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The Multidimensional Character of Electric Systems Storage

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Abstract

In this paper we discuss the state-of-the-art in storage technology development as well as the use of storage in a wide array of utility and customer applications. We also discuss the value and use of these various technologies, and how they might influence market design and structure should they become technically and economically viable for use in electric power systems.

Introduction

The development and application of various forms of storage for use in electric utility systems has received considerable attention for the past several years. Most regard a breakthrough in cost effective and reliable storage to be a game-changer for how modern electric power systems are managed and operated. The pressing need for better energy storage technologies for both utility applications and electric drive vehicle applications have provided incentives for increased R&D and venture capital funding.

By all accounts the electrified world will continue to pursue the supply alternatives of highly reliable and inexpensive electric power generation. Effective alternatives may include the deployment of renewable energy resources, nuclear power, clean coal generation, and other generation resources; the transmission upgrades necessary to interconnect these resources with load; and various conservation and demand response programs. In concert with these new alternatives, electric service providers should also consider energy storage technologies as a strategic choice that allows for optimum use of both new and existing resources of all kinds. Energy storage technologies are not an alternative to any particular resource decision; they are a valuable adjunct to all resources that will allow for improved energy management and increased capacity from other resources.

The use of storage to shift load and/or provide frequency regulation make its use desirable if cost effective when compared to other forms of services. Some regard storage as necessary to mitigate the uncertainty associated with variable generation sources such as wind and PV. Others view storage as a mechanism for enhancing reliability when large fluctuations in load occur due to disruptions or other such phenomena. Depending upon its scale and location, storage can enhance the public good aspects (reliability) of the system, as well as providing individual buyers and sellers a physical hedge against price variations for energy, allowing for more efficient market structures and reduced amount of regulatory attention.

In addition, and in parallel, there is a move to create a smart grid that will contain a high level of smart technologies, that is, technologies with embedded computers that collectively can provide a network of distributed intelligence. The smart grid will incorporate standardized communication protocols, affording significant interoperability with other devices. And, whatever form it eventually takes, it will be integrated with a smart electricity infrastructure at the distribution level, with the energy management system (EMS) at the transmission level, and with grid operations and planning. Some predict this vision will be implemented by 2025. One study [1] suggests that "With parallel advances in smart vehicles and the smart grid, plug-in hybrid electric vehicles (PHEVs) will become an integral part of the distribution system itself within 20 years, providing distributed storage, emergency supply, and grid stability." The use of small storage devices distributed randomly in a grid is a novel concept that could have significant impact. The confluence of advances in batteries and grid intelligence provide the potential to transform the transportation sector over the next 20 years.

Pricing, and Opportunities for Customers

The emergence of a variety of electricity storage technologies in many shapes, sizes and forms provides enormous flexibility in the future design, operation and use of the electric supply system. These technologies may also put the customer into the driver's seat in determining how the system evolves, since economical distributed storage of bulk power makes electricity more like any other commodity or service. What has been unique historically about electricity is its required just-in-time production and delivery, combined with tremendous scale economies, both in production and in transport. The advent of economical storage at a variety of scales can alter the economic mix of generation sources. As examples, the timing mismatch between the availability of renewable sources of generation and the customers' demand for electricity can be hedged by storing night time wind that would have to be spilled without storage and daytime demand that would have to be served by expensive generation. Consequently, there may be less need for inefficient peaking generation, if the output from large, base-load facilities can be stored to serve everyone's peak needs. Previously, the only economical means of storage for large volume power requirements was through large-scale, pumped-storage hydroelectric facilities. To the extent that storage at the individual customer level becomes economical, individual customers are far more potent in determining the future shape of the supply system, its institutions and their regulatory oversight. In that case electricity may become more like any other commodity customers buy.

The capability of storing a commodity can add value to both buyers and sellers for three possible reasons: 1) By matching the time between when buyers want to use the commodity, when producers can or find it economical to make it and when suppliers have it to sell, 2) By serving as a physical hedge against price fluctuations , and 3) By enhancing product quality.

An additional distinction between electricity and other commodities is its speed of transit. The transportation time-lag between sellers and buyers for most goods and services is an important, planned component of supply, as in the "packing" of natural gas in the pipelines in anticipation of a period of heavy demand. Electricity does not have this in-transient inventory capability since it travels at the speed of light. So buyers and producers may find the ability to store electricity both economical and capable of enhancing the reliability of supply in the face of equipment failures and unanticipated natural events. The suppliers of transport services (transmission and distribution providers) may also be able to enhance their performance at reduced cost through deployment of storage devices throughout the network.

For most commodities, low cost storage means that the time schedule of production need not match the customers' preferred schedule of consumption. How much storage is provided by who, where and when, is simply a matter of economics and convenience. Thus with most marketed commodities "reliability" is never an issue, except if a supplier who promised delivery at a particular time defaults. In that case, the buyer usually switches venders, so every supplier has a strong incentive to keep their promise. With most other commodities, there may be alternative ways of transporting the service, so a breakdown in one transport mechanism is rarely a problem. If it is, the customer can store some of the commodity in order to insure availability. That is the second difference with electricity, and again it has to do with its transport. There is only one economical way to haul electricity because of huge scale economies in transport with increasing voltage, so usually most customers are connected by only one transportation link. In this case it is difficult for individual customers to choose their own reliability of electric service unless they can afford to have two separate lines serving them and/or to install their own back-up generation. Economical small-scale storage provides every customer another option for selecting their own, desired level of reliability, similar to the choice available to buyers of almost every other commodity.

Economical small-scale storage by each customer provides buyers with an important physical hedge against wide price variations. This demand smoothing should not only level out production costs for electricity over time, it also allows customers to avoid buying from suppliers who are trying to exercise market power at certain times, and it should lead to more "self-regulating" markets, requiring less-stringent routine oversight. The successful implementation of economical storage capacity requires confronting all buyers with the "correct", time-varying prices; only then might the regulatory oversight of the pricing of electricity be reduced.

Low-cost, high-capacity and rapid-release storage can also be of tremendous value to some types of generators, particularly those based upon widely fluctuating renewable sources, and/or to grid operators. While the cost and capacity characteristics of storage devices, and their charging rates, are of value in most all applications, and therefore to almost every user, the speed of discharge is of primary value to generators and/or grid operators to off-set the rapid loss of generation. This ramping capability is generally of less direct value to retail customers. All of these factors enter into the ultimate efficient design of the system that addresses: who should install what kind of storage capacity and where? To the extent that a proper pricing system is in place, de-centralized market forces can lead much of the way to an efficient and effective system design.

Proper Pricing to Induce Efficient Storage

Accustomed to the traditional utility form of supply institutions in the electric industry, policy prescriptions to encourage implementation of new technologies are usually in the form of payments or subsidies. However, if retail customers are the potential beneficiaries of many services provided by storage, and those devices are best located near or on the premises of individual electricity customers, then getting the delivered prices "right" for the provision of reliable electric service is essential. This will certainly be the case with the widespread adoption of plug-in electric vehicles whose economical storage capacity is determined by the price-spread between electricity and gasoline. The first step needed is to implement real-time (or "dynamic") pricing for all electricity customers. Otherwise, vehicle batteries that could be charged with no inconvenience to the customer at night, might be charged during the day and force additions to system generation, transmission and distribution capacity. Only if customers receive the proper real-time price signals will non-users of electric vehicles be spared those extra costs.

Of course, if proper real-time prices are implemented, customers may have an additional incentive to install storage at the retail level: to hedge the time varying price of electricity purchased for uses other than their cars and trucks. Thus night-time electricity purchases might be stored (either in batteries or thermally) for daytime cooling on the hottest summer afternoons. These storage equipment investments will not be made without the proper time-varying prices. During the peak-use periods, those prices need to include not only the cost of providing electric-energy (marginal generation costs plus delivery losses), but also the marginal capacity costs of constructing new generation and a proper share of additional transmission and distribution system capacity. Since these latter costs are usually translated into customer prices by Federal and state regulatory bodies, those institutions need to participate in the implementation of a proper pricing system. The potential benefits are substantial. As an example, through a Monte-Carlo analysis of system effects of implementing a real-time-pricing scheme based only on wholesale energy price variations, it has been estimated that further savings in generation capacity and in transmission and distribution capacity requirements, of from 7-10 percent might be achieved [6]. Inclusion of the proper capacity costs in peak prices might double the variations in prices with a proportional further reduction in generation and network capacity needs.

What additional price signals are required to induce customers to install and use storage capability to enhance the reliability of the services they desire? When do customers choose to provide their own reliability, rather than relying on the grid for that service? In theory, the answer here is also to include the proper, time-varying costs of providing reliability over the supply network in the time-varying prices paid by customers. This aspect of pricing once again requires the close cooperation of regulatory authorities, since as Mount, Schulze and Schuler [7] have emphasized, reliability of a service provided *over a grid* is a public good because everyone in the neighborhood gets the same level of service reliability, regardless of their true desires. Is it possible that with economical, widespread, distributed electric storage capability, the reliability of service provided over the grid could be greatly reduced so that each customer could provide the additional level of reliability they want, individually? Could distributed storage convert reliable electricity supply from a public to a private good? We will never know unless the proper prices are instituted on the current supply network by the regulators.

The beauty of a network system that has properly integrated prices is that it reveals individualized preferences. It is flexible, and it frequently reveals previously unimagined customer (and consequently supplier) responses. As an example, if the proper pricing schemes for energy (market-based, real-time-varying with capacity costs added during peak periods), and for reliability (additional operating and capacity costs to provide generating reserve and capacity margins, plus duplicate lines, transformers and equipment to provide redundancy on the delivery system, all added to peak period prices), the resulting outcomes could tell us much about peoples' preferences and subsequent technological opportunities. A number of alternative scenarios might result. With the proper pricing, and sufficiently low-cost battery storage installed by many end-use customers, some buyers might find themselves indifferent between using their storage to 1) provide further hedges against within-day price differences, 2) using that additional storage to provide them with additional back-up in case the network supply were to fail, or 3) selling the capability of discharging their stored electricity back into the grid as a ramping capability (if the characteristics of their storage device was suitable). In this case, further inferences might be made about the state of technology and the accuracy of regulatory-set reliability components of prices by the resultant scenarios.

As an example, if after making all of the changes in the pricing structure outlined above, prices were to become the same all-day long, the conclusion would be that it is less costly for customers to hedge price differences and bear the capital cost of batteries, than it was for the supply system to provide a range of generator-types (peakers, intermediate- and base-load units). If centralized storage had been more economical than distributed batteries, then the system designers should have co-opted widespread distributed storage. Furthermore, if both types of storage exist simultaneously, and there are level prices throughout the day plus the distributed batteries have widespread spare capacity, then it can be concluded that on the margin, it is better to let customers provide any further reliability! Even if prices were to vary during the day, if that variation is due to fluctuating generation market prices, and if there is also widespread excess capacity in distributed storage at all hours of the day, then once again it can be concluded that it is economical to rely upon customers to provide further reliability through their own storage decisions. In this case, however, if the price spreads don't decline over time and the reliability charges that are included in the prices for network supply also do not decline over time, the regulatory process that establishes those reliability charges should be investigated.

The probable outcomes from establishing a proper pricing regime would probably not be the extreme cases illustrated above where the reliability function is transformed by distributed storage from a public good provided off the grid to a private good whose desired level is determined individually by each customer – this can be seen in Indian cities today. The more likely scenario, because of technological limits to advances in storage technologies at certain scales, would be a combination of sizes and types of storage devices installed throughout the electricity supply network. Some customers might provide their full reliability needs on-site during some periods, while other customers relied on remote, utility-provided back-up.

Applications can be divided between power and energy at a one-hour energy discharge rating, with 15 min capacity an exemplary power storage requirement and a nominal 4 hours storage capacity for energy type applications.

Unlike power equipment most storage equipment (e.g. batteries) are rated in MWHr. Based on the national labs studies, performance and cost requirements can be estimated:

- Power costs: $500-1000/kW
- Energy storage costs < $200/kWhr
- Power storage costs < $500/ kWhr
- Life 10-20 years w/ minimum daily cycling
- More than 80% useable capacity
- More than 80% round trip efficiency

The power applications requiring only 15-30 min energy storage have been the first to achieve commercial viability with 100's of MW's of Li-Ion battery capacity being installed in the last several years in frequency regulation and spinning reserve service [9]. The TAM (Total Available Market) for the energy type storage is significantly larger with ~5-10x storage capacity needed per MW – studies indicate currently a $15B potential in the US alone, provided the cost and technical requirements can be achieved. Unfortunately, no conventional technologies can achieve them today - particularly the cost metric of $200/kWhr and the 10-20 year life metric. Emerging technologies will need to mature before these applications can achieve broad market penetration.

Table 1: High-Value Storage Propositions

Energy Storage Value Proposition		Discharge Duration	Capacity (MW)	Avg Benefit ($/kW)	Avg Benefit ($M/MWH)	US TAM (MW/a)	US TAM (MWH/a)	US TAM ($M/a)
Power	Wind Integration, Short Term	< 15 min	1-500	750	$3.00	230	58	$173
	Area Regulation	15-30 min	1-40	1400	$5.60	100	33	$187
Energy	Renewables Capacity Firming	2-4 hrs	1-500	800	$0.20	3600	10800	$2,160
	Load Following	2-4 hrs	1-500	800	$0.20	3600	10800	$2,160
	Time Shift	2-8 hrs	1-500	550	$0.14	1800	9000	$1,238
	Time of Use Cost Mgmt	4-6 hrs	<1	1226	$0.31	6400	32000	$9,808

Grid Scale Energy Storage Technologies

The US National Labs have done significant work [3,4,8] investigating potential grid scale applications of energy storage; assessing both the technical requirements, value propositions, and scale of some 20-30 different applications. Table 1 is excerpted from the Sandia study laying out results for the highest value applications. Note that these studies do not address developing world or micro-grid applications with less stiff and/or less reliable systems where the value propositions are much higher – however very useful for establishing target performance objectives.

PNNL has defined a simple cost of storage metric: Capital cost ($) / [Energy (kWHr) * Life (cycles) * Round Trip Efficiency (pu)]. Useful, but doesn't include capital and financing costs so emphasizes total cost of ownership over initial acquisition costs. This is a valid approximation for the developed world but probably inadequate for others e.g. India currently has financing cost up to 14%. Current battery technologies hover above

Table 2: Contrasts in commercially available electrochemical battery technologies

		Specific Energy	Specific Power	Cell Cost	Cycle Life	C/D Efficiency
		(Wh/kg)	(W/kg)	($/kWh)	C/20/C/20 80% DOD	Input(Wh)/ Output(Wh)
Lead Acid	Flooded (Standard)	25	120	60	800	60%
	VLR/AGM/Gell	40	180	142	600	60%
	Carbon Matt	100	720	426	1200	70%
NiMH	Sint/Sint	51	3,150	650	1,600	98%
	Foam	90	1,800	550	1,400	90%
NiCd	Sint/Sint	60	1,500	500	1,900	98%
Li Ion	$LiCoO_2$	185	1,500	1,000	700	70%
	$LiMnO_2$	143	770	600	500	75%
	$LiFePO_4$	200	1,400	700	4,000	90%
NaS		130	22	600	3500	90%
NiZn		100	900	500	300	85%
Flow Battery	Vanadium Redox	10	6	500	10,000	60%
	Zinc Bromide	85	55	600	10,000	60%

the 10c/kWhr/cycle, too expensive and not robust enough – this metric needs a 5-10x improvement i.e. a rugged but inexpensive storage solution.

Battery Technology

A battery consists of multiple series connected cells each formed by two half-cells connected by an ion-conducting electrolyte. A separator between the half-cells allows ions to flow, but prevents physical electrical shorting between the electrodes. One half-cell contains the anode electrode to which negatively charged ions migrate; the other half-cell contains the cathode electrode to positively charged ions migrate.

Figure 2 [10] is a simplified Ragone plot of specific energy vs. power densities for commercially available battery technologies with annotation referencing EV applications. NiMH batteries have been widely deployed in power tools and Hybrid EVs (e.g. Toyota Prius) – they are now being displaced by lighter Li-Ion batteries (e.g. Tesla/Chevy Volt).

For grid power applications cost targets are achievable at $500/kWhr – state of the art lithium-ion batteries being developed for EV's are selling for less than this today with 4C (15 min) discharge ratings. Lithium Iron Phosphate batteries [LFPO] currently can achieve 3,000-4,000 deep discharge cycles with over 90% capacity utilization and 90% RTE, so an excellent fit for grid power applications. A 10 year cycle life of 3000-4000 deep discharge cycles can be achieved provide the battery can be operated at 25 degrees C. Table 2 contrasts commercially available electrochemical battery

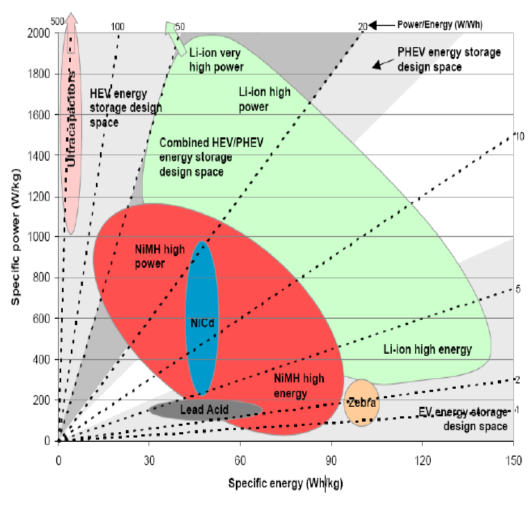

Figure 2: A Simplified Ragone Plot

technologies against critical requirements for grid energy storage applications. Red & green color highlights illustrate passing and failing grades on specific requirements. Clearly achieving target costs of $200/kWhr is challenging with only Pb-Acid there – unfortunately this technology has limited cycle life, round

trip efficiency, and usable capacity. Due to the low capital cost Pb-Acid is the de-facto energy storage solution in the developing world despite technical shortcomings.
Flow batteries have held great promise for multiple hour energy storage as they store energy in independently scalable electrolyte tanks – however, progress has been disappointing with high costs, poor densities, and low round trip efficiency. PNNL has concluded that none of the available flow technologies can achieve the specified requirements and something new is necessary

Non Chemical Energy Storage

Pumped Hydro Storage

Pumped hydro was widely deployed in the 1970's to augment new nuclear build - there are some 40 operating plants in the US. Although topographical constraints limit siting – pumped hydro has been the only large-scale energy storage solution existent. Pumped storage construction costs can vary widely dependent on the extent of civil work required ($1000-3000/kW). The economic life of the plant is very long (75 years) with little maintenance costs. The economic returns can come from multiple sources: capacity payments, on peak to off peak price differentials, renewables smoothing, and ancillary services. Deutsche Bank [11]
has recently conducted a study recommending pumped storage development in the Northern Alps and Norway to augment greatly increased European renewable generation.

Modern plants with variable speed electrical machines promise 80% round trip efficiency and greater siting flexibility: using closed water systems, abandoned mines, underground caverns, machine bored tunnels, seawater pumping, tidal barrages, … Prospects for greater deployment of pumped hydro facilities look quite promising.

AA-CAES (Advanced Adiabatic Compressed Air Energy Storage)

Compressed air energy storage also holds great promise for large-scale energy storage. CAES systems in the 100's of MW power scale are being contemplated[1] using modified gas turbine compressor/expanders with the turbine equipment coupled to electrical motor/generators for AC/AC storage per Figure 4. The compressed air would be stored in underground caverns – such as used today for NG storage. Princeton University [15] studied the availability of such to augment wind energy per Figure 5.

Advanced Adiabatic CAES systems were studied under recent EU FP6 R&D programs [12,13,14]- they capture, save, and restore the thermal energy inherent in the compression cycle. Round trip efficiency in the 70-80% range potentially achievable. An intriguing possibility with this technology is the integration of natural gas combustion with an energy storage facility. Cost prospects for AA-CAES are in the $1000-$1500/kW range. Such a facility would have similar market potential and flexibility as the pumped storage facility.

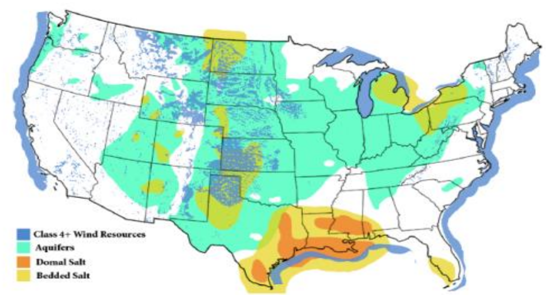

Figure 3: Sites for AA-CAES for augmenting wind

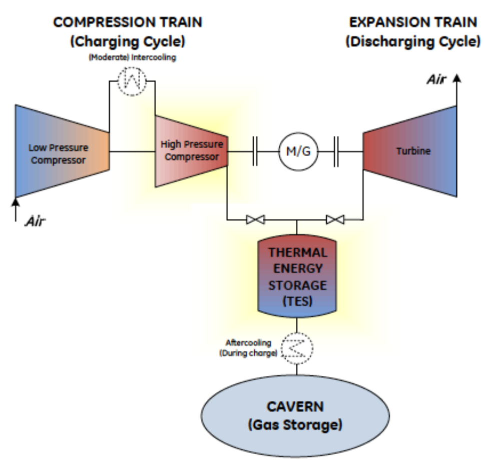

Figure 4: AA-CAES

RAES (Regenerative Air Energy Storage)

Multiple venture funded companies (LightSail, SustainX, and General Compression) are now trying to replicate at smaller MW scale compressed air energy storage based on mature engine technology to achieve near isothermal compression / expansion. Compressed air can be stored in fiber wrapped steel vessels or in constructed underground facilities. However, costs are challenging at the smaller scale and round trip efficiencies likely bounded at 60%.

Solar Thermal

Thermal storage is being integrated into next-generation concentrating solar thermal (CSP) plants. Since thermal storage is much less expensive than storing electricity this approach is promising but dependent on reducing the costs of the solar collectors, trackers, and heliostats that make up a CSP system. Concrete/rock, thermal salts, and high temperature molten glass are being investigated as storage media. Thermal storage can smooth out power fluctuations due to cloud passing, increase overall plant capacity factor, as well as shift generation from peak sun to early evening to better match load profiles.

CSP plants have recently been very challenged by the rapid declines in PV costs. The addition of thermal storage plus higher temperature / more efficient ‘power tower’ technology may alter this economic equation.

Emerging Technologies

Much academic effort and venture capital going into energy storage technology development – given the level of effort, the power industry can expect significant progress in the next decade. Examples include:

Na Ion: CMU spinout is developing a room temperature aqueous battery based with NaMnO2 cathode based on inexpensive non-toxic materials. GE has also recently developed a NaMH high temperature battery for 8+ hour backup applications.

Nickel Iron: Originally commercialized by Edison, a very robust electrochemistry. Modern variants are being developed that promise both low cost and 10’s of thousands of cycles.

Metal-Air: Zn, Iron, & Li variants under development. Zn very inexpensive but RTE low 50-60%. Li-Air under development at IBM R&D – very high energy density possible, safety issues with lithium metal anode. An Iron-Air battery under development at USC is potentially energy dense, safe, and inexpensive.

3rd Generation Li-Ion: Much effort going into lithium technology development: safer inorganic electrolytes, less costly thick electrodes, lithium anodes, compound carbon/silicon anodes, polysulfide cathodes, … all promise significant evolution of the technology.

Liquid Metal: MIT spinout developing high-temperature Mg-Sb battery with a molten salt electrolyte - immiscible phases stratify by density into distinct layers. Liquid metal has potential to be a large-scale battery.

Advanced Flow: New flow batteries are under development (Li-Ion, Iron, and Li-Polysulfide) that potentially overcome some of the limitations of existing technology i.e. tolerant of electrolyte cross contamination, low cost electrolyte & separator materials.

Solid State: Multiple teams working on nano-structured, quantum-effect solid batteries/capacitors – e.g. Stanford professors are developing a quantum dot capacitor. These R&D projects hold promise of fast, dense storage without cycle degradation.

Using Distributed Storage to Provide Ancillary Services

Many types of storage installed at different locations on a grid have the capability to provide frequency regulation, mitigate the variable generation from renewable sources, reduce the ramping costs of conventional generating units, and modify/flatten the daily pattern of dispatch for conventional generating units. An additional advantage of distributed storage is that the peak delivery of power to load centers on the grid is reduced because these storage units can be discharged during peak periods to reduce the net load supplied from the bulk power grid. As a result, there is less transmission congestion. In other words, distributed storage can be viewed as a partial substitute for transmission upgrades as well for the number of peaking units needed to maintain Operating Reliability. Currently, the cost of storage is generally too high to make a viable economic case for providing ancillary services. Although frequency regulation is an important exception at this time, this is a relatively small market. It is, however, highly likely that the cost of storage will continue to decrease in the future and many promising new technologies were discussed above. The theme in this section of the paper is to consider how the availability of inexpensive storage capacity would affect operations and costs on an electric delivery system.

A promising form of storage is distributed, located on distribution networks and owned by customers. This type of storage is generally referred to as “Deferrable Demand” (DD) because the purchase of power from the grid (charging a battery in an Electric Vehicle (EV) or charging a thermal storage device for space conditioning) is disconnected from the delivery of an energy service (transportation or space cooling and heating). Compared to the batteries in electric vehicles, thermal storage, as a supplement to air conditioning and/or electric resistance heat, could have a much larger impact on the grid. For example, the air conditioning load accounts for over a third of the total summer load in many parts of the nation.

The main economic difference between DD and utility-owned distributed storage is that customers own the DD, and could, with appropriate rate structures, reduce their monthly bills substantially. Even though the customers must cover the cost of installing DD, this cost of DD is likely to be substantially lower than the cost of an equivalent amount of distributed storage. The full cost of utility-owned storage will eventually be incorporated into customers' bill in some way, but the cost of DD is shared with the delivery of another energy service. For example, the main rationale for buying an EV is to reduce the cost of driving because the cost/mile from charging a battery is much less expensive than buying an equivalent amount of gasoline. Adding a "smart charger" is relatively inexpensive and this makes it feasible to charge the battery when the price of electricity is lowest, and, under the right regulatory environment, to provide frequency regulation and ramping services. If customers are compensated for providing ancillary services, their net payments to the utility will be even lower. The economic issue is, as usual, to determine whether the reductions in their utility bill are sufficiently large to justify financing the capital cost of installing DD devices.

Some ancillary services provided to the grid by customers have a long history. Providing emergency reductions in demand, using interruptible contracts with industrial customers, is a good example. Although many wholesale customers have the potential to manage their own DD capabilities, it is likely that Aggregators of Residential Customers (ARC) will manage the DD capabilities for groups of residential and small commercial customers in such a way that the customers are unaware of the timing of their power purchases for charging DD devices. The economic rationale for customers is that an ARC will reduce the cost of purchases from the grid and lower their bills without affecting the delivery of energy services. In this sense, an interruptible contract is not strictly a form of DD for industrial customers. A company like EnerNOC Inc. is an example of an ARC that can provide emergency reductions of demand by turning off customers' air conditioners for a few minutes using a wireless signal [18]. This capability is a valid example of DD. Another example of DD is the management of water pumps by Enbala Power Networks to provide frequency regulation [19]. In fact, controlling the timing of water pumping is a potentially large source of DD, particularly in regions like California that have large areas of irrigated agriculture.

Recent research at Cornell University has investigated how the addition of wind turbines to a grid interacts with storage capacity and DD [20]. The analysis uses a stochastic form of Multi-Period Security Constrained Optimal Power flow (MSCOPF), the second generation SuperOPF, which optimizes the hourly operations on a network for a day [21]. In this sense, it corresponds to a day-ahead market. The potential amount of wind generation each hour is stochastic and equipment failures (contingencies) may occur. In general, the probability density function of potential wind generation for any hour is skewed to the right and may have a point mass at zero (the potential generation for wind speeds less than 5 m/sec is zero) and another at the maximum rated capacity (for wind speeds over 15 m/sec and less than 25 m/sec). For wind speeds greater than 25 m/sec, the turbines cut out to avoid damage.

If no storage is available, conventional generating units (e.g. natural gas turbines) must provide the up and down ramping services needed to compensate for the uncertainty of wind generation. The analysis assumes that reserve capacity for up and down ramping reserves are purchased in a day-ahead market to supplement the standard type of reserves purchased to cover contingencies. Providing these ramping reserves is quite different in some ways from standard reserves. The standard reserves purchased to cover contingencies are typically for up ramping to cover relatively rare equipment failures. The ramping reserves for mitigating wind variability are dispatched more frequently, and this may result in a substantial amount of additional wear-and-tear for the turbines. When the costs of purchasing ramping reserves and delivering ramping services are considered, the basic economic question is to determine whether is pays to provide more down ramping capacity to offset high levels of potential wind generation. In general, lower levels of potential wind generation are always dispatched, but the expected savings in fuel costs from dispatching high levels of potential wind generation may be too low to cover the cost of acquiring additional ramping capacity. As a result, the expected amount of potential wind generation spilled is positively related to the marginal cost of providing ramping services.

If storage or DD capacity is available and able to provide an inexpensive source of ramping, it will displace conventional generating units and provide most of the ramping reserves to mitigate the variability of wind generation, and in addition, it will be optimum to dispatch more of the potential wind generation and displace more generation from conventional sources. Comparing Figures 1 and 2 demonstrates how the availability of (inexpensive) storage capacity affects the hourly dispatch of conventional generating units for a hot summer day using a network on which wind turbines can supply about 20% of total generation. The stochastic behavior of potential wind generation is represented in the analysis as a set of possible system states for each hour. Each state has a probability associated with it. In Figure 1, there is no storage capacity available and expected hourly level of generation ranges from a peak of 55 GWh to a low of 30 GWh. This is basically an economically expensive situation because so much installed peaking capacity is needed to maintain Operating Reliability. In addition, the optimum ranges of conventional generation each hour are relatively large. The up ramping requirement

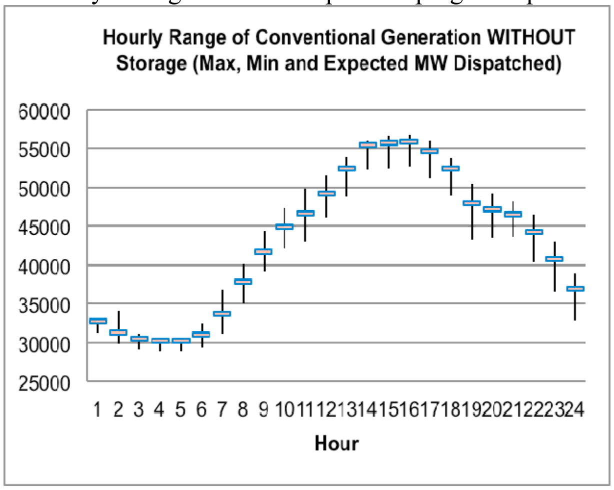

Figure 1: Hourly Ranges of Conventional Generation without Storage

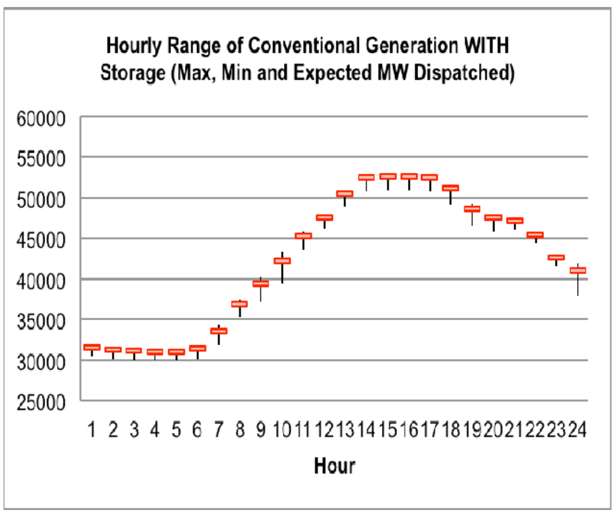

Figure 2: Hourly Ranges of Conventional Generation with Storage

for a given hour is determined by the difference between the maximum generation in the next hour and the minimum generation in the current hour. The same rationale for determining down ramping applies. Since the ranges of generation for each hour are large, the amount of ramping reserves purchased is also large and this is relatively expensive. As a result, a relatively large amount (18%) of the potential wind generation is spilled during the day.

The results in Figure 2 are quite different from Figure 1 because storage capacity is available. In this example, the storage is DD provided by ice storage (with an energy capacity equal to 3% of the total expected demand for the day). The most important difference in Figure 2 is that the peak level of conventional generation is over 3 GW lower and the minimum level is roughly 2 GW higher, reducing the daily ramp up and ramp down by 5 GW. To extent that power systems are designed to meet the peak system load, the reduction of 3 GW in the peak power purchased from the grid with DD reduces the amount of installed peaking capacity needed to maintain System Adequacy and the associated capital costs. The second important difference in Figure 2 is that the hourly ranges of conventional generation are much smaller and this reduces the amount of hour-to-hour ramping capacity needed. With DD providing an inexpensive source of ramping reserves, most hour-to hour ramping is provided by DD, reducing the cost of purchasing ramping reserves from conventional generating units, and in addition, less wind generation is spilled (only 8% of the daily potential instead of 18%).

The size of the reduction in the amount of ramping reserves purchased from conventional sources when is DD available depends on how expensive it is to use DD to provide ramping services. In Figure 2, the cost comes from the basic inefficiency of storage. If the cost of ramping reserves is made the same for DD as it is for conventional generating units, the use of storage changes dramatically. Figures 3 and 4 show the upper and lower bounds on the hourly level of energy stored and the corresponding expected levels. The model determines these bounds endogenously. With inexpensive DD in

Figure 3 (consistent with the results shown in Figure 2), the bounds are relatively far apart, reflecting the flexibility needed to mitigate the variability of wind

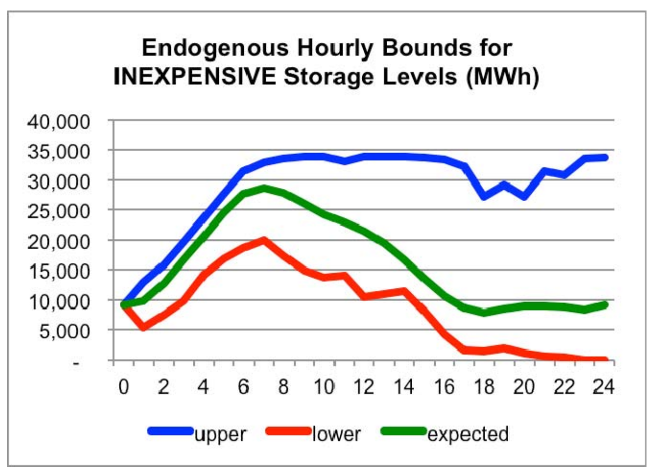

Figure 3: The Endogenous Bounds on the Hourly Energy Stored with Inexpensive DD

generation. When the cost of ramping reserves from DD is high in Figure 4, the bounds are close together because the storage capacity is used primarily to shift purchases of energy from peak to off-peak periods to benefit from price arbitrage. Since ramping reserves are more expensive in Figure 4, more wind generation is spilled

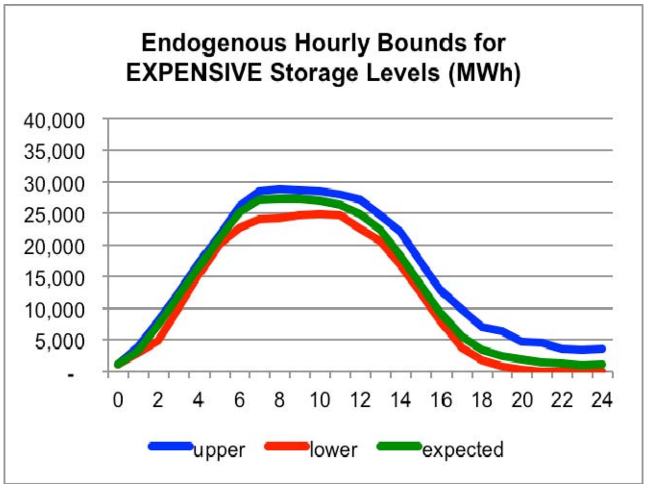

Figure 4: The Endogenous Bounds on the Hourly Energy Stored with Expensive DD

(12% of the daily potential rather the 8%). However, both cases, with ramping reserves that are inexpensive or expensive, reduce the maximum amount of conventional capacity needed to meet the peak demand by similar amounts.

If an equivalent amount of Energy Storage System (ESS) is collocated at wind sites instead of the DD at load centers, the reductions of Generation Costs, Ramping Costs and Capital Costs of Conventional Generation compared to the case with no storage are all slightly larger than they are with DD. However, with both DD and ESS, the reductions of Capital Costs are the most important and account for 74% and 72% of the total reduction for DD and ESS, respectively. Although it is well known that customers with DD should pay dynamic (e.g. real-time) prices for purchasing energy, or time-of-use rates as a rough approximation, to benefit from day/night price arbitrage, structuring their payments to recognize their contributions to reducing the system costs of capital and ramping correctly is not straightforward and not reflected at all well by current rate structures.

A very important barrier to adopting DD is that the current structure of the retail rates, in particular, does not reflect the correct economic incentives for customers. The following three modifications to current rate structures should be implemented.

1) Incentives for day/night price arbitrage: if customers only pay flat rates for energy, then non-adopters of DD would be free loaders and pay lower bills than the adopters because the latter have to cover storage inefficiencies to get the same amount of energy services delivered. Dynamic or real-time pricing is essential to provide the correct economic incentives for day/night price arbitrage and reward adopters and penalize non-adopters.

2) Incentives for reducing the peak system load: most customers do not pay a demand charge at all, and when their level of demand is measured with a traditional meter, this level is the maximum demand over a billing period even if it occurs at night when the system load is low. If customers are to get the correct economic benefit from reducing their demand at the peak system load, they or an aggregator should pay for their actual demand during peak load periods.

3) Incentives for providing ramping services: even though the FERC has opened the door to allowing demand response to participate in markets for ancillary services, at this time, state regulators in most states have not shown much initiative in designing more appropriate rate structures for customers who provide ramping services. One exception is the current initiative taken by the CAISO to establish new forms of payment for providing “flexible ramping products” that mitigate wind variability. Our current view is that DD should be metered separately from non-deferrable demand to measure the ramping services delivered and make it easier for customers or aggregators to participate directly in ramping markets.

Our analysis shows the important potential benefits of using DD to reduce system costs. However, unless the economic incentives for demand-side participation change to reflect the true system costs and benefits, it seems unlikely that customers will appreciate the potential economic benefits of the smart grid, and the utility industry will continue to depend on supply-side solutions for problems and assume that regulators will ensure that customers pay the cost in their bills.

Conclusions

Low-cost, high-capacity and rapid-release storage can be of tremendous value to both the supply side and the demand side of electricity production, delivery, and use. There are several technologies on the horizon that promise to be useful in the myriad of applications such as frequency control, regulation of economical, renewable, but uncertain sources such as wind, elimination of costly conventional unit ramp, and implementing deferrable demand among others. How the system evolves will likely hinge on which technologies become the most economical at an appropriate scale first. What is essential, both to have these emerging technologies used most effectively and to spur the most economical innovations are to get the pricing of systems-services correct ahead of time. Only then can generators and consumers truly reveal what they want and are willing to pay for.

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