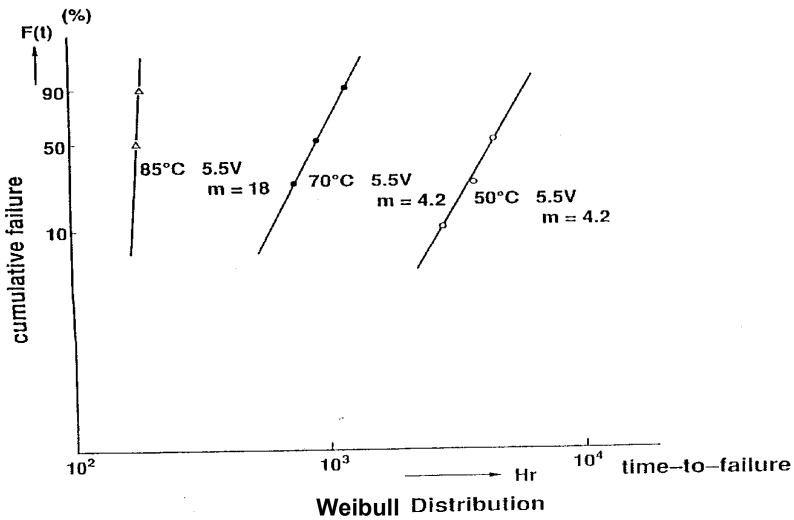


Figure 41 Life Performance – Weibull Analysis (NEC Design type I)

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